Orion

Customised Price-Quality Path Main Proposal

About this regulatory proposal

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

Orion is an electricity distributor. We deliver power from the national grid to homes and businesses across Central Waitaha Canterbury.

We build, maintain and upgrade our network – including substations, poles, overhead conductors, and underground cables – to provide a safe, reliable and resilient electricity supply, now and into the future.

The revenue we earn, and the quality of service we deliver, are regulated by the Commerce Commission, through a price-quality path, which sets the maximum price we can charge and the minimum quality standards we must deliver in each regulatory period. Most electricity distributors operate under default price-path settings set by the Commission. A customised price-quality path (CPP) allows a distributor to seek tailored price and quality standard settings where its specific circumstances justify a step change in investment.

This document is our CPP proposal for the period 1 April 2027 to 31 March 2032 (FY28–32). It outlines the information the Commission needs to make that determination for this period. Detailed analysis, modelling and supporting evidence are provided in our full CPP application and our Asset Management Plan 2026.

Our proposal has been shaped by engagement with customers, service delivery partners and other stakeholders. It supports the delivery of safe and reliable electricity services, responds to population and demand growth, strengthens resilience, prepares the network for future energy needs, and improves efficiency and capability.

We welcome feedback from customers and stakeholders through the Commission's consultation processes.

Executive Summary

Executive summary

1 Orion New Zealand Limited (Orion) is applying for a customised price-quality path (CPP) for the 5-year period from 1 April 2027 to 31 March 2032 (FY28–32).

2 We consider that the default price-quality path (DPP4) does not adequately reflect Orion's circumstances or provide for the level and profile of investment required to meet our regulatory obligations and customer expectations including future network needs.

3 We are seeking approval for total expenditure of $1.51 billion over the CPP period to deliver the investment required to respond to these circumstances and promote the long-term benefit of consumers.

4 This proposal outlines why a CPP is required, how our CPP plan has been developed and tested, and how it delivers prudent and efficient investment aligned with customers priorities and expectations. It is supported by our Asset Management Plan 2026, and the documents that comprise our CPP application.

5 The Commission will assess the CPP application in accordance with its statutory process, including consultation with customers and stakeholders. Information on how to participate in this process will be made available on the Commission's website. Its final decisions on our application will be made in early 2027.

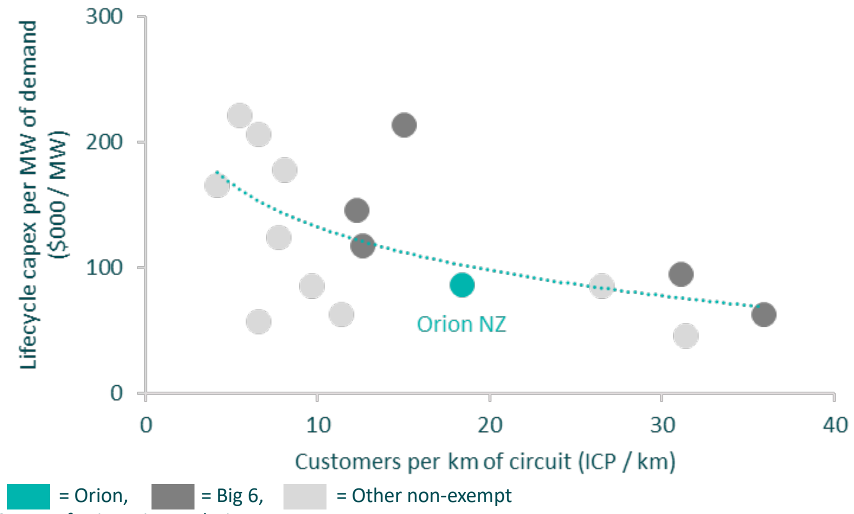
Our circumstances necessitate a step change in investment and capability

6 Orion is operating in a period of sustained change, shaped by both legacy and emerging circumstances that together require a step change in investment and capability.

7 The 2010-11 Canterbury earthquakes have impacted our expenditure profile over the past decade. Significant investment was required to restore the network and support recovery, enabled by our FY15–19 CPP. However, to manage price impacts for customers, we deferred some expenditure during this period, including non-critical asset renewal and maintenance activity. In the subsequent DPP period, the post-earthquake rebuild drove higher than expected growth in our region, making it prudent to direct investment toward network expansion to support this growth, necessitating further deferral.

8 The impact of these historical circumstances is illustrated in Figure 1, which shows that our recent renewal investment has been below our peers over the last 5 years.

Figure 1 Lifecycle capex per MW by customer density (average 2021–25)



Source: farrierswier analysis

9 Looking forward, our operating environment is becoming more complex and customer expectations are changing. We face ongoing seismic risk, and increasing exposure to severe weather events due to climate change. Greater awareness of these risks, shaped by recent experience of their impacts, is lifting expectations for network resilience and preparedness across New Zealand and in the electricity sector.

10 Continuing strong population and demand growth across parts of Central Waitaha Canterbury is driving the need for ongoing network expansion and reinforcement, particularly in rapidly growing towns such as Lincoln and Rolleston.

11 At the same time, the transition to a low-carbon energy system is changing how the network is used and managed, with increasing uptake of distributed energy resources (DER) introducing new operational complexity and capability requirements. Managing these changes requires modern systems and enhanced organisational capability to efficiently plan and operate an increasingly complex network.

12 We have a long-standing history of successful demand-side load management to flatten network peak demand and reduce the need to invest in network capacity upgrades. Independent analysis found this has delivered cost savings of deferred transmission investment of approximately $11 million per annum, since 2021 for the Upper South Island. We will continue to refine our time-of-use pricing to influence the timing of customer electricity use and thereby reduce the impact of strong growth and electrification on the network. Our plan also seeks to utilise non-network solutions such as solar and battery storage to defer or avoid expenditure in network capacity upgrades. Despite the above initiatives, strong regional growth requires us to expand the network into new subdivisions, make new connections to the existing network and upgrade the network where underlying growth exceeds the capability of demand-side management and non-network solutions.

A CPP is required to maintain performance and meet future needs

13 Orion's strategy (Figure 2) is designed to respond to these circumstances. A CPP enables the strategy to be delivered by aligning expenditure, prices and service outcomes with Orion's circumstances and customer expectations, and to promote the long-term benefit of consumers.

Figure 2 The Orion Group strategy

14 These circumstances give rise to a set of clear and interrelated investment needs that must be addressed to maintain current service levels and meet future requirements. Together, they require a step change in investment across 5 strategic priorities:

- **Maintain safety and reliability by increasing asset renewal and maintenance activity** Several asset fleets are in degraded or deteriorating condition due to their age profile, while others face elevated risk due to known model or design issues. As outlined above, some non-critical renewal and maintenance work was deferred to prioritise more urgent and critical assets, consistent with prudent asset management. This deferred work now needs to be addressed, alongside emerging renewal requirements identified through improved asset information and management tools.

- **Support population and demand growth by expanding and upgrading the network at emerging constraint points.** Strong population growth and urban development in Central Waitaha Canterbury is forecast to continue for many years. Over the CPP period, we expect this to drive around 4,400 additional connection requests per annum and increase peak demand on the network by 16.5%, net of customer owned generation and storage. Ongoing investment in new connections, zone substations and network reinforcement is required to meet this demand while maintaining security of supply across the network.
- **Strengthen resilience to earthquakes and increasingly severe weather events by upgrading at-risk assets and expanding vegetation management activities.** Natural hazards can cause substantial damage to electricity networks, leading to widespread and prolonged outages, and causing major disruption for households, businesses and the wider economy. The network is not considered to be sufficiently resilient to withstand an Alpine Fault or other major seismic event. Targeted investment and additional operating expenditure are required to build the resilience of underground and overhead assets particularly exposed to seismic and climate risk, and ensure compliance with further proposed amendments to the *Electricity (Hazards from Trees) Regulations 2003.*[1]
- **Prepare for future energy needs by investigating, piloting and implementing new assets, systems and processes.** Like other distribution networks, Orion has a critical role in supporting the energy transition and decarbonisation. We are committed to supporting and enabling customers who choose to adopt DER – such as electric vehicles, solar PV and batteries – to gain greater control of their energy bills and to achieve greater utilisation of the network. To do this, the network must evolve to operate in a more dynamic, decentralised environment. Investment is required to enable DER and low-carbon technology connections at greater scale and pace, and increase the use of demand-side flexibility, microgrids and other non-network solutions to manage peak demand and defer capital-intensive network upgrades.
- **Enhance efficiency and capability by completing the transition to a modern, resilient and fit-for-purpose information and communication technology (ICT) environment.** Following earthquake recovery and the COVID-19 period, several of our core ICT systems became outdated, and in some cases, would ultimately become unsupported by vendors. Independent reviews by specialist consultants confirmed that, without significant renewal or replacement, these systems would not support Orion's future business needs. With most of the programme already delivered, investment is required to complete the transition and support improved asset management capability, cyber resilience and customer service, and enable further efficiency gains over time.

15 Overall, deferring the additional CPP investment would not be prudent or efficient. Delays would increase total costs over time, leading to greater future price impacts and poorer outcomes for customers and the Central Waitaha Canterbury region.

[1] At the time of publication, proposed amendments to the Electricity (Hazards from Trees) Regulations have been developed. While subject to finalisation and gazettal, they provide a clear indication of the expected future requirements on EDBs.

A rigorous multi-stage process underpins our plan

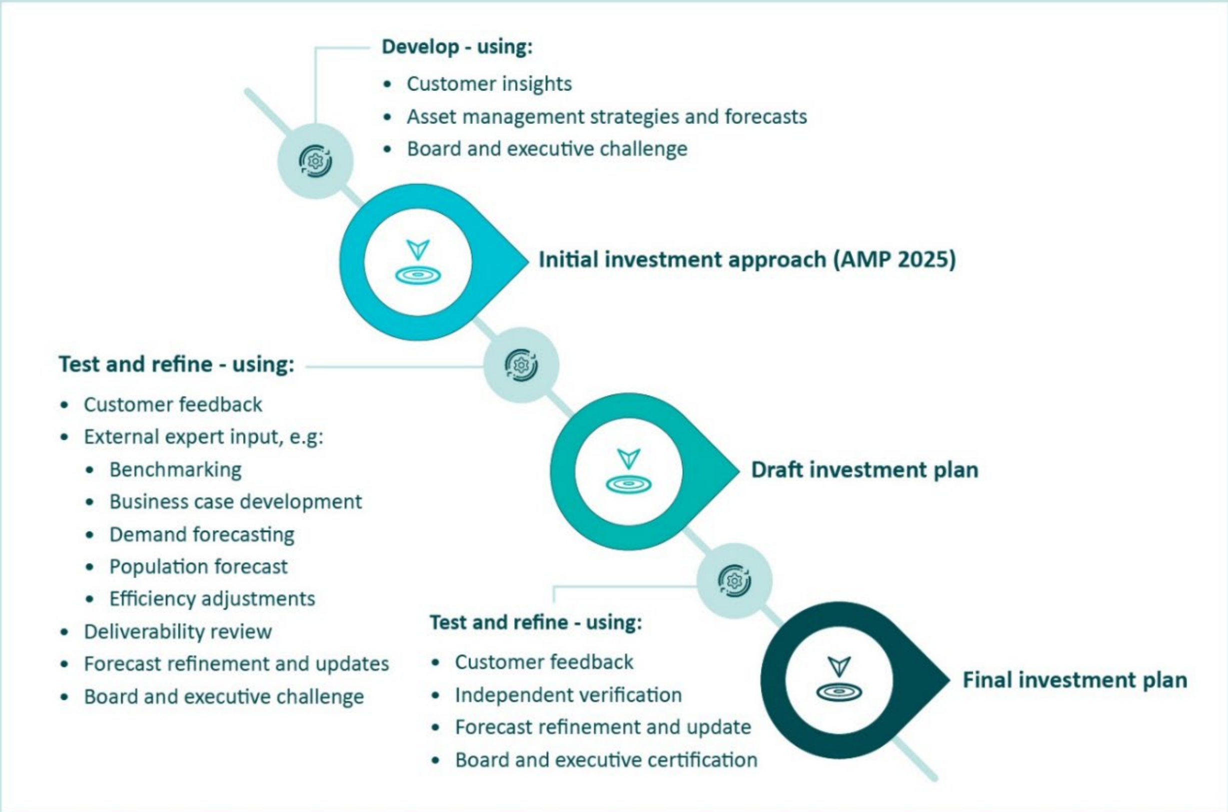
16 We undertook a rigorous, structured process to develop and test the CPP plan, progressing from an initial investment approach through to a draft plan and final plan (Figure 3).

17 At each iteration, the plan and supporting forecasts were tested and refined through multiple rounds of customer and stakeholder engagement, structured Board and executive review and challenge, and input from internal and external subject matter experts.

18 External expert input was used to strengthen and validate key elements of the plan. For example, we engaged consultants to assist us with benchmarking, business case development, demand and population forecasting, and financial modelling. The draft plan and supporting materials were then subject to independent verification, independent audit, and further internal review and challenge.

19 Feedback from each stage was used to refine the investment programme and supporting evidence, resulting in a well-tested, evidence-based plan that reflects customer priorities, is supported by robust analysis, and has been comprehensively tested through internal and external scrutiny.

Figure 3 Summary of Orion's CPP plan development process



Customer feedback has informed its development

20 We implemented a comprehensive, multi-channel engagement programme to inform the development of our CPP plan and ensure it reflects customer and stakeholder preferences and priorities. We built on our established customer engagement programme and drew on recognised good practice, including the IAP2 Spectrum of Public Participation[2] and insights from other CPP applications, and similar regulatory processes in New Zealand and Australia.[3]

21 Engagement occurred over multiple phases between August 2024 and April 2026 and used a mix of direct and participatory methods. This approach enabled informed feedback on complex investment choices, supported by testing of alternative options reflecting different trade-offs between price and service outcomes. It also ensured a wide range of perspectives were heard and considered.

22 Across this engagement, the feedback was clear and consistent:

- customers expressed high satisfaction with the current levels of safety and reliability and identified maintaining these levels is a top priority, particularly in the context of growth, electrification, and increasing climate and natural-hazard risks
- strengthening network resilience is also a key priority, with strong support for targeted investment in high-risk assets
- stakeholders expect the network to keep pace with population and demand growth to support regional and economic growth
- customers also indicated support for a strategic and measured approach to enabling new technologies and non-network solutions.

23 In addition, customers consistently identified affordability as their primary concern. Feedback emphasised the importance of avoiding price shocks, while indicating some tolerance for moderate, well-signalled price increases where clear benefits are demonstrated, particularly investments in maintaining reliability and building resilience.

Feedback and scrutiny have refined the plan

24 Both the scale and composition of our CPP plan have been shaped by the feedback we received in testing and validating the plan, including customer engagement.

25 For example, feedback on our initial investment approach directly influenced the overall scale of planned investment, by confirming that the option that balanced trade-offs between price and service levels was consistent with customer preferences. As a result, we did not pursue the alternative options we consulted on in our Asset Management Plan Update 2025, which included an accelerated option with higher price impacts and a limited option with higher long-term risks.

26 Importantly, our final plan reflects what customers told us matters most – maintaining current safety and reliability levels, strengthening resilience to mitigate the risk of prolonged outages after major seismic or weather events, keeping pace with growth to support regional development without overbuilding, preparing for the future while avoiding the risks around early adoption, while focusing on efficiency to keep prices as low as possible.

27 In addition, we adjusted the scope and timing of selected investments to reflect improved inputs, updated analysis, the independent verifier, and our Board and executive. We also

[2] See IAP2 Spectrum of Public Participation — Engagement Institute

[3] Including the recent engagement approaches adopted by Aurora Energy, Powerco and Transpower in New Zealand, and Ausgrid and Endeavour Energy in Australia.

incorporating efficiency assumptions into our largest non-network operating expenditure portfolios.

28 Overall, we reduced the total forecast expenditure under the CPP plan relative to the initial investment approach by $228 million or 13%. This has reduced total planned investment from $1.79 billion to $1.51 billion. The key capital expenditure (capex) changes we made in response to customer feedback and other input are summarised in Table 1.

Table 1 Summary of key changes to CPP capex ($m, FY26 constant)

Feedback or driver	Our response
Customers expressed strong support for our proposed $24 million renewal of poles at-risk of wildfire and landslip damage. The independent verifier found that the need for and benefit of this investment had not been justified	Rescoped programme to address wildfire risk poles only. We have deferred the landslip risk pole remediation to further investigate methods to manage landslip risk **Overall reduction over CPP period: $15 million**
Customers recognised the need for LV reinforcement, and generally preferred the option included in the draft plan, which assumed high demand growth and very cold winter conditions The independent verifier found the growth assumptions underlying the draft LV reinforcement programme were overly risk-averse, and recommended programme optimisation to reflect benefits from planned investments in network transformation and an integrated asset management system	In response to customer concerns about affordability and the verifier's findings, we adjusted the LV reinforcement programme from a high to a medium demand forecast, and included a small provision to reinforce high growth areas We also refined the programme to account for the introduction of advanced voltage management of the LV network **Overall reduction over CPP period: $16.9 million**
The independent verifier recommended monitoring the Electricity Authority's ongoing distribution connection pricing reform process to ensure forecast customer contributions capex reflects the new connection pricing methodology rules expected to be finalised in April 2026	We adjusted customer contribution settings to align with the connection pricing methodology rules, increasing new customers' contribution to the cost of their connection, and helping ensure that existing customers do not subsidise the connection of new customers **Overall reduction over CPP period: $9 million**
Internal review of risks and timing of major projects	We removed growth projects from the CPP programme where timing remains uncertain, and will utilise CPP reopener processes if projects need to be reintroduced **Overall reduction over CPP period: $32.4 million**
Internal review of draft asset renewals programme	We refined our renewal investments by updating unit rates, reprioritising work programmes, and refining the scope and timing of programmes. This led to an overall reduction across the programmes. **Overall reduction over CPP period: $16.8 million**
Internal review of draft RSE programme	We reduced RSE investment by reprioritising scope and timing of initiatives and updating unit rates. **Overall reduction over CPP period: $17.5 million**

Our CPP plan delivers targeted customer outcomes aligned to strategic priorities

29 Our CPP plan is summarised in the infographic at the end of this executive summary. The planned expenditure is targeted to deliver clear customer outcomes aligned with the strategic priorities outlined in paragraph 14, and ensure sufficient organisational capacity and capability to deliver the programme efficiently and effectively.

30 Capital expenditure is concentrated in areas that deliver the best outcomes for customers, including increased asset renewal activity, targeted resilience programmes, and network upgrades to keep pace with forecast growth in population and peak demand.

31 Operating expenditure also increases to support increase maintenance activity, expanded vegetation management, and enhanced capability to manage a more complex and dynamic network.

32 These investments build on the strong foundations established in recent regulatory periods and are focused on maintaining current service levels while positioning the network to meet future needs, consistent with customer priorities and long-term interests.

33 Over the CPP period, we plan to invest a total of $1.51 billion, comprising $932 million in capex and $578 million in operating expenditure (opex). This level of investment is approximately $260m, or 20%, above our related allowances under DPP4 and expected DPP5 levels, reflecting the step change in investment required (Figures 5 and 6).

Figure 5 Orion's planned capex compared with forecast capex under DPP4

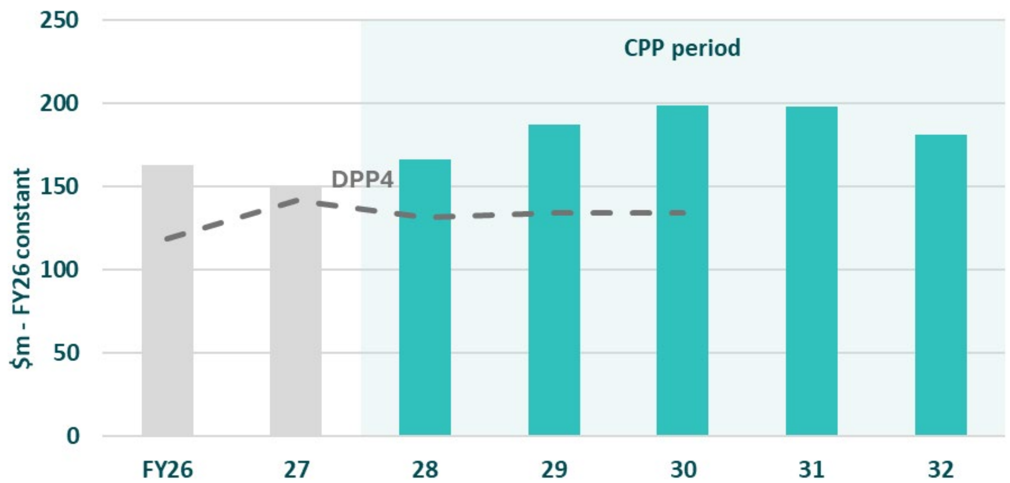
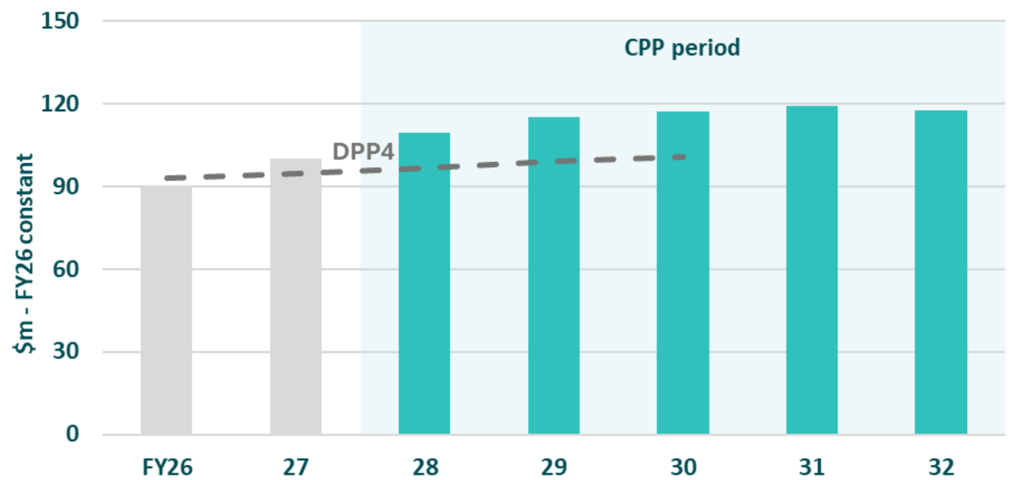


Figure 6 Orion's planned opex compared with forecast opex under DPP4



Anticipated price impacts

34 Following the Commission's determination, Orion will set lines charges reflecting approved levels of revenue. Electricity retailers will determine how these charges are reflected in the tariffs paid by end consumers.

35 To illustrate the expected price impacts, we have estimated the effect of the CPP plan on the distribution component of monthly electricity bills for a typical residential and small business customer for each year of the CPP period.

36 As Table 2 shows, we expect the distribution component of a typical residential customer bill to be around an average of $4 per month higher under our CPP plan, than if we remained on a default pathway. This is lower than the price impacts we consulted on as part of our initial investment approach, which were around $8 per month, and also lower than the $6.50 per month indicated in our draft CPP investment plan consultation.

Table 2 Estimated impact on the distribution component of monthly electricity bills for typical customers ($ nominal)

Indicative distribution revenue (average / month)[4]	FY28	FY29	FY30	FY31	FY32	CPP period average
Under our proposed CPP						
Residential	72	74	81	88	94	**82**
Small Business	84	86	94	102	110	**95**
If we stayed on the DPP						
Residential	68	73	82	84	85	**78**
Small Business	79	85	95	98	99	**91**
Difference resulting from our CPP						
Residential	4	1	-1	4	9	**4**
Small Business	5	2	-1	4	11	**4**

37 We consider the price impacts of our final CPP plan are broadly consistent with customers' willingness to pay:

- as outlined above, the price impacts under our initial investment approach and draft plan where higher than those under our final plan
- feedback through our engagement on these earlier versions of our plan indicated a tolerance for moderate price increases where clear benefits were demonstrated, particularly where investment supported maintaining reliability and improving resilience
- customers also expressed a strong preference for smooth price increases that avoid price shocks, and we have smoothed our planned revenues over the CPP period to reflect this preference.

38 Acknowledging customers' concerns about affordability, we recognise that a CPP will result in higher lines charges over the coming years and are mindful of the importance of an affordable electricity supply. However, we consider that a CPP over FY28–32 best promotes the long-term interests of customers.

[4] Excludes transmission charges passed through in distribution lines charges, and all other costs that make up a customer's bill from their retailer. Actual impacts for individual customers will vary depending on their electricity consumption, tariff structure, and retailer pricing decisions.

The plan is deliverable with capacity and capability in place

39 We have assessed the deliverability of the CPP programme, focusing on our service delivery partner (SDP) capacity, materials and equipment supply, and internal capability and governance. The findings, together with our strong delivery track record and established service delivery model, indicate that the programme can be delivered over the 5-year CPP period.

40 In particular, we undertook analysis in collaboration with our SDPs confirming that sufficient Christchurch-based field resources are available to Orion to deliver projected work volumes over that period. SDPs also confirmed they are willing and able to scale up resources (including by drawing on regional capacity) if required due to unforeseen circumstances. A phased ramp-up approach to delivery will ensure their workloads increase at a manageable rate.

41 In addition, we have secure supply arrangements in place, including long-term supplier agreements, maintained inventories, and through active monitoring of supply chain risks. We will complement this with targeted enhancements to our internal capacity and capability, including scaling our core delivery teams in line with our physical works volumes and strengthening our investment governance.

42 Taken together, these measures provide confidence that the CPP plan can be delivered safely and efficiently without compromising service quality, a conclusion supported by the independent verifier.00

Service quality and reporting arrangements support accountability

43 As outlined above, our CPP engagement found that customers are satisfied with current levels of reliability and they identified maintaining these levels as a top priority. Consistent with this, and our objectives over the CPP period, we do not propose a quality standard variation. The Commerce Commission will set our quality standards and incentives as part of its CPP Determination.

44 In addition, we will track and report on 26 service measures across key service attributes, including reliability and resilience, safety, customer service, power quality, environmental impact, efficiency and network planning, and support for the energy transition. These comprise 13 established measures as well as 13 new measures that extend performance monitoring into areas of increasing importance to customers.

45 To support transparency, we will publish an Annual Delivery Report that brings together information on expenditure, outputs and outcomes over the CPP period, enabling stakeholders to assess delivery against the CPP plan and customer priorities, and to understand any material changes over time.

46 Together, these quality standards, service measures and reporting arrangements provide a robust and proportionate framework for informing stakeholders about our performance over the CPP period.

The CPP plan is robust and aligned with customer expectations

47 Overall, our CPP plan provides a coherent and well-evidenced response to the challenges and opportunities facing our network. It will deliver a balanced package of investment, service outcomes and price impacts that reflects customer preferences that will deliver long-term benefits for consumers. Table 3 summarises how the proposal aligns with key considerations and where supporting evidence is provided.

Table 3 Alignment of the CPP plan with key considerations and supporting evidence

Key considerations	How the proposal aligns	Key evidence and related approaches	Supporting chapters
Long-term benefit of consumers	Delivers a balanced package of cost and outcomes aligned with customer priorities and expectations	Customer engagement, assessment of cost–outcome trade-offs and willingness to pay, and long-term network planning	Chapters 2, 3
Customer preferences and willingness to pay	Reflects customer feedback obtained through comprehensive, multi-stage engagement programme	Customer engagement, consultation on investment options, and incorporation of feedback into the proposal	Chapter 3
Deliverability	Demonstrates deliverability based on assessment of SDP capacity, supply chain arrangements, and internal capability and governance	SDP capacity modelling, phased delivery approach, supply chain arrangements, and organisational capability enhancements	Chapter 4
Risks and uncertainty management	Outlines key assumptions and limitations underpinning forecasts and outlines how risks are managed. Where investment timing or scope remains uncertain, projects are designated as contingent or nascent rather than included in the base forecast	Contingent and nascent project classifications, options analysis, and risk analysis and management processes	Chapters 5-13
Prudent and efficient expenditure	Reflects disciplined, bottom-up forecasting from an efficient baseline, supported by market-tested cost inputs, benchmarking, and strong governance over scope, timing and delivery	Bottom-up forecasting, top-down efficiency adjustments where appropriate, asset condition and risk analysis, demand and connection growth forecasts, cost estimation, options analysis, unit rate reviews, benchmarking and independent verification	Chapters 5-13
Alignment of expenditure, outputs and outcomes	Provides clear line of sight between expenditure, outputs and expected customer outcomes, aligned with CPP strategic priorities	Plan structure is aligned to strategic priorities, supported by service measures and performance reporting	Chapters 2, 513, 15
Pricing and revenue	Determined in accordance with the IMs, reflecting efficient cost of delivering the proposed services	Application of IMs, financial modelling and cost allocation	Chapter 14
Quality standards	Does not propose quality standard variation, reflecting customer expectations for no change in reliability and expected performance	Customer engagement, historical and forecast reliability performance	Chapter 15
Visibility of delivery performance	Proposes annual delivery report (ADR) to provide enhanced visibility of CPP delivery and facilitate stakeholder assessment	Proposed ADR role and measures	Chapter 16

Our CPP plan at a glance

Planned expenditure	Strategic priority area	Investment focus areas	Customer outcomes
$710m	Maintain safety & reliability	• Lift asset renewals to address ageing fleets and past deferrals • Upgrade critical zone substations • Expand preventive and corrective maintenance • Target local safety and supply quality risks	• Reliable supply with outages maintained at current levels • Reduced risk of major outages • Improve reliability of supply in localised areas
$282m	Support population & demand growth	• Deliver major capacity and system growth projects • Reinforce 11 kV network and clear backlog constraints • Shift to proactive LV reinforcement • Connect over 4,400 new customers per year	• Capacity to support growth and economic activity • Timely, reliable new connections • Electrification enabled through a mix of increased network utilisation and upgrades
$78m	Strengthen resilience	• Replace ageing subtransmission cables and reconfigure network • Increase vegetation management • Replace poles in high wildfire risk areas • Establish emergency fuel storage	• Faster restoration following disruptions • Reduced risk of widespread outages • Improved performance during extreme weather events
$34m	Prepare for future needs	• Improve network visibility, data and analytics • Enable flexible connections and active network management • Deploy non-network solutions (e.g. batteries, demand response) • Support low-carbon technologies and DER integration	• Easier uptake of EVs, solar and batteries • Reliable network as demand patterns evolve • Lower long-term costs from increased network utilisation
$106m	Enhance efficiency & capacity	• Complete transition to modern ICT and data platforms • Enhance operational technology and automation • Expand analytics and AI capability • Strengthen cybersecurity and digital services	• Faster restoration and more responsive service • Better investment decisions and network performance
$300m	More efficient operations supporting lower long-term costs	• Expand workforce and delivery capacity • Build capability in advanced planning, risk and digital operations • Upskill workforce and address emerging capability gaps • Provide facilities and resources to support programme delivery	• Timely delivery of investment programme • Efficient delivery supporting value for money

Total investment of $1.51 billion to deliver a safe, reliable, efficient, and future-ready network that meets customer and community expectations and serves their long-term interests.

1

1 About Orion

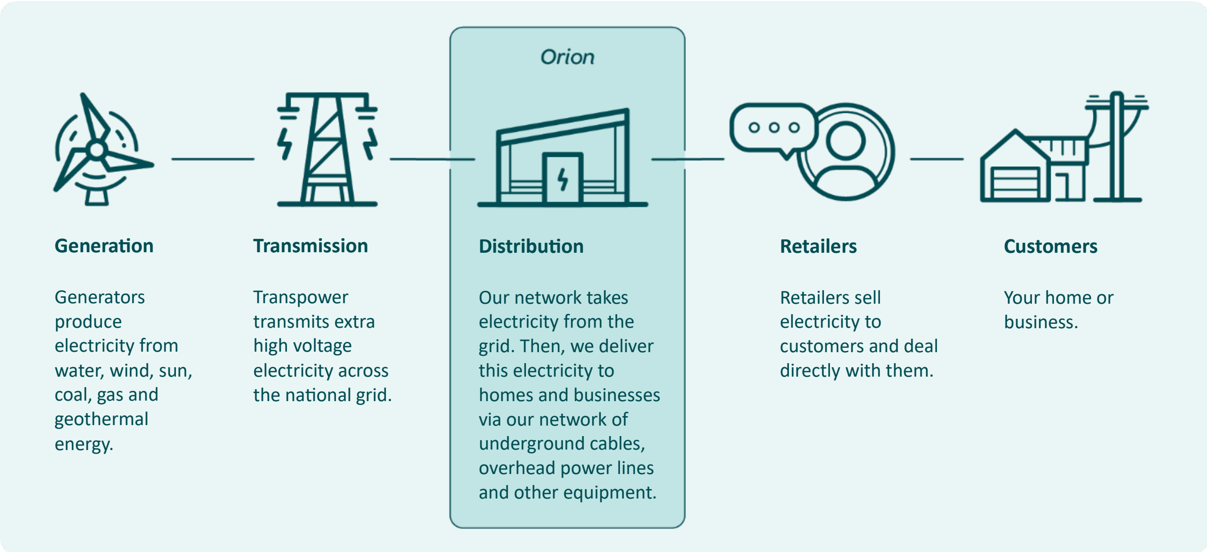
48 Orion New Zealand Limited (Orion) is New Zealand's third-largest electricity distribution business (EDB). We deliver electricity from the national grid to homes and businesses across Central Waitaha Canterbury in the South Island (Figure 1.1). We also increasingly receive electricity from customers – such as from solar photovoltaic and battery systems – which is exported back into our network.

49 We own and operate an electricity distribution network comprising substations, poles, powerlines, underground cables, and associated equipment. Operating this network requires significant capital investment to build, upgrade and extend it, as well as operating expenditure to inspect and maintain assets and run the business day-to-day.

50 Our network is in one of the country's fastest growing regions, with both customer numbers and demand continuing to increase.

51 The following sections summarise our ownership, governance and purpose, regulatory framework, network area and customers, and network assets.

Figure 1.1: Orion's role in New Zealand's energy system



1.1 Our ownership, governance and purpose

52 Orion is a community-owned limited company with 2 shareholders:

- **Christchurch City Council**, through Christchurch City Holdings Ltd (approximately 89%)
- **Selwyn District Council** (approximately 11%).

53 Under Section 36 of the *Energy Companies Act 1992*, our principal objective is to operate as a successful business. We achieve this by balancing the interests of our shareholders, our community, and electricity consumers.

54 Orion is governed by a Board of Directors appointed by our shareholders. The Board sets our strategy and objectives, monitors performance, and oversees the overall direction of the business.

55 We are committed to delivering a safe, reliable, resilient network that supports our community and the long-term interests of consumers. This is reflected in our strategic focus on maintaining service quality, keeping the network utilised and accessible, and supporting our community through the energy transition.

56 These priorities are brought together in the Orion Group strategy (Figure 1.2).

Figure 1.2 The Orion Group strategy

57 Orion has a fully owned subsidiary, Connetics Limited (Connetics). Together, Orion and Connetics make up the Orion Group.

58 Connetics is operationally and financially ring-fenced from our regulated electricity distribution business. Our transactions are conducted on an arm's-length basis, and only costs attributable to regulated services are recovered through Orion's regulated revenues. Connetics operates as one of our service delivery partners; it also provides services to other electricity distribution businesses and third parties outside of our network region.

1.2 Our regulatory framework

59 Orion is subject to price-quality regulation under Part 4 of the *Commerce Act 1986*. The Commerce Commission (the Commission) determines the maximum revenue we can recover through lines charges for our services, 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.

60 The Commission can set 2 types of price-quality path for EDBs: a default price-quality path (DPP), or a customised price-quality path (CPP). DPPs are set using a low-cost, standardised approach and are intended to reflect the efficient costs of a typical New Zealand EDB. CPPs are set through a more detailed and rigorous assessment process, allowing the specific circumstances, risks, and expenditure needs of an individual EDB to be considered. 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.

61 Orion has been subject to a DPP for the past 7 years. Prior to this, we were granted a 5-year CPP in 2013, for the period FY15–19, to address the impacts of the 2010–2011 Canterbury earthquakes. At the end of that period, we transitioned back onto a default path. We are currently on DPP4, which came into effect on 1 April 2025 and applies until 31 March 2030.

1.3 Our network area and customers

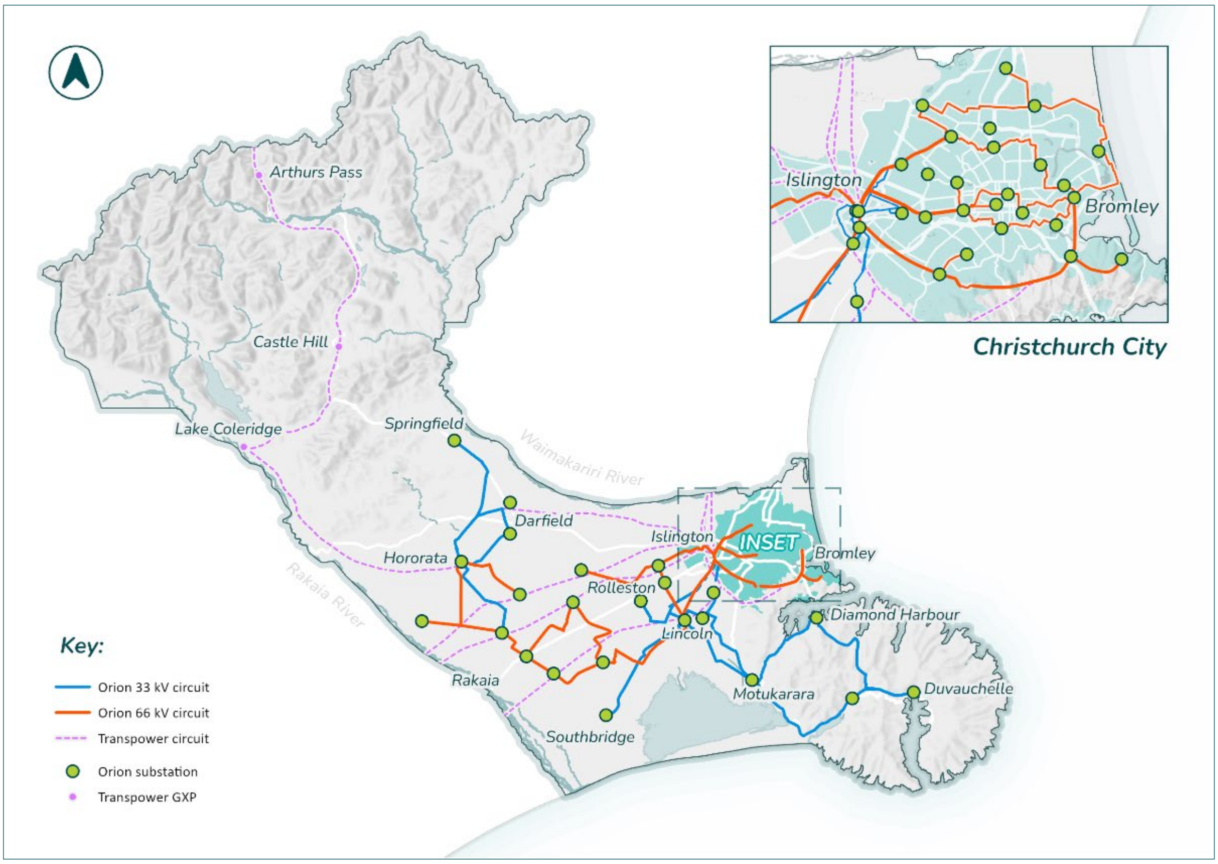
62 Our network area spans more than 8,000 square kilometres, from the Banks Peninsula in the south to Arthurs Pass in the north, and from the Rakaia River in the west to the Waimakariri River in the east (Figure 1.3). It includes 2 distinct geographical regions:

- **Ōtautahi Christchurch and its suburbs**, representing around 6% of our physical network area and 83% of customer connections.

- **Selwyn District and Banks Peninsula**, including fast-growing towns such as Lincoln and Rolleston, as well as rural and high-country areas, representing around 94% of our network area and 17% of connections.

63 All consumers connected to the national grid within our network footprint are supplied through our network and pay our lines charges, although their retailer manages the customer relationship.

Figure 1.3: Orion's network area



64 We supply electricity to more than 235,000 homes and businesses across our network, and this number is expected to grow strongly over the CPP period (see Chapter 2). Our customer base reflects the diversity of our network area and includes:

- residential customers in urban Christchurch, growing townships, peri-urban areas, and rural communities
- business and industrial customers across sectors such as technology, manufacturing, construction, tourism, retail, agriculture, and food processing
- education, research, healthcare and other public service facilities
- major infrastructure, including an airport and seaport.

1.4 Our network

65 Our network comprises:

- **52 zone substations,** transforming electricity from the transmission network and providing switching and protection
- more than **12,000 distribution transformers** supplying local areas
- more than **86,000 power poles** supporting overhead lines and crossarms and maintaining network integrity
- more than **12,000 kilometres of overhead conductors and underground cables** delivering electricity to customers.

66 Further information about Orion is provided in Asset Management Plan 2026 – Section 3 Who we are, and is available on our website.

67 Information on our current operating context is provided in Chapter 2 of this main proposal.

2

2 Why we are seeking a CPP

68 Orion New Zealand Limited (Orion) is applying for a customised price-quality path (CPP) for the 5-year period from 1 April 2027 to 31 March 2032 (FY28–32).

69 The default price-quality path (DPP4) does not adequately reflect Orion's circumstances or support the level and timing of investment required. We are seeking a CPP to progress 5 strategic priorities necessary to maintain our current service levels and meet future needs.

70 Remaining on DPP4 would require deferral of essential investment in core assets and delay discretionary but high-value investment that supports these priorities and delivers long-term benefits. This would not be prudent or efficient, and would not be in the long-term interests of customers. Over time, it would lead to outcomes inconsistent with customers' stated preferences and expectations.

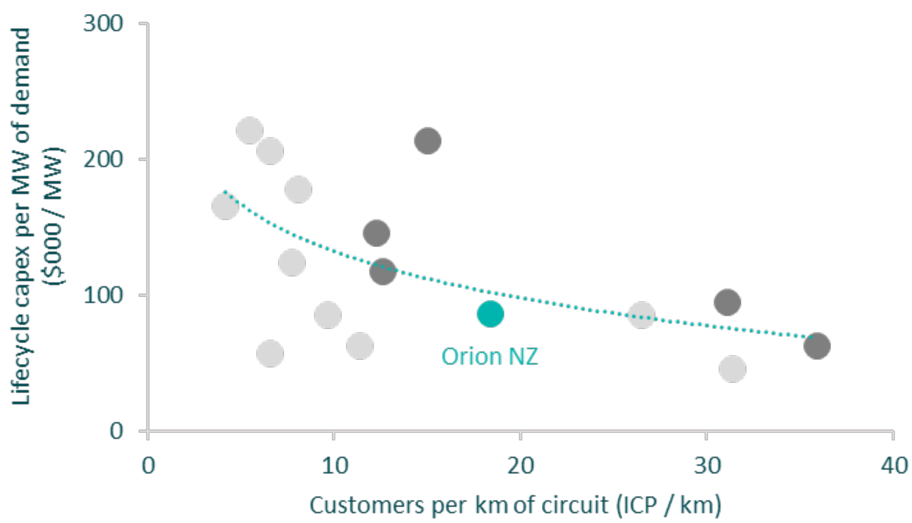
2.1 Our circumstances

71 Orion is operating in a period of sustained change, shaped by both legacy and emerging circumstances that together require a step change in investment and capability.

72 The 2010-11 Canterbury earthquakes have had a lasting impact on our historical expenditure, which still influences our network today. 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 DPP period (FY21–25), we prudently prioritised investment in system growth and new connections to accommodate stronger-than-forecast population and demand growth, resulting in further deferral of renewal activity.

73 The impact of these decisions is evident in our recent lifecycle investment profile. As shown in Figure 2.1, our lifecycle capex has been below that of comparable networks over the past 5 years. This position is not sustainable if we are to maintain current levels of safety and reliability.

Figure 2.1 Lifecycle capex per MW by customer density (average 2021–25)



= Orion, = Big 6, = Other non-exempt EDBs

Source: farrierswier analysis

74 Looking forward, our operating environment is becoming more challenging. Central Waitaha Canterbury continues to experience sustained growth, which is forecast to continue at least into the 2050s. In the coming years, strong population growth across Selwyn and Greater Christchurch, combined with ongoing urban development and economic activity, will drive increased demand for new connections and network capacity.

75 Our region also remains exposed to seismic risk, and climate change is increasing the frequency and severity of extreme weather events, including storms, high winds, flooding, and wildfire. These risks are already being experienced across our network, increasing stakeholder and customer expectations for resilience and preparedness.

76 Climate risks are particularly evident in parts of our network, such as the Port Hills and Banks Peninsula, where overhead lines traverse terrain with elevated exposure to wildfire and landslips. Weather events in 2017 and 2024 caused asset damage and supply interruptions, demonstrating the consequences of these risks for customers. More broadly, vegetation-related risk remains a material driver of outages, reflecting the scale of our overhead network and its proximity to trees and shelterbelts.

77 At the same time, the electricity system is undergoing a series of changes. Electrification and decarbonisation are increasing reliance on electricity, while uptake of distributed energy resources (DER) is changing how the network is used and managed. These developments create opportunities to improve network utilisation and defer some traditional investment, while introducing greater planning complexity, new operational risks, and increased capability requirements.

78 Cost pressures have also intensified. Since COVID-19, global supply chain constraints and input cost increases in our sector have outpaced general inflation, increasing the cost of delivering network and information and communication technology (ICT) investment. This reinforces the need for efficient, well-targeted expenditure supported by improved systems and decision-making capability.

79 Together, these factors mean that Orion must increase investment across multiple areas to maintain current service levels and meet future needs. We recognise this means our lines charges will increase over the coming years. We are conscious that this will make things more difficult for customers already facing cost-of-living pressures. But we are convinced that moving to a CPP from FY28 is in customers' long-term interests.

2.2 Our CPP plan drivers

80 In the coming years, Orion will address 5 strategic priorities that are becoming increasingly important to delivering services that our customers value. These priorities reflect the most significant drivers of forecast expenditure over the CPP period and form the basis of our planned investment programmes. They are:

- **Maintaining network safety and reliability levels** by increasing asset renewal and maintenance activity to the levels required to manage the growing risks of our ageing assets
- **Supporting the strong population and demand growth in our network area** by expanding and upgrading the network at emerging constraint points and investing in customer connections
- **Strengthening the network's resilience** to earthquakes and increasingly severe weather events by upgrading at-risk assets and increasing vegetation management
- **Preparing for future energy needs** by investigating, piloting, and implementing new assets, systems and processes to build the capabilities required to plan and operate the network in the changing energy environment

- **Enhancing our efficiency and capability** by completing the transition to a modern, resilient, and fit-for-purpose ICT environment.

2.2.1 Maintaining safety and reliability

81 Orion performs well in terms of network safety. In the years following the 2010-11 Christchurch earthquakes, our reliability performance improved, then stabilised around 2017. Since then, both SAIDI and SAIFI have remained broadly consistent, with typical year-to-year variation reflecting weather conditions and operational factors.

82 Through engagement for this CPP proposal, customers told us they expect this level of performance to be maintained. To do so, we need to increase our asset renewal and maintenance activity.

2.2.1.1 Increase asset renewal activity

83 As assets age, failure risk and reactive maintenance costs increase. Consistent with good asset management practice, Orion aims to renew assets before these risks and costs escalate. This proactive approach is essential for maintaining network safety and reliability, and managing whole-of-life asset costs effectively.[5]

84 Over the CPP period, we plan to increase our levels of renewal investment relative to recent periods. This increase is required to address:

- **Asset condition risk**: several asset fleets are in poor condition or have increased risk due to type issues. The condition of other fleets will deteriorate without sufficient intervention. In some cases, this reflects the fleet's age profile. For example, many overhead assets were installed in the 1960s and 1970s and are now at or nearing the end of their expected lives. In other cases, deterioration reflects historical gaps in asset management approaches or known issues with specific asset models. We need to increase renewals in these fleets to improve or stabilise asset health, which is essential to maintaining safety and reliability.
- **Past deferrals and accumulated backlog**: as noted above, we deferred some non-critical renewals to prioritise more urgent and critical work in line with prudent asset management. In addition, some asset fleets (e.g. overhead distribution conductors) have historically been managed on a largely reactive basis, with no established proactive renewals programmes. As a result, renewal backlogs have accumulated across several asset fleets and must now be addressed to ensure asset health can be effectively managed.
- **Better information and improved asset management tools**: we have recently implemented enhanced asset inspection methods and decision-support tools, including detailed below-ground pole inspections. We will roll out further enhancements over the CPP period, including destructive testing of distribution conductors to inform new proactive renewal programmes. These improvements provide more accurate and timely information on asset condition, supporting more robust renewal forecasting. The resulting analysis to-date indicates that renewal requirements are increasing.
- **Emerging renewals needs**: we expect a large volume of telecommunications poles to be progressively transferred to us over the CPP period. These poles support our crossarms but are no longer required for telecommunications services. We expect a substantial proportion of the transferred poles to require renewal during the CPP period and beyond.

[5] Noting that for some less critical assets, we adopt a reactive approach where we consider this is appropriate.

> ***"We accept that where the network is ageing, Orion should increase expenditure to renew it in a timely fashion, provided that doing so is on balance, through whole-of-life, the least-cost way of maintaining existing levels of service. It is important that Orion's customers aren't competitively or economically disadvantaged by lower levels of network reliability relative to those on other electricity networks."***
>
> Customer Advisory Panel, 2025

2.2.1.2 Increasing maintenance activities

85 Orion undertakes preventive and corrective maintenance, as well as reactive maintenance to manage asset condition and performance. As network assets age, the incidence of defects and condition-related issues increases. Preventive and corrective activities enable us to identify and address defects before they result in safety incidents or unplanned outages. This is critical to maintaining network safety and reliability between renewal cycles and is a key part of effective whole-of-life asset management.

86 Over the CPP period, we plan to increase maintenance activity over current levels. This step-change is driven by:

- **Past deferrals**: to limit the level of overspend relative to the DPP expenditure limits, we deferred non-critical maintenance for some asset classes. This deferral has elevated the risk of asset defects and faults leading to reliability and safety incidents.
- **Improved inspection regimes**: we will introduce new or expanded inspection regimes for selected asset fleets to better identify emerging risks and improve the depth and quality of our asset information. We will also update preventive maintenance practices to align with good industry practice and adopt new techniques.
- **Transferred asset condition risk**: as noted above, ownership of a significant number of telecommunications poles will transfer to Orion. Responsibility for their inspection, maintenance and eventual replacement will transfer to us, increasing maintenance requirements over the CPP period and beyond.

> ***"The power flows uninterrupted, all day and every day – which is all you want from a lines company."***
>
> Customer Perceptions Survey, 2024

2.2.2 Supporting growth

87 Orion's network area is experiencing strong and sustained growth. Selwyn is the fastest-growing district in New Zealand, with average population growth of around 5.5% per annum between 2020 and 2025, compared with around 1% nationally. Across Greater Christchurch, growth is more moderate but higher than the national average.

88 To inform our planning, we commissioned independent population forecasts from Geografia, a consultancy specialising in data-driven economic, demographic, and spatial analysis. These forecasts indicate that this growth is expected to continue to at least 2055.

89 Between 2025 and 2032:

- Selwyn's population is projected to increase by approximately 30,000 (around 4.3% per annum)
- Christchurch's population is projected to increase by approximately 35,000 (around 1.1% per annum).

90 The forecasts were developed using a robust methodology, including benchmarking against official projections from Stats NZ, with differences identified and explained. They were also informed by engagement with local councils, regional agencies, and economic experts to ensure alignment with local development plans and observed growth trends. Overall, the

forecasts are consistent with the scale and spatial distribution of growth identified in local and national planning frameworks. Further detail is provided in Chapter 7.

91 Customers and stakeholders expect the network to have sufficient capacity to support forecast growth while maintaining current levels of reliability and security of supply. Meeting this expectation requires sustained investment in both customer connections and system growth at levels above those of a typical New Zealand EDB.

2.2.2.1 Continue investing more in customer connections

92 Population growth is driving ongoing residential, commercial, and industrial development, increasing demand for new and upgraded network connections. We forecast around 4,400 new connections per year during the CPP period. This includes:

- new homes and businesses in large, mixed-use subdivisions on the fringes of fast-growing towns like Lincoln and Rolleston (including developments such as Earlsbrook and Arbor Green)
- development within existing urban areas in Christchurch, including medium-density townhouses and high-density apartment blocks.

93 We also expect several large industrial customers to decarbonise their operations, increasing load and requiring upgrades to existing connections.

2.2.2.2 Continue investing more in system growth

94 Population growth, urban development, and increased economic activity is driving higher electricity demand. We forecast peak demand to increase by 16.5% over the CPP period, from 718 MW in FY27 to 837 MW in FY32.

95 Supporting this growth requires both expanding the network into new areas and increasing capacity within the existing network. Greenfield development drives expansion, while intensification within established urban areas increases peak loading and utilisation of existing assets. Addressing these impacts requires significant system growth investment over the CPP period, including new zone substations and reinforcement of the low voltage network. We will also continue to pursue non-network solutions to manage peak demand and defer or reduce the scale of capital investment where this is efficient (see section 2.2.4).

> ***"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."***
>
> Business owner, Powerful Conversations, 2024

2.2.3 Strengthening resilience

96 Orion's network is exposed to significant natural hazard risk. Central Waitaha Canterbury lies in a high seismic risk zone and is also vulnerable to large earthquakes associated with the Alpine Fault. Research indicates there is about a 75% probability of an Alpine Fault rupture within the next 50 years, which has historically produced earthquakes of around magnitude 8.[6] In addition, climate change is increasing the frequency and severity of extreme weather events in New Zealand, including storms, flooding and wildfire.[7]

97 These hazards have the potential to cause substantial damage to electricity networks, resulting in widespread and prolonged outages. As demonstrated following the 2010–11 earthquakes, such outages create major disruption for households, businesses and the wider economy. This risk is compounded by the reliance on electricity to support critical services including hospitals,

[6] 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).

[7] For example, see Climate change and possible impacts for New Zealand | Earth Sciences New Zealand | NIWA

emergency services, communications (mobile and internet connectivity) and home medical equipment.

98 Engagement undertaken for this CPP confirms that customers expect a resilient network. They support investment to reduce the likelihood and consequences of major outages and to prepare the network for the impacts of climate change. In response, we are targeting investment in assets most exposed to seismic and climate-related risks, including replacing vulnerable sections of underground and overhead network, and increasing vegetation management to reduce storm-related outages.

2.2.3.1 Replace underground network sections in Christchurch city

99 The 2011 earthquake highlighted vulnerabilities in the underground network supplying Christchurch, particularly its reliance on ageing oil-filled subtransmission cables. These legacy assets were more susceptible to damage from ground movement, resulting in high levels of asset damage. The way they were configured (including installation in common trenches) limited our ability to isolate faults and restore supply efficiently.

100 Since then, we have rebuilt and reconfigured the most heavily damaged sections of the network, including replacing 4 subtransmission cables with modern cable technology that provides improved seismic resilience. New network development has been constructed to this higher standard.

101 However, significant sections of aging oil-filled cable remain in service. While still operational, these assets are approaching end of life and present increasing reliability, environmental, and operational risk. As they supply the central city and inner suburbs, failure would have widespread customer and economic impacts, making the current risk profile unacceptable.

102 We are progressing reconfiguration of the remaining network and replacing oil-filled cables with modern cable systems. We plan to replace 5 cables over the CPP period (with the remainder to be replaced by FY38). This investment will materially improve resilience by reducing vulnerability to seismic damage, eliminating risks associated with oil-filled technology, and enabling faster fault isolation and restoration.

> ***"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."***
>
> Residential customer, Powerful Conversations, 2025

2.2.3.2 Replace poles exposed to elevated wildfire risk

103 Analysis by Fire and Emergency New Zealand[8] has identified elevated wildfire risk across parts of our rural network, including in the Port Hills, Castle Hill, Mt Horrible, and Broadfield. Past fire events in these areas have resulted in damage to network assets. Wooden poles increase ignition risk and fire spread potential, increasing outage and safety risks.

104 To mitigate these risks, from FY26 we have begun progressively replacing poles in these areas with fibre-cement alternatives. This will reduce ignition risk, improve resilience to wildfire, and lower safety risks for customers, the public, and our staff and service delivery partners. The case for investment is strengthened by evidence of increasing fire incidence associated with climate change.

[8] New Zealand Fire Service Commission *Research Report Number 55*. Available at: https://www.fireandemergency.nz/assets/Documents/Research-and-reports/Report-55-Spatial-Wildfire-Prediction-across-NZ-a-significant-update.pdf

> ***"With increasing frequency and intensity of storms and more fires, it would be good if the poles can withstand these conditions."***
>
> Rural customer, Powerful Conversations, 2025

2.2.3.3 Increase vegetation management activities

105 Orion operates approximately 5,900 km of overhead lines, many of which run alongside hedges, shelterbelts, and mature trees. Vegetation near lines presents an ongoing risk to reliability and safety, as falling or overhanging trees can interrupt supply, damage assets, and create hazardous conditions during both normal operations and emergency response.

106 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 vegetation interference with lines, 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.

107 At the time of publication, further amendments have been signalled to the *Electricity (Hazards from Trees) Regulations 2003,* to strengthen requirements for vegetation management near electricity lines. Orion supports these changes; however, compliance with the signalled amendments will lead to a material increase in vegetation management activity and expenditure relative to historical levels.

108 We plan to increase our activity levels over the CPP period to strengthen resilience and comply with the signalled amendments. We will deploy advanced tools such as LiDAR to improve identification of encroachments, target work more effectively, and provide robust evidence of compliance.

2.2.4 Preparing for future energy needs

109 Orion already integrates non-network solutions and demand-side flexibility into business-as-usual operations. We actively enable the connection of DER, including electric vehicles, solar PV, and battery storage, and have a longstanding practice of utilising flexibility solutions such as hot water load control and managed load for major customers. We have also strengthened our planning processes to systematically assess non-network solutions alongside traditional network investment, supported by scenario-based forecasts of demand, generation, and storage.

110 However, rapid technological change and increasing uptake of DER are changing how the network is used. As customers play a more active role in generating, storing, and managing electricity, demand patterns are becoming more variable and less predictable. This is increasing the complexity of operating the network and requires a transition to a more dynamic and decentralised operating environment.

111 In response, developing and embedding the capabilities needed to support a more flexible, data-enabled network is a key strategic priority over the CPP period. Our focus is on enabling DER and low-carbon technology connections at greater scale and pace, increasing the use of demand-side flexibility, microgrids and other non-network solutions to manage peak demand, and ensuring these options are consistently considered alongside traditional network investment in all major decisions.

112 Our engagement indicates that customers expect the network to support new technologies while maintaining reliability and affordability. In response, we are undertaking staged and targeted investment to build these capabilities. Over the CPP period, we will transition from initial deployment to integration into business-as-usual operations.

113 Over time, this investment will enable more efficient use of existing network capacity, help defer or avoid some traditional capacity-driven investment, and support continued population

growth and electrification at lowest long-term cost. It will also ensure the network remains safe, reliable, and responsive to evolving customer needs.

> ***"Start to think about future-proofing the network. We are a nation that is focusing on plugging everything into the network, including cars."***
>
> Customer Perceptions survey respondent, 2024
>
> ***"Investment in non-network solutions should be focused on how it can help with reliability or strengthen resilience."***
>
> Residential customer, Powerful Conversations, 2025

2.2.5 Enhancing efficiency and capability

114 In the decade following the Canterbury earthquakes, we deferred major upgrades to our core ICT systems. Initially, our ICT strategy prioritised business continuity and minimising disruption while the organisation focused on earthquake recovery. It then shifted to supporting remote working and workforce mobility during the COVID-19 pandemic.

115 While appropriate in the circumstances, this resulted in a growing proportion of legacy systems. Key platforms became increasingly unfit for purpose – for example, our billing system was no longer meeting operational requirements; our works management and geographic information systems were in a deteriorated condition; and our financial system had reached end-of-support. Independent reviews by specialist consultants confirmed that, without significant renewal, these systems would not support our future operational and regulatory requirements. They also identified material gaps in digital capability relative to good practice in network management and customer service.

116 In FY21, we initiated a structured programme of system renewal and capability uplift to address these issues, which will be completed during the CPP period. This investment is foundational to delivering our broader strategic priorities, including maintaining safety and reliability, strengthening resilience, and preparing to meet future needs. It will deliver benefits such as lower ICT maintenance costs; reduced cyber risk; increased labour efficiency and productivity; improved asset management and maintenance planning; and better customer service.

> ***"If you have an efficient service, you can spend twice as much money elsewhere that needs it"***
>
> Residential customer, Powerful Conversations, 2024

2.2.6 Implications of remaining on DPP4

117 Remaining on DPP4 would require us to defer essential and high-value investment. This includes core network asset renewals – some of which have already been deferred following the Canterbury earthquakes and to limit overspend during the DPP3 period – as well as discretionary investments that support our strategic priorities, align with customer preferences, and deliver net long-term benefits.

118 Figures 2.2 and 2.3 illustrate the scale of this constraint, comparing planned capital and operating expenditure under our proposed CPP with the allowances implied under DPP4. They show a material and persistent gap between the expenditure required to deliver a plan that reflects Orion's specific circumstances and the available allowances. Closing this gap under DPP4 would require widespread deferral of investment across multiple programmes.

Figure 2.2 Planned capital expenditure over the CPP period compared with forecast capex allowance for DPP4

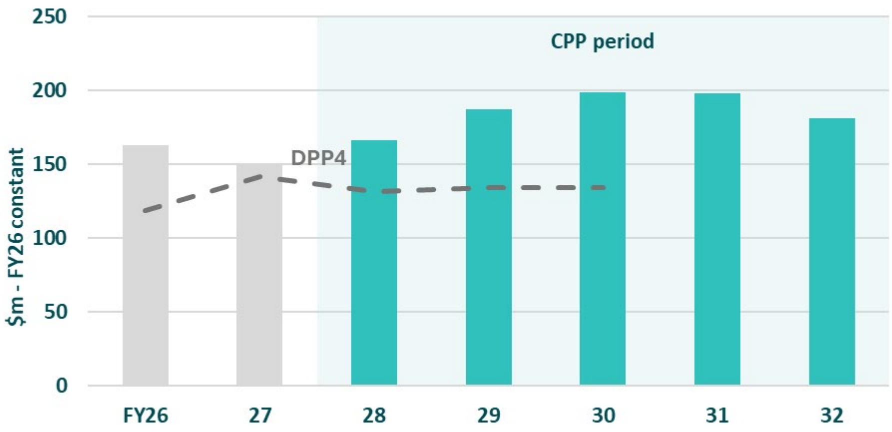
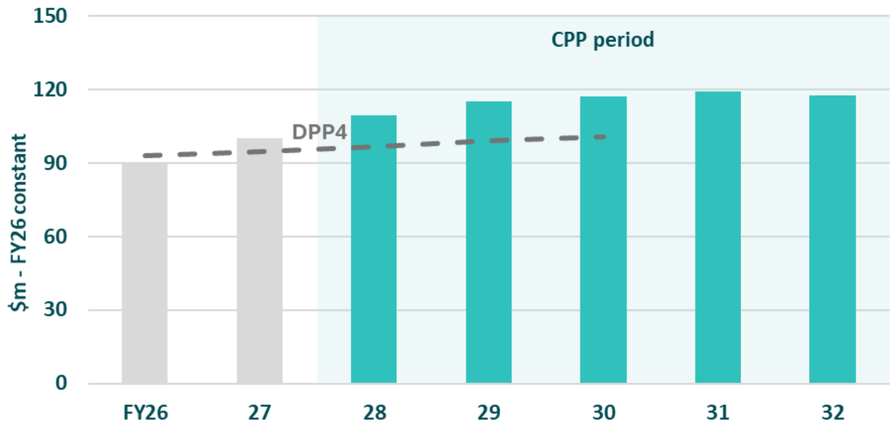


Figure 2.3 Planned operating expenditure over the CPP period compared with forecast opex allowance for DPP4



119 Much of our planned expenditure – particularly on major renewal and system growth projects, network transformation, and ICT – is supported by cost–benefit analysis demonstrating that benefits exceed costs (see Box 2.1). Deferring these investments would therefore delay or forgo net customer benefits, including improvements in reliability, resilience, and service quality.

Box 2.1 Illustrative cost-benefit analysis

For planned major investments, we have assessed costs and benefits over the full asset life. For example, the planned construction of a new substation in the fast-growing Lincoln township (see Chapter 7) has an estimated benefit-to-cost ratio of 1.95:1, rising to 2:1 when the planned non-network solution is first used to defer construction by one year. Over 40 years, the project delivers a net present value of $11.3 million.

Deferring the investment further would increase the risk of capacity-related outages and reduce the reliability of supply for a high growth urban environment. While illustrative, this example reflects how this type of analysis underpins a significant share of our planned CPP expenditure.

120 To assess the longer-term implications of deferring core network assets, we undertook a high-level review of our 20-year asset renewal requirements.[9] This review found that elevated levels of renewal investment will be required through to at least 2045 to maintain safety and reliability performance. Based on projected population growth, investment in new connections will also remain at similar levels over time. Long-term maintenance requirements are likewise expected to remain broadly consistent with planned CPP levels.

[9] This review focused on asset fleets where renewals are forecast using a volumetric approach.

121 Together, volumetric asset renewals, major renewal and system growth projects, resilience investments, customer connections, and network maintenance accounts for approximately 70% of total planned CPP expenditure. Our analysis indicates this level of investment is necessary to maintain service standards and support ongoing growth.

122 Constraining expenditure in these areas over the next 5 years would not reduce long-term costs. Instead, it would increase the scale of future investment required, heighten delivery risk, and lead to greater price impacts for customers over time.

123 In particular, deferring asset renewals would result in the accumulation of renewal backlogs, increasing safety and reliability risk, and leading to a more reactive approach to asset management. This is inherently less efficient and more costly than the planned and proactive approach underpinning our proposal.

124 The remaining 30% of expenditure relates to network transformation and ICT, and the internal capability and facilities required to deliver the CPP plan effectively. While some of this expenditure could be deferred to moderate short-term price impacts, doing so would limit efficiency improvements, and reduce customers' ability to connect to and use the network in new and flexible ways.

125 The economic cost of these outcomes is material. Reduced reliability and increased outage duration would disrupt business continuity and erode confidence in electricity supply, particularly in the context of major natural hazard events. Additional costs would arise if the network does not enable timely new or upgraded connections or support customers' adoption of new technologies.

126 Over time, the cumulative cost of these impacts would outweigh any short-term reduction in lines charges. Customer feedback reinforces this conclusion, with customers consistently prioritising maintaining reliability, strengthening resilience, and enabling new technology uptake.

> ***"As a consumer, I support Orion's continued investment in strengthening network reliability and resilience — especially in light of increasing climate events and growing electrification needs. The focus on proactive asset management, modernising infrastructure, and preparing for a more distributed energy future is well aligned with what we'd hope to see from a future-ready electricity network."***
>
> Submission on initial investment approach, 2025

127 For these reasons, limiting expenditure to DPP4 levels would not be prudent or efficient. It would defer efficient investment, increase long-term costs and risks, and undermine the reliability and quality of service customers expect (see Box 2.2). These outcomes are not in consumers' long-term interests.

Box 2.2 Likely customer and community outcomes of remaining on DPP4

Without additional investment, we expect that over time:

- reliability levels would decline, leading to more frequent and longer unplanned outages, and safety risk to our service delivery partners and the public would increase
- resilience would not improve, leaving the risk of prolonged and widespread outages during and after natural disasters unmitigated
- our ability to keep pace with population and peak demand growth would decline, lengthening the waiting period for new customer connections, and constraining regional development and decarbonisation
- our ability to support new technologies would not improve, constraining customer adoption of solar PV, batteries and electric vehicles, and reducing our ability to leverage non-network solutions to defer or avoid system growth upgrades
- opportunities to enhance our efficiency and improve our customer service by leveraging modern ICT capabilities would be lost.


3

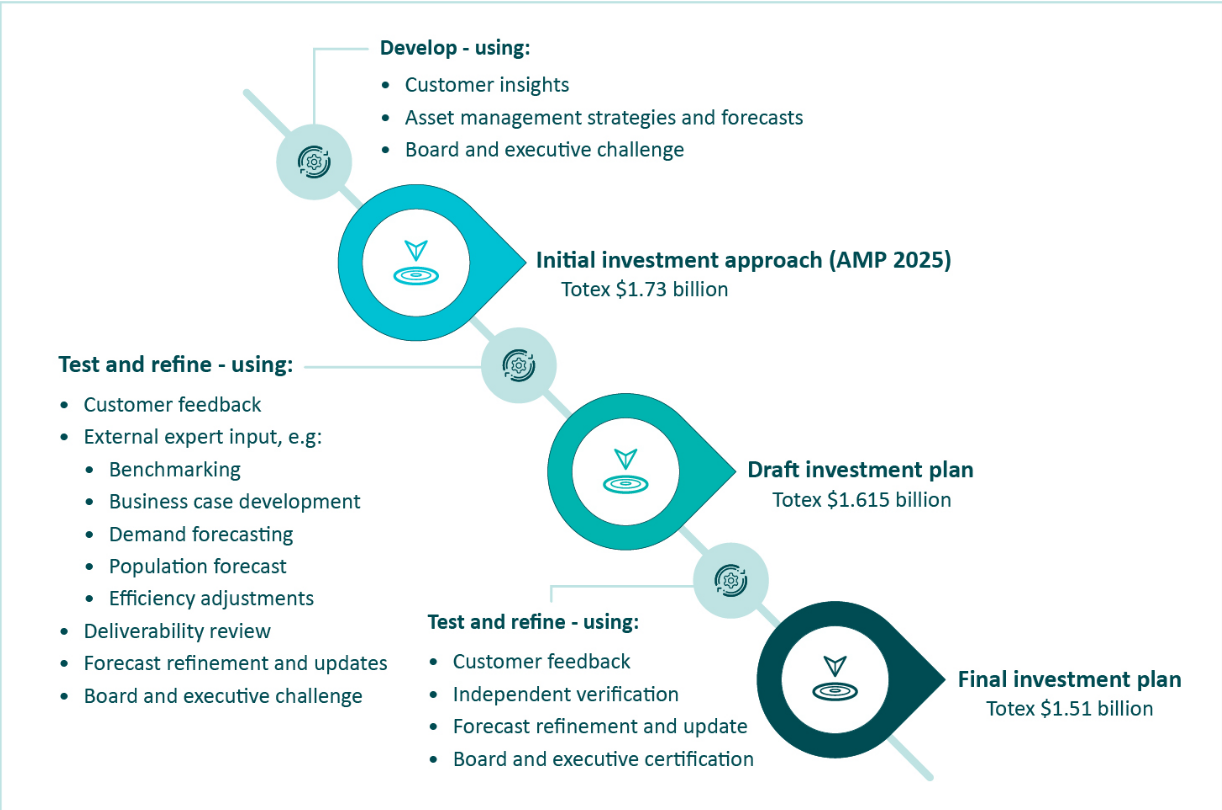
3 How we developed and tested our CPP plan

128 Orion first signalled the need for a step change in expenditure in our 2023 Asset Management Plan (AMP). In our 2024 AMP, we indicated that we were considering a CPP with a decision contingent on the Commission's DPP4 determination.

129 Following that determination, we concluded a customised price path was required to enable the investment necessary to respond to Orion's specific circumstances (see Chapter 2). We then undertook a rigorous and iterative process to develop, test, refine and finalise our investment plan for FY28–32 (Figure 3.1). This included:

- **developing an initial investment approach** as part of our 2025 AMP update, informed by early engagement with customers, with input from and oversight by our Board and Integrated Leadership Team (ILT)
- **testing and refining this approach to form our draft plan** through customer engagement and Board and ILT challenge, and by strengthening the expenditure forecasts and supporting evidence through input from internal and external subject matter experts
- **testing and refining the draft plan to form our final CPP plan** through customer engagement, and by subjecting both the plan and supporting materials to multiple rounds of structured internal review and challenge, as well as independent verification.

Figure 3.1 Summary of Orion's CPP proposal development process



130 Together, these steps demonstrate that our CPP plan has been systematically developed, rigorously tested, and independently scrutinised. This provides confidence that our plan is aligned with customer priorities, supported by robust evidence and challenge. The level of expenditure proposed is also consistent with what a prudent and efficient electricity distributor would reasonably require, in Orion's circumstances, to meet expected demand and deliver the quality of service customers expect.

131 The sections below provide further detail on this process. Boxes 3.1 and 3.2 outline our customer engagement approach and internal governance arrangements, respectively.

> ***"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."***
>
> Rural customer, Powerful Conversations, 2025

Box 3.1 Overview of customer engagement approach

We undertook an extensive engagement and communication programme from August 2024 to April 2026 to inform the development of our CPP proposal and ensure it reflects customer and stakeholder priorities, preferences and expectations. Our approach built on our established engagement programme and drew on recognised good practice, including the IAP2 Spectrum of Public Participation and insights from CPP and similar regulatory processes in New Zealand and Australia.

Engagement was delivered as a staged programme, with each phase building on the one before to ensure the customer voice informed our planning and decision-making throughout. Recognising the complexity of electricity issues, we combined targeted direct and participatory engagement using a mix of qualitative and quantitative methods.

The programme included public consultation processes alongside a range of methods to enable broad participation and diversity of views. For example, these include:

- **Customer Advisory Panel:** an independently chaired panel providing insights on customer needs and feedback on our plans
- **'Powerful Conversations' community workshops:** interactive sessions with urban, rural, residential and business customers to explore issues in-depth and test ideas
- **Annual surveys:** including Customer Perceptions Surveys of around 1,000 customers to track expectations and inform investment priorities, and Customer Pulse Surveys of around 500 customers.

These activities were complemented by a communication programme from November 2024 to December 2025, including targeted advertising, digital and social media, stakeholder communications and newsletters to around 110,000 homes and businesses. Customers were directed to our Have Your Say website to access information and provide feedback on our investment plans and CPP proposal.

We engaged Signature Consulting to independently facilitate the Customer Advisory Panel sessions. Signature Consulting is an experienced consultant to utility companies and their suppliers, and chaired the Electricity Authority's Innovation and Participation Advisory Group. This support ensured the panel's discussions were well-informed, enabling them to understand and challenge our investment proposals.

We also engaged the customer research firm, Curiosity Company, to assist us in designing, facilitating and interpreting the Powerful Conversations workshops and annual surveys. This ensured the research methods were appropriate for drawing out informed customer views, and the findings were robust and suitable for informed decision-making.

Further detail, including compliance with clause 5.5.1 of the IMs, is provided in our CPP Engagement Report.

Box 3.2 Overview of internal governance, review and challenge

The development of our CPP proposal was overseen by a CPP Steering Committee, with the CEO and CFO as key participants. The Committee met monthly and was responsible for providing strategic direction, oversight and challenge, including reviewing key assumptions, risks and trade-offs.

All members of our integrated leadership team (ILT) and Board also had oversight, and approved the planned investments and forecast expenditure at key stages. The ILT and Board were regularly updated on progress, including at weekly ILT meetings and all Board meetings throughout the process. In addition, both were actively involved in:

- deciding to apply for a CPP (with the Board formally approving this decision)
- testing and endorsing our strategic rationale for the CPP and the strategic priorities underpinning the proposal
- reviewing and challenging the expenditure forecasts at key stages through structured sessions in November and December 2024, May, June, August and November 2025, and February, April and May 2026
- approving the draft investment plan for independent verification (the Board)
- reviewing our response to the verifier's findings, and the updated forecasts reflecting that response.

The ILT and Board also reviewed and provided feedback on this proposal during drafting, and formally approved it for submission to the Commission on 29 May 2026.

3.1 Develop initial investment approach

132 To develop our initial approach for the CPP period, we drew on the expenditure forecasts for the 2025 AMP update, and insights from Phase 1 of our customer engagement (Box 3.3).

133 We also drew on our ILT and Board, who provided oversight and tested and challenged key elements of the approach including the strategic rationale for a CPP, the expenditure forecasts, and the options considered.

134 This approach established a clear need for a CPP, confirming that the DPP4 allowances would not be sufficient to efficiently manage, maintain, and operate our network in a way that would meet customers' expected service levels. It identified 5 key challenges and opportunities over the CPP period, consistent with the strategic priorities underpinning our CPP plan (see Chapter 2). It also assessed 3 alternative investment approaches to address these challenges and opportunities, reflecting different trade-offs between price and service outcomes:

- **Preferred option (balanced investment):** increased investment across renewal and maintenance, resilience, network capacity, and supporting systems. Sufficient to maintain current safety and reliability levels, improve resilience to natural hazards, support forecast growth and decarbonisation, and build capability to deploy advanced technologies where efficient. Average price rises are moderate in the short term ($8.00 per month +/- $1.00 for residential customers) and lower over time.
- **Alternative 1 (limited investment):** no change in renewals and maintenance investment, and some increase to improve resilience, capacity and supporting systems. Results in growing maintenance backlogs and increased reliance on reactive renewals. Constrains ability to support growth, decarbonisation and the efficient deployment of advanced technologies. Average price rises are lower in the short-term ($2.00 per month +/- $1.50 for residential customers) but likely to be higher in the future.
- **Alternative 2 (accelerated investment):** higher investment increases, enabling earlier and more extensive asset renewal, enhanced maintenance, and accelerated resilience and capacity upgrades. Improves reliability relative to current levels and supports future growth and earlier adoption of new technologies. Average price rises are higher in the short term ($13.50 per month +/- $2.50 for residential customers) but lower over time.

Box 3.3 Phase 1: Early engagement (August 2024 – March 2025)

How we engaged	What we heard
To deepen our understanding of customer needs, priorities and expectations, and inform the development of our initial investment approach, we engaged through: • Customer Advisory Panels (4 sessions) • Powerful Conversations (3 community workshops with 80 urban, rural and Banks Peninsula customers) • rural customer surveys (800 customers across five agricultural shows) • annual Customer Perceptions Survey 2024 (1,000 customers) • customer insights and feedback analysis (including previous engagement, complaints and operational feedback)	Phase 1 engagement highlighted the following customer priorities: • a safe and reliable power supply is important to customers, and satisfaction with our current reliability levels is high • a resilient network that can withstand major damage after natural hazards and be more quickly repaired after these events is also important • the electricity network must have sufficient capacity to support growth without compromising reliability for existing customers • the electricity network should be future-proofed to ensure it remains reliable and accommodate new technologies and customer choice Orion needs to run the network as efficiently as possible to keep costs down for customers, now and in the future

"Electricity is available when I need it (or the community), as I need it. Limited outages."

Residential customer, Powerful Conversations, 2024

135 The total forecast expenditure to deliver the preferred investment approach was around $1.73 billion over the CPP period, compared with $1.28 billion for the limited option, and $2.02 billion for the accelerated option.

136 We published a customer summary of the initial approach in April 2025.[10] The summary outlined our reasons for seeking a CPP, the preferred investment option and what it would mean for customers. It compared this option with the alternatives we considered, providing an overview of each option's investment priorities, risks, customer outcomes, total expenditure, and impact on average residential line charges. It also explained that these impacts would be in addition to increases under DPP4, and why we preferred the balanced investment option.

3.2 Test and refine to develop draft investment plan

137 We tested our initial investment approach through:

- customer engagement, and the insights this provided on customer preferences, priorities and expectations
- input from internal and external subject matter experts
- internal review and challenge.

138 Based on the feedback and input we received, we refined our investment programme and forecast expenditure to develop our draft plan.

[10] See 2025 Asset Management Plan Update.

3.2.1 Customer engagement

139 We consulted on our initial investment approach between April and October 2025 (Box 3.4). We sought public submissions on our customer summary by 30 May 2025, seeking feedback on whether there were aspects of the alternative options we should further consider. We also conducted deep and broad engagement, including through Customer Advisory Panel sessions, community workshops and surveys.

140 Through this consultation, we heard that customers' top priorities are safety, reliability and resilience to earthquakes and severe weather. While they supported investments to support growth, enable new technologies, and improve efficiency, the relative importance placed on these priorities varied depending on how customers were engaged.

> ***"The reliability of the service we have now is very good. It should never fall below the current standard set."***
>
> Urban customer, Powerful Conversations, 2025

141 Customers consistently emphasised the importance of affordable electricity, but there was tolerance for modest, well-signalled price increases where clear benefits were demonstrated, particularly where investment supported reliability and resilience. Surveys indicated customer satisfaction with current reliability levels is high, and residential customers are not willing to pay for further improvements beyond these levels.

> ***"Everybody here would be prepared to pay a little bit, but what does that look like for everyday families?"***
>
> Rural customer, Powerful Conversations, 2025

142 Overall, across all Phase 2 engagement, the preferred investment option received most support. The outcomes of this option also aligned with customer priorities and expectations. We therefore focused on refining this balanced approach and strengthening the robustness of the associated expenditure forecasts.

> ***90% of residential respondents and 92% of business respondents are satisfied with the reliability of their power supply***
>
> 2024 Customer Perceptions Survey
>
> ***On average around 63% of residential survey respondents are happy with current reliability levels and did not wish to pay more to reduce power outages***
>
> 2025 Customer Pulse Survey

Box 3.4 Phase 2 engagement: Consultation on initial investment approach (April – October 2025)

How we engaged	What we heard
To test alignment of the initial approach with customer priorities and willingness to pay, and consult on options for the overall level and pace of investment, we engaged through: • Customer summary of initial approach and submissions received (37 responses via email and online questionnaire) • Customer Advisory Panel (4 session focused key aspects of the approach) • Powerful Conversations (2 community workshops with ~60 urban and rural customers) • Business customer interviews (15 in-depth interviews across diverse sectors)	Phase 2 engagement highlighted that most customers supported our preferred balanced investment approach over the high and low investment alternatives, with top priorities of safety, reliability and resilience to earthquakes and severe weather events. • Satisfaction with current reliability is high, and most customers are not willing to accept an increase in unplanned outages • There is strong support for improving resilience, with rapid restoration of supply following major events seen as important, very important, or essential by almost all participants • There is an expectation that the network keeps pace with growth and is prepared for the future

• Customer Pulse Survey (~ 500 residential and business customers)	Affordability is a major concern, but most customers indicated willingness to pay a modest amount and prefer price increases to be smoothed over time.

64% of residential respondents and 61% of business respondents strongly or partially supported our proposed balanced investment approach.

2025 Customer Pulse Survey

"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."

Rural customer, Powerful Conversations 2025

3.2.2 Input from internal and external subject matter experts

143 Orion's staff refined and updated the initial investment approach and associated expenditure forecasts. We applied our established forecasting models and methodologies (see Chapters 5–13) and reviewed the outputs through our decision-making and governance frameworks.

144 We also engaged external experts to strengthen and validate the robustness of our forecasts through targeted input in key areas (see Table 3.2). For example, these included benchmarking, business case development, demand forecasting, population and growth forecasting, and financial modelling.

3.2.3 Deliverability review

145 We took a long-term strategic approach to planning for the CPP period to ensure we can deliver the planned works programme on time, without adversely impacting service quality for customers. As part of this approach, we reviewed key deliverability risks and associated mitigation measures, focusing on:

- our service delivery partners' capacity to complete the projected work volume
- Orion's ability to secure a reliable and timely flow of materials and equipment
- Orion's organisational capacity and capability to manage and oversee delivery.

146 Our review considered whether deliverability risk may be impacted by variability in forecast assumptions and cost estimates. We considered that no explicit adjustment was required to accommodate this risk because, while some deviation from assumptions is expected, the CPP work programme is large and diverse and over-/under-forecasting of costs is likely to balance out.

147 This review confirmed the works programme is fully deliverable, including that our service delivery partners have sufficient Christchurch-based capacity available and are committed to supporting delivery (including scaling up resources if required in response to unforeseen circumstances). See Chapter 4 for further detail. The independent verifier also found the works programme to be deliverable (see section 3.3.2.2).

Table 3.2 External expert input supporting the robustness of expenditure forecasts

Area of input	Expert and scope	Contribution to the CPP proposal
Expenditure benchmarking	Farrierswier Consulting benchmarked Orion's historical expenditure against a peer group of New Zealand EDBs at a category level	Confirms expenditure is broadly consistent with peers, supporting an efficient starting point and informing the application of efficiency assumptions
Unit rate benchmarking	Ergo Consulting reviewed the unit rates used in volumetric capex forecasting against those across the New Zealand electricity sector	Confirms cost inputs underpinning capex forecasts are efficient and aligned with sector benchmarks
Business case development	Ergo Consulting supported development of business cases for major zone substation renewal projects; Energy Networks Consulting developed an economic calculator and user guide to assess cost-benefit across renewal and growth options	Ensures significant investments are supported by robust technical solutions, appropriate scope, and consistent economic assessment of options
Demand and DER forecasting	Frontier Economics reviewed and enhanced the demand forecasting process, including DER forecasts, and development of a weather normalisation model	Supports confidence that demand and DER forecasts are robust, fit for purpose, and tailored to Orion's network characteristics
Population growth forecasting	Geografia, an Australia-based demography, economics, and spatial analytics specialist, provided long-term population and dwelling growth projections for Orion's network area	Ensures key inputs to demand forecasts reflect expected growth in the network area over the CPP period and beyond
Financial modelling	PwC supported the development of our financial model, combining modelling capability with expertise in electricity regulation and CPP requirements	Provides assurance that the model is robust and compliant
Reference class forecasting	EA Technology benchmarked planned activities and expenditure in the network transformation workstream against comparable programmes delivered by EDBs in New Zealand, Australia and the UK	Confirms planned expenditure in this relatively new investment area is prudent and supported by relevant industry benchmarks
Cost inflation forecasting	Sapere provided forecasts of key input cost drivers (including metals, labour, CPI and producer prices), based on published third-party data. These were used to develop tailored escalation factors to convert real expenditure into nominal terms	Ensures escalation factors reflect expected cost pressures across capex and opex programmes and support conversion of real to nominal expenditure forecasts

3.2.4 Internal review and challenge

148 We held multiple review and challenge session with our Board and ILT. Both the ILT and Board challenge sessions were structured around detailed overviews of the planned investment programme and expenditure forecasts. These were updated to reflect the inputs outlined above.

149 The participants were provided with detailed overviews of the programme elements and associated forecasts, the expected benefits or customer outcomes, and the key changes since the previous challenge sessions.

150 The challenge sessions focused on rigorously testing whether the programme is justified, deliverable, and aligned with customer needs and good asset management practice. This included assessing whether:

- expenditure appropriately reflects underlying needs and input costs
- modelling approaches are robust
- efficiencies and non-traditional options have been adequately explored.

151 The session also examined whether Orion can realistically deliver the programme over the CPP period, ensuring the forecasts are both credible and achievable.

152 Table 3.3 sets out examples of feedback from internal review and challenge from across the plan development process.

Table 3.3 Examples of feedback from Board and ILT challenge sessions

Plan area	Challenge	Response
Resilience	Questioned the timing of planned investment in strengthening resilience, including how the value of resilience had been factored into decisions around this timing	Decisions on resilience investment timing were made using our risk framework, guidelines and appetite. Optimal timing for key programmes (66 kV cable replacement and fire risk poles) was made using options analysis
66 kV cable replacement	Specifically challenged timing of 66 kV cable replacement, and requested we explore accelerating the programme to align with customer feedback	66 kV cable replacement programme was adjusted to deliver 1 major project per year, in line with this feedback
Demand and connections forecasts	Challenged the population forecasts used to forecast demand growth and customer connections, noting that Stats NZ data may not be a reliable source for growth in our region, particularly for the outer years	External subject matter expert engaged to provide long-term population and dwelling growth projections for Orion’s network area (see Table 3.2 and Chapter 7 for further detail)
System growth	Questioned whether use of non-network solutions to defer 11 kV and low voltage reinforcement had been considered and incorporated into expenditure forecasts	Forecasts include opex provision with 2.5% of capex avoided from FY29 for LV and deferral of one $1.9m 11 kV project every second year starting in FY29 to demonstrate our commitment to non-network solutions (see Chapter 10)
Risks and uncertainties	Requested provision of clear list of unforeseen and contingent items to inform further consideration of forecasting risk management, including potential reopeners	List prepared and shared with ILT and Board, as part of on-going discussion of the risks on cost estimates and timing of projects due to deviations of forecast assumptions (see Chapter 7 for further detail on contingent and nascent projects)
Operational technology	Questioned the operational technology forecasts, particularly their peaky nature	Peakiness reflects our ADMS upgrade 2-year cycle (see Chapter 11)
Vegetation management	Requested further risk assessment be incorporated into the forecast, particularly in relation to compliance with extended Growth Limit Zone ‘clear to sky’ requirements	Used LiDAR scan of our non-urban network to identify encroachments that need to be cleared to meet the requirements and incorporated into network opex forecasts (see Chapter 12)
Efficiency	Questioned whether and how efficiency assumptions were incorporated into expenditure forecasts, and emphasised continuing need to consider how we can improve efficiency and factor that into our investment profile	Indicated where efficiency gains had already been incorporated into forecasts, and outlined planned approach to considering additional top-down efficiency assumptions (including input from external subject matter expert (see Table 3.1 and Chapter 5)

3.2.5 Draft investment plan

153 Through this testing and refinement process, we confirmed the strategic case for a CPP and updated the programmes and forecasts to develop our draft plan. The plan included investment across multiple areas to deliver on the 5 strategic priorities underpinning this proposal (see Chapter 2), while also enabling its efficient implementation. Total forecast expenditure was approximately $1.615 billion over the CPP period. This was approximately –7.3% lower than the preferred option, which was $1.73 billion, as outlined in our initial approach.

154 For 3 initiatives still under development, the draft plan incorporated our preferred option for the scope and timing, and set out alternative options for consultation:

- **Oil-filled 66 kV cables replacement programme (resilience)**: the draft plan provided for replacement of 4 of the most vulnerable cable routes over the CPP period at forecast cost of $72 million, with an average price impact of ~$0.60/month. Alternative options being considered were:
    - replacing one cable route (2 cables) for approximately $32 million (~$0.30/month)

    - replacing all 6 remaining routes (12 cables) for approximately $118 million (~$1.00/month).

> ***"If we have a big earthquake, we need to do all we can to keep everyone safe, and that means having electricity."***
>
> Urban customer, Powerful Conversations, 2025

- **Low-voltage network reinforcement (growth):** the draft plan included a proactive programme combining traditional upgrades with non-network solutions to strengthen the network 'just in time', ahead of service quality deterioration (~$0.10/month). Alternative options being considered were:
    - a reactive approach, with lower upfront cost and higher peak-period risk
    - an accelerated traditional approach, prioritising reliability at a higher cost (~$0.20/month)
    - an innovation-focused approach, with a similar upfront cost to the draft plan but enabling greater customer participation and uptake of new technologies.

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

- **Non-network solutions (deferring major network upgrades):** the draft plan included $30 million (the network transformation portfolio) to enable greater use of non-network solutions. Alternatives being considered were to reduce or accelerate this investment.

> ***"Investment in non-network solutions should be focused on how it can help with reliability or strengthen resilience."***
>
> Akaroa customer, Powerful Conversations, 2025

155 The draft investment plan, expenditure forecasts and supporting documentation were provided to the independent verifier in July 2025. We published a customer summary of this plan on 6 November 2025, and invited public submissions until 15 December 2025.[11]

156 The customer summary outlined what we had heard from customers so far, our consultation to date, the rationale and planned expenditure for each of the 6 investment areas, and customer and price impacts. It also set out the proposed service measures that we put forward for consultation.

157 For the 3 initiatives under development, the summary described set out the preferred option alongside the alternatives being considered and their price-service trade-offs, and sought feedback.

[11] See Orion CPP Consultation - November 2025

3.3 Test and refine to form final investment plan

158 Our draft investment plan was also tested through further customer engagement, and subject to independent verification and ILT and Board review. Based on the feedback and input we received, we refined the investment programmes and updated the expenditure forecasts to form our final CPP plan.

3.3.1 Customer engagement

159 We received 36 submissions on the customer summary, and conducted further engagement between November 2025 and April 2026 (Box 3.5). Feedback indicated that customers and stakeholders recognised the need to increase investment to maintain network performance and meet future needs, and broadly supported the plan.

160 At the same time, affordability was the major concern, and there is strong expectation that price impacts on customers should be minimised. Participants also emphasised the importance of transparent, well-justified investment decisions, smoothing price impacts over time, and protecting vulnerable customers.

Box 3.5 Phase 3 engagement: Consultation on draft plan (November 2025 – April 2026)

How we engaged

To test alignment of the draft plan with customer expectations, and consult on the options for investing in 66 kV cable replacement, low voltage reinforcement, and non-network solutions, we engaged through:

- customer summary of draft plan and public submissions (36 responses)
- Customer Advisory Panel (1 session)
- Powerful Conversations (4 community workshops with 90 urban, rural and Banks Peninsula customers, including one business-focused session)
- stakeholder meetings and webinars (39 participants from businesses, energy retailers, industry groups, community and government organisations, and local MPs)
- annual Customer Perceptions Survey (1,080 customers)
- Customer Pulse Survey (500 residential and business customers)

What we heard

Phase 3 engagement highlighted that customers broadly demonstrated an understanding of the need for increased investment to maintain network performance over the long term, prioritising safety, reliability, and resilience. However, affordability was their primary concern.

In relation to the specific investment options consulted on:

- customers strongly supported the planned investment in 66 kV cable replacement, which was seen as reducing the risk of prolonged outages following major seismic events while limiting impacts on customer bills
- most customers supported the planned LV reinforcement programme, which assumed high demand growth on the LV network and very cold winter conditions
- non-network solutions were supported provided risks around early adoption of new technologies are managed

Community stakeholders also emphasised the importance of keeping pace with strong regional growth without overbuilding.

"We accept that where the network is ageing, Orion should increase expenditure to renew it in a timely fashion, provided that doing so is on balance, through whole-of-life, the least-cost way of maintaining existing levels of service. It is important that Orion's customers aren't competitively or economically disadvantaged by lower levels of network reliability relative to those on other electricity networks."

Orion Customer Advisory Panel

161 Maintaining the current levels of safety and reliability was seen as non-negotiable, but there was little appetite to pay more to improve reliability. There was clear and consistent support for key programmes to strengthen resilience, including the 66 kV cable replacement and the vulnerable poles programme.

162 Customers recognised the scale and pace of growth in the region, and expected the network to keep pace with demand without overbuilding. For low voltage reinforcement, they prioritised future-proofing the network and planning for worst-case scenarios (particularly during peak winter demand). Non-network solutions were widely supported as a

complementary approach, provided they are implemented in a staged and flexible way that manages risk and avoids overinvestment in uncertain technologies.

3.3.2 Independent verification

163 We engaged GHD Ltd (GHD), under a tripartite deed with the Commerce Commission, to act as the independent verifier for our proposed expenditure forecasts in accordance with the Input Methodologies (IMs).

164 GHD's role was to assess whether the expenditure in our draft plan is consistent with the IM expenditure objective. This includes whether the expenditure is prudent and efficient and reflects the network services required by consumers.

3.3.2.1 Verification process

165 GHD formally assessed our draft plan against the IM Schedule G - Terms of Reference for Verifiers. The scope of is assessment included our strategy, asset management and planning frameworks, key inputs and assumptions. It also conducted a detailed assessment of 20 identified programmes and one contingent project, representing around 75% of the total planned expenditure.

166 GHD undertook this assessment by reviewing documents and other information, and conducting workshops and interviews with our executives, managers, functional leads and subject matter experts. For example, it reviewed 267 documents, more than 170 models, and around 260 information-request responses. It held around 50 interviews and follow-up interactions with subject matter experts.

167 GHD provided its draft report for factual review on 15 December 2025, and issued its final report on 31 March 2026, prior to lodgement of this CPP application.

3.3.2.2 Verifier's findings and recommendations

168 GHD concluded that Orion has an appropriate strategic and planning framework to support the CPP proposal, with a clear line of sight from strategy through to proposed expenditure. It also found that:

- our forecasting methodologies and inputs to be generally reasonable, including our cost estimation approach, cost escalation assumptions and demand forecasts
- our consumer engagement to be extensive and effective, and consistent with the requirements in the IMs[12]
- the proposed works programme is deliverable over the 5-year period, subject to implementation of planned workforce, contractor and supply chain measures.

169 Of the expenditure it assessed, GHD accepted 95% as consistent with the IM expenditure objective. Where it did not accept all or part of the planned expenditure, it identified where further refinement or information may be required (see Table 3.4 for further detail).

[12] At the time of GHD's assessment, we were part way through our engagement so this conclusion reflected engagement completed as of the assessment, and planned engagement through to formal submission of our CPP application.

Table 3.4 Summary of independent verifier's expenditure forecast assessment outcomes ($m, FY26 constant)

Expenditure category	CPP forecast	Percent of subtotal
Total network capex	**928.1**	
Assessed and accepted	594.3	64%
Assessed and not accepted	41.7	4%
Not assessed	292.0	31%
Total non-network capex	**58.4**	
Assessed and accepted	42.8	73%
Assessed and not accepted	-	-
Not assessed	15.7	27%
Total network opex	**207.7**	
Assessed and accepted	136.7	66%
Assessed and not accepted	5.3	3%
Not assessed	65.8	32%
Total non-network opex	**355.1**	
Assessed and accepted	341.9	96%
Assessed and not accepted	13.2	4%
Not assessed	-	-

3.3.3 Final investment plan

170 Customer and independent verifier feedback was shared and discussed with our ILT and Board, and their input informed the finalisation of our CPP plan.

171 In response to the independent verifier's feedback, we resolved a range of issues during the verification process – for example, by providing additional information and adjusting certain inputs to our expenditure forecasts in response to feedback. In addition, we considered GHD's draft verification report, which was provided to us in December 2025, and made several adjustments to our investment plan to address the draft findings.

172 In response to customer concerns about affordability, we applied a strong focus on prudent and efficient investment throughout the development process. In finalising the plan, we applied an affordability lens to our decision-making while ensuring we could deliver service levels and outcomes customers told us they value. This required carefully balancing near-term price impacts with the long-term benefits of timely investment, recognising that acting now – efficiently and at the right scale – is critical to maintaining a safe, reliable and resilient network.

173 Overall, between our draft investment plan and our final investment plan, we further reduced our total forecast expenditure by approximately $105 million (a decrease of approximately 6.5%). This has reduced the total planned investment from $1.615 billion to $1.51 billion.

174 Table 3.5 summarises the key capex refinements to our CPP plan between the draft and final investment plans.

Table 3.5 Summary of key changes made to capex in finalising our CPP plan ($m, FY26 constant)

Feedback or driver	Our response
Customers expressed strong support for our proposed $24 million vulnerable poles programme to manage wildfire and landslip risk The independent verifier found that the need for and benefit of this investment had not been justified	Rescoped programme to address wildfire risk poles only. We have deferred the landslip risk pole remediation to further investigate methods to manage landslip risk **Overall reduction over CPP period: $15 million**
Customers recognised the need for LV reinforcement, and generally preferred the option included in the draft plan, which assumed high demand growth and very cold winter conditions The independent verifier found the growth assumptions underlying the draft LV reinforcement programme were overly risk-averse, and recommended programme optimisation to reflect benefits from planned investments in network transformation and an integrated asset management system	In response to customer concerns about affordability and the verifier's findings, we reviewed and adjusted the LV reinforcement programme from a high to a medium demand forecast, and retained a small provision to reinforce high growth areas We also refined the programme to account for the introduction of advanced voltage management of the LV network **Overall reduction over CPP period: $16.9 million**
The independent verifier recommended monitoring the Electricity Authority's ongoing distribution connection pricing reform process to ensure forecast customer contributions capex reflects the new connection pricing methodology rules expected to be finalised in April 2026	We have adjusted customer contribution settings for standard connections to align with Electricity Authority reforms. The new settings increase new customers' contribution to the cost of their connection, reducing forecast connections capex and helping ensure that existing customers do not subsidise the connection of new customers. **Overall reduction over CPP period: $9 million** We continue to work through the Electricity Authority's reforms in relation to larger non-standard connections and will share our findings with the Commission in coming months. We believe the reforms for non-standard connections will further reduce our Customer Connections expenditure forecast.
Internal review of risks and timing of major projects	We removed growth projects from the CPP programme timing remains uncertain, and will utilise CPP reopener processes if projects need to be reintroduced. **Overall reduction over CPP period: $32.4 million**
Internal review of draft asset renewals programme	We refined our renewal investments by updating unit rates, reprioritising work programmes and refining the scope and timing of programmes. This led to an overall reduction across the programmes. **Overall reduction over CPP period: $16.8 million**
Internal review of draft RSE programme	We reduced RSE investment by reprioritising scope and timing of initiatives and updating unit rates. **Overall reduction over CPP period: $17.5 million**

4

4 Delivering the CPP plan

175 To deliver the CPP plan, Orion must complete a substantial volume of work over the 5-year CPP period. In some programme areas, projected workloads are materially higher than in the current (FY21–25) and assessment (FY26–27) periods, including the overhead network, underground network, and substation programmes.

176 However, in other areas – such as customer connections and reactive maintenance – workloads are expected to remain broadly consistent with these periods. In addition, the projected increase in work volumes is not proportional to the planned increase in expenditure over the CPP period. A meaningful portion of the uplift in expenditure relative to recent historical levels is driven by cost escalation in labour and materials, rather than an increase in units of work. This distinction is important for deliverability, as price-driven increases do not place additional demands on our service delivery partners (SDPs).

177 Orion is confident that the plan is fully deliverable, based on our strong track record (see Box 4.1), our established relationships with SDPs, and a structured, long-term approach to planning. We have also systematically assessed deliverability risks and embedded targeted mitigations, focusing on:

- SDP capacity to support CPP programme delivery
- security of materials and equipment supply
- Orion's organisational capacity and capability.

178 The following sections set out the evidence supporting our conclusion that the CPP plan is fully deliverable.

Box 4.1 Orion's strong delivery record

Our delivery capability has been proven in operating environments comparable to those over the CPP period, including sustained periods of higher work volumes and increased demand on SDP capacity. These include the Canterbury earthquake recovery programme (2011–2017), which required large-scale network repair and reinforcement, and the ongoing Canterbury subdivision boom (from 2012), during which SDPs have progressively expanded their capacity to support sustained network growth and regional development.

More recent delivery experience further demonstrates our ability to adapt delivery approaches and scale resourcing in response to changing requirements. One example is the Bromley to Milton 66 kV cable replacement and commissioning (2022–2024). This major resilience project was delivered in high-traffic urban areas. We used an early contractor engagement model to optimise route planning and risk mitigation prior to contract award. This approach enabled the project to be delivered on time while minimising community impacts and maintaining cost efficiency. The same model has since been applied to the Milton to Halswell 66 kV replacement (2023–2026) and will be used for the planned 66 kV replacement projects in the CPP period.

Another example is the high-risk poles replacement programme (2022–2024). Following the introduction of enhanced pole testing methods, a larger-than-expected number of poles were reclassified as high risk, requiring accelerated replacement. Given the urgency of this work, our SDPs rapidly mobilised additional crews and adjusted their work programmes, successfully clearing the backlog of high-risk poles within 2 years.

4.1 Service delivery partner capacity

179 Orion contracts all network construction, renewal, and maintenance activities to SDPs (see Box 4.2). Deliverability of the CPP programme therefore depends on SDPs' ability to provide sufficient field resources over the CPP period.

180 We have assessed SDP capacity and delivery risks. This assessment:

- quantified field resource requirements across the period and confirmed SDP capacity and willingness to meet them
- aligned delivery volumes with a phased ramp-up profile to ensure sustainable increases in workload.

Box 4.2 Orion's service delivery partners

We have five service delivery partners:

- Connetics (our wholly owned, arms-length, contracting subsidiary)
- Independent Lines Services
- Ventia
- Power Jointing Ltd
- Lemacon.

These SDPs know our network, standards and operating environment, align with our safety and quality expectations, and can scale resources to meet changing programme demands. The relationships are stable and long-term, built through consistent workflows and sustained engagement, which gives us confidence they can support us to deliver both routine work and increased programme volumes.

4.1.2 Confirmed SDP capacity and commitment

181 In collaboration with SDPs, we modelled the field resources required in each year of the CPP period to deliver the projected works programmes, expressed as a proportion of SDP capacity. The analysis[13] focused on 3 core network areas that together account for most of the projected CPP work volumes:

- **overhead network** (including poles, crossarms, steel structures, and overhead conductors)
- **underground network** (including cables, cabinets and jointing)
- **substations** (including zone and distribution substations, power transformers, and secondary systems).

182 In each area, it compared the required field resources to 2 measures of SDPs' Christchurch-based field resource capacity: the capacity currently available to us (current local capacity for Orion); and the total capacity that could be made available to us if required (full local capacity for Orion).[14]

183 To ensure these capacity measures are realistic, we validated them through a bottom-up sense check. This involved reviewing the number of crews each SDP currently employs or contracts, alongside historical delivery data. We then compared projected work volumes with observed productivity rates and confirmed crew numbers to assess whether the projected workloads are achievable based on demonstrated performance. We also considered the potential impacts of regional and sector-wide demand on SDP capacity (see Box 4.3).

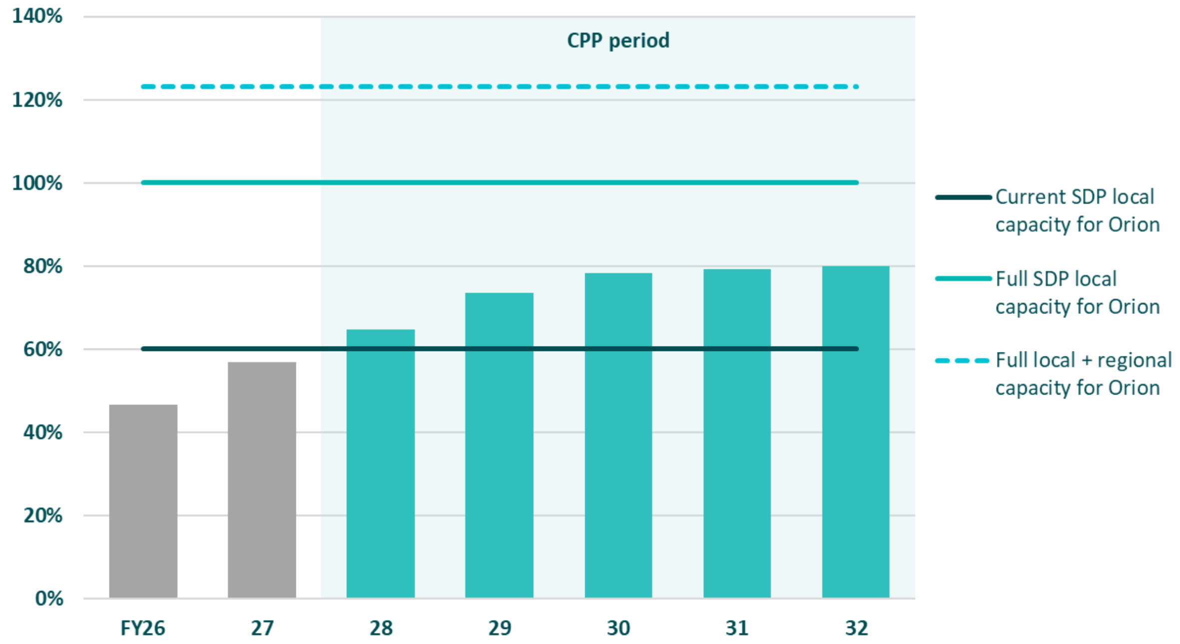
[13] The analysis excluded work volumes related to third-party emergency works, some corrective maintenance activities (such as defect rectification), some preventative maintenance activities, and customer connections work. Emergency outage response volumes are expected to remain stable, with SDPs confirming no change in allocated resources for this critical work.

[14] This analysis was undertaken in May 2025, and our projected CPP work volumes were updated in April 2026.

184 Taken together, this analysis demonstrates that our SDPs have sufficient local capacity to fully deliver our planned work volumes over the CPP period, without needing to draw on regional resources that may be committed to neighbouring networks or on external capacity.

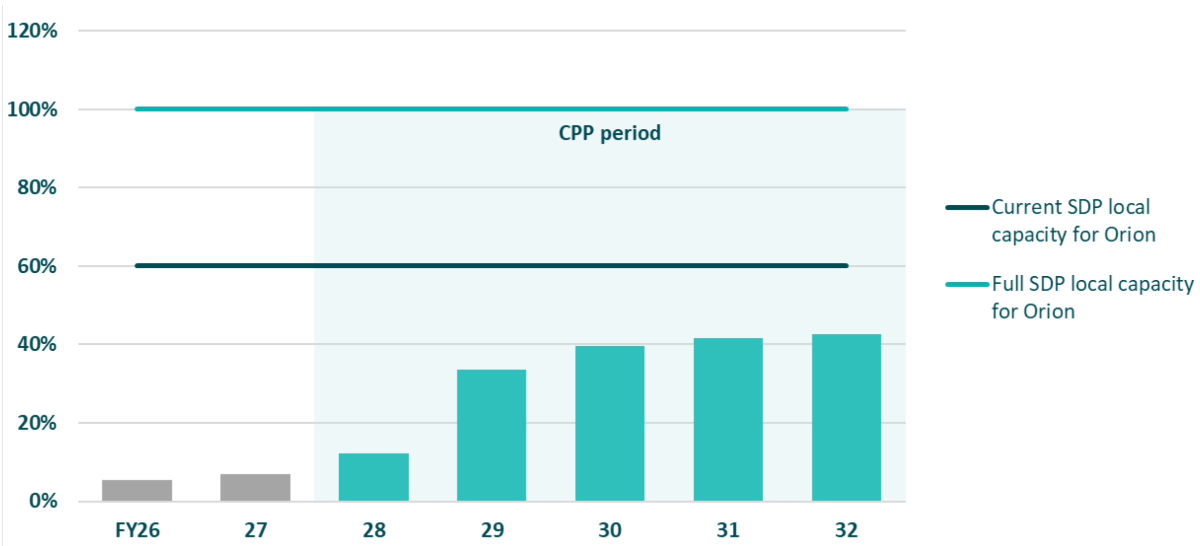
185 For the overhead works, projected annual requirements are higher than the current local capacity for Orion, but are within 80% of full local SDP capacity for Orion (Figure 4.1). SDPs have committed to allocating additional local resources from FY28 to meet this, without relocating resources from other regions. The programme has been structured to allow for a steady increase in volumes over time, giving SDPs sufficient lead time to plan their workforce accordingly.

Figure 4.1 Projected field resource requirement to deliver overhead work volumes as a proportion of SDP local and regional capacity



186 For underground works, the projected volumes are lower than current local capacity for Orion, and well below the full local SDP capacity for Orion (Figure 4.2).

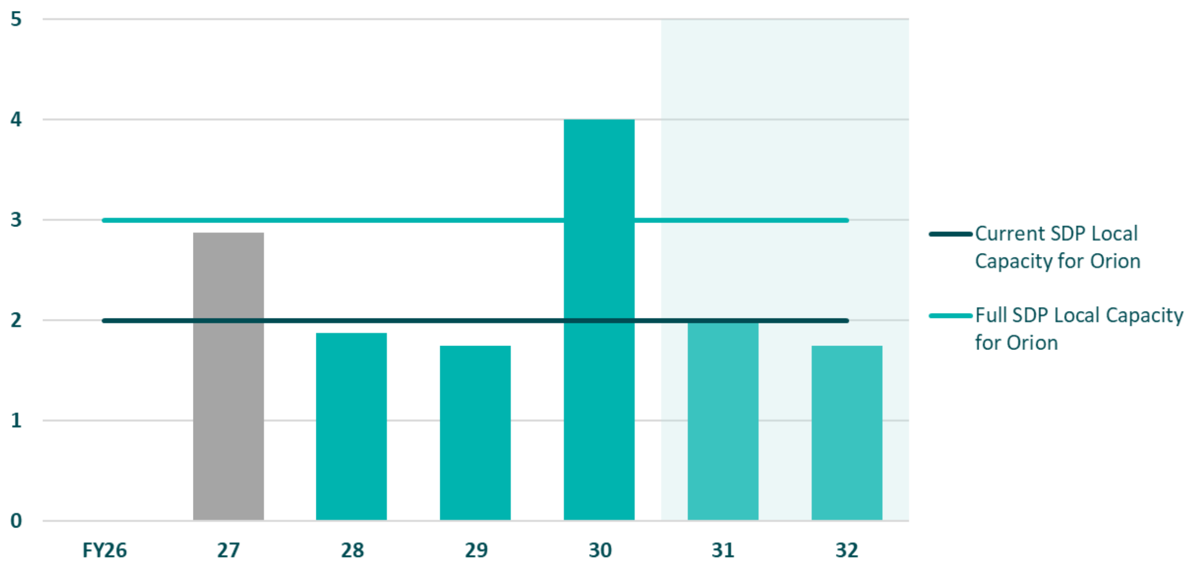
Figure 4.2 Projected field resource requirement to deliver underground work volumes as a proportion of local SDP capacity



187 For zone substation major works, planned project numbers are within current local SDP capacity for Orion in most CPP years (Figure 4.3). While FY30 represents a potential programme peak, in practice projects are delivered over multi-year windows and annual peaks are

smoothed through sequencing, outage planning and procurement lead times. An additional SDP has confirmed capability and capacity to undertake zone substation work if required, lifting available resourcing to the full local capacity scenario. If further additional capacity is needed in FY30, this could be sourced through regional crews mobilised by existing SDPs or specialist subcontractors. We are confident the programme is deliverable within available local capacity on this basis. Other substation-related work categories are addressed in the Deliverability Memo.

Figure 4.3 Planned zone substation major projects compared with local SDP capacity (number of projects)



188 As part of our planning and engagement, all SDPs have confirmed their commitment to supporting delivery of the CPP plan, including scaling up resources if required in response to unforeseen circumstances.

189 Given this evidence of available capacity and commitment, we have retained the full scope of the CPP plan. Delivery has been deliberately structured to support efficient mobilisation, including prioritisation of key portfolios based on asset health, safety risk, and reliability outcomes.

190 Vegetation management volumes are projected to increase, and our specialist SDPs[15] have confirmed sufficient capacity and scalable systems to deliver this work.

Box 4.3 Consideration of broader context for SDP capacity

In analysing SDP capacity to deliver the planned volume of works over the CPP period, we considered both the regional and sector-wide context. Orion's neighbouring EDBs – MainPower, EA Networks and Alpine Energy – operate substantially smaller networks. These networks are expected to remain under DPP4 revenue allowances until at least the end of FY30, and have not signalled a step change in activity levels over FY28–FY32. This suggests there may be scope for regional reallocation of resources to support Orion's works programme over this period, if required.

SDP capacity is also influenced by workforce dynamics beyond the local Canterbury region. At the national level, Transpower's RCP4 programme is expected to increase demand for electrical trade resources. In addition, Australia's renewable energy build-out is creating sustained demand for similar skills. However, Orion's SDPs are Canterbury-based businesses with established local workforces and long-term operational commitments. Given our strong relationships with these partners, and their confirmed commitment to supporting CPP delivery, we are confident they will prioritise Orion's work over opportunities outside the region.

[15] Treetech Specialist Treecare Ltd and Delta Utilities.

4.1.3 Phased ramp-up approach

191 We will implement a phased ramp-up of delivery to ensure SDP resources are mobilised in a controlled and sustainable manner. Work volumes will increase progressively, enabling efficient scaling while maintaining service quality.

192 This approach also provides flexibility to adjust the sequencing of work across portfolios in response to changing delivery conditions.

193 Mobilisation plans will support this approach by setting out clear sequencing, milestones, and early alignment with SDPs. These plans will ensure shared understanding of CPP objectives, delivery expectations, and operational constraints.

4.2 Materials and equipment supply

194 We have secured reliable access to the materials and equipment required to deliver the CPP plan. Connetics, in its dual role as an SDP and Orion's inventory manager, maintains long-term contract arrangements and agreed stock levels of approved equipment and spare parts. We work closely with Connetics to manage critical inventories, which are regularly reviewed.

195 In addition, we have taken steps to ensure access to the physical resources required to deliver the CPP programme. For example:

- suppliers have confirmed their ability to meet increased order volumes over the CPP period
- local manufacturing and stockholding arrangements support supply of cables up to 33 kV
- we have established multi-year agreements with key equipment manufacturers, which have confirmed their ability to meet increased order volumes over the CPP period
- we actively monitor market conditions, including lead times and supplier constraints, to manage emerging risks.

196 These arrangements provide confidence in the ongoing availability of critical materials and equipment.

4.3 Organisational capacity and capability

197 While SDPs deliver the majority of the field work, we retain full responsibility for programme oversight, delivery management, and investment control.

198 We have a strong track record of planning and delivering large-scale work programmes (see Box 4.1). However, we recognise that the step change in work volumes and investment over the CPP period requires a corresponding strengthening of our internal capacity and capability to ensure effective delivery of the plan.

199 We have already taken steps to improve capability and capacity in preparation for a CPP. For example:

- in late 2024, we restructured our organisation including a refinement to the network portfolio function, establishing clear accountability for coordination and packaging of the annual works plan
- at the same time, we upgraded our work management system (Maximo)
- in 2025, we deployed a learning management system integrated with LinkedIn Learning.

200 We have also tested our recruitment systems at scale, hiring 77 staff in FY23 and 75 in FY24, while maintaining low voluntary staff turnover of under 10%.

201 We plan to build on these improvements through 3 additional initiatives targeted at continuously improving our asset management capabilities, building required capabilities, and scaling core delivery capacity:

- **Asset management improvement**: we are implementing a structured programme of asset management improvements to strengthen how we plan, prioritise and deliver our investment programme. A key focus is improving works pipeline management, including multi-year programme visibility, scheduling integration and SDP capacity planning, to support longer-term planning, and enhanced coordination and bundling of work to maintain efficient delivery. We are also improving our risk-based investment prioritisation framework. These, and other, improvements are set out in our Asset Management Plan 2026, Section 18 – Asset Management Improvement.
- **Capability Shift initiative**: to respond to rapid skill obsolescence and meet emerging skill requirements, we will establish new roles to support staff in developing the skills needed for the future. This initiative represents a step change in our forecast corporate support operating expenditure (see Chapter 13).
- **Expansion of core delivery teams**: to scale our workforce in line with projected work volumes, we plan to increase the number of FTEs in programme management, engineering, field delivery, and operational support roles in FY27–28. This increase is reflected in our CPP headcount forecasts and fully costed within the SONS portfolio (see Chapter 13).

202 We expect to fill approximately 60% of the new roles through external recruitment, 30% through internal promotion, and 10% through contractor or secondment arrangements. This sourcing mix is consistent with established practice in capital-intensive regulated industries undergoing transformation and aligns with ratios recommended in relevant benchmarking sources.[16]

203 For more information on our delivery model, approach to planning and sequencing work, and procurement approach and principles, see Section 17, How we deliver, of our 2026 AMP.

4.4 Deliverability justification

204 We consider the CPP programme can be delivered safely, effectively, and efficiently over the 5-year period based on the following:

- **SDP capacity**: detailed resource modelling confirms that SDPs have the capacity to deliver the projected work volumes across the assessed network areas, which represent approximately 80% of total projected work volumes.
- **SDP capability and commitment**: established relationships with capable SDPs, which have confirmed their commitment to support CPP delivery.
- **Managed ramp-up and delivery flexibility**: a phased delivery approach supports orderly mobilisation and allows adjustment of sequencing as delivery conditions change.
- **Secure and resilient supply chains**: long-term supplier agreements, maintained inventories, confirmed supplier scalability, and active market monitoring support availability of critical materials and equipment.

[16] For example, see Deloitte Insights (2024). *The Skills-Based Organization: A New Operating Model for Work and the Workforce*. Deloitte Development LLC. https://www.deloitte.com/content/dam/insights/articles/2024/us175310_consulting-the-skills-based-org-report/di-the-skills-based-organization-report.pdf; LinkedIn (2024). *Workplace Learning Report 2024*; LinkedIn Learning. https://learning.linkedin.com/content/dam/me/business/en-us/amp/learning-solutions/images/wlr-2024/LinkedIn-Workplace-Learning-Report-2024.pdf; and Gartner (2024). Future of Work Trends: The Rise of Agile Talent and Internal Mobility. Gartner HR Research Library. https://www.gartner.com/en/articles/future-of-work-trends.

- **Strong internal capability and governance**: targeted investment in internal capacity, enhanced investment and risk management capability, and a clear delivery structure ensure effective oversight and control.
- **Proven delivery model and track record**: Orion's track record demonstrates that the CPP programme is achievable without reprioritising core activities or compromising service outcomes.
- **Independent verification**: the verifier concluded that the risks relating workforce availability, materials, equipment and logistics are manageable, and that the programme is deliverable provided key strategic measures continue to be implemented.

5

5 Expenditure summary

205 This chapter provides an overview of our planned expenditure for the CPP period, bringing together the expenditure discussed in the chapters to follow. It outlines:

- how we have organised and presented the planned expenditure
- our total planned expenditure over the CPP period
- the planned capex and opex components
- our expenditure forecasting approaches
- our approach to efficiency
- the assumptions underpinning these forecasts.

5.1 Organisation and presentation of expenditure

206 We have organised the planned expenditure into 8 main categories: 4 capital expenditure (capex) and 2 operational expenditure (opex) categories, each comprising several portfolios, and 2 mixed categories comprising both capex and opex components (see Figure 5.1).

207 This structure reflects how we plan, prioritise and deliver work across the network, and does not always align directly with regulatory information disclosure categories. The mixed categories group activities that are operationally integrated and best considered holistically. Presenting these together improves transparency of the full cost of delivering the relevant service outcomes and illustrates how we make capex–opex trade-offs.

Figure 5.1 Our expenditure categories

Capital expenditure	
Network capex – renewals	Chapter 6
Network capex – system growth	Chapter 7
Network capex – other	Chapter 8
Non-network capex – general corporate	Chapter 9

Capital and operating expenditure	
Network transformation	Chapter 10
Information and communications technology	Chapter 11

Operating expenditure	
Network opex	Chapter 12
Non-network opex	Chapter 13

208 Throughout this proposal, expenditure is presented on the following basis, unless stated otherwise:

- in constant price terms (FY26 dollars)
- including capitalisation of internal labour
- net of forecast customer capital contributions
- after applying efficiency assumptions
- on a financial year basis (1 April to 31 March)
- Where figures are rounded, minor rounding differences may occur in tables.

209 In the figures, expenditure is presented for the following periods:

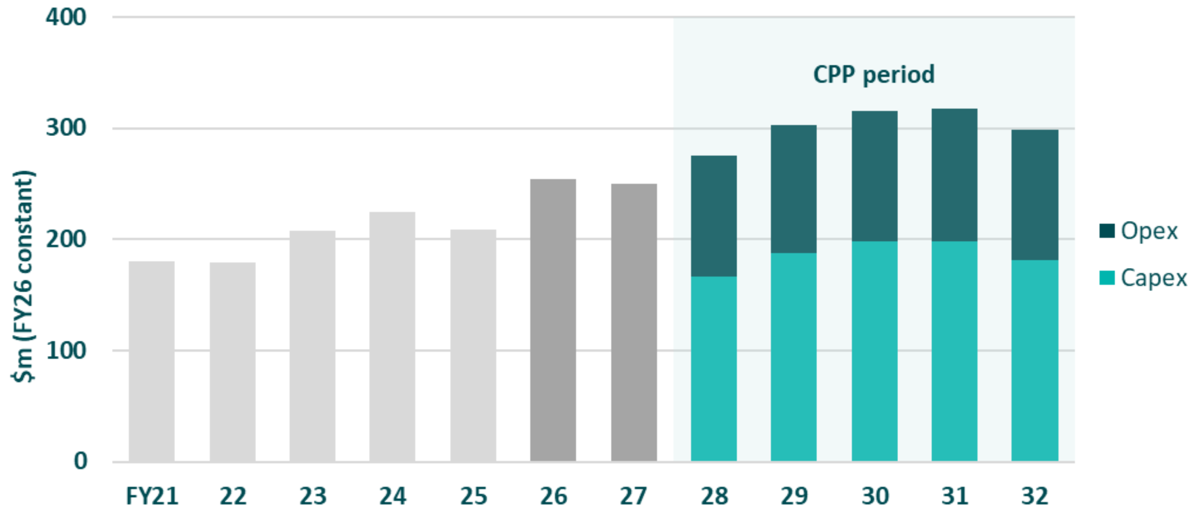
- current period (FY21–25): actual expenditure
- assessment period (FY26–27): actual and forecast expenditure
- CPP period (FY28–32): planned expenditure.

5.2 Total expenditure

210 Orion's planned total expenditure (totex) over the CPP period is $1.51 billion, or an annual average of $302 million. It represents the investment required to address our 5 strategic priorities for this period (outlined in Chapter 2) and meet our regulatory obligations.

211 Figure 5.2 presents the planned totex per annum, split between capex and opex, compared with our historical spend.

Figure 5.2 Planned total expenditure, per annum



212 The planned uplift in investment and activity reflects a step-up in renewals to address ageing assets and resilience requirements, demand growth, and the operating and capability uplift required to deliver a 'future-fit' network, while maintaining safe and reliable network performance.

5.3 Capital expenditure

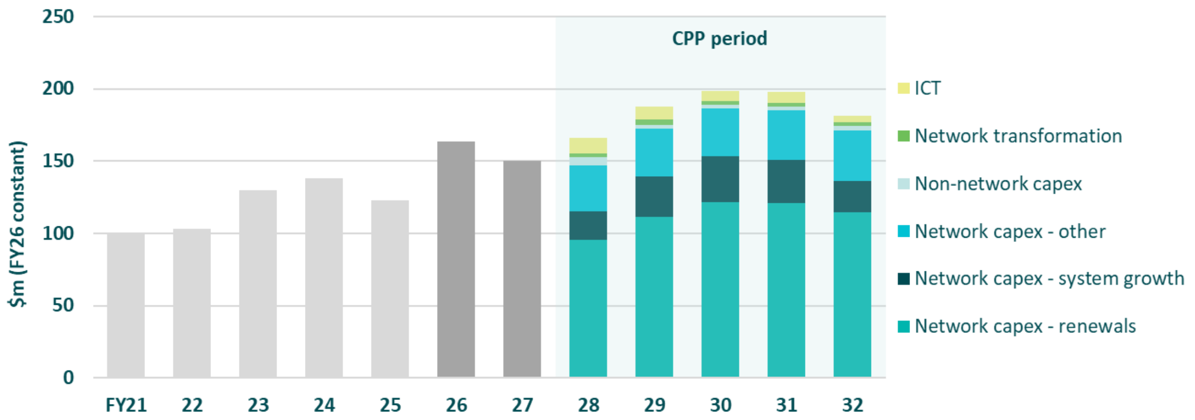
213 Capex refers to investments in the assets required to deliver network services that meet the performance levels customers expect. This includes both network assets (such as poles, cables, and switchgear) and non-network assets (including ICT systems, property, and vehicles).

214 Many of our assets remain in service for more than 50 years. The regulatory framework allows us to recover the efficient costs of these investments over their expected lives, including compensation for the cost of capital. This ensures the cost of long-lived assets is shared equitably between current and future customers who benefit from their use.

215 In developing our capex forecast for the CPP period, we sought to identify the efficient and prudent level of capital investment required to address the 5 strategic priorities outlined in Chapter 2, and achieve the asset management objectives set out in our Asset Management Plan 2026.

216 Figure 5.3 presents the planned capex per annum by expenditure category, compared with our historical spend.

Figure 5.3 Planned capex by expenditure category, per annum



217 Our total planned capex over the CPP period is $931.6 million. Our annual capex increased over recent periods, rising from $99.1 million in FY21 to $163.7 million in FY26. This trend is forecast to continue over the CPP period, with planned annual capex increasing to $166.3 million in FY28, peaking at $198.6 million in FY30, then declining slightly to $181.2 million in FY32.

218 The increase in planned capex is primarily driven by:

- **Ageing assets and resilience requirements:** we plan increasing renewals volumes across multiple fleets to address assets in poor or deteriorating condition, clear backlogs from past deferrals, strengthen resilience to earthquakes and severe weather, and maintain legislative and regulatory compliance. This is necessary to sustain network safety and reliability over the long term, in line with customer expectations.

- **Population growth and increasing demand:** investment in system growth is required to provide capacity for new connections, meet rising peak demand, and maintain security of supply. This reflects continued population and economic growth across our network area and the need to support development in a timely and efficient manner.

- **Transition to a more dynamic energy system:** network transformation investment reflects the shift toward greater electrification and uptake of distributed energy resources such as solar and batteries. It is required to build capability to plan and operate the network more flexibly, enabling better utilisation of existing assets, more targeted investment, and increased use of non-network solutions to defer traditional upgrades.

- **Digital enablement and changing technology landscape:** ICT investment is required to complete the transition to a modern, resilient, and fit-for-purpose technology environment. This supports operational efficiency, evolving regulatory and customer requirements, and the digital capabilities needed to manage a more complex energy system. As the sector shifts toward software-as-a-service and cloud-based solutions, a greater share of ICT costs is expected to move to opex over time.
- **Supporting organisational capacity:** general corporate investment reflects the need to expand facilities and physical resources – including office space, vehicles, tools, and equipment – to support the larger workforce required to deliver the CPP programme.

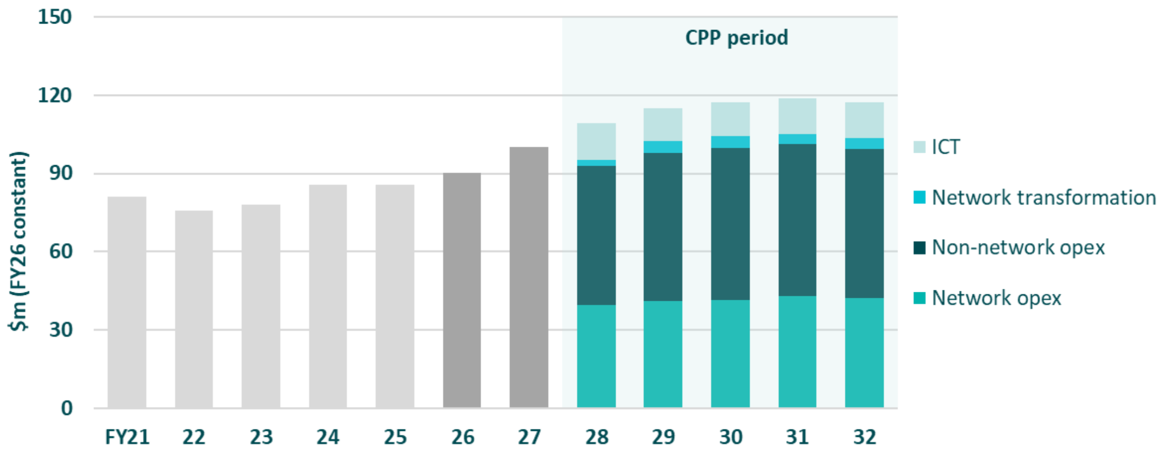
219 Chapters 6 to 11 provide further detail on our planned capex programmes, including key drivers, forecasting approaches, and how we have ensured the planned expenditure is prudent and efficient.

5.4 Operating expenditure

220 Opex comprises the day-to-day costs required to operate, maintain and support our network and business. This includes expenditure on people, systems, services provided by our service delivery partners, and corporate support necessary to ensure the network operates safely, reliably and efficiently.

221 Figure 5.4 presents the planned opex per annum by expenditure category, compared with historical expenditure.

Figure 5.4 Planned opex by expenditure category, per annum



222 Our total planned opex over the CPP period is $578.1 million. Annual opex increased in recent periods, rising from $81.2 million in FY21 to $90.3 million in FY26. This trend is expected to continue over the CPP period, with annual opex increasing to $109.3 million in FY28 and $117.5 million in FY32.

223 The increase in planned opex is driven by a combination of factors affecting how we operate and maintain the network:

- **Asset condition, resilience, and compliance requirements**: increased network opex reflects a step-up in preventive and corrective maintenance to address deferred maintenance activity and the elevated asset risk this has created, respond to updated asset condition information, and better utilise our integrated asset management system. Additional vegetation management is also required to strengthen resilience to extreme weather and comply with anticipated changes to the *Electricity (Hazards from Trees) Regulations 2003*.
- **Transition to a more active and flexible network**: network transformation opex supports improved real-time network visibility and more active system operation. This enables

more flexible customer connections and facilitates the use of non-network solutions, including the procurement of services to defer traditional network investment.

- **Digital enablement and increasing system complexity**: additional ICT opex is required to complete the transition to a modern, resilient technology environment. This underpins access to and use of network data, supports digital tools, and enables more efficient management of an increasingly complex energy system and evolving customer expectations.
- **Operating model and capability uplift**: delivering the CPP plan requires increased operational, engineering, and corporate capability, driving higher system operations and network support (SONS) and corporate support costs. This also reflects a shift toward a more data-driven and technology-enabled operating model.

224 The forecast increase in non-network opex is partly offset by assumed efficiency gains within the SONS and corporate support portfolios (see section 5.6). These efficiencies reduce opex by approximately $5 million over the CPP period. They build over the CPP period and by FY32 reduce our forecast opex by approximately $1.4 million per year.

225 Chapters 10 to 13 provide further detail on our planned opex programmes, including key drivers, forecasting approaches, and the basis on which we consider the expenditure to be prudent and efficient.

5.5 Forecasting approaches

226 In general, we developed our CPP forecasts using bottom-up methodologies that estimate required work volumes and apply associated unit rates. This approach ensures transparency and repeatability.

227 The methodology applied for each expenditure category is tailored to its underlying cost drivers, and typically includes one or more of the following approaches:

- volumetric forecasting
- tailored (project-specific) forecasting
- base-step-trend forecasting.

228 Our capex cost estimation framework is underpinned by our Pricebook, a centrally managed database of approved unit rates and component costs. Ergo Consulting reviewed these unit rates against those used across the New Zealand electricity sector, providing assurance that the cost inputs underpinning our capex forecasts are efficient and aligned with industry benchmarks. The independent verifier also reviewed the unit rates and found them to be efficient.

5.5.1 Volumetric forecasting

229 We used volumetric forecasting for capex programmes with relatively large volumes of similar works, such as poles and crossarms. For network capex, accurate cost estimates depend on the availability of historical outturn costs from comparable completed projects. This information is used to derive the average unit rates for application to future work volumes. These unit rates are often combined to form building block costs that reflect the main components of typical works.

230 Our volumetric forecasts were prepared on a P50 basis and assume that:

- the scope is well defined and consistent with the need case
- unit rates based on historical outturns capture the impact of past risks
- the aggregate impact of historical risks is spread across portfolios over time

- to maintain a portfolio effect, a large number of projects will be undertaken
- the volume of historical works assessed is sufficiently large to provide a representative average cost.

231 For non-network capex, we have used expected volumes and unit rates informed by discussions with vendors and historical cost outcomes.

5.5.2 Tailored forecasting

232 We used tailored forecasting for discrete, material capex projects – such as major renewals and system growth projects – based on defined project scopes. For larger projects, this approach was supplemented with cost estimates from external engineering consultants.

233 We develop network project scopes through desktop asset reviews, including aerial imagery, site layout drawings, underground service records, and cable duct information. These inputs provide reasonably accurate estimates for materials and work quantities.

234 Activity costs are based on historical delivery costs, service delivery partner rates, quotations, and external reviews. Material costs reflect supply contracts and historical installation costs for similar projects, updated to reflect current service delivery partner prices.

235 While individual project estimates are subject to uncertainty over a CPP period, portfolio-level risk diversification mitigates aggregate estimation risk. Accordingly, no additional portfolio-level estimation contingency has been included in the CPP capex forecast.

236 For large non-network systems or facilities, costs are forecast based on a combination of tender responses and desktop estimates, informed by historical procurement outcomes and vendor engagement.

5.5.3 Base-step-trend forecasting

237 We used a base-step-trend methodology to forecast recurring expenditure where historical expenditure provides a reasonable starting point for what we expect to spend in the future. We used this method to forecast the following expenditure categories: system growth capex (a part of the 11 kV reinforcement portfolio); network opex (all portfolios); non-network opex (SONS and corporate support).

238 This approach is widely used by utilities and economic regulators for forecasting recurrent expenditure. It involves:

- selecting a representative base year(s)
- adjusting the base year to remove significant non-recurring items or the impact of significant events (e.g. major storms)
- adjusting for step changes
- applying trends for ongoing cost drivers, including expected sector-wide productivity gains where applicable.

239 The objective is to establish a sustainable expenditure baseline and project it forward in a manner consistent with prudent and efficient delivery.

5.6 Efficiency

240 Orion places a strong emphasis on maintaining and improving efficiency across its operations. This is embedded in how we plan, deliver, and govern both capex and opex. Our CPP forecasts reflect this focus by starting from an efficient base, applying disciplined cost estimation practices, and incorporating realistic assumptions about ongoing productivity where supported by evidence and regulatory precedent.

241 Our forecasts do not rely on optimistic or speculative efficiency gains. Instead, they reflect:

- efficient current expenditure, demonstrated through benchmarking (Box 5.1)
- robust, market-tested cost inputs for future capital investment
- prudent, transparent treatment of productivity improvements in opex forecasts where appropriate.

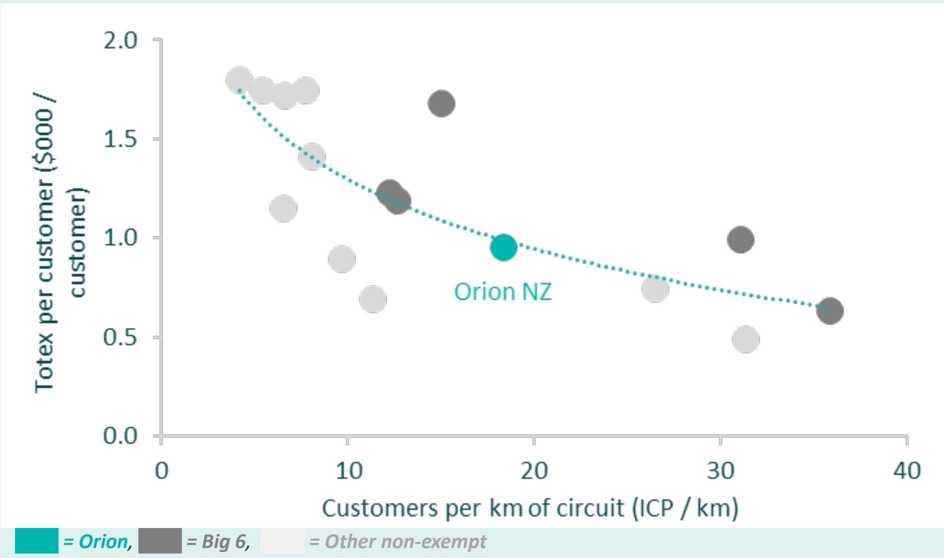
242 The sections below outline our approach to maintaining and improving efficiency in practice, how future efficiencies are reflected in our forecasts, and our other efficiency initiatives.

Box 5.1 Overview of benchmarking analysis and results

To help ensure our expenditure forecasts start from an efficient base, we engaged Farrierswier Consulting (farrierswier) to assess our expenditure and performance relative to comparable networks. Farrierswier benchmarked our historical capital and operating expenditure against a defined peer group of New Zealand EDBs at a category level, using publicly available data and established techniques. This approach helps identify the drivers of expenditure and assess performance in the context of our network characteristics, operating environment, and policy settings.

Overall, the results indicate that Orion's expenditure is broadly consistent with peers across most measures. Total expenditure sits toward the lower end of the 6 largest EDBs (the Big 6),[1] and close to or slightly below wider peer trendlines when plotted against customer density (Figure 5.5).

Figure 5.5 Totex per customer v customer density (average 2021–25)



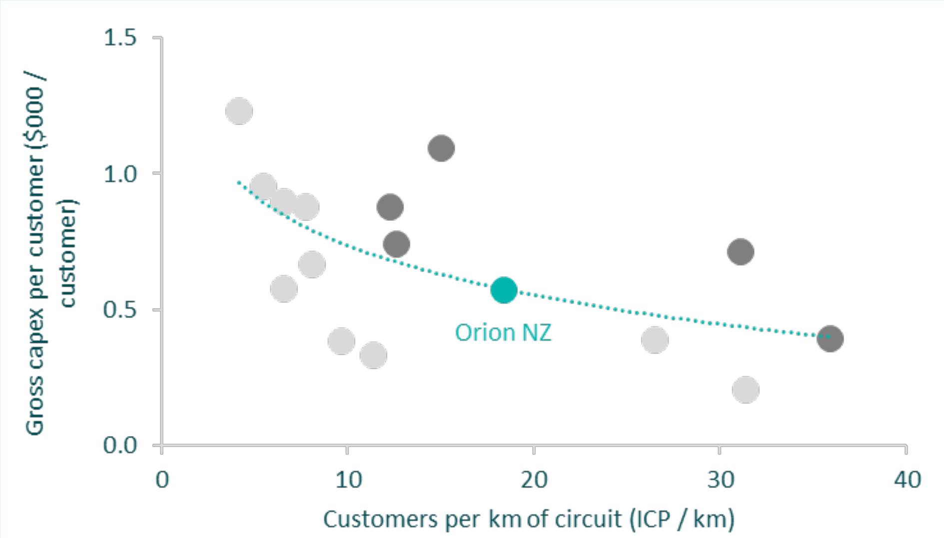
Source: farrierswier analysis

Total gross capex generally sits toward the lower end of the Big 6 (Figure 5.6). By category:

- Lifecycle capex (total reliability, safety and environment capex plus asset replacement and renewal capex) is low relative to peers when plotted against customer density.
- Renewals capex is particularly low, sitting notably below the wider peer trendline.
- System growth capex sits around the middle of the range, likely reflecting our deferral of non-critical renewals during DPP3 to support higher-than-forecast population and demand growth (discussed in Chapter 2).

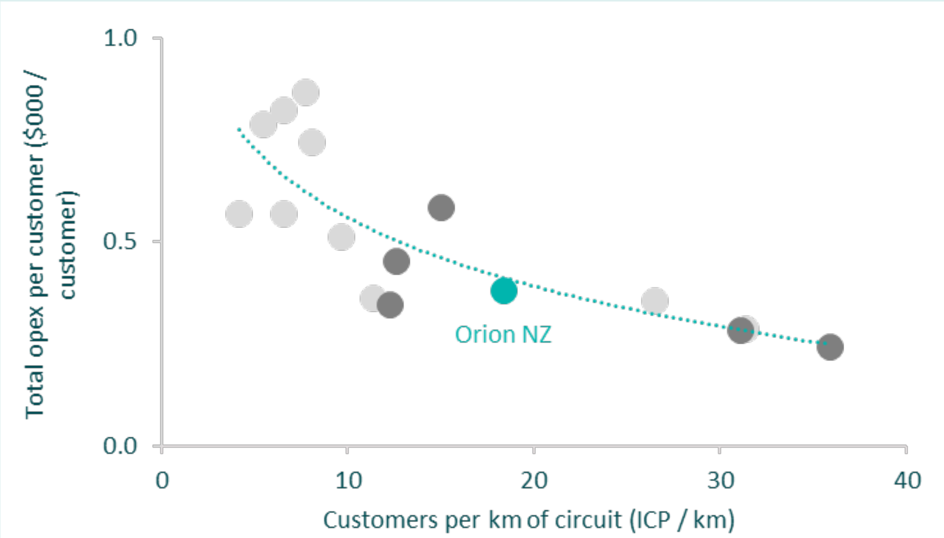
- Gross connections capex is broadly in line with the Big 6 on a per-customer and per-km basis, but higher than the wider peer group. However, capex per new connection is relatively low, suggesting the higher per-customer and per-km results are primarily driven by strong connection growth.
- Non-network capex is generally low compared to the other Big 6 on a per-customer, per-MW and per-km basis over 2021–25, and sits very close to the trendline when plotted against customer density.

Figure 5.6 Gross capex per customer v customer density (average 2021-25)



Source: farrierswier analysis

Figure 5.7 Total opex per customer v customer density (average 2021-25)



Source: farrierswier analysis

5.6.1 Approach to maintaining and improving efficiency

243 Our approach to efficiency is grounded in continuous improvement rather than one-off adjustments. Key elements include:

- regular testing of cost efficiency through benchmarking, market engagement, and independent review
- strong governance over scope, standards, and delivery models to ensure value for money
- investment in systems, data, and capability that supports efficient planning and delivery over time
- active management of scale and complexity as the network grows and new obligations emerge.

244 This approach recognises an important distinction commonly made by economic regulators between:

- **catch-up efficiency**, which reflects the scope for an organisation to close a gap to the efficient frontier, and
- **ongoing productivity**, which reflects how the efficient frontier itself is expected to evolve over time due to sector-wide improvements in technology, processes, and management practices.

245 Benchmarking indicates that we operate at or near the efficient frontier for New Zealand EDBs in aggregate (Box 5.1). Accordingly, our CPP forecasts are not premised on material catch-up efficiency. Instead, they focus on maintaining efficiency as scale increases, and on capturing realistic, sector-wide productivity improvements where conditions are supportive.

5.6.2 How efficiency is reflected in our capex forecasts

246 Efficiency is reflected in our capex forecasts primarily through disciplined cost estimation and delivery practices, rather than through the application of top-down efficiency factors.

247 Key features of our capex forecasting approach include:

- market-tested and benchmarked unit rates, informed by competitive procurement, recent contract outcomes, and supplier engagement
- portfolio-specific cost estimates that reflect current delivery models, standards, and risk profiles
- governance processes that challenge scope, timing, and cost assumptions before inclusion in the CPP programme.

248 This ensures that forecast capex reflects the efficient cost of delivering the required outputs at the time they are needed.

249 This approach is consistent with good electricity industry practice, which generally expects capex efficiency to be demonstrated through robust estimation, procurement, and delivery practices, rather than through explicit productivity factors applied mechanically to forecast expenditure.

5.6.3 How efficiency is reflected in our opex forecasts

250 Most opex forecasts have been developed using a base-step-trend approach, with efficiency incorporated in 2 complementary ways – by starting from an efficient base, and by applying explicit productivity assumptions where appropriate.

5.6.3.1 Efficient base

251 First, our forecasts start from an efficient base. As outlined above, our historical opex has been tested through benchmarking and review, and we consider it to be efficient in aggregate. This base reflects current service levels, delivery models, and operating conditions, without embedding unproven assumptions about future savings.

252 By establishing an efficient starting point, the CPP framework ensures that customers are not funding inefficient historical costs, while also avoiding the risk of double-counting efficiency through both base adjustments and forward-looking productivity assumptions.

5.6.3.2 Productivity assumptions

253 Second, where appropriate, we have applied explicit productivity assumptions to trend forward efficient base opex. These assumptions are intended to reflect expected sector-wide ongoing productivity,[17] not Orion-specific catch-up efficiency.

254 Consistent with recent regulatory precedent:

- As a starting point, we adopted a 0% productivity assumption as the baseline for all opex portfolios, consistent with the Commerce Commission's DPP4 decision for New Zealand EDBs. The Commission's analysis, drawing on econometric work by Cambridge Economic Policy Associates Ltd (CEPA), found that opex productivity in the New Zealand EDB sector has declined since 2008, with only modest recent stabilisation.[18] On that basis, the Commission concluded that the historical evidence did not support applying a positive industry-wide productivity assumption in the DPP4 period. We consider this is an appropriate baseline for the CPP period.
- We then departed from that baseline for our SONS and corporate support portfolios by adopting a 0.5% annual productivity assumption. This is supported by Australian regulatory precedent[19] and reflects the realistic benefits from our planned system, data and process improvements over the CPP period.

255 This differentiation reflects differences in operating conditions and the likelihood of realising measurable productivity gains. SONS and corporate support functions are expected to benefit from our planned system, data and process improvements and from embedding scale increases over time. A 0.5% annual productivity assumption therefore represents a credible and achievable efficiency target for these portfolios. It also reflects expected sector-wide ongoing productivity gains in Australia, consistent with the intention of the productivity assumption in a base-step-trend approach.[20]

256 In contrast, network opex portfolios and the non-network opex components of the ICT and network transformation portfolios are undergoing material growth and capability uplift. These activities are not yet in steady state, and applying a positive productivity factor would risk understating prudent and efficient expenditure requirements.

5.6.3.3 Consideration of independent verifier recommendation

257 In finalising our forecasts, we considered the independent verifier's recommendation to apply a 1% productivity factor across all opex portfolios. We did not adopt this recommendation, as we consider it to be unsupported by the evidence and inconsistent with relevant regulatory precedent.

258 In support of its recommendation, the verifier referenced Ofgem's decisions to apply a 1% productivity assumption for energy networks in Great Britain. In our assessment, that assumption reflects a deliberate policy challenge set by Ofgem rather than an estimate of expected sector-wide ongoing productivity.[21] Orion's benchmarking indicates that we operate at or near the efficient frontier among New Zealand EDBs. Accordingly, the relevant question is what sector-wide productivity gains are reasonably achievable over the CPP period, not the pace at which Orion should close a gap to peers. We are not aware of evidence supporting a 1% sector-wide productivity assumption in that context.

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[17] In its DPP4 decision, the Commerce Commission explained: "Our forward view of productivity should reflect economy and sector-wide improvements, to ensure the base, step, and trend approach delivers an efficient baseline".
See: Commerce Commission, *EDB DPP4 Final Decision*, *Reasons Paper*, *Attachment C – Operating Expenditure*, 20 November 2024, p.98; link.
[18] Ibid, p. 97 – 111.
[19] The Australian Energy Regulator has adopted a 0.5% annual productivity assumption for Australian EDBs. In doing so, it has recognised that historical productivity growth in the distribution sector has been achieved in part through ICT investment, and that ongoing ICT spend may be necessary for distributors to continue finding productivity gains over time.
[20] That is, to reflect the ongoing, sector-wide efficiency improvements that a prudent and efficient distributor is expected to achieve over time, and to pass those expected gains through to customers.
[21] See: Ofgem, *RIIO-3 Final Determinations Overview Document*, 4 December 2025, para. 8.22; link.

259 The verifier also referenced EDB-specific proposals or decisions to depart from sector-wide productivity assumptions in Australia and in New Zealand. For example, the 1% assumption proposed by TasNetworks was accepted indirectly by the AER in circumstances where the resulting opex forecast aligned with the AER's alternative estimate.[22] Similarly, the higher productivity assumptions applied by the Commerce Commission for Aurora Energy reflected catch-up efficiency unique to that EDB's circumstances.[23] Neither example supports applying a 1% ongoing productivity assumption to New Zealand EDBs operating at or near an efficient frontier.

5.6.4 Other efficiency initiatives

260 In addition to the explicit productivity assumptions for SONS and corporate support, our planned investment is expected to support broader efficiency improvements across the business. Where anticipated savings from specific initiatives were sufficiently certain and quantifiable within the CPP period, we incorporated those efficiencies directly into our expenditure forecasts. Examples include improvements in scheduling, data quality, and workflow automation that reduce forecast service delivery partner and overhead requirements.

261 However, many planned investments, particularly those relating to ICT and foundational digital capability, are enabling in nature. While they are expected to improve efficiency and service delivery over the long term, the timing and magnitude of those benefits are uncertain within the CPP period. Consistent with a prudent forecasting approach, we have not pre-emptively netted down expenditure for identified benefits that are unlikely to be fully realised during the CPP period. We have, however, included a top-down 0.5% productivity factor for the SONS and corporate support portfolios where some benefits are expected to materialise by the end of the CPP period from our planned ICT and other investments.

5.7 Assumptions underpinning forecasts

262 Our expenditure forecasts are underpinned by a set of core assumptions and reflect the best available information at the time of preparing this proposal. While uncertainty is inherent in forecasting over a multi-year period, we have applied robust methodologies and conservative assumptions to ensure our forecasts represent prudent and efficient expenditure. The key trade-offs, limitations, and assumptions are outlined below.

5.7.1 Capex-opex trade-offs

263 Our expenditure forecasts reflect deliberate trade-offs between capex and opex, assessed on a whole-of-life, least-cost basis to deliver required service outcomes.

264 For asset lifecycle, there is a trade-off between asset renewal capex and corrective and reactive maintenance opex. Our Strategic Asset Management Plan and supporting Asset Class Strategies aim to maintain asset fleet health through timely renewal. The base level of maintenance expenditure assumes this asset health is maintained. Accordingly, any deferral of renewal capex would result in increased corrective and reactive maintenance requirements and associated step-changes in opex.

265 For growth and security of supply, there is a trade-off between system growth capex and non-network solution opex. Where emerging demand can be met through demand management, flexibility services, or other non-network solutions, upfront capital investment in traditional network augmentation can be avoided or deferred.

[22] See: Australian Energy Regulator, *TasNetworks 2024–29 Distribution Revenue Proposal, Draft Decision, Attachment 6 – Operating Expenditure*, September 2023, p. 21; link.
[23] See: Commerce Commission, *Decision on Aurora Energy's Proposal for a Customised Price-Quality Path*, *Final Decision*, 31 March 2021, para. E134; link.

266 Consistent with our long-standing success in demand side management, we are committed to supporting the development of the market for non-network solutions and to deploying these wherever they are feasible and cost-effective. These alternatives are assessed on a like-for-like economic basis to ensure customers receive reliable supply at lowest long-term cost. Our forecasts reflect an efficient balance between traditional network investment and non-network solutions, noting that capital investment is required to meet strong urban expansion into new subdivisions and to connect new customers.

5.7.2 Key limitations

267 Forecasting expenditure over a multi-year period involves inherent uncertainty. While we have applied robust methodologies and used the best available information, actual outcomes may differ from forecasts.

268 Key uncertainties and limitations include:

- **Data maturity**: this proposal is based on the best asset information available at the time of drafting. While asset condition and inspection coverage continues to improve, current data maturity may influence the timing and scope of renewal forecasts. As asset intelligence improves, future lifecycle modelling and risk assessments will continue to be refined.
- **External dependencies**: growth-related expenditure is influenced by factors outside our control, including developer decisions, housing policy, and large commercial and industrial investment. These factors can change quickly and may require reprioritisation of investment or, if appropriate, a regulatory price-path reopener.
- **Industry inflation**: as witnessed in the immediate post-COVID period, actual inflation in our industry may outstrip forecasts. If this occurs, the volume of work that can be completed within a set financial constraint will be impacted. The impact of the Middle East conflict may result in higher actual inflation to that forecast.
- **Deliverability constraints**: the forecasts assume that planned programmes can be delivered at the required pace. We are confident that our service delivery partners have the capacity to deliver the volume of works the CPP plan involves. We actively manage delivery risks through workforce planning, contracting strategies, and programme governance (see Chapter 4 of this proposal and Section 17 of our Asset Management Plan).

5.7.3 Key assumptions

269 The following assumptions have the most material influence on our forecasts:

- **Demand growth**: our system growth forecasts are based on forecast number of new connections 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. (More information on forecast demand growth and projected connections growth is provided in Chapters 7 and 8, respectively.)
- **Energy transition**: we assume that the uptake of new technologies, including EVs, solar PV and battery storage, progresses broadly in line with current projections. Significant deviations in uptake or policy direction could influence the timing and scale of investment.
- **Regulatory settings**: we assume no material change in regulatory obligations beyond those already signalled. We also assume that emerging regulatory workstreams are implemented progressively with reasonable transition timeframes. Changes in regulatory requirements or funding mechanisms could affect expenditure timing and levels.

- **External coordination**: we assume that the timing of housing developments, commercial projects, and third-party infrastructure upgrades aligns broadly with information currently provided by councils and developers.

270 Consistent with prudent asset management practice we will continue to monitor these factors and update our plans as new information becomes available.

271 Overall, we consider our forecasts represent the prudent and efficient level of expenditure required to deliver safe, reliable, and future-ready network services, while appropriately managing uncertainty and maintaining flexibility to adapt as conditions evolve.

6

6 Network capex – renewals

272 Renewal capital expenditure funds the replacement or refurbishment of existing network assets nearing the end of their expected lives and the reactive replacement of assets following failure. This investment is essential to maintain network safety, reliability, and resilience.

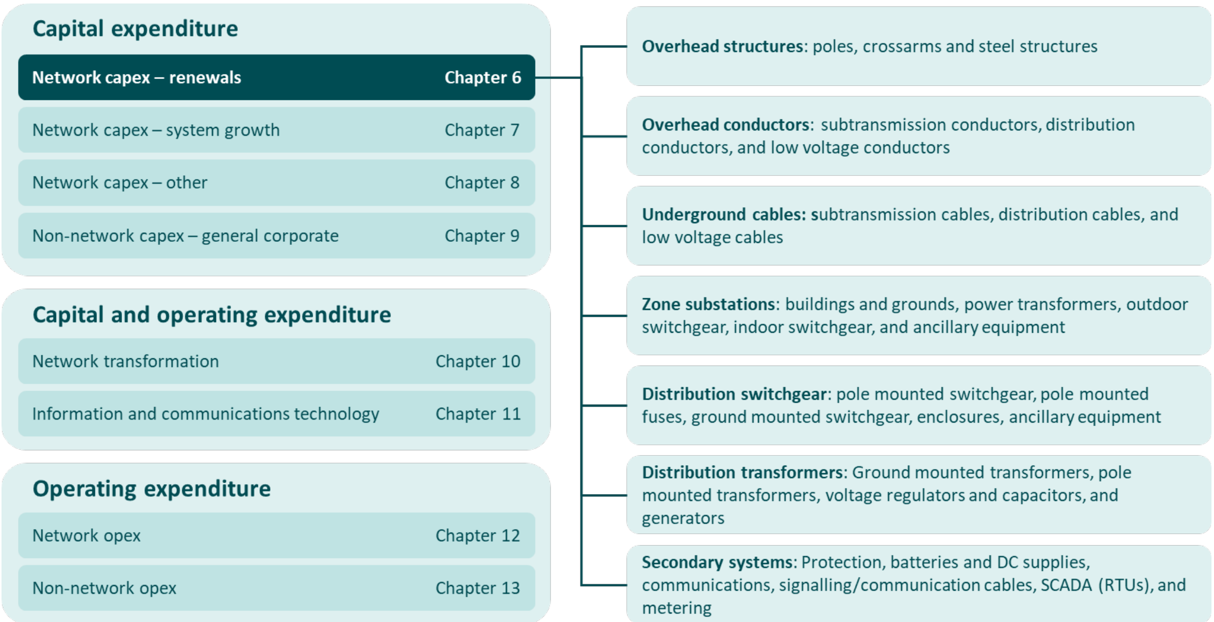
273 As assets age and their condition deteriorates, failure risk and maintenance costs rise. Orion seeks to renew ageing network assets before these risks and costs escalate, managing asset condition, safety risk, network performance, resilience, and obsolescence, and meeting regulatory and legislative requirements.

274 As Chapter 2 noted, Orion's safety and reliability performance has been strong, and customers expect this to continue. Meeting that expectation requires an increasing level of investment in renewals in the coming years, due to historical investment patterns and asset health trends.

275 In addition, Orion's network operates in a high seismic risk region and is increasingly exposed to climate-driven extreme weather events. These hazards can cause widespread and prolonged outages with significant customer and community impacts. Our customers support targeted resilience investment to strengthen the most exposed parts of the network.

276 Figure 6.1 shows where renewal capex sits within our overall expenditure and lists our renewal portfolios and the asset fleets within each.

Figure 6.1 Renewal capex portfolios and asset fleets



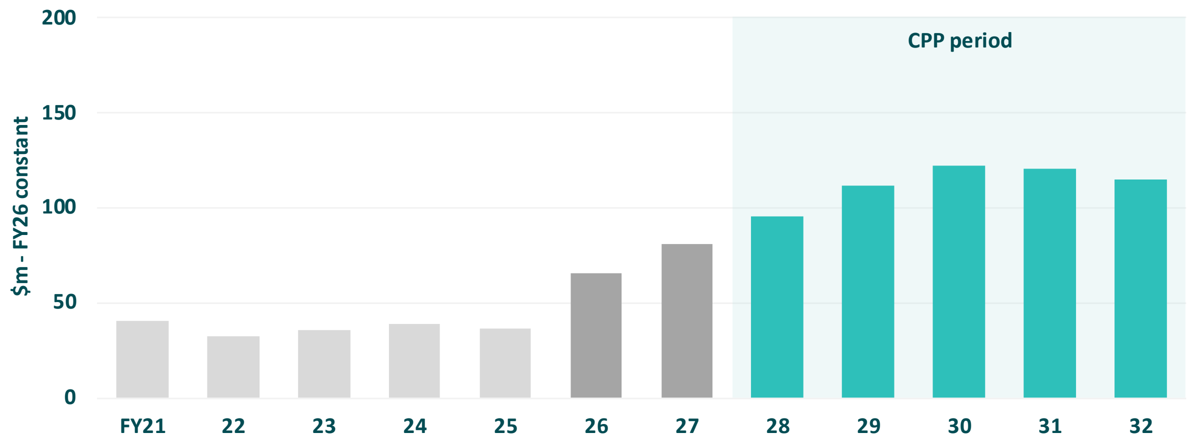
277 This chapter provides an overview of:

- our planned renewal capex
- its key drivers
- our forecasting approaches
- the capex for each portfolio
- why the planned capex is prudent and efficient.

6.1 Renewal capex

278 Orion's total renewal capex for the CPP period is $564 million, or an average of $113 million per annum. It is our largest expenditure category, representing 61% of total capex and 37% of totex for this period. Figure 6.2 shows the planned renewal capex per annum compared with historical spend.

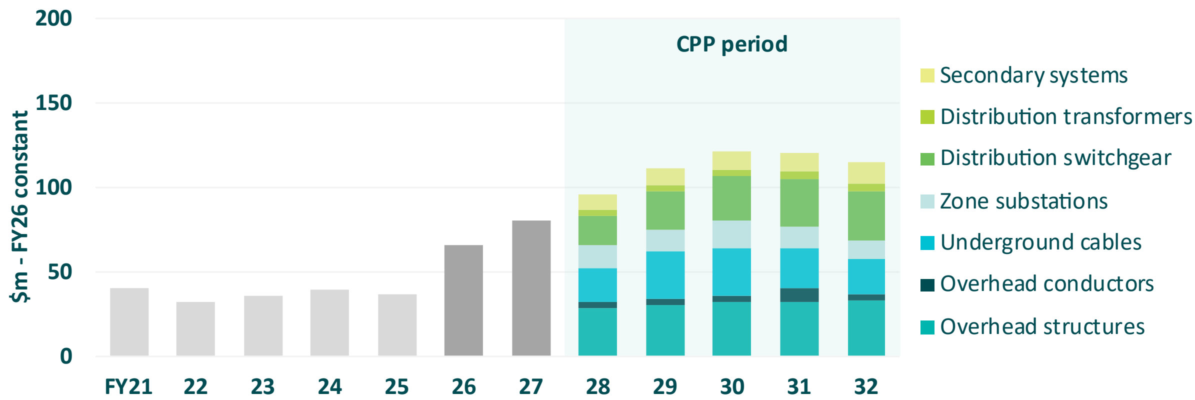
Figure 6.2 Planned renewal capex per annum



279 Our annual renewal capex increased stepwise in FY26 and is forecast to continue rising until FY30, before easing slightly and stabilising in FY31–32.

280 Figure 6.3 shows the planned annual renewal capex by portfolio.

Figure 6.3 Planned renewal capex per annum by portfolio



281 Annual expenditure is forecast to increase across most renewal capex portfolios. Those with the largest uplifts include cables and overhead structures. Our key renewal works over the CPP period include:

- maintaining the current health of our poles fleet, replacing poor condition telecoms poles and poles exposed to elevated wildfire risk with fire-resistant alternatives
- increasing the standalone proactive crossarm replacement programme and reestablishing a steel structures renewal programme
- progressing our 66 kV cable replacement programme to help ensure the network is resilient to major events including earthquakes
- renewing switchgear with poor asset health and certain assets with type issues leading to safety risks.

6.1 Key drivers

282 At a high level, renewal capex is driven by the need to maintain safe and reliable network performance through proactive asset health management and targeted investments to strengthen resilience across our asset fleets. Building on discussions in Chapter 2, we set out some of the overall drivers for planned renewal capex over the CPP period below. These drivers are then expanded on for particular fleets in the remainder of this chapter.

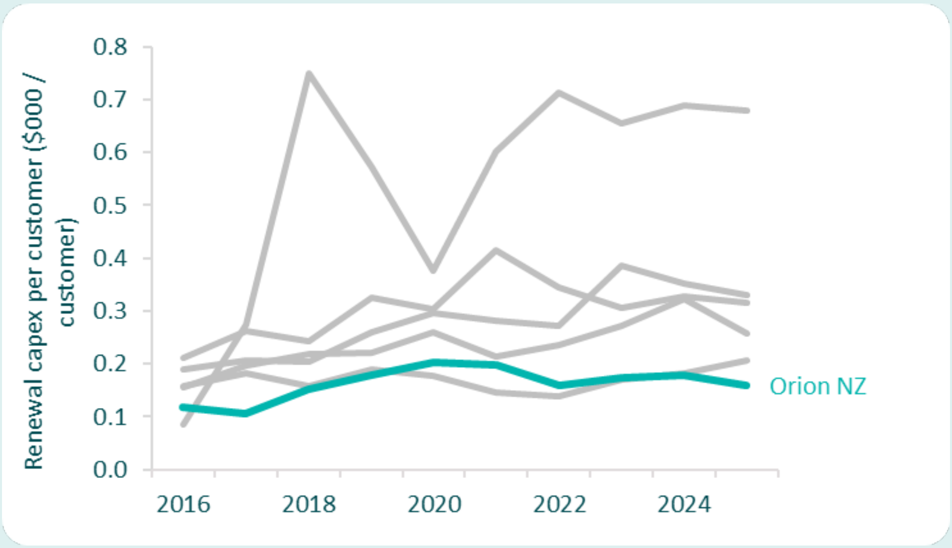
- **Safety risk**: condition deterioration or design limitations can increase safety risk to workers and the public. The planned renewals programme prioritises mitigation of these risks to ensure continued safe operation of the network.
- **Asset condition and health risk**: several asset fleets are in poor condition or have increased risk due to 'type issues' (issues that are specific to a particular model or design). The condition of other fleets will deteriorate without sufficient intervention. In some cases, this reflects the fleet's age profile. For example, many overhead assets were installed in the 1960s and 1970s and are now at or nearing the end of their expected lives. In other cases, such as certain distribution switchgear, there have been gaps in historical asset management practices or known issues with specific models. We need to increase renewals in these fleets to effectively manage asset health.
- **Past deferrals and accumulated backlog**: as noted above (see box 6.1), we deferred some non-critical renewals to prioritise more urgent and critical work in line with prudent asset management. In addition, proactive renewal programmes have not previously been in place for some asset fleets (e.g. overhead distribution conductor), with replacement being largely reactive. As a result, renewal backlogs are accumulating across several asset fleets, which need to be addressed to ensure we can maintain appropriate levels of safety and reliability.
- **Improved asset information and forecasting**: enhancements to inspection methods and decision-support tools have improved the accuracy of our renewal forecasts. Findings to date indicate some assets require renewal at a faster rate than previously understood.
- **Emerging renewal needs**: we expect a large volume of telecoms poles to be progressively transferred to us over the CPP period. These poles support Orion crossarms but are no longer required for telecommunications services. We expect a substantial proportion to require renewal during the CPP period and beyond
- **Natural hazard risk**: certain assets and network areas have been identified as particularly exposed to earthquake and wildfire risk. To mitigate the risk of widespread and prolonged outages following earthquake and severe weather events, we plan targeted investment to strengthen the resilience of network areas and assets most exposed to these risks.
- **Compliance requirements**: renewals investment is required to ensure ongoing compliance with legislative and regulatory obligations. For example, this includes conductor clearance requirements, seismic strengthening to meet the New Building Standard (NBS) thresholds, and fire standard compliance.

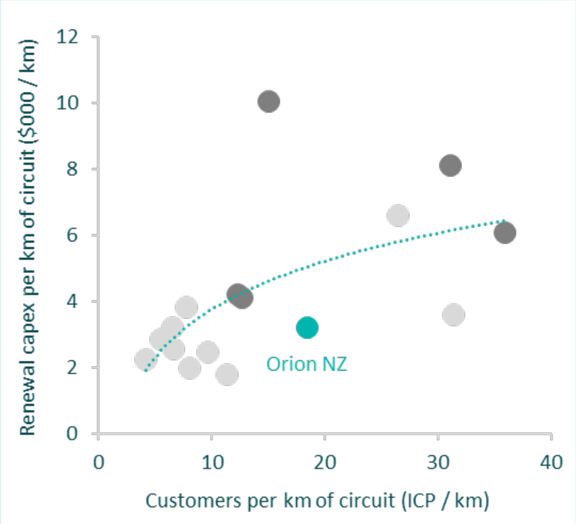
Box 6.1 Historical renewal expenditure

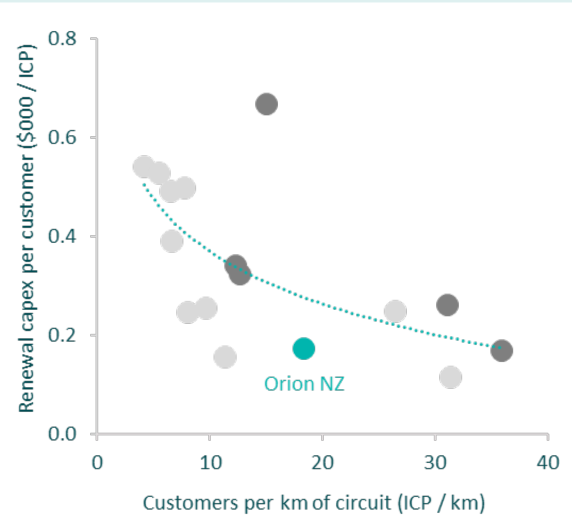
As depicted below, our renewal capex has been below that of comparable networks in recent years. Recovery from the 2010-11 Canterbury earthquakes has had a lasting impact on our historical expenditure, which is still influencing our network today. Significant investment was required to restore the network 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 activities. In the subsequent DPP period (FY21–25), we prudently prioritised investment in system growth and new connections to accommodate stronger-than-forecast population and demand growth, with consequential deferral of renewal activity. The impact of these decisions is evident in our recent renewal investment profile below.

We plan to address the accumulated backlog during the CPP period. Further deferral would increase safety and reliability risks and likely result in higher long-term costs.







= Orion, = Big 6, = Other non-exempt

Source: farrierswier analysis

6.2 Forecasting approach

283 Orion forecasts renewal capex for each asset fleet using bottom-up approaches tailored to the volume, type and cost of the assets to be renewed. Our renewals forecasting framework comprises the following key components:

- **Asset health modelling**: we assign asset health index (AHI) scores to assets across all fleets, based on age, condition, performance and known degradation mechanisms. These scores are used to model future fleet health under different investment scenarios and to inform risk-based renewal volumes.
- **Asset-specific forecasting methodologies**: we use a range of methods across our asset fleets, including volumetric forecasting and tailored estimates.
- **Costing methodology**: we convert forecast renewal volumes, programme scopes and project scopes into forecast capital expenditure using asset-specific unit prices, delivery assumptions, and escalation factors.

284 Together, these components provide a structured and risk-aligned basis for forecasting renewal capex across our asset fleets. Each component is outlined further below.

6.2.1 Asset health modelling

285 Asset health reflects the expected remaining life of an asset, and acts as a proxy for failure probability. We have developed an AHI for each fleet.

286 Assets are given AHI scores, based on inputs such as their age, condition assessment results, and known degradation mechanisms. For certain fleets, we also take account of factors such as make and model of the asset (and whether it faces any type issues), performance history, defect history, and location. This score (which ranges from H1 to H5) indicates the asset's relative likelihood of failure risk and likely replacement period (Figure 6.4).

Figure 6.4 Example of asset health index scoring

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

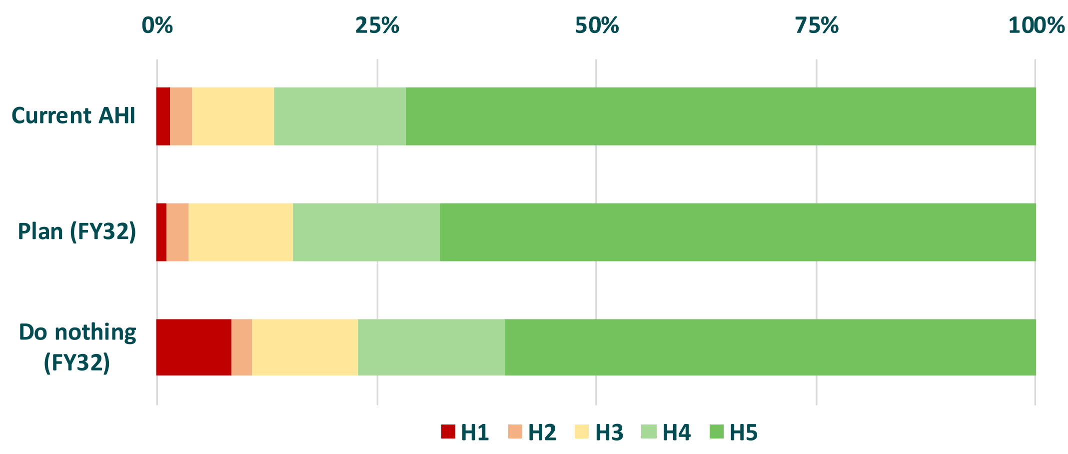
287 We use AHI to establish the current health profile of each asset fleet, expressed as the proportion of the fleet within each score category. From this baseline distribution, we model the future health trajectory of the fleet under a range of intervention scenarios.

288 Figure 6.5 provides an example of this modelling, showing a fleet's current asset health and its projected asset health.[24] The 'planned renewals' scenario illustrates the impact of a planned level of investment on the future health of that fleet over a forecast period. The 'do nothing' scenario illustrates the impact if no renewals are undertaken during that period.

289 We present all forecast health modelling against a hypothetical 'do nothing' scenario to illustrate the full potential deterioration over the forecast period. This scenario is not intended to represent a viable investment option.

[24] 'Current' asset health represents the first year of forecasted health in each fleet model, based on the model build date, which may vary across fleets.

Figure 6.5 Illustrative example of asset health modelling



290 Asset health modelling is the starting point for forecasting the quantity of renewals required per year during a given period. It provides the foundation for our renewal decision-making. Assessing projected health trends against forecast renewal volumes enables us to gauge whether planned investment is sufficient to manage overall fleet condition. Over the CPP period we will evolve this methodology, with health scores transitioning to broader risk scores that account for the criticality (potential failure consequences) of the assets.

6.2.2 Forecasting methodologies

291 To forecast required renewal quantities for a fleet, we use one or more methods, depending on the nature and volume of the assets in the fleet, and the available asset data. These methods use defined modelling and assumptions to forecast the volume of assets likely to require replacement each year.

6.2.2.1 Volumetric forecasting

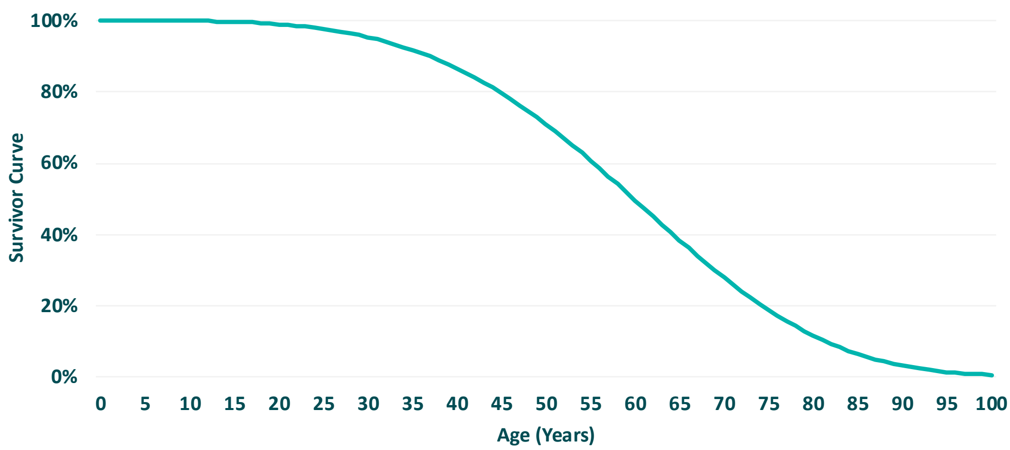
292 We use volumetric forecasting methods for fleets that typically require a larger volume of smaller, routine renewal works (such as poles). These methods use projected AHI and defined intervention thresholds to estimate the number of assets expected to require renewal in each year, and aggregate these to forecast annual fleet-level volumes. The specific methods we use – including survivor curve models, replacement expenditure (repex) models, condition-based approach, and age-based approach – are outlined in the sections on each asset fleet below.

293 Some assets within a fleet require replacement due to known type issues, safety risks, or compliance requirements. For example, these may be assets with unreliable components or identified design defects that present unacceptable safety or reliability risks. These issues differ from normal wear and tear and are addressed through targeted renewal programmes. These programmes are incorporated into overall renewal forecasts both as volumetric works and identified units based on their respective timing.

294 For large fleets with reliable historical end-of-life data, future replacement volumes may be forecast using survivor curves. A survivor curve model uses information on 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. The replacement rate curve can then be applied to the current population of assets to predict the future number of replacements. This approach assumes that historical asset failure rates provide an appropriate proxy for expected asset deterioration.

295 A survivor curve model is a statistical method used to forecast when a specific population of assets are likely to fail or require replacement, based on how long similar assets have historically remained in service. The model estimates the probability that an asset survives to a given age. For example, Figure 6.6 indicates there is a 50% probability that an asset in this population will remain in service for 60 years (or the median survival age is 60 years).

Figure 6.6 Illustrative example of asset health modelling



296 The model is then applied to the current asset age profile to forecast the quantity of assets expected to reach end of life in each future year. Our forecast replacement volumes are based on the central (P50) survival estimate derived from the fitted curves. The survivor curve forecasting method is well suited to large, homogenous fleets with high replacement volumes and robust historical data, such as hardwood and concrete poles. It captures the effect of condition implicitly, as historical replacements reflect condition-driven failures.

Box 6.2 Repex modelling

Repex models are used by many EDBs and economic regulators to forecast renewal needs, including in previous CPP processes and by network businesses regulated by the Australian Energy Regulator.

Repex models assume that asset replacements occur over a range of ages around an expected service life, rather than at a single fixed point in time. This approach recognises that assets have longer or shorter than average lives, produces a smooth replacement rate, and is appropriate where historic data is limited. It is widely used where detailed historical replacement data is limited and asset age provides a reasonable proxy for condition.

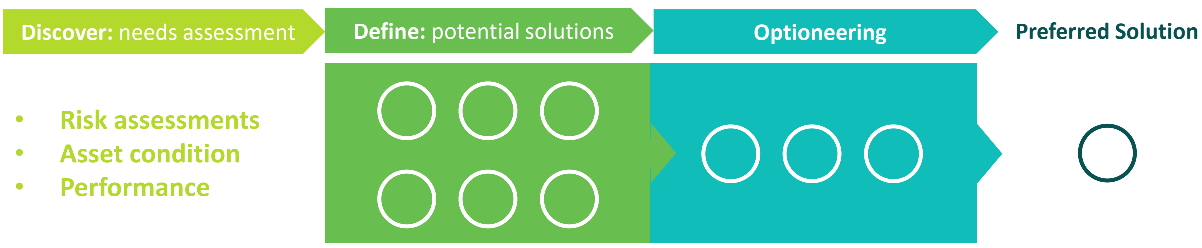
Our repex approach uses a normal distribution for the expected life for each sub-fleet in place of the survivorship function. The normal distribution is defined by the mean (expected life of the asset type) and the standard deviation – the square root of the expected life. The replacement rate curves produced from the repex models are then applied to the current asset populations to predict future replacement volumes.

6.2.2.2 Tailored approach to developing major projects

297 For major renewal projects that are relatively large and have a clearly defined scope and timing, we use a tailored approach that involves developing a full business case. Under this approach, individual projects are considered separately to determine timing and scope.

298 The approach assesses alternatives and options to get from a longlist to a shortlist, and then a preferred option. Assessing potential solutions and options is typically an iterative process with the level of detail and accuracy improving as the business case is further developed.

Figure 6.7 Approach to identifying major renewal project solutions



299 These stages guide us in identifying and prioritising major renewal projects necessary to manage asset risk, address deteriorating condition, and maintain network performance. This method is typically used where renewal need is likely to require a large bespoke solution, for example subtransmission cable replacement and zone substation renewal projects.

300 In the discover stage, we draw on information such as risk assessments, asset condition data, and network performance history to identify where subtransmission or zone substation renewal investment may be needed. For major projects, this includes assessing failure risk and the consequences of failure for customers and the network.

301 In the define stage, we identify a range of potential solutions for addressing the need. For example, these may include like-for-like replacement, refurbishment, rebuilds, or non-network solutions. They may also include a combination of approaches, or accepting the residual risk and deferring investment.

302 In the optioneering stage, as part of our business casing process we develop a shortlist of options based on safety, feasibility, risk reduction, potential cost, and other factors. We assess the justification for each option by applying standardised equipment failure rates and the value of customer reliability metrics. These tools allow us to quantify the expected benefits of reducing outages and service disruptions.

303 Once the preferred solution is selected, we use the defined project scope to prepare a more detailed estimate of forecast capex. The scope is used to determine the quantity of assets required (e.g. size of power transformers or kilometres of cable), which is multiplied by the relevant rates from our building blocks cost estimation tool.

6.2.3 Cost estimation

304 In general, our forecasts are developed using predictive forecasting techniques to estimate necessary work volumes, then applying unit rates. This bottom-up approach has been developed to ensure cost estimates are transparent, repeatable, and linked to outturn costs where available.

305 Programmes with relatively large volumes of similar works are categorised as volumetric works for estimation purposes. The main determinant of accurate costings for volumetric works is feedback of historical costs from completed equivalent projects. This is used to derive average unit rates to be applied to future work volumes. These unit rates are often combined to form building block costs that include the main components of large projects.

306 Our capex cost estimation process utilises our Pricebook – a centrally managed dataset of defined costs. This provides a consistent and controlled mechanism for incorporating feedback from completed works and updating equipment costs. We are continuing to enhance this approach by strengthening how actual project costs are captured and systematically fed back into future cost estimates.

307 Using this approach, volumetric unit rates are assumed to reflect P50 estimates. This is based on scope being reasonably well defined, and that unit rates derived from historical works already capture past risk impacts. Over time and with a sufficiently large volume of future work, cost variances will tend to offset one another.

308 For tailored renewal projects, cost estimates use a bespoke set of building block unit rates and associated quantities. This enables us to compile a project-specific cost estimate aligned to the defined scope. Project scopes are determined from desktop reviews of asset information such as site layout drawings, underground services drawings, and available cable ducts. These assessments provide reasonably accurate estimates for materials and work quantities, for example, building extensions and cabling lengths. Costs are informed by similar previous projects and updated with current unit rates from our price-book.

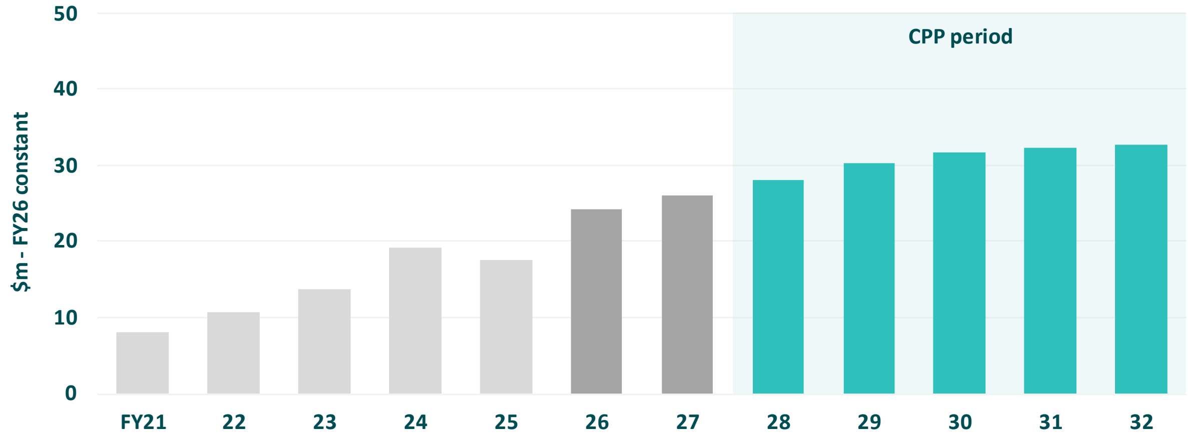
6.3 Overhead structures portfolio

309 Overhead structures support the overhead conductors that convey electricity across our network. This portfolio includes 3 asset fleets: poles, crossarms and steel structures. The planned capex, investment drivers, and forecasting approach are outlined below.

6.3.1 Overhead structures renewal capex

310 Overhead structures renewal capex over the CPP period totals $155 million, with annual capex as shown in Figure 6.8.

Figure 6.8 Planned renewal capex – overhead structures portfolio



311 Annual overhead structures renewal capex has increased steadily since FY21. This trend continues over the CPP period, with annual capex rising gradually up to FY32. This is largely attributable to managing a larger pole population, increased investment in the crossarms and steel structure fleets.

6.3.2 Pole renewals

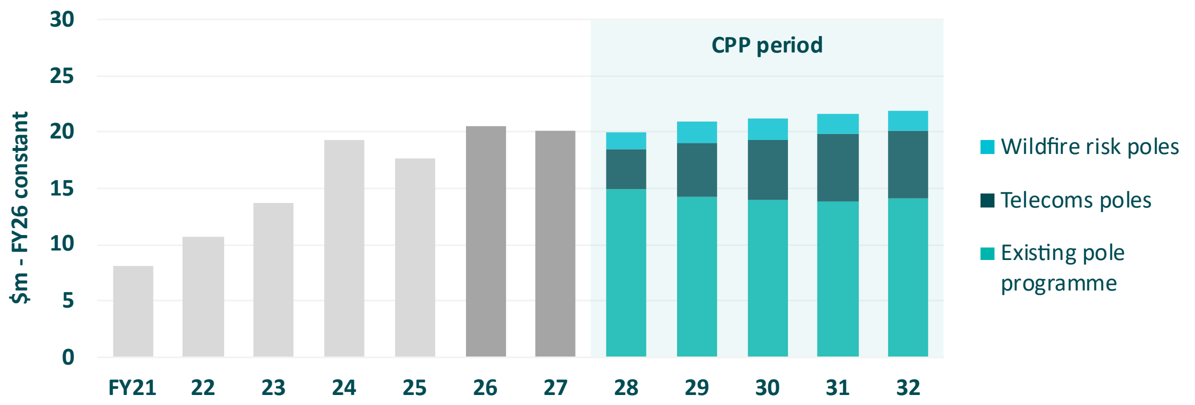
312 Our poles fleet includes more than 86,000 poles. Around 70% are wood (including hardwood and softwood). Most of the remainder are concrete, and a small proportion is steel. The majority of newly installed poles are wood. A substantial number of timber poles have exceeded their expected lives. We also use poles owned by a local telecommunications provider. As this provider no longer uses these poles, they are being progressively transferred to our ownership.

313 Pole renewal capex over the CPP period is $106 million, comprising 3 programmes:

- $8.9 million for wildfire risk poles
- $25.6 million for telecoms poles
- $71.1 million for our existing ‘BAU’ pole replacement.

314 Figure 6.9 shows the annual capex by programme.

Figure 6.9 Planned renewal capex – poles fleet



315 Over the CPP period, annual capex for the existing pole replacement declines. However, our overall poles renewal capex increases slightly, due to required renewal expenditure on the telecoms and wildfire risk pole programmes (discussed below). Historical pole renewal capex increased as we introduced enhanced inspection and condition assessment methodologies.

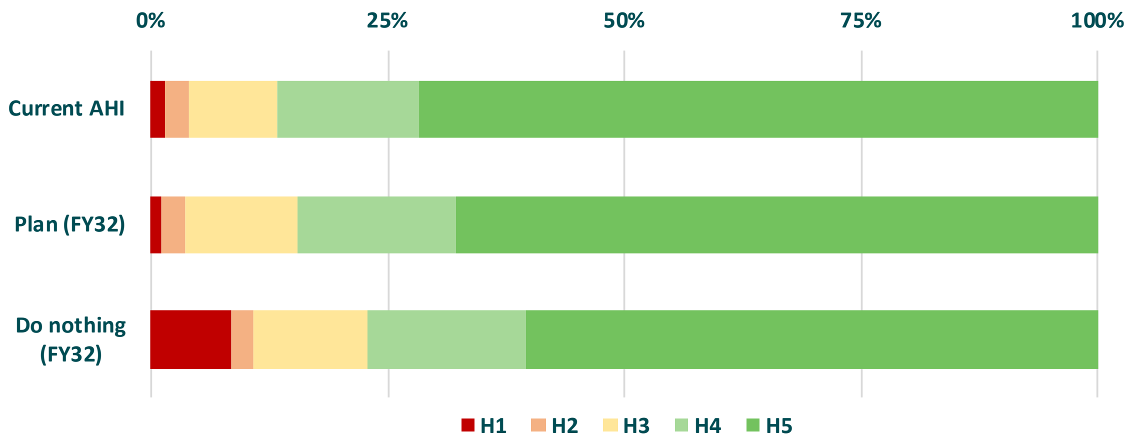
316 When a pole is replaced, we also replace the crossarm assembly for efficiency. The pole replacement unit rate provides for this; these renewals are included in pole renewal capex (and excluded from crossarms renewal capex).

6.3.2.1 Pole renewals investment drivers

Asset health and condition risk

317 The primary driver of pole renewal over the CPP period is maintaining fleet health to support safety and reliability. We aim to keep the proportion of H1 poles broadly stable. With the planned renewal capex, this proportion is forecast to remain stable until FY32 (Figure 6.10).

Figure 6.10 Asset health modelling for poles fleet



Box 6.3 Pole replacement versus reinforcing

Orion's approach to pole renewal is based on replacement rather than reinforcing or 'nailing'. Canterbury's seismic and liquefaction risk makes replacement a more appropriate solution. This is supported by external analysis that demonstrates that a properly embedded pole performs better in a seismic event than a reinforced pole. Our standard deep-embedment approach is also a more effective mitigation against liquefaction risk.

Reinforced poles can introduce additional risk for our staff and service providers who need to climb them. The added steelwork can obstruct access, limit safe attachment points for climbing equipment, and may create a false sense of structural security. Feedback from other EDBs and truss suppliers indicates there is no clear guidance on whether it is appropriate to climb a pole once a pole has been reinforced.

Overall, on our network, the potential cost-deferral benefit from pole reinforcement does not offset the technical issues and risks, only some of which are summarised above.

Inspection methodology uplift

318 In FY22, we enhanced our pole inspection and condition assessment methodology to include detailed below-ground inspections. This identified increased volumes of deteriorated poles, increasing the number of required replacements. A full inspection cycle under the new methodology is currently being completed. Addressing priority, poor-condition poles drove the uplift in FY24 expenditure seen on Figure 6.9 above.

Renewal of telecoms poles

319 As noted above, we expect around 15,000 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.

Wildfire risk

320 Analysis by Fire and Emergency New Zealand (FENZ)25 has identified elevated wildfire risk in parts of our rural network, including Port Hills, Castle Hill, Mt Horrible, and Broadfield. Past wildfires in these areas have damaged network assets. Wooden poles increase ignition and fire spread risk, heightening outage and safety exposure.

321 To mitigate this risk, we propose replacing wood poles in these areas with fibre-cement poles. This wildfire risk pole programme will improve resilience and reduce outage and safety risk for customers, the public, and our staff and service delivery partners. The case for investment is strengthened by evidence of increasing fire incidence associated with rising temperatures.26

322 In consultations, customers supported proactive investment in replacing poles exposed to wildfire risk to strengthen resilience and maintain reliability, particularly for rural and remote communities where restoration timeframes are longer and outage impacts greater.

6.3.2.2 Forecasting poles renewals volumes

General pole renewals

323 For hardwood and concrete pole sub-fleets, we applied survivor curve models to forecast annual replacement volumes.

324 For softwood and steel poles, we used an age-based repex method (Box 6.2). These sub-fleets have younger age profiles than hardwood and concrete poles, so historical failure data is insufficient to develop survivor curves.

[25] This classifies wildfire risk based on the interaction between topography, fuel characteristics, and weather conditions. Head Fire Intensity (HFI) values above 4,000 kW/m are classified as 'extreme', 'very extreme', or 'catastrophic', indicating conditions where effective fire suppression is extremely challenging. See *Spatial Prediction of Wildfire Hazard Across New Zealand* (FENZ / Scion / research reports)
[26] Analysis by Scion Research showed that New Zealand experienced 3 consecutive record warm winters (2020–2022), each warmer and drier than the year before. As temperatures rise, it predicts that the incidence and intensity of fires will increase.

325 We assumed an expected service life for softwood poles, based on a weighted average of historical renewals data. For steel poles, our assumed service life reflects their small population and historically low replacement rates.

Telecoms pole programme

326 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 pole programme

327 For this programme, we applied a risk-based forecasting approach to determine renewal volumes and timing. This involved:

- **Identifying fire risk areas and exposed assets**: we have experienced wildfires in Port Hills, Mt Horrible, Broadfield, and Castle Hill areas, which have affected our assets. We also identified areas within our network that have elevated fire risk, based on the 2025 FENZ Head Fire Intensity (HFI) analysis noted above. We have approximately 4,700 wood poles within HFI zones classified as extreme and above. We excluded LV poles where costs outweighed benefits, removed poles that are likely to be replaced as part of general renewals, and prioritised higher consequence areas.
- **Assessing solution options and volumes**: we evaluated short-listed options against a range of criteria and chose replacement with fibre-cement poles as the preferred option. We prioritised approximately 1,600 pole replacements, phased over around 15 years, which we based on deliverability and the level of wildfire-related risk reduction.

328 For poles renewal programmes, quantities are adjusted to exclude poles replaced under conductor renewals, growth, customer-driven, or relocation projects, where costs are captured in other portfolios.

6.3.2.3 Forecasting pole renewal costs

329 For general and telecoms poles, unit rates are based on recent historical average replacement costs and include crossarm assembly replacement. For wildfire risk poles, unit rates are based on recent fibre-cement replacements at Mount Horrible (FY26).

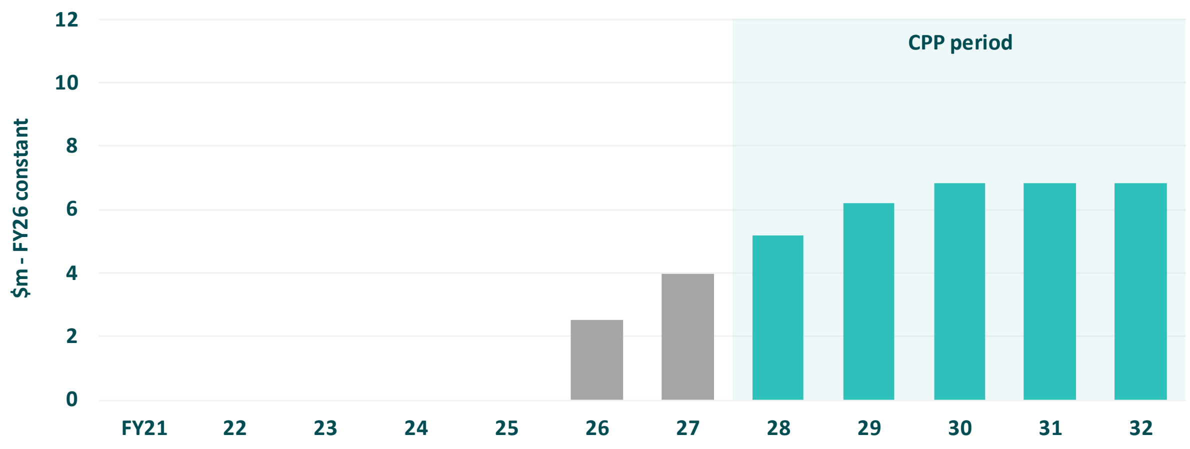
330 Unit rates assume work is carried out proactively. When a large volume of poles is replaced in a single job, the unit rate will generally be lower due to economies of scale. Unit rates are independently reviewed and are maintained within Orion’s centrally managed Pricebook, updated annually. All forecasts include direct overheads.

6.3.3 Crossarm renewals

331 Our crossarms fleet includes approximately 143,000 crossarm assemblies attached to the poles in our overhead network. Most are hardwood, with small numbers of steel. Types and configurations vary due to legacy designs, suppliers, and by voltage level.

332 Crossarm renewal capex over the CPP period is $31.9 million. Figure 6.11 shows this capex per annum compared with historical spend.

Figure 6.11 Planned renewal capex – crossarms fleet



333 Historically, we did not undertake proactive crossarms replacements other than those captured with pole renewals. Failure risk (as indicated by AHI) is increasing as the fleet ages; in FY26 we initiated a proactive standalone crossarm renewal programme to address end-of-life crossarms. We plan to continue this during the CPP and our initial focus is on old crossarms with pin-type insulators.

334 Our planned annual crossarm capex increases in the early CPP years, then stabilises from FY30, reflecting a ramp-up to a steady state of approximately 2,700 replacements per year.

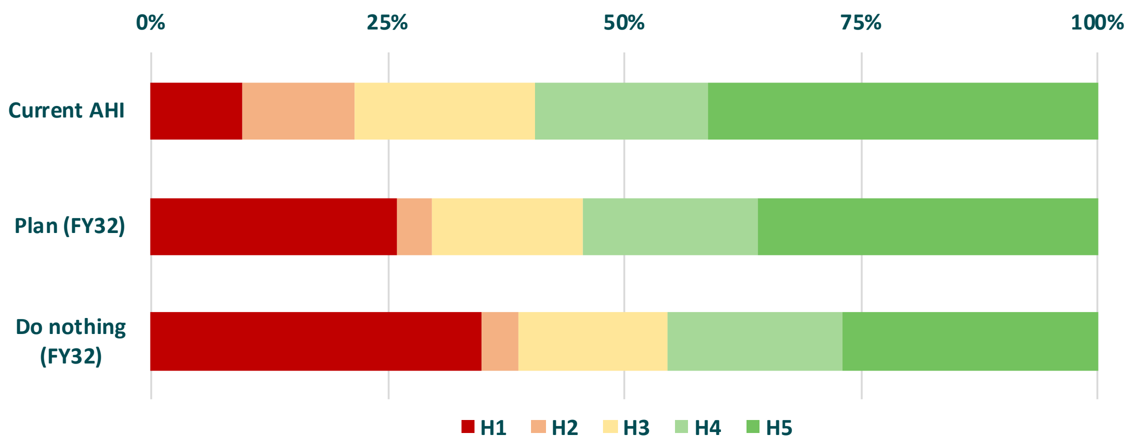
6.3.3.1 Crossarm renewals investment drivers

Asset health and condition risk

335 We assess crossarm condition using defect data, inspection results and known type issues. A significant proportion are in poor condition, reflecting fleet age and the absence of a specific crossarms proactive renewal programme before FY26.

336 The planned programme begins addressing the backlog. However, even with increased renewal volumes, the proportion of H1 crossarms is forecast to rise to approximately 25% by FY32 (Figure 6.12). Residual risk will be managed by prioritising renewals based on risk and criticality.

Figure 6.12 Asset health modelling for crossarm fleet



Safety and reliability risk

337 Crossarm failure can cause conductors to fall, creating significant safety risk to the public and field staff. Failed insulators can also initiate fires. Poor condition crossarms pose a higher risk in areas with fire risk or in densely populated areas. Renewal works are prioritised based on condition, location, and network criticality.

338 Crossarm failures interrupt supply and contribute to SAIDI and SAIFI. Planned replacements reduce unplanned outages and customer impact and will be coordinated with other overhead works to minimise disruption.

339 We have identified a safety risk associated with certain pin-type insulators installed on some high voltage crossarms. These are susceptible to cracking under environmental and mechanical stress, increasing flashover risk and potential ignition of timber crossarms or poles.

6.3.3.2 Forecasting crossarm renewal volumes and costs

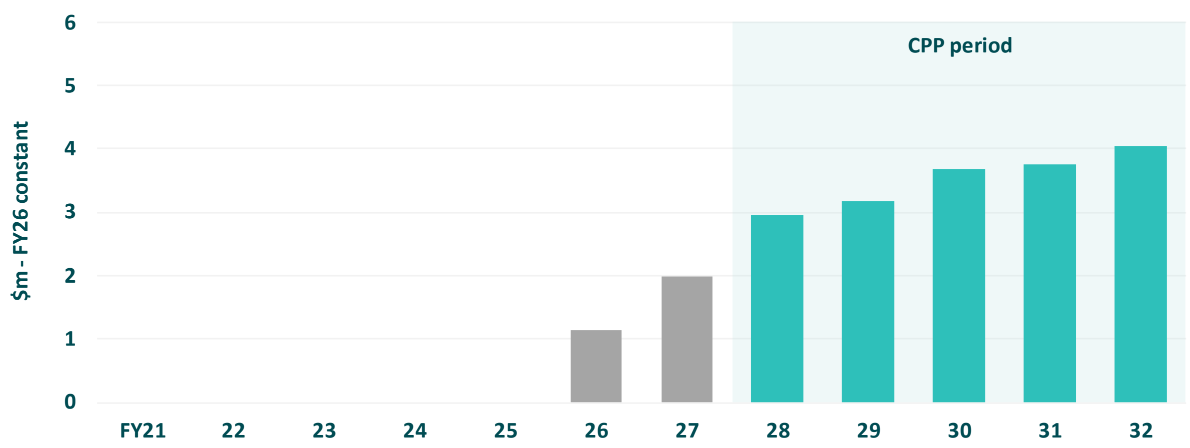
340 We forecast replacement volumes using the repex methodology (see Box 6.2). Unit rates reflect an estimated average replacement cost covering a wide range of brownfield installations and include the full crossarm assembly.

6.3.4 Steel structure renewals

341 Our steel structures fleet comprises 395 galvanised steel lattice towers, including associated insulators and foundations. The fleet includes multiple tower designs and foundation types.

342 Steel structure renewal capex over the CPP period is $17.6 million, with annual capex as shown in Figure 6.13.

Figure 6.13 Planned renewal capex – steel structures fleet



343 In recent years we have undertaken little proactive steel structure refurbishment. This activity is planned to increase from FY26 and will continue rising over the CPP period before stabilising.

6.3.4.1 Steel structure renewals investment drivers

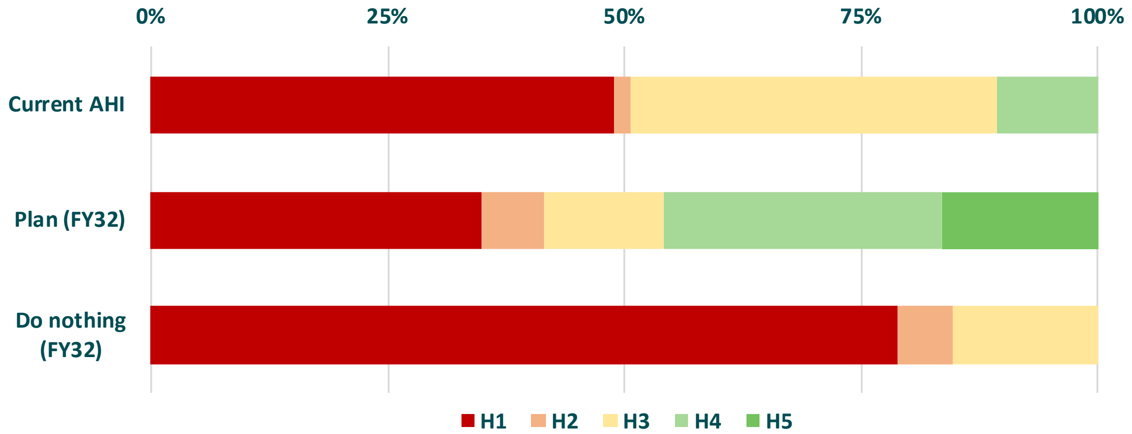
Asset health and condition risk

344 We inspect each tower on a 5-year cycle and assess condition of both upper and lower structures to derive an overall health score. Currently, a large proportion of the fleet is in deteriorating health due to tower age and ageing protective coatings. Almost half the towers are painted, and most were painted 15-25 years ago.

345 The tower painting programme was previously deferred under constrained DPP allowances, creating a refurbishment backlog. Further delaying replacement or painting until severe corrosion has occurred would increase structural risk and remediation costs.

346 Currently, nearly half of the fleet is H1 (refurbishment within one year) and almost all of the fleet is H3 or lower (within 10 years). Under the planned programme, these proportions reduce substantially (see Figure 6.14), materially lowering near-term risk.

Figure 6.14 Asset health modelling for steel structures fleet



347 While not restoring the fleet to target health levels, the programme represents a prudent and deliverable programme to manage deteriorating asset health and align with service delivery partner capacity.

348 We intervene before severe corrosion develops and leads to failure risk. We will focus on more critical assets to manage overall risk levels of the fleet. Works are coordinated with overhead line activities to minimise outages and customer disruption.

Foundation integrity risk

349 Some towers use direct-buried steel grillage foundations which are susceptible to below-ground corrosion. Weakened or failed foundations can result in tower failure, creating reliability and safety risks. We are progressively encasing grillages in concrete to arrest corrosion and mitigate this risk.

Site-specific constraints

350 In some cases, replacement of towers with monopoles is more practical and cost-effective than refurbishment. This applies to towers where painting is not feasible or which have inadequate clearances to meet current safety requirements. This may also apply if towers are relatively small and have reached the end of their serviceable life.

6.3.4.2 Forecasting steel structure renewals volumes and costs

351 We apply a volumetric methodology to forecast refurbishment and replacement volumes. This involves:

- assigning each tower a condition score through 5-yearly inspections
- classifying towers by corrosion zone
- applying degradation curves by condition and exposure to determine optimal intervention timing.

352 This approach targets refurbishment before severe corrosion develops, reducing safety and reliability risk while avoiding premature replacement.

353 We may make limited exceptions to our approach above, where lifecycle outcomes are improved. In restricted areas, we replace degraded steel rather than painting. Where appropriate, we replace smaller towers with monopoles to eliminate recoating requirements.

354 We are progressively encasing grillage foundations in concrete to mitigate long-term corrosion risk. Works under this portfolio are estimated using the volumetric approach described in section 6.3.

6.4 Overhead conductor portfolio

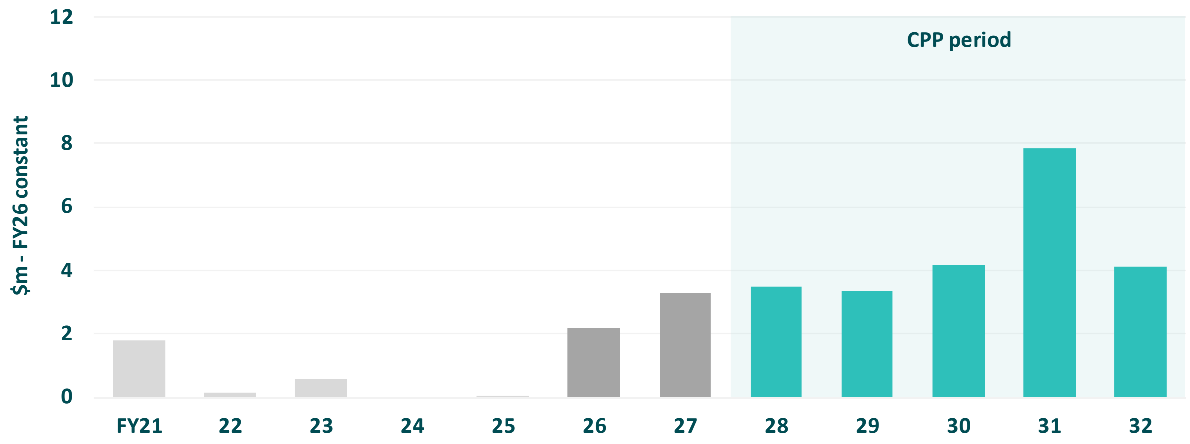
355 Overhead conductors convey electricity from Transpower's grid exit points (GXPs) across our network to customer premises. This portfolio comprises 3 asset fleets, based on their respective voltages, each of which also includes conductor hardware components:

- subtransmission conductors (33 kV and 66 kV)
- distribution conductors (11 kV)
- low voltage conductors (400 V), including streetlighting circuits.

6.4.1 Overhead conductor renewal capex

356 Overhead conductor renewal capex over the CPP period totals $23 million, with annual capex as shown in Figure 6.15.

Figure 6.15 Planned renewal capex – overhead conductor portfolio



357 Historically, we have undertaken limited proactive conductor replacements due to prioritising other asset fleets. Failure risk (as indicated by AHI) is increasing as the fleet ages and in FY26 we initiated a proactive standalone renewal programme to address end-of-life conductors.

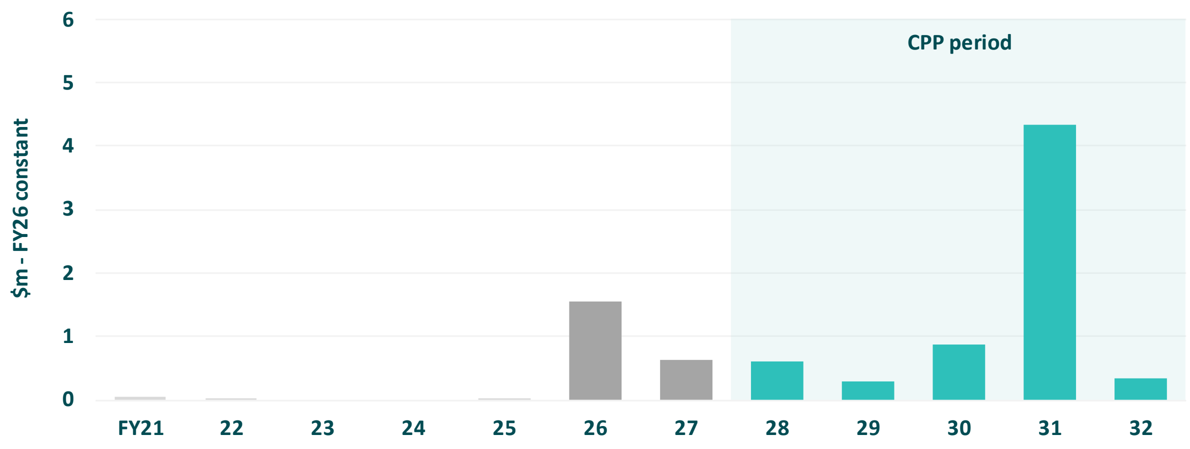
358 Our planned renewal capex is forecast to remain broadly in line with FY26–27 for the first years of the CPP period, then trend upward to FY32. This broadly reflects the age profile and condition of each conductor fleet, as well as targeted replacement of higher risk circuits.

6.4.2 Subtransmission conductor renewals

359 Our subtransmission overhead conductors operate at 66 kV and 33 kV and distribute electricity from GXPs to and between zone substations. These are critical assets, requiring high levels of reliability and resilience. The fleet comprises approximately 515 circuit km, predominantly aluminium conductor steel-reinforced (ACSR), and a small volume of copper. Expected service life varies by conductor type, size, and location. Coastal and industrial environments are known to accelerate corrosion.

360 Subtransmission conductor renewal capex over the CPP period is $6.5 million, with annual capex as shown in Figure 6.16.

Figure 6.16 Planned renewal capex – subtransmission conductor fleet



361 As discussed above, we undertook limited proactive conductor replacements and are now initiating a proactive standalone renewal programme to address end-of-life conductors. Our planned renewal capex is relatively small over the CPP period other than Bromley – Heathcote major project in FY30-31 (see Box 6.4). The majority of spend in FY26-28 relates to rectifying clearance violations, which we are working with Transpower to address.

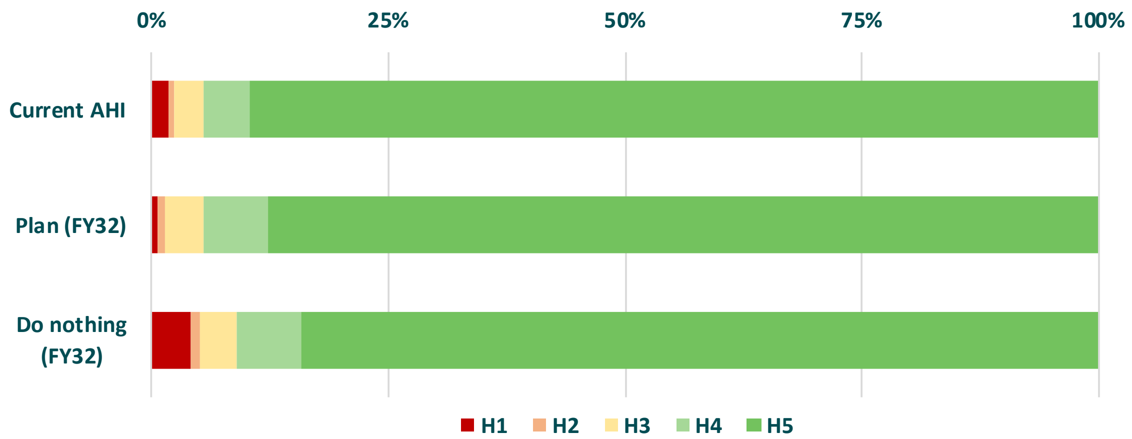
6.4.2.1 Subtransmission conductor renewals investment drivers

Asset health and condition risk

362 We assess the health of our subtransmission conductor fleet using a combination of preventive maintenance inspections, condition testing (including Cormon testing), and age-based modelling by conductor type, size, and corrosion zone.

363 The fleet is currently in reasonable health overall (Figure 6.17). However, certain coastal 66 kV circuits exhibit elevated corrosion and deterioration, including loss of zinc coating and strand degradation. These circuits present higher safety and reliability risks. The planned renewals programme prioritises these assets for intervention.

Figure 6.17 Asset health modelling for subtransmission conductor fleet



364 Under the planned renewals programme, the proportion of H1 conductor will decrease slightly by FY32, while the proportion of H2–H3 conductor remains broadly stable.

Safety and reliability risk

365 Subtransmission conductor failure can result in fallen live conductors and presents significant public and worker safety risks. Corrosion and clearance non-compliance increase this risk on certain circuits. Failure can also interrupt supply to zone substations and affect large customer populations.

Box 6.4 Overview of Bromley to Heathcote major conductor renewal project

The Bromley to Heathcote (BRM-HTE) 66 kV conductors are Wolf ACSR type, double circuits and a total circuit length of 8.22km. The BRM-HTE circuits were installed in 1957 and are 69 years old. We have undertaken various tests on the conductors. The latest Corman tests showing 8 of 14 sampled spans have high / severe galvanising loss. Points in a conductor with galvanising loss indicate weaknesses that could result in a conductor drop. Further conductor sampling tests in FY26 confirmed corrosion and outer layers of the conductor failing tensile strength testing.

The BRM-HTE circuits traverse areas with potential public safety risk. These areas include commercial / industrial areas (e.g. lines directly above buildings), parks, residential housing, and a state highway. If the conductor were to fail in these areas, there is elevated risk of safety incidents. The circuits also traverse areas where there is dry grass in the summer, if the conductor were to drop in these areas, it may ignite fires which is also another public safety concern. If both BRM-HTE circuits were to fail, which is conceivable as one conductor breaking could hit the other circuit, this could then cause both Heathcote and Barnett Park zone substations to lose load, potentially impacting up to 12,000 customers.

We undertook options analysis to consider individual span replacements versus replacing both circuits at the same time. Our planned solution is to replace both circuits at the same time.

6.4.2.2 Forecasting subtransmission conductor renewals

366 In most cases, we use a tailored approach to forecast major subtransmission overhead conductor replacement projects.[27] These circuits are replaced based on condition and risk, as assessed for each circuit. We determine the degradation trend over time and estimate when replacement will likely be needed. We prepare individual business cases (including options analyses) to determine the most efficient solution and develop an expected project scope for the selected solution.

367 For other subtransmission conductor renewals, we forecast the volume of renewals per annum using a repex model (Box 6.2). Clearance violations are identified individually.

6.4.2.3 Forecasting subtransmission conductor renewals costs

368 For major projects, we prepare tailored desktop cost estimates using a building-block approach aligned to the expected project scope. Costs are phased in accordance with project delivery schedules.

369 For volumetric renewals, we apply a price (P) × quantity (Q) methodology, multiplying forecast replacement kilometres by externally reviewed unit rates maintained in our centrally managed Pricebook, updated annually. All forecasts include direct overheads.

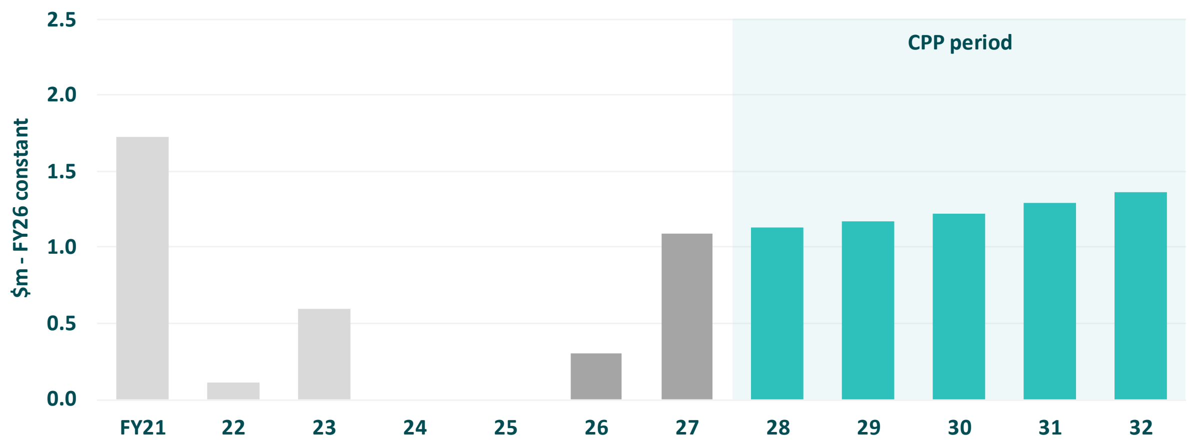
6.4.3 Distribution conductor renewals

370 Our 11 kV overhead conductor fleet comprises approximately 3,125 circuit km and forms the backbone of our rural and outer-urban network. The fleet is predominantly ACSR with smaller volumes of copper and aluminium types.

371 Distribution conductor renewal capex over the CPP period is $6.2 million, with annual capex as shown in Figure 6.18.

[27] Major projects are those with a total cost greater than $5 million.

Figure 6.18 Planned renewal capex – distribution conductor fleet



372 As discussed above, we undertook limited proactive conductor replacements and are now initiating proactive standalone renewal programmes to address end-of-life conductors. Our planned renewals capex is broadly in line with FY26–27, with a slight upward trend over the CPP period. Our planned renewal capex is relatively small over the CPP period, and we expect this to gradually grow over time as asset condition deteriorates.

6.4.3.1 Distribution conductor renewals investment drivers

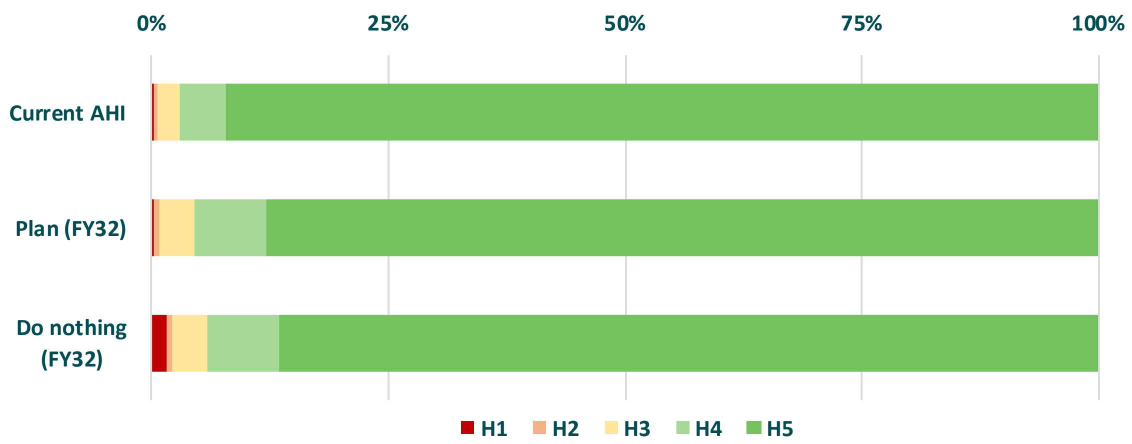
Asset health and condition risk

373 We assess the overall health of the 11 kV conductor fleet using repex models (Box 6.2). These models forecast the volumes of conductor of each type, size, and corrosion zone combination that will need to be replaced. Condition is based on 5-yearly visual inspections undertaken alongside pole inspections. A portion of our ACSR distribution conductor population is approaching expected end of life. However, the overall fleet is in good health, with a very small amount classified as H1 (Figure 6.19), including conductors that are:

- end-of-life small diameter copper conductor known to be a type issue in the industry
- older ACSR conductor near coastal (high corrosivity) regions.

374 With the planned renewals capex, the proportion of conductor in H1 is forecast to remain stable over the CPP period.

Figure 6.19 Asset health modelling for distribution conductor



Safety risk and reliability risks

375 Conductor failures and clearance issues pose safety risks to the public and field staff. Some conductor types can have type issues that increase failure risk, e.g. those with diameters of less than 50 mm². These conductors are less resilient. In addition, some breakages of conductors were caused by a design issue with the connectors between conductors and fuses in rural areas. We are progressively replacing these connectors with a different type, when they break or when other work is undertaken on the assets.

376 Distribution conductor failures contribute to SAIDI and SAIFI. Planned renewals help mitigate failure risk associated with ageing assets and connector degradation.

6.4.3.2 Forecasting distribution conductor renewal volumes and costs

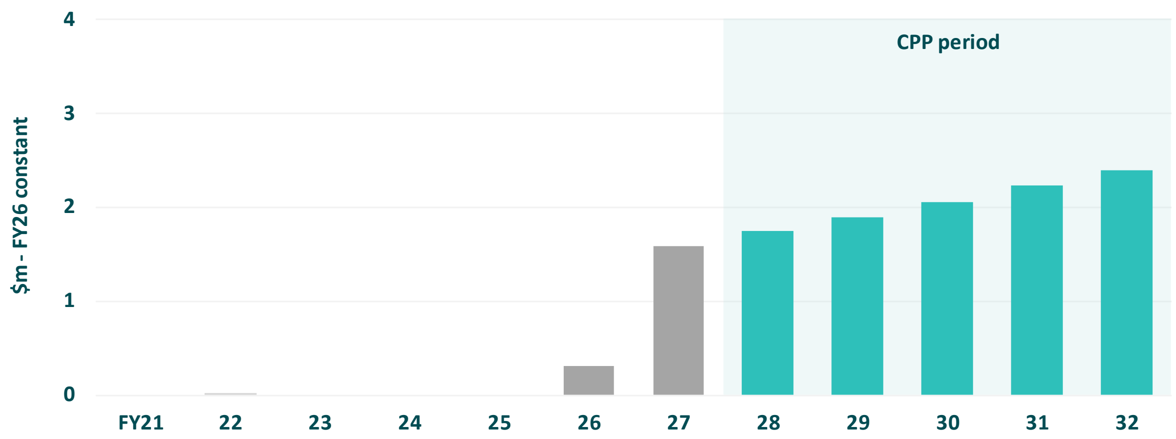
377 We forecast the volume of renewals per annum for each distribution conductor sub-fleet (defined by conductor type, size, and corrosion zone) using repex models (Box 6.2). In applying this approach, we used different expected asset service lives for each sub-fleet. We generally replace conductor on a like-for-like basis using preferred conductor types, unless capacity or safety considerations support an alternative solution.

6.4.4 Low voltage conductor renewals

378 Our low voltage (LV) overhead conductor fleet comprises approximately 2,300 circuit km, predominantly copper, with smaller volumes of aluminium.

379 LV conductor renewal capex over the CPP period is $10.3 million, with annual capex as shown in Figure 6.20.

Figure 6.20 Planned renewal capex – low voltage conductor fleet



380 Historically, we addressed any isolated sections requiring repairs or replacement through reactive maintenance. However, the risk of failure is increasing as the fleet's population ages. To mitigate this risk, we initiated a more proactive renewals programme in FY26.

381 Our planned annual renewals capex is trending upward over the CPP period. This reflects the planned ramp-up of the proactive renewals programme, targeting small-diameter copper conductors that are performing poorly, and have a known industry-wide type issue.

6.4.4.1 LV conductor renewals investment drivers

Asset health and condition risk

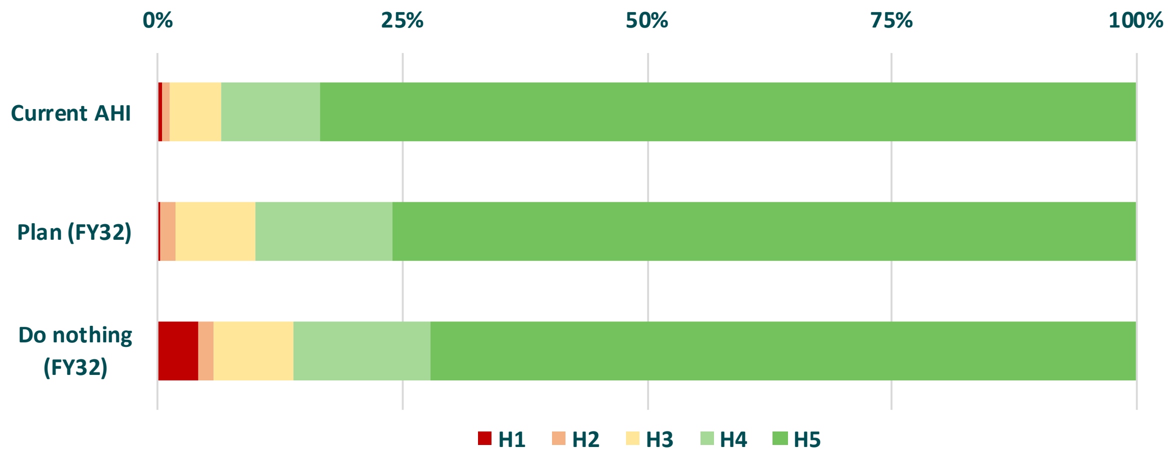
382 Most of the fleet was installed within the past 40 to 50 years and remains within expected service life. Given the fleet's relatively young age profile and fewer customers per circuit, a targeted run-to-failure strategy was deemed appropriate in the past as the impact on reliability was relatively small.

383 We determine the health of the LV conductor fleet using repex models (Box 6.2). These models determine how many kilometres of conductor of each type, size and corrosion exposure combination need to be replaced. We plan to undertake more detailed condition assessments to prioritise this programme over the CPP period.

384 Current fleet health is good, with a very small amount of LV conductor expected to require replacement within 1 year (H1) (Figure 6.21), including end-of-life small diameter copper conductor known to be a type issue in the industry.

385 Planned renewal work is expected to maintain asset health at current levels.

Figure 6.21 Asset health modelling for low voltage conductors



Safety and reliability risk

386 LV conductor failures pose public safety risks and can result in localised supply interruptions. Some conductor types can have type issues that increase failure risk, e.g. those with diameters of less than 50 mm^2. These conductors are less resilient.

6.4.4.2 Forecasting LV conductor renewals volumes and costs

387 We apply repex modelling to forecast renewal volumes (see Box 6.2). We generally replace LV conductors on a like-for-like basis, unless undergrounding is requested and partially funded by third parties.

388 We use a volumetric methodology to calculate renewal capex, based on forecast replacement kilometres and externally reviewed unit rates.

6.5 Underground cables portfolio

389 These assets serve the same purpose as overhead conductors, which is to convey electricity from GXPs across our network to zone substations, then to distribution substations (and larger customers), and finally onto customer premises and council-owned streetlights. We do not collect standard condition data on these assets because they cannot be readily inspected due to their underground location.

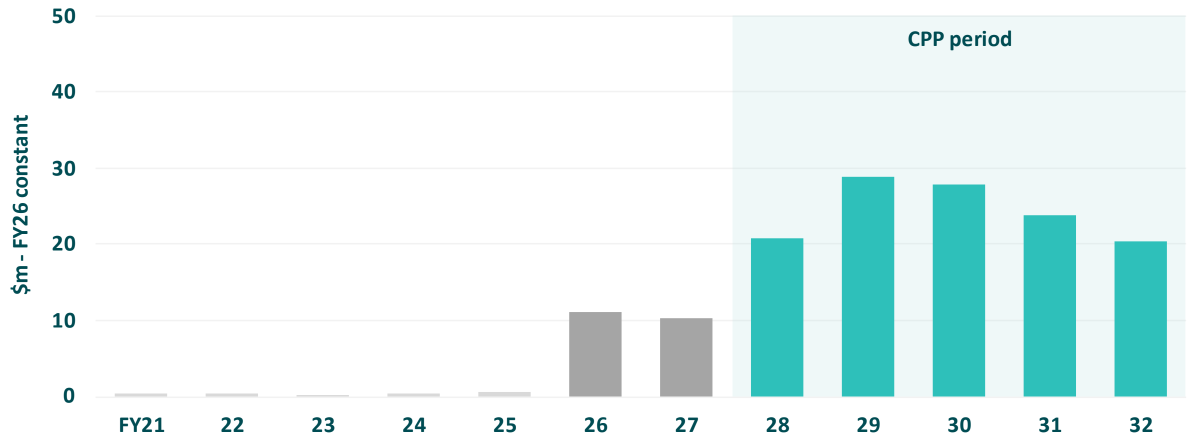
390 This portfolio includes 3 asset fleets, based on their respective voltage levels:

- subtransmission cables – 33 and 66 kV
- distribution cables – 11 kV
- low voltage cables – 400 V.

6.5.1 Underground cables renewal capex

391 Underground cables renewal capex over the CPP period totals $121.7 million, with annual capex as shown in Figure 6.22.

Figure 6.22 Planned renewal capex – underground cables portfolio



392 Annual renewal capex increases over the CPP period, primarily reflecting progressive delivery of major projects under the 66 kV oil-filled cable replacement programme and commencement of a proactive programme to replace deteriorating paper-insulated lead-covered (PILC) distribution cables. We expect to undertake ongoing minor renewals across distribution and LV fleets due to reactive replacement following faults or third-party incidents.

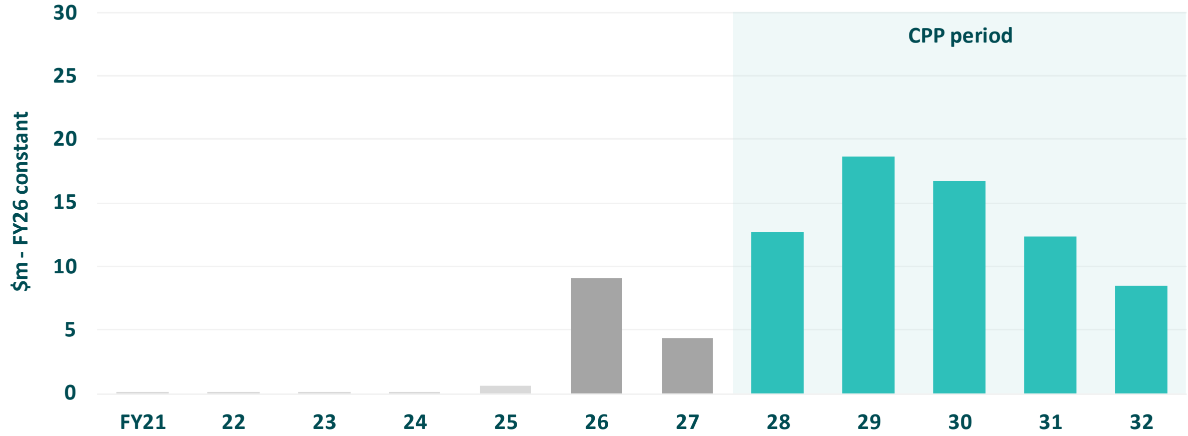
6.5.2 Subtransmission cables renewals

393 Our subtransmission cable fleet comprises approximately 140 circuit km of 33 kV and 66 kV cable. The fleet is predominantly cross-linked polyethylene insulated cables (XLPE). This has been our standard installation type since 2001. We have around 2 circuit km of PILC cable.

394 In addition, several 66 kV oil-filled cable circuits (approximately 40 km) remain in service. From FY23, we have been progressively replacing this sub-fleet with XLPE cable, and plan to continue this programme over the CPP period (see Box 6.5).

395 Subtransmission cable renewal capex over the CPP period is $68.9 million, with annual capex as shown in Figure 6.23.

Figure 6.23 Planned renewal capex – subtransmission cable fleet



Box 6.5 66 kV oil-filled cable replacement programme

Orion commenced a staged programme in FY23 to replace all remaining 66 kV oil-filled subtransmission cables. At this stage 12 circuits (approximately 40 km) are yet to be replaced, with full removal of oil-filled technology planned by 2039.

Why replacement is needed

The remaining oil-filled cables are approaching end of life and present increasing reliability, resilience, maintenance, and environmental risk. These cables are not considered to be sufficiently resilient to withstand a major seismic event. Without replacement, a growing proportion of the subtransmission cable fleet would have increased poor health assets over the next decade (Figure 6.23). The 2011 earthquake demonstrated the vulnerability of oil-filled cables to seismic movement with four 66kV circuits being damaged beyond repair. Oil systems also require specialist maintenance capability and carry inherent leakage risk.

The oil-filled cables are equipped with aluminium conductors and a corrugated aluminium outer sheath covered in polyethylene. The sheaths are in poor condition, increasing the risk of insulation degradation leading to cable failure, and the potential for oil leaks. While oil leaks are typically small, they are difficult and costly to detect and repair. In particular, the Addington to Milton oil-filled cables have ongoing oil leaks which we have been unable to locate and repair.

Technical benefits of XLPE

All replacements will be XLPE cables. Compared with oil-filled technology, XLPE cables provide improved seismic resilience and can be repaired by locally available jointers, enabling faster restoration. They also eliminate oil-related maintenance and environmental risks and deliver lower whole-of-life costs.

Benefits of meshed 66 kV network

In response to lessons from the Canterbury earthquakes, Orion reviewed the 66 kV network architecture and decided to transition from a predominantly radial configuration to a meshed ring linking major urban zone substations. As oil-filled cables are replaced, the network is progressively reconfigured into this meshed arrangement. Renewals are a mix of like-for-like, and alternative routes with larger but fewer cables. The architectural change materially improves security of supply by increasing supply diversity and strengthening interconnection between the 2 major urban GXPs. This will enable greater load transfer between zone substations, enhancing resilience to future seismic events and ability to support future load growth.

This programme will deliver a safer, more resilient and lower risk subtransmission system for customers.

6.5.2.1 Subtransmission cables renewals investment drivers

Asset health and condition risk

396 We assess the health of subtransmission cables based on various factors, including age, fault history, inspections, sheath tests, and, when appropriate, online partial discharge and tan delta tests. In the case of oil-filled cables, we also consider cable fluid leakage rates.

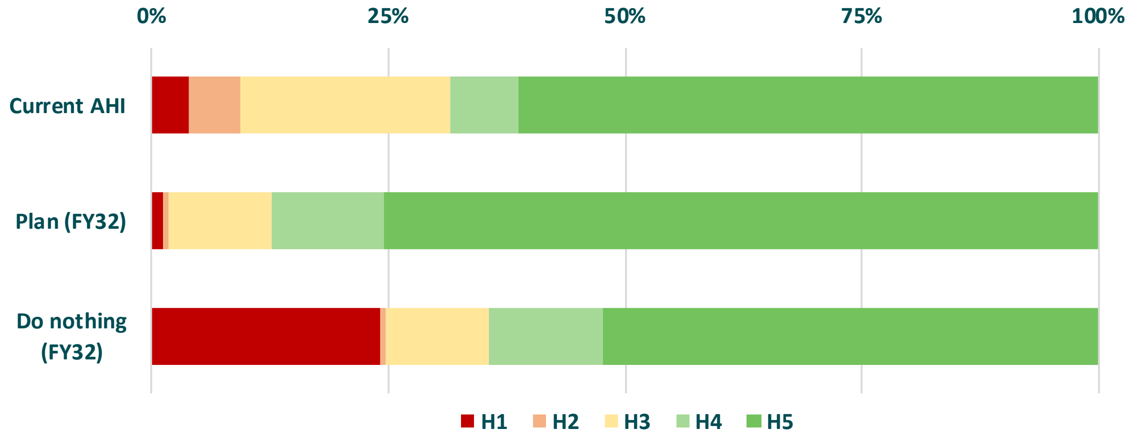
397 Our XLPE cables are still well within their expected operating lifespan and are assessed to be in good serviceable condition. However, the 66 kV oil-filled cables are in poor condition. These assets were installed between 1967 and 1981, and will progressively reach expected

end-of-life over the next 10-15 years. These cables were also materially affected by ground movement during the Canterbury earthquakes.

398 All oil-filled cable repairs require specialist oil-filled cable repair expertise, which is increasingly difficult to obtain. Continued deterioration increases maintenance costs and environmental risk exposure.

399 Figure 6.24 shows the current and forecast AHI profile for the subtransmission cable fleet.

Figure 6.24 Asset health modelling for subtransmission cables fleet



400 The oil-filled cables are concentrated within the H1–H3 categories. With the planned investment, these assets are progressively removed from the fleet, materially improving overall fleet health and reducing exposure to condition-driven failure risk.

Seismic resilience and major outage risk

401 Oil-filled cables are particularly vulnerable to earthquake-induced ground movement. Repairs are labour-intensive and require specialist skills, equipment and spare parts that are increasingly scarce. Restoration of a single fault can take several days at a minimum. In a major seismic event involving multiple simultaneous failures, restoration capability would be materially constrained, increasing the likelihood and duration of widespread outages.

Safety risk

402 With electrification of transport, heating, cooking, and communication, electricity supply is becoming increasingly important. For example, loss of supply for home heating can place lives at risk in extreme winter conditions. We know that improving the resilience of our network to major events, such as earthquakes, has a direct linkage to improved safety and wellbeing of our communities.

6.5.2.2 Subtransmission cable renewal projects

403 For oil-filled cables, renewal work is based on identified projects forming part of the meshed 66 kV network architecture (Table 6.1). Consistent with our tailored forecasting approach (see section 6.3.2.2), these projects were selected and scoped using a full business case process. Broad routes are known, enabling estimation of route length and scope, including trenching restrictions and route diversity considerations.

Table 6.1 Major subtransmission cable projects capex ($m, FY26 constant)	
Project	**Capex**
Oxford-Tuam to Milton 66 kV XLPE cable and Oxford-Tuam 66 kV switchroom - replacing Addington - Oxford	**16.1**
Addington to Fendalton oil-filled cable replacement	**23.6**
Oxford-Tuam to Lancaster 66 kV XLPE cable – replacing Addington - Oxford	**10.9**
Papanui to McFaddens 66 kV oil-filled cable replacement	**16.5**
Addington to Armagh 66 kV oil-filled cable replacement	**1.9**
All projects	**68.9**

6.5.2.3 Forecasting subtransmission renewal costs

404 We developed tailored project estimates for the identified 66 kV projects based on desktop studies. Costs are built up from building block unit rates using the estimated route lengths and scoped works. The costs are phased in line with delivery timing. Unit rates are informed by a recent 66 kV project, with adjustments for site-specific constraints, such as direct drilling required under railroads or other limitations.

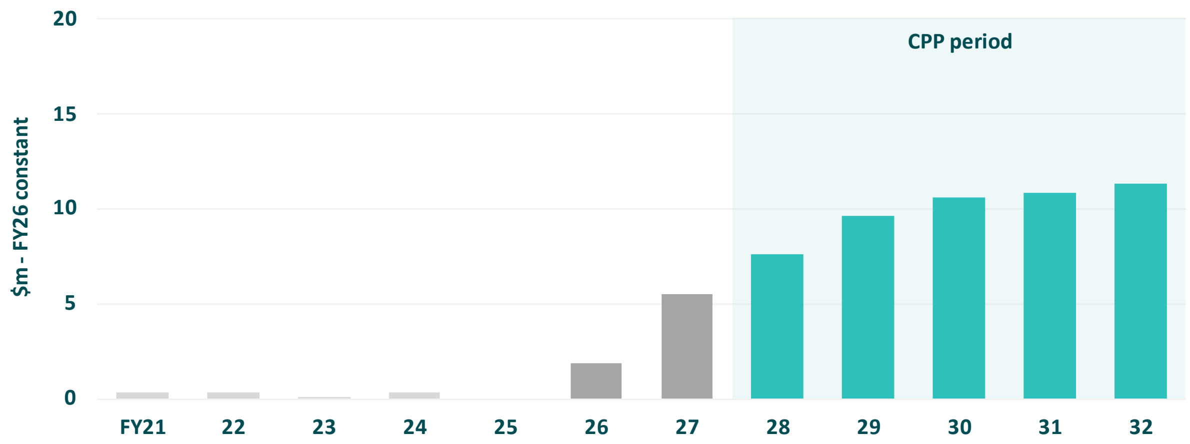
6.5.3 Distribution cable renewals

405 Our distribution cables fleet comprises 2,927 circuit km of 11 kV underground cable, primarily located in urban Christchurch. It delivers power from zone substations to distribution substations and directly connected customers.

406 The fleet consists of approximately 1,500 km of PILC cable and 1,425 km of XLPE cable.

407 Distribution cable renewal capex over the CPP period is $49.9 million, with annual capex as shown in Figure 6.25.

Figure 6.25 Planned renewal capex – distribution cables fleet



408 Investment increases over the CPP period as we establish and ramp-up a proactive distribution cable renewal programme.

6.5.3.1 Distribution cable renewals investment drivers

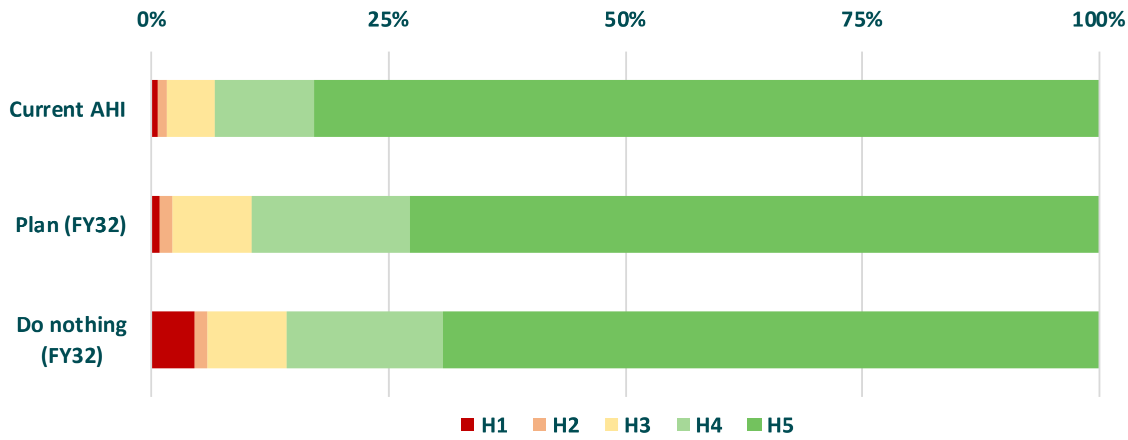
Asset health and condition

409 We assess the health of distribution cables based on a combination of age and failure history to identify failure clusters. We also receive feedback on internal condition from contractors conducting cable fault repairs.

410 Many PILC cables were damaged during the 2011 earthquakes. Although repaired and rejointed, ground movement permanently degraded lead sheaths and insulation, reducing expected service life. Joint density analysis (used as a proxy for condition) shows that PILC cables have approximately twice the number of joints per kilometre as XLPE cables. Each joint introduces a new potential failure point, increasing overall failure likelihood.

411 Figure 6.26 shows the current and forecast AHI profile for the distribution cable fleet.

Figure 6.26 Asset health modelling for distribution cable fleet



412 The overall fleet health is good, with a small number of cables expected to require replacement within 1 year (H1). The proportion of H1 assets 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 type. This also concurs with historical performance, where approximately 90% of failures in the last 5 years were attributed to PILC cables.

413 The planned investment will maintain this level of fleet health. If no renewals were undertaken, that number would increase, with an associated increase in reliability risk which is not consistent with our risk tolerance.

Reliability risk

414 Failure of 11 kV cables supplying zone substations and larger connected customers presents a significant reliability risk. Fault location is typically complex and time consuming to locate, resulting in extended outage durations.

415 Replacing cables before failure generally results in shorter outages than reactive replacement, as alternative supply arrangements, e.g. temporary generation, can be planned. Distribution cable renewals are coordinated with other works within the same outage zones to minimise customer disruption.

Safety and compliance risk

416 We undertake targeted overhead-to-underground conversions where:

- clearance violations exist under NZECP34:2001
- overhead lines are located near high-density areas
- undergrounding is more cost effective than ongoing vegetation management.

417 Approximately 2 km per annum of such conversions are included in the forecast.

6.5.3.2 Forecasting distribution cable renewals volume and costs

418 We forecast distribution cable renewals volume using repex modelling (see Box 6.2). Expected asset life is represented as a normal distribution. We estimate distribution cable renewals costs using a volumetric methodology. Unit rates reflect an estimated average cost covering a wide range of brownfield conditions and include trenching, reinstatement, jointing and traffic management costs.

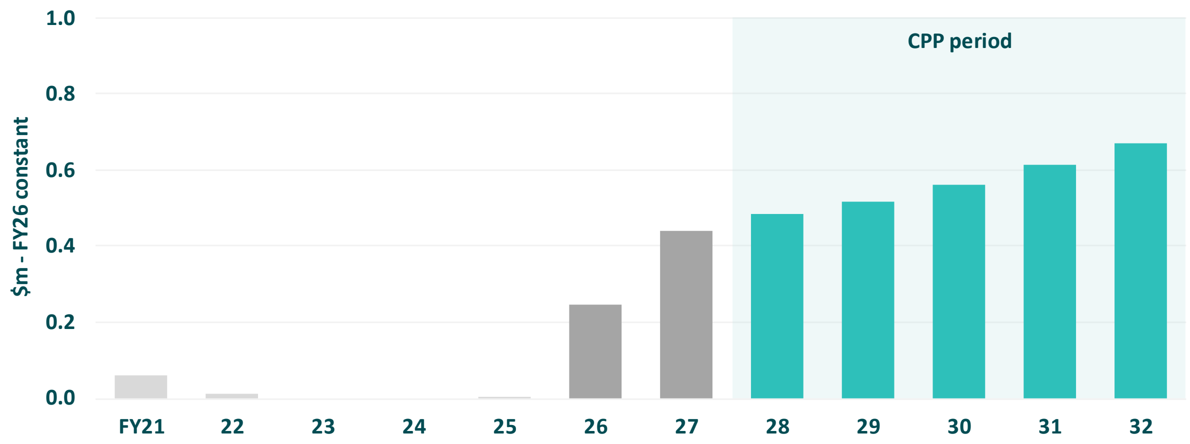
419 Distribution cables replaced under the signalling and communications cable renewal programme are excluded from this forecast.

6.5.4 Low voltage cable renewals

420 Our LV cables fleet comprises approximately 3,300 circuit km of 400 V underground cable, largely concentrated in urban Christchurch. Our LV underground cable system is the final stage of the underground distribution network, delivering electricity to customer premises and council-owned streetlighting. Three types of LV cable are in service: PILC, PVC, and XLPE.

421 LV cable renewal capex over the CPP period is $2.8 million. Annual capex is shown in Figure 6.27.

Figure 6.27 Planned renewal capex – low voltage cable fleet



422 Historically, we have undertaken limited proactive LV cable replacements due to prioritising other asset fleets. Failure risk (as indicated by AHI) is increasing as the fleet ages and in FY27 we plan to initiate a proactive standalone renewal programme to address end-of-life LV cables.

6.5.4.1 Low voltage cable renewals investment drivers

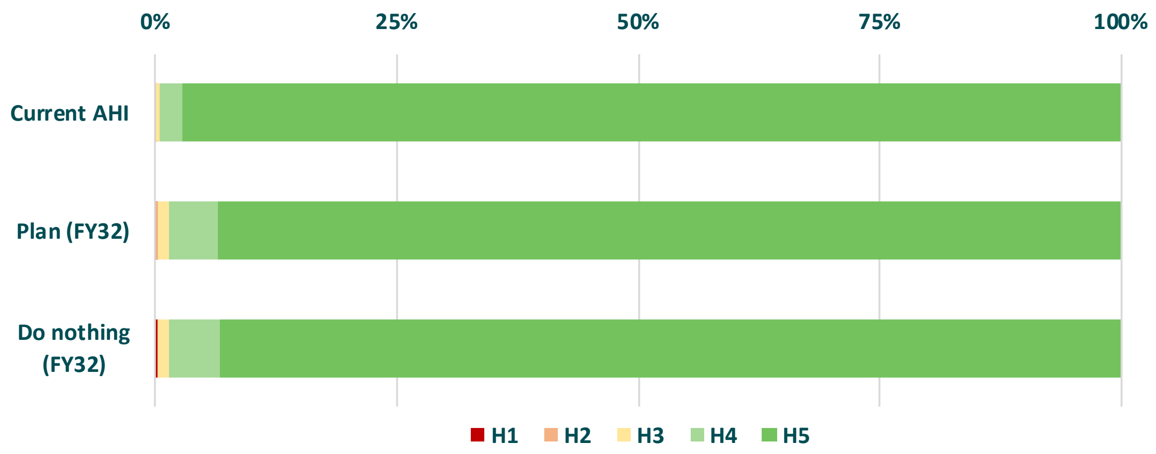
Asset health and condition risk

423 We cannot readily inspect the condition of LV cables due to their inaccessibility. Historically, we have repaired these cables on failure, replacing short runs of cable at the time of repair, or when replacing related LV assets, such as distribution boxes.

424 Most of the fleet has been installed within the past 40 years and remains within expected service life. Given the fleet's relatively young age profile and fewer customers per circuit, a targeted run-to-failure strategy remains appropriate as the impact on reliability is relatively small.

425 Figure 6.28 shows the current and forecast AHI profile. The planned investment maintains overall fleet health.

Figure 6.28 Asset health modelling for low voltage cable fleet



Reliability and risk management

426 Although LV faults affect fewer customers than higher voltage assets, failures can still cause disruption and safety risk where cable is exposed.

6.5.4.2 Forecasting low voltage cable renewals volumes and costs

427 We forecast expected renewals volumes using a repex model (see Box 6.2), with expected life represented as a normal distribution.

428 Costs are estimated using a volumetric approach. Unit rates reflect estimated average cost covering a wide range of brownfield conditions and include trenching, reinstatement, jointing, and traffic management.

6.6 Zone substations portfolio

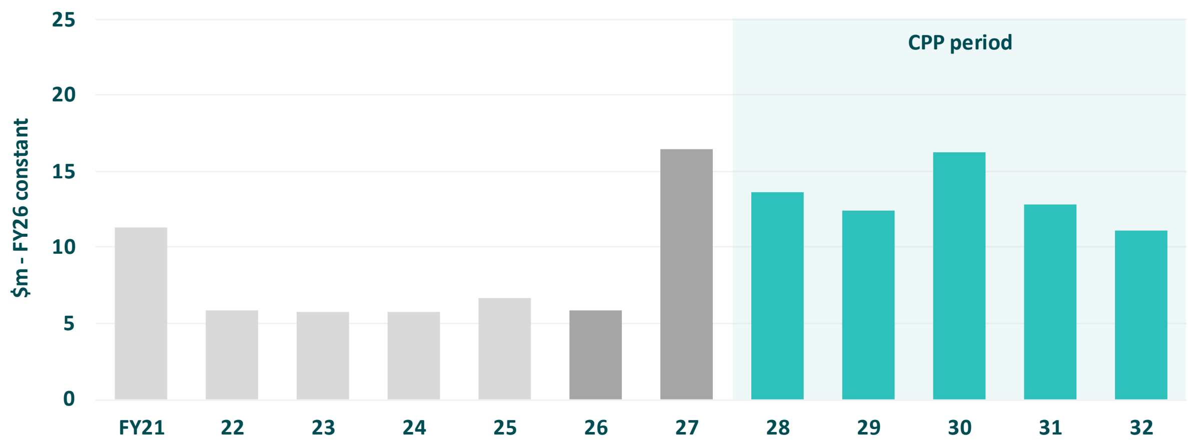
429 Zone substations are critical hubs in our network, housing high voltage infrastructure that typically serves multiple suburbs. We operate 52 zone substations. This portfolio comprises 5 asset fleets – power transformers, outdoor switchgear, indoor switchgear, buildings and grounds, and ancillary equipment.

430 Over the CPP period, we plan a combination of major, site-specific renewal projects and fleet-based renewal programmes for building and grounds, power transformer refurbishments, and ancillary equipment.

6.6.1 Zone substation renewal capex

431 Zone substations renewal capex over the CPP period totals $66.1 million, with annual capex as shown in Figure 6.29.

Figure 6.29 Planned renewal capex - zone substations portfolio



6.6.2 Major zone substation renewal projects

432 For major, site-specific renewal zone substation projects renewal work is based on identified projects (Table 6.2). Consistent with our tailored forecasting approach (see section 6.3.2.2), these projects were selected and scoped using a full business case process. These projects address material safety, resilience, condition, configuration and capacity risks that cannot be efficiently managed through incremental or reactive works.

Table 6.2 Major zone substation renewal project capex ($m, FY26 constant)

Project	Capex
Middleton ZS 11 kV circuit breaker replacement and building	1.2
Halswell 66 kV outdoor switchyard replacement	2.2
Diamond Harbour ZS 33kV outdoor to indoor (ODID) conversion	0.55
Darfield ZS Replacement	2.8
Addington outdoor switchgear and transformer replacement	11.4
Hororata ZS 33 kV ODID conversion and transformer replacement	4.4
Shands Road ZS rebuild	10.7
Dallington ZS 11 kV switchboard replacement	6.1
Bankside ZS 11 kV switchgear replacement	2.4
Portman ZS – 11 kV switchboard replacement	3.5
McFaddens 11 kV switchboard replacement	6.3
Moffett St 11 kV switchgear replacement	3.9
All projects	**55.5**

Box 6.6 Overview of Addington 66 kV zone substation renewal project

Addington is a critical 66 kV zone substation supplying approximately 170 MW to Christchurch, including a significant portion of the CBD. The site connects 4 Transpower 66 kV circuits and supplies multiple downstream zone substations.

Need: key primary assets are at or beyond expected service life and present increasing safety and resilience risk:

- transformers T6 and T7 (installed 1958–1963) exceed 60 years of service and show deterioration indicators
- twenty-four 66 kV disconnectors and 3 minimum-oil 66 kV circuit breakers are forecast to reach end of life within the next decade
- sections of the 66 kV gantry exhibit corrosion and are coated in lead-based paint, creating health and safety exposure
- oil interceptors and fire separation arrangements do not meet current standards.

The 66 kV bus operates without a bus coupler circuit breaker, resulting in slow fault clearance and widespread voltage depression during bus faults. Given the magnitude of load supplied, this configuration creates material resilience and power quality risk as equipment ages. These risks relate to asset condition and network configuration and cannot be efficiently addressed through maintenance or non-network solutions.

Solution: we propose to replace transformers T6 and T7, renew sections of the 66 kV bus structure and associated switchgear, and install a 66 kV bus coupler. This targeted renewal:

- reduces safety exposure by removing ageing oil-filled equipment and lead-coated structures
- improves fault clearance performance and operational flexibility
- reduces common-mode failure risk
- strengthens resilience of a key CBD supply hub.

This option delivers the highest net present value of the credible alternatives considered and achieves material risk reduction at lower cost than full switchyard replacement.

6.6.2.1 Major zone substation renewals investment drivers

433 The planned projects span urban, rural, and strategically critical substations. While site characteristics differ, the key investment drivers are common across multiple projects.

End-of-life bulk oil indoor switchgear

434 A number of zone substations contain 11 kV bulk oil indoor switchgear at or beyond the typical expected lifespan and based on its limitations compared with modern vacuum or SF_6 equipment, bulk oil switchgear has:

- lack of arc flash detection and containment (worker safety issue)
- limited spare parts availability
- higher maintenance cost

Safety risk – arc flash and fire

435 The bulk oil switchboards across multiple sites are not arc flash rated and do not incorporate arc flash detection or venting. In most cases, effective arc flash mitigation cannot be retrofitted within existing buildings.

436 Internal faults can be catastrophic, potentially resulting in oil fire, extensive equipment damage and personnel risk. Replacement with modern indoor vacuum switchgear materially reduces this exposure.

Modular building issues

437 There are 85 buildings spread across our zone substations. Several of these buildings are modular prefabricated buildings, installed prior to 1995. Independent structural assessments identified NBS (IL4) ratings below our minimum 67% requirement.

438 Issues with this type of building can include structural cracking from ground movement, insufficient seismic strength, moisture ingress and high humidity, rodent ingress, and limited ability to accommodate arc flash ducting. Installation of modern switchgear within these buildings would require substantial modification and may further compromise structural

integrity. Where indoor switchgear replacement is planned for such buildings, we are also replacing the building. We also replace the building if there is insufficient space to accommodate the switchgear.

End of life outdoor switchgear and structures

439 Similar to indoor switchgear, we also plan to replace many bulk / minimum oil 33 and 66 kV outdoor circuit breakers over the CPP period. These oil-filled circuit breakers have exceeded their expected life and have the following drivers:

- lack of arc flash protection (worker safety issue)
- inadequate fault ratings (safety issue)
- limited spare parts availability and are orphan assets
- higher maintenance cost compared to modern outdoor switchgear.

440 In addition, some of the older switchyards that contain this gear no longer comply with modern safety clearances, which further increases worker safety risk. Some of the switchgear also lack appropriate phase clearances, causing unnecessary faults.

441 We are also planning to replace some disconnectors in our network that have exceeded their expected life. These are of an older design, which require frequent maintenance which lead to higher cost compared to modern versions.

442 In the case of Addington, where we are replacing bulk and minimum oil circuit breakers, disconnectors and transformers, there is the added complication of lattice structures that contain lead paint which pose a safety and environmental risk.

Power transformer condition and emerging capacity constraints

443 At some sites, ageing power transformers exhibit deterioration indicators such as moderate oil leaks, corrosion and elevated dissolved gas levels. In certain cases, load is expected to exceed firm capacity within the planning horizon. The combination of declining asset health and emerging capacity constraints increases outage risk under contingency conditions.

Network configuration and resilience risks

444 At strategically significant substations, legacy configuration arrangements increase consequence of failure. These include lack of bus couplers, multiple feeders supplied from common circuit breakers, limited redundancy in rural C4-classified sites, and dependence on ageing 33 kV infrastructure. Renewal projects address these configuration risks as part of broader site modernisation.

Collective risk position

445 Collectively, the major renewal projects address:

- safety risks to operational and maintenance personnel
- increasing probability of failure of end-of-life primary plant
- substandard seismic performance of critical infrastructure
- emerging capacity constraints
- network configuration vulnerabilities.

446 Without renewal, several zone substations would continue operating with obsolete oil-based switchgear housed within buildings that do not meet resilience or modern standards. The risk profile would increase over the CPP period.

447 Projects have been prioritised based on consequence of failure, asset condition and obsolescence, safety exposure, seismic non-compliance and deliverability.

6.6.2.2 Forecasting major zone substation projects

448 Major zone substation renewal projects are forecast using a tailored (project-specific) methodology (see section 6.3.2.2).

449 Projects are identified through condition assessment, building seismic assessments and business case development. Scope is defined through detailed engineering assessment and desktop studies, including layout drawings, site specific conditions and constraints, building footprint and adequacy to accommodate new switchgear, seismic remediations required, fire separation requirements, and network configuration.

450 Costs are developed using building block unit rates informed by recent zone substation renewals and peer reviewed by an independent third-party specialist. Estimates reflect brownfield conditions and temporary supply arrangements.

451 Given the discrete and material nature of these projects, no estimation contingency has been applied beyond project-level allowances. Diversification across projects mitigates aggregate forecast uncertainty.

6.6.3 Zone substation renewal programmes

452 This portfolio includes renewal programmes for 3 asset fleets:

- Power transformers (refurbishment only)
- Buildings and grounds
- Zone substation ancillary equipment.

453 The following sections set out the basis for these programmes, while total capex for the programmes is included in section 6.7.1.

6.6.3.1 Power transformer refurbishment

454 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 66 kV and 33 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.

455 This fleet comprises 81 power transformers. The fleet also includes bunding, oil containment, firewalls, and neutral earthing resistors (which are devices that limit the fault current that can flow through the neutral conductor of a transformer).

Asset health and condition risk

456 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. These projects are combined with other renewals such as switchgear, where the other equipment is also nearing or at end of life, and are included within the forecasts for the major projects set out in section 6.7.2. Some of the older transformers have moderate oil leaks or external condition deterioration.

457 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
- they are less likely to fail, which has a positive impact on network reliability
- defects are removed, which means the asset is more reliable and less likely to leak which has a positive environmental impact.

458 Our service delivery partners have a refurbishment workshop at Papanui zone substation, minimising transportation costs.

Forecasting power transformers renewals volumes and costs

459 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.

6.6.3.2 Zone substation buildings and grounds

460 This fleet comprises zone substation buildings and associated site infrastructure that house indoor switchgear and secondary systems, together with the grounds the substations are located on. Buildings include 70 permanent-type structures (tilt slab, concrete block and brick) and 15 modular prefabricated structures. Site infrastructure can include switchyards, earthing systems, oil containment, fencing and gates, accessways, gantries and security systems. Heating, ventilation and air conditioning (HVAC) systems are also included.

Asset health and condition risk

461 We undertake routine visual inspections assessing factors such as physical security, weather tightness, general condition, security, cleanliness, and appearance.

462 Permanent buildings have generally performed well. However, some modular buildings housing 11 kV zone substation circuit breakers and control equipment are prone to moisture ingress and high humidity and rodent ingress, which can accelerate equipment deterioration. Where switchgear replacement is planned for such buildings, we are also replacing the building.

Safety and reliability risk

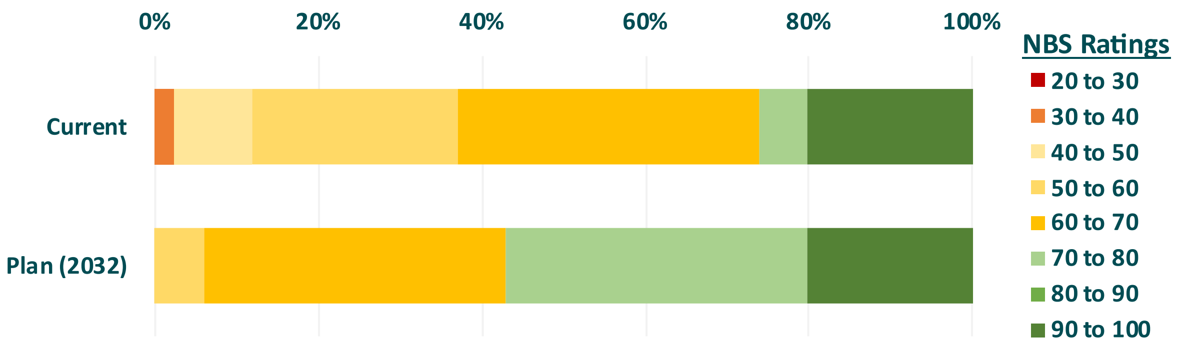
463 Prior to, or in the few years following, the Canterbury earthquakes, seismic assessments and upgrades of approximately half of our zone substation buildings were completed. These involved strengthening the buildings to at least 67% of the NBS[28] for IL4[29] buildings. A considerable number of the remainder remain below this threshold. This creates safety risk for staff, service delivery partners, and the public, as well as reliability risk, in a major seismic event.

464 Figure 6.30 shows the current seismic resilience profile of the fleet. Nearly half of the buildings are below 67% NBS and will require remediation or replacement, either standalone or alongside primary plant renewal.

[28] NBS ratings are based on the New Zealand standard Initial Seismic Assessment (ISA) tool which is a desktop assessment of the likely seismic performance of a building. We are also getting some Detailed Seismic Assessments (DSA) completed to confirm ratings of our lowest NBS buildings and their required remediations.

[29] Building Importance Levels (IL) are defined in the Building Code Clause A3 where IL4 buildings are essential to post-disaster recovery. We consider Zone Substation buildings to fall in IL4 category.

Figure 6.30 NBS scores – zone substation buildings



Forecasting minor buildings and grounds renewals volumes and costs

465 Renewals volumes for minor buildings and grounds works are forecast using a base-trend approach. The base year reflects recent actual expenditure on recurring works, adjusted for abnormal items. Costs are estimated using a volumetric methodology for typical building elements, e.g. roofing, fencing, and HVAC.

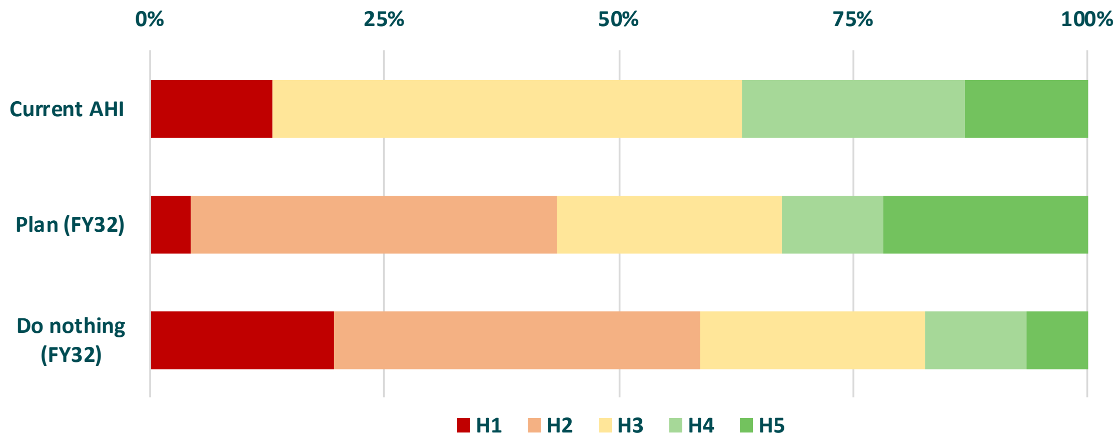
6.6.3.3 Ancillary equipment

466 This fleet includes zone substation equipment not included in other fleets. It currently includes load management equipment, being ripple controllers, ripple transmitters, and coupling cells. The total number of ripple plant is 45.

Asset health and condition risk

467 We monitor asset condition through inspection and performance monitoring. We have experienced reliability issues with ageing static frequency converters (ripple transmitters), which are prone to failure with age. As Figure 6.31 shows, more than half of our ripple plant will reach end of life within the next decade.

Figure 6.31 Asset health modelling for ancillary equipment fleet



Forecasting ancillary equipment renewals volumes and costs

468 Renewal volumes are forecast using an age-based approach, applying expected asset life to the fleet age profile. This is appropriate where age is a reasonable proxy for condition and detailed failure data is limited.

469 Costs are estimated using a volumetric methodology based on historical costs.

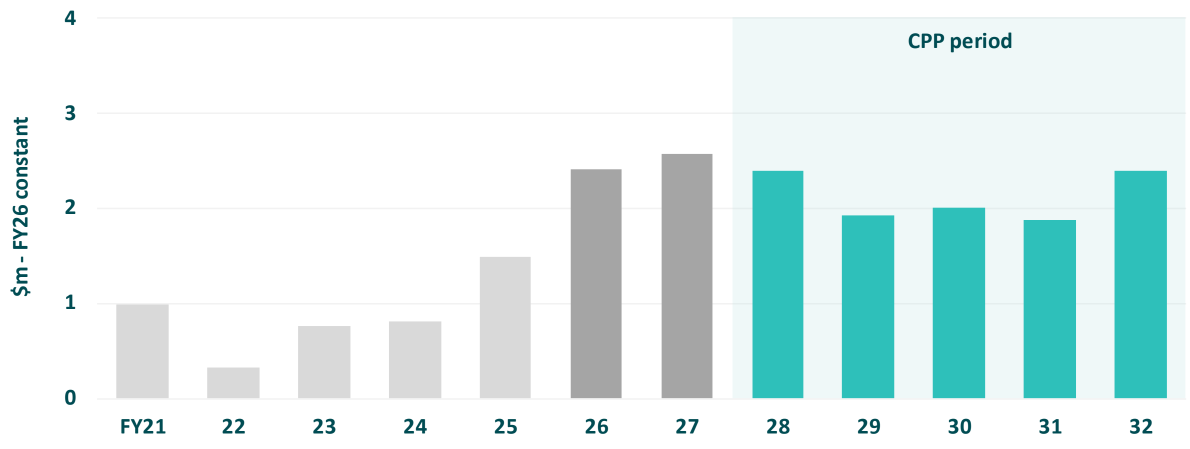
6.6.3.4 Forecast capex

470 Zone substation programmes renewal capex over the CPP period is $10.5 million, comprising:

- $4.2 million for power transformer refurbishments
- $4.1 million for buildings and grounds
- $2.3 million for ancillary equipment.

471 Annual capex is shown in Figure 6.32.

Figure 6.32 Planned renewal capex – zone substations renewal programmes



472 Historically, we undertook limited power transformer refurbishment and are now initiating a proactive refurbishment programme to complement replacement works. Power transformer replacements are excluded from this forecast as they are included as part of the projects set out in section 6.7.2.

473 Buildings and grounds renewal capex only includes minor building work. Other investment, such as significant building replacements or refurbishment work (forecast as part of the projects set out in section 6.7.2 and the reliability, safety and environment portfolio in Chapter 8), replacement of older buildings where their dimensions are insufficient, and standalone seismic reinforcements, are all excluded from this forecast. The investment will improve safety and ensure zone substations remain fit for purpose.

474 The expected life of ancillary equipment results in a variable forecast as the equipment was installed in clusters.

6.7 Distribution switchgear portfolio

475 Switchgear is a collective term for switches and circuit breakers used to control, protect, isolate, and configure our electricity network. 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 both interrupt fault currents during system abnormalities and switch load currents during normal routine operation. They are strategically located across the network to meet requirements for system protection, isolation, and operating flexibility.

476 This portfolio includes 5 asset fleets:

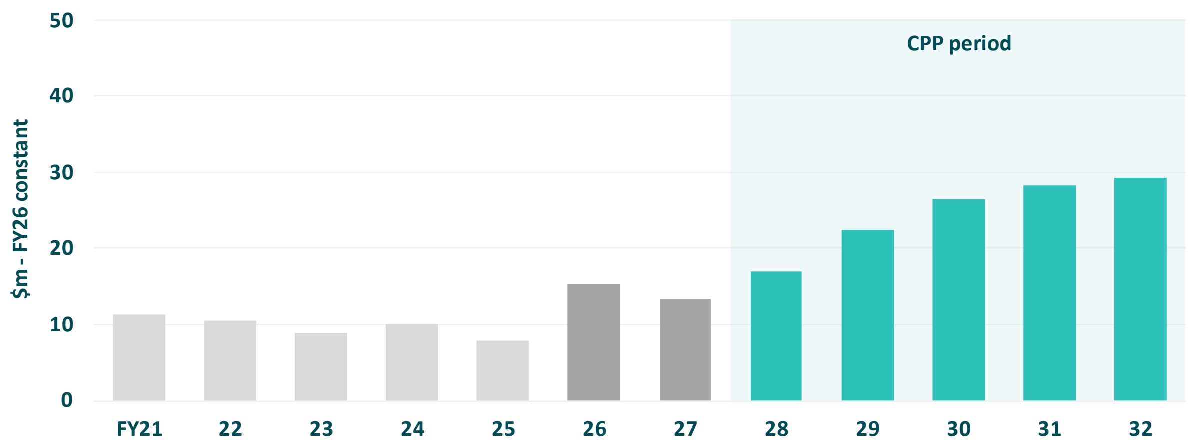
- pole mounted switchgear[30]
- pole mounted fuses
- ground mounted switchgear
- enclosures
- ancillary equipment.

477 These assets are critical to the safe and reliable operation of both our overhead and underground networks. Failure of switchgear can expose the public and field staff to electric shock or arc flash hazards, damage primary equipment, and interrupt supply to customers.

6.7.1 Distribution switchgear renewal capex

478 Distribution switchgear renewal capex over the CPP period totals $124 million, with annual capex as shown in Figure 6.33.

Figure 6.33 Planned renewal capex - distribution switchgear portfolio



479 Annual renewal capex increases over the CPP period when compared with FY21–27, mainly due to increased investment in ground mounted switchgear and enclosures. The programme is targeted at managing safety, compliance, and reliability risks. It addresses elevated arc flash and explosive failure risks in certain switchgear types, and seismic non-compliance in a large proportion of our distribution substation buildings.

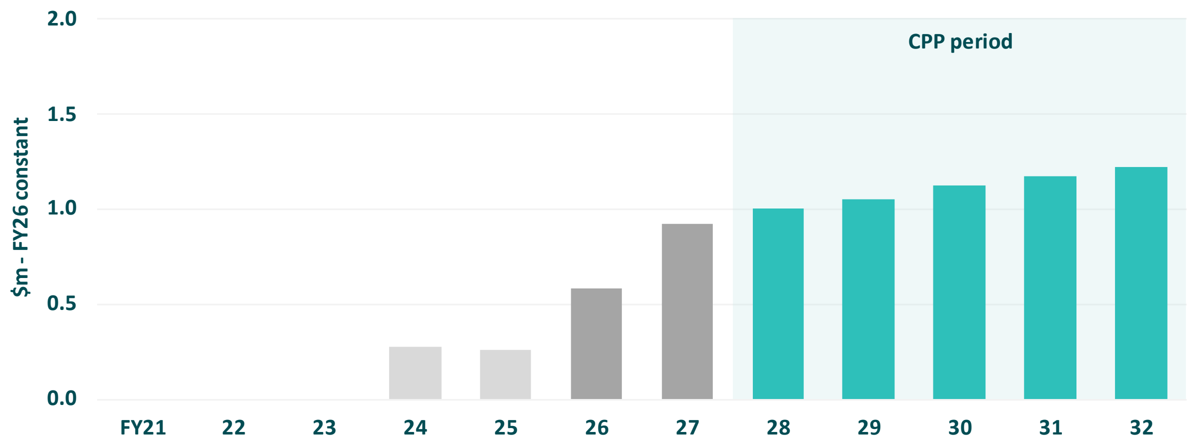
[30] Note there is no planned renewal capex for this fleet during the CPP period. These are relatively new assets and, so far, the fleet shows no significant degradation, defects, or type issues.

6.7.2 Pole mounted fuses renewals

480 Our pole mounted fuses fleet includes 3 types, each with a specific role. They include protecting equipment from overloads or short circuits, providing isolation of a faulty section of the network, or providing isolation where no overcurrent protection is needed.

481 Pole mounted fuses renewal capex over the CPP period is $5.6 million. Annual capex is shown in Figure 6.34.

Figure 6.34 Planned renewal capex – pole mounted fuses fleet



482 We have undertaken limited proactive renewals historically for pole mounted fuses due to prioritising other fleets. Historical renewals were limited to ones that were replaced together with poles in FY24 and 25. We are planning proactive renewals, starting in FY26 and slowly ramping up over the period. We are also planning to replace existing fuses with sparkless types which prevent igniting fires when the fuses operate. These sparkless fuses will be prioritised in extreme or higher wildfire risk areas.

6.7.2.1 Pole mounted fuses renewals investment drivers

Asset health and condition risk

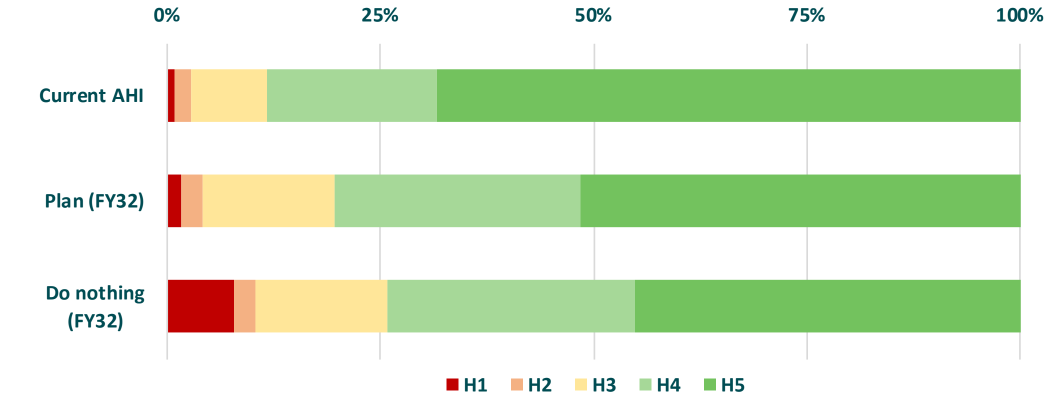
483 Our pole mounted fuses are inspected as part of our 5 yearly overhead conductor inspection. We have not historically recorded condition scores for this fleet, but as the fleet is relatively young, we expect only a small proportion is nearing end of life.

484 We have begun a programme of work to replace fuses in rural areas and/or areas with dry grass, such as the Port Hills, with sparkless fuses, which are designed to minimise fire risk from fuse operation. This will contribute to improved safety and reliability for this asset fleet.

485 Most of the fleet remains within expected service life. Given the fleet's relatively young age profile, a run-to-failure strategy was deemed appropriate in the past as the impact on reliability was relatively small. Historically, proactive renewals were limited to those fuses that were replaced together with poles. We are planning proactive renewals, from FY26.

486 Figure 6.35 the current and forecast AHI for our pole mounted fuses fleet. Our aim is to maintain asset health at a similar level over the AMP period.

Figure 6.35 Asset health modelling for pole mounted fuses fleet



6.7.2.2 Forecasting pole mounted fuses renewals volumes

487 We forecast replacement volumes (excluding sparkless fuses) using a repex method (see Box 6.2). Sparkless fuses tend to cost more than standard drop out fuses due to their advanced arc-quenching technology and improved safety features.

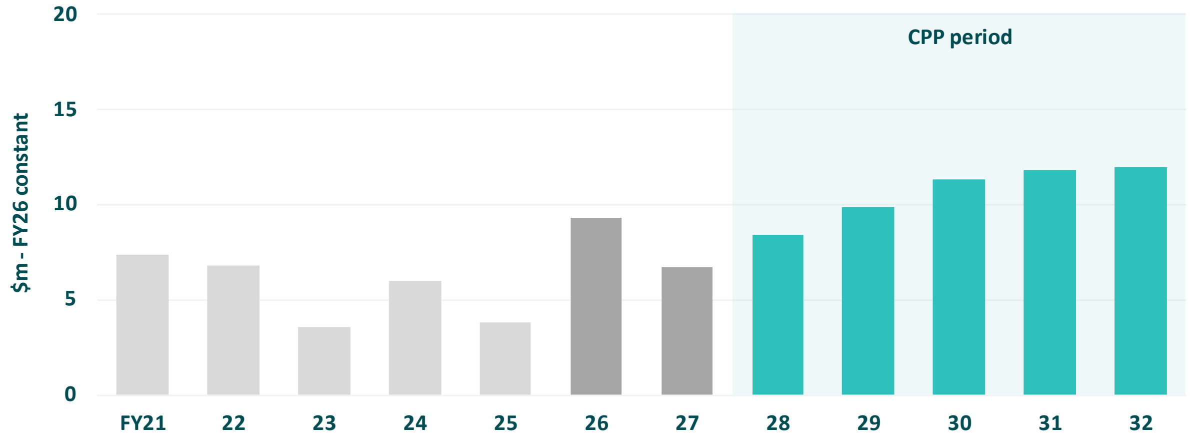
488 The sparkless fuses programme cost has been trended forward based on recent expenditure. Costs for all other fuses are estimated using a volumetric approach. Unit rates are then based on an estimated average cost covering a wide range of brownfield conditions.

6.7.3 Ground mounted switchgear renewals

489 Our ground mounted switchgear fleet is generally associated with our underground cable network. This fleet includes ring main units (RMUs), Magnefix switching units (MSUs), and indoor switchgear panels.

490 Ground mounted switchgear renewal capex over the CPP period is $53.4 million, with annual capex as shown in Figure 6.36.

Figure 6.36 Planned renewal capex – ground mounted switchgear fleet



491 The planned capex is higher than FY21 – 25. This is primarily due to an increased focus on safety-driven replacements of oil-filled indoor switchgear, MSUs, and type issue RMUs. Our forecast steadily increased over the period as we prioritise high risk type issue RMUs, then oil-filled indoor switchgear and MSUs.

6.7.3.1 Ground mounted switchgear renewals investment drivers

Asset health and condition risk

492 We aim to replace poor condition ground mounted switchgear units before they fail as in-service failure can be a significant safety issue, as it can expose service delivery partners or the public to electric shock or arc flash. Failures can also affect supply to consumers.

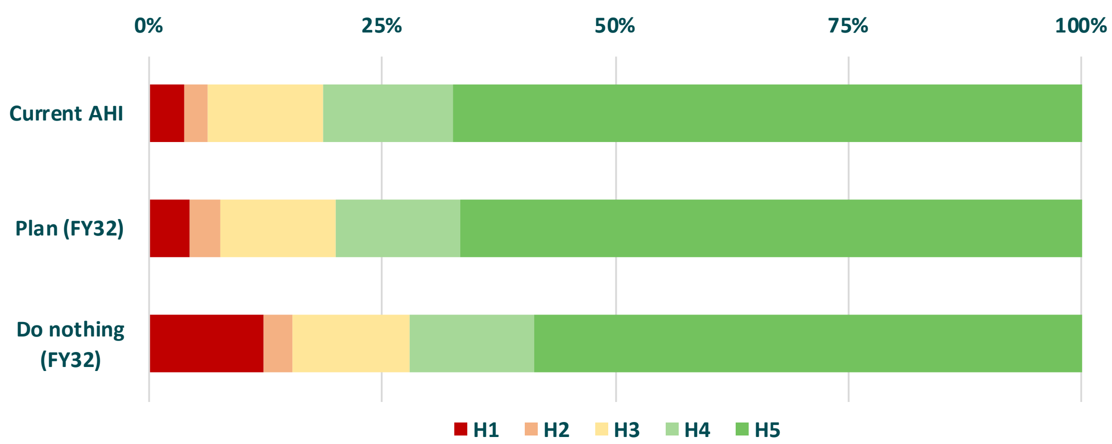
493 We have identified a type issue with a RMU model that was installed on our network between 2014 and 2019. This issue has resulted in 10 units having internal phase to earth faults which pose both safety and network interruption risks. Two significant explosive failures in the past 2 years have heightened our awareness of the safety consequences related to these units; other owners of these units have experienced the same failure modes. We are phasing out these units over the next 10 years. In the meantime, we have put in place safety mitigation measures, such as strapping down the RMU top cover.

494 We are progressively replacing our older oil-filled indoor switchgear panels. This is an appropriate response to minimise the potential safety and operational risks associated with ageing oil-filled switchgear. The older designs of oil-filled switchgear may not meet current safety standards, and most are unable to be retrofitted with arc flash protection. These units can fail catastrophically, releasing hot oil and gases that may cause serious injury or fatalities. These assets tend to utilise obsolete relay types as well, which are communicating with other relays via pilot cables which are unreliable and overdue for replacement (see section 6.10.5).

495 We have identified a safety risk where unfused MSUs may contribute to prolonged clearance times for transformer and LV faults. This can result in higher arc flash hazards, which could irreparably damage these assets. We are addressing this issue through our replacement programme.

496 Figure 6.37 shows the current and forecast AHI for our ground mounted switchgear fleet. A sizable proportion of the large MSU population is nearing end of life, so a substantial number will require renewal during the CPP period to maintain the health of the fleet. The figure also accounts for RMUs with safety type issues; they are included as H1 to reflect end-of-life factors.

Figure 6.37 Asset health modelling for ground mounted switchgear fleet



6.7.3.2 Forecasting ground mounted switchgear renewals volumes and costs

497 We forecast replacement volumes of RMUs with type issues based on the number of units in service. For all other renewals, we use a repex method (see Box 6.2).

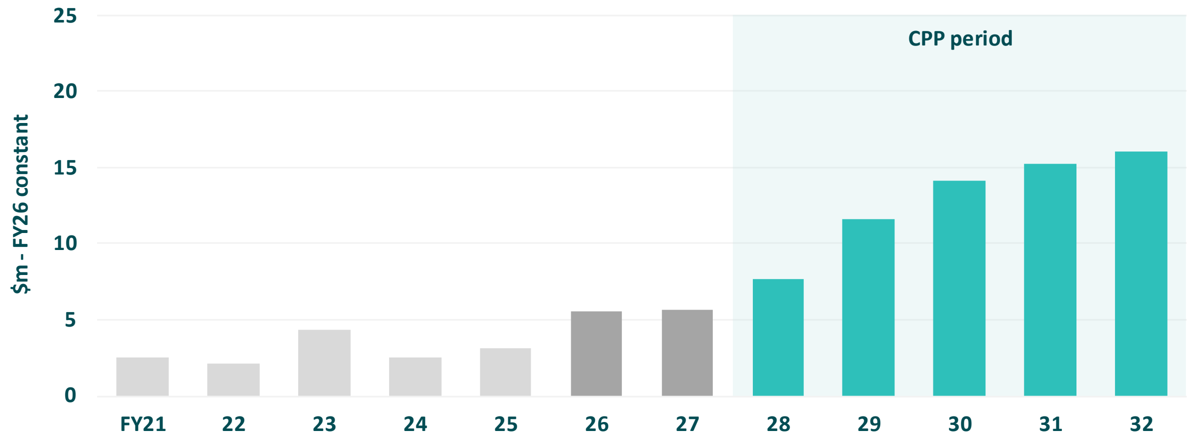
498 Costs are estimated using a volumetric approach. Unit rates are based on historical average unit cost covering a wide range of brownfield conditions. They include installation, design and commissioning, and exclude any related land purchase costs.

6.7.4 Enclosures renewals

499 Our enclosures fleet comprises the buildings and housings that contain distribution network assets. It includes distribution cabinets, distribution boxes, kiosks, and LV panels, as well as substation buildings located outside zone substations. These assets provide physical protection, electrical segregation and security for switchgear, transformers, and LV connections.

500 Enclosure renewal capex over the CPP period is $64.7 million, as shown in Figure 6.38.

Figure 6.38 Planned renewal capex – enclosures fleet



501 The planned capex is materially higher than FY21–25. The main reasons for this increase are an increased focus on proactive remediation to increase the ratings of our distribution substations against the standard required for a new building, safety drivers associated with skeleton LV panels, and continuing to replace distribution boxes/cabinets when they reach their expected life each year, driving a substantial renewals programme. We are prioritising safety related renewals first, i.e. skeleton panels, then starting our renewal of enclosures without skeleton panels after FY29.

6.7.4.1 Enclosures renewals investment drivers

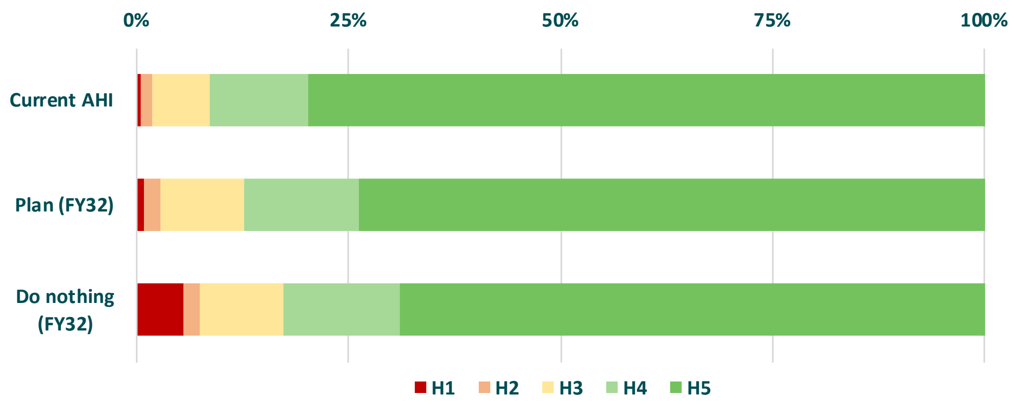
Asset health and condition

502 Most enclosure types are relatively young (excluding distribution substation buildings). However, a large volume of distribution boxes will reach their expected life during the CPP period.

503 We inspect distribution cabinets and boxes every 5 years and kiosks and distribution substation buildings every 6 months. While overall condition is reasonable, corrosion, moisture, pollution ingress, and ageing materials are increasing renewal needs.

504 Figure 6.39 shows the current and forecast AHI for our enclosures fleet. Many enclosures are nearing end of life, primarily driven by distribution cabinets and boxes, so a substantial number of renewals will be needed during the AMP period to maintain the health of the fleet. The figure also accounts for enclosures with skeleton LV panels which are a safety issue for our service delivery partners.

Figure 6.39 Asset health modelling for enclosures fleet (excluding distribution substation buildings)



Safety risk – skeleton LV panels

505 Around 45% of the LV panel population are legacy ‘skeleton’ panels, which are an uninsulated type of switchgear with exposed live terminals and busbars. Interim public safety measures (replacing enclosure doors, improving locking systems, installing polycarbonate screens and safety signage) reduced public exposure risk but did not fully address operational safety risk. We are replacing many of these with kiosks or distribution cabinets when due for replacement. Progressive replacement of skeleton panels is therefore a primary safety driver for this portfolio. Renewals are coordinated with kiosk and cabinet replacement where feasible.

506 Enclosure failure can expose live parts, damage enclosed assets, and increase outage duration. Planned renewal reduces both safety and reliability risk.

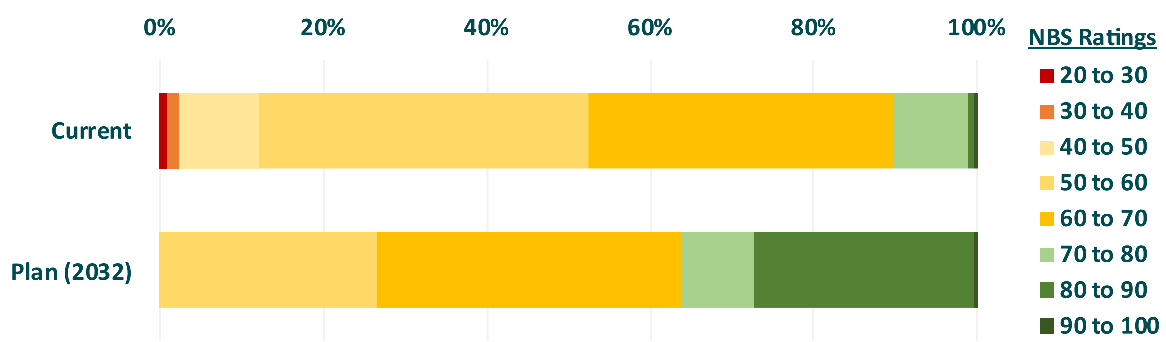
Seismic resilience and compliance

507 Distribution substation buildings are classified as Importance Level 3 (IL3). Our remediation trigger is when they fall below 70% of the New Building Standard (NBS) for IL3. We chose that percentage as we know that typically insurance companies will not insure buildings that are below 67 % of the NBS, and 70% allows for building deterioration over time. Initial seismic assessments indicate:

- 173 of 247 buildings are below 67% NBS.
- approximately 90% are below our 70% NBS remediation trigger.

508 Buildings below 70% NBS present safety risk to staff, resilience risk in a major earthquake, and potential compliance and insurance risk. Our objective is to remediate most buildings to at least 80% NBS for IL3 (providing headroom above the target), with approximately 25% converted to kiosks.

Figure 6.40 NBS ratings



Reliability and third-party damage

509 Distribution box and cabinet faults resulting in outages have trended upward over the past 5 years, primarily due to ‘assisted’ faults, e.g. vehicle collision. While many failures are assisted events, ageing assets increase vulnerability and consequence.

Flood and fire resilience

510 We have updated our distribution box design to improve flood resilience by raising fuse and connection levels.

511 Fire separation risk associated with oil-filled transformers housed in kiosks is addressed within the Distribution Transformer portfolio, with enclosure renewals coordinated accordingly.

6.7.4.2 Forecasting enclosure renewal volumes

512 We apply different forecasting approaches for this fleet reflecting the nature of each asset type.

513 For distribution substation buildings requiring seismic remediation, renewal volumes are derived from the number of buildings below 70% NBS for IL3. Buildings are prioritised based on lowest NBS rating. We assume:

- 75% are strengthened to ≥80% NBS
- 25% are replaced with kiosks – this would likely be done when the cost of refurbishment exceeds the cost of kiosk conversion.

514 For kiosks, distribution boxes and cabinets, we forecast replacement volumes using a repex approach (see Box 6.2). For LV panels (non-skeleton type), where age data is incomplete, we use a percentage-of-population forecasting approach.

515 When some urban LV lines are due for renewal, we may convert these to underground connections by installing a new distribution cabinet or box; the programme expenditure sits in the enclosures fleet forecast, while the issues being managed relate to existing overhead lines and are covered in related asset management documentation. The annual forecast is based on historical expenditure spend.

6.7.4.3 Forecasting enclosure renewal costs

516 Capex amounts are forecast based on unit rates using a volumetric approach, multiplying the forecast number of replacements (Q) by the unit rate (P). The unit rates are based on estimated average cost covering a wide range of brownfield conditions. If the enclosure has a skeleton panel that also needs to be replaced, this has an additional cost per panel.

6.7.5 Ancillary equipment renewals

517 Our ancillary equipment fleet comprises mainly distribution switchgear-related assets not captured in the fleets above, e.g. 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. We have no planned capex on this fleet during the CPP period.

6.8 Distribution transformers portfolio

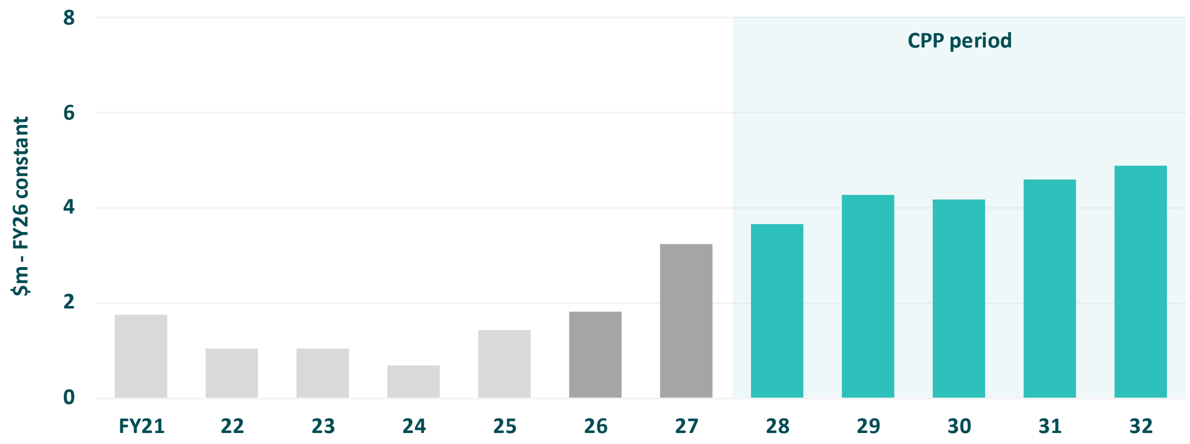
518 Distribution transformers convert electricity from 11 kV to 400 V to supply our customer connections. We have more than 12,000 distribution transformers installed on our network. Their performance is essential for maintaining a safe and reliable network. This asset class includes 4 asset fleets:

- ground mounted transformers
- pole mounted transformers
- voltage regulators and capacitors
- generators.

6.8.1 Distribution transformers renewal capex

519 Distribution transformers renewal capex over the CPP period totals $21.6 million, with annual capex as shown in Figure 6.41.

Figure 6.41 Planned renewal capex - distribution transformers portfolio



520 Our forecast renewal capex increases over the CPP period when compared to FY21–25. This is primarily due to increased investment in pole mounted and ground mounted transformer renewals. The programme is targeted at managing network reliability and safety risks. It addresses seismic safety risks posed by larger pole mounted transformers, which we plan to convert to ground based distribution substations.

6.8.2 Distribution transformers renewals

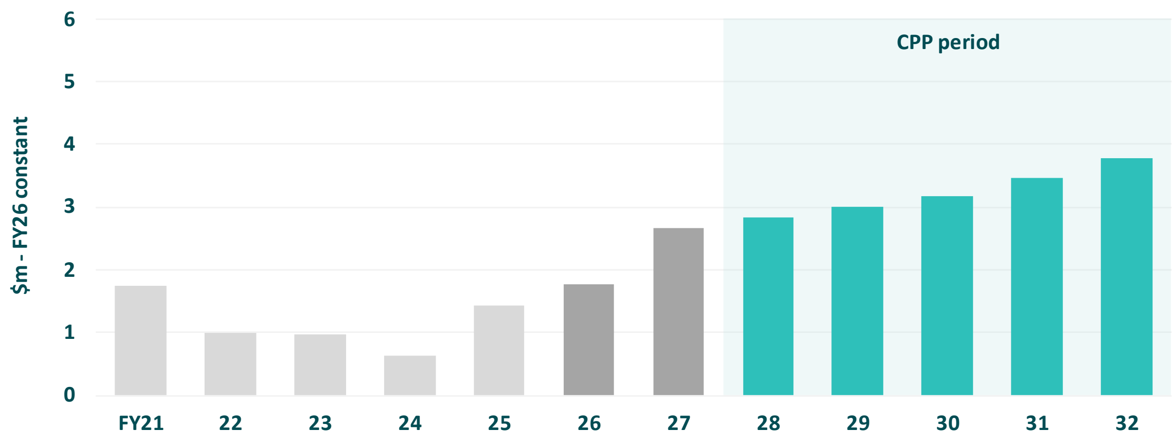
521 This includes both pole and ground mounted transformers.

522 Our pole mounted transformers are typically used in our overhead network in rural and suburban areas. These transformers avoid the need for concrete pads or enclosures but are more vulnerable to extreme weather and environmental damage.

523 Our 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. They are installed either outdoors or inside a building or kiosk.

524 Ground mounted and pole mounted transformer renewal capex over the CPP period totals $16.3 million. Annual capex is shown in Figure 6.42.

Figure 6.42: Planned renewal capex – ground mounted and pole mounted transformer fleets



525 Proactive replacements in FY21 to 25 were limited due to prioritising other assets. Our ground mounted transformers forecast is increasing in line with enclosures and ground mounted switchgear, as these assets are usually replaced together. 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. We also plan to convert large pole mounted transformers to ground mounted equivalents due to the seismic and safety risks.

6.8.2.1 Ground mounted transformers renewals investment drivers

Asset health and condition risk

526 We periodically inspect ground mounted transformers. We have identified a risk with some of our larger units, located inside or next to kiosks in residential areas, may be inadequately separated from nearby combustible structures, such as wooden fences or trees.[31] We also have approximately 200 transformers in customer premises which may not meet fire separation standards. This is a risk as there may be combustible surfaces nearby. We need to assess the fire ratings of the customer buildings to ensure they are sufficient.

527 We have not experienced any transformer fires causing damage to customer property to date, however, if a transformer caught on fire, it is likely to leak oil. If the oil is not contained, it will spill outside the kiosk and could be ignited or spread.

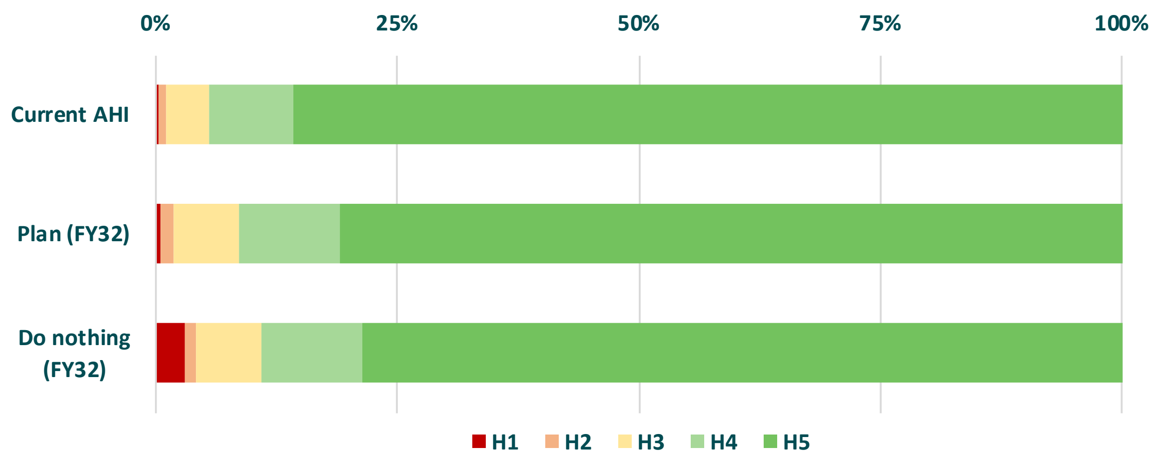
528 We intend to convert some large pole mounted transformers to ground mounted units when they come due for renewal, as this will make them more resilient to extreme weather, lightning, reduce the need for working at heights, and mitigate safety risks related to earthquakes.

529 A targeted run-to-failure strategy for smaller, low consequence units (less than 100 kVA) remains appropriate as the impact on reliability is relatively small.

530 Figure 6.43 shows the current and forecast AHI for our ground mounted transformers fleet. The fleet is generally in good condition, with a very small number at 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 will decline slightly over the CPP period as we need to slowly ramp up renewals as we collect condition data required to prioritise the work programme.

[31] We are subject to a fire separation standard that specifies the distance that oil-filled transformers need to be from combustible surfaces.

Figure 6.43 Asset health modelling for ground mounted transformers fleet



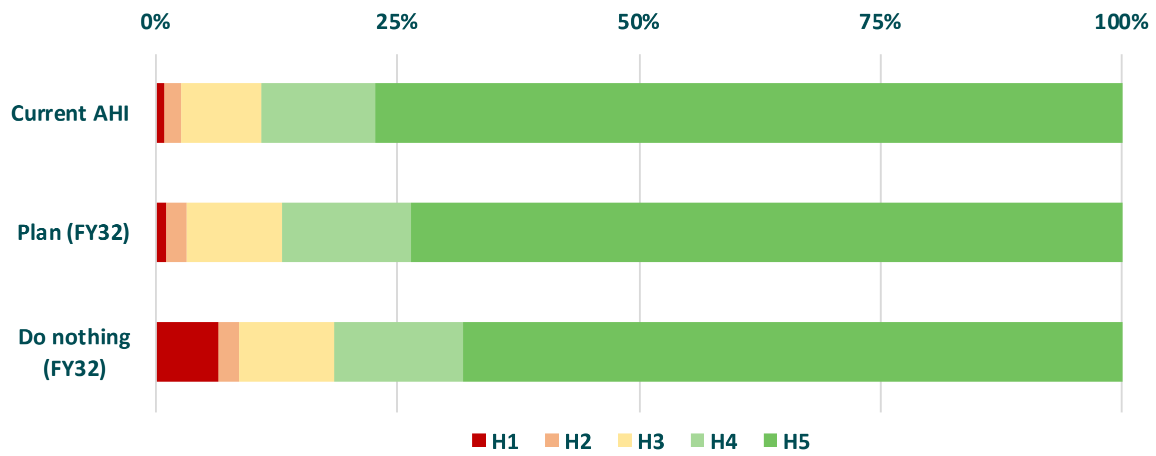
6.8.2.2 Pole mounted transformers renewals investment drivers

Asset health and condition risk

531 Our inspections of pole mounted transformers are done as part of a visual inspection of pole top hardware that occurs every 5 years.

532 Figure 6.44 below shows current and forecast AHI for our pole mounted transformers fleet. Some pole mounted transformers have already exceeded their expected life.

Figure 6.44 Asset health modelling for pole mounted transformers fleet



533 Most of the fleet remains within expected service life. Given the fleet's relatively young age profile, a targeted run-to-failure strategy remains largely appropriate. However, as a large volume of units are now reaching their expected life each year, we plan to undertake a new proactive programme of replacements starting in FY26, focussing on ageing units that are larger and have higher failure consequence. This programme will ramp up as our fleet ages over the AMP period. While asset health continues to deteriorate due to the ageing population, a much greater deterioration is arrested.

6.8.2.3 Forecasting distribution transformers renewals volumes and costs

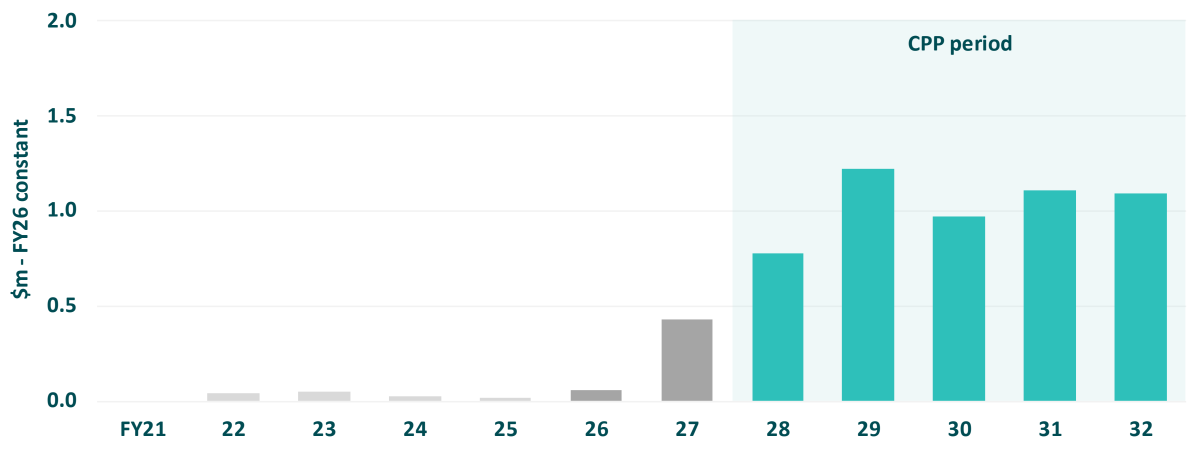
534 For both fleets we forecast replacement volumes using a repex method (see Box 6.2). Costs are estimated using a volumetric approach for both fleets. Unit rates for ground mounted transformers are based on the historical average replacement cost for a particular size transformer. For pole mounted transformers, we assume a single replacement cost that represents an average across all types and sizes.

6.8.3 Voltage regulators and capacitors renewals

535 Our voltage regulators are devices that keep the voltage at which electricity is supplied to customers at a constant level, regardless of load fluctuations. Capacitors provide reactive voltage support. The fleet includes voltage regulators, static synchronous compensators (STATCOMs), voltage support capacitors, and ferro-resonance capacitors.

536 Voltage regulators and capacitors renewal capex over the CPP period is $5.2 million, as shown in Figure 6.45.

Figure 6.45: Planned renewal capex – voltage regulators and capacitors fleet



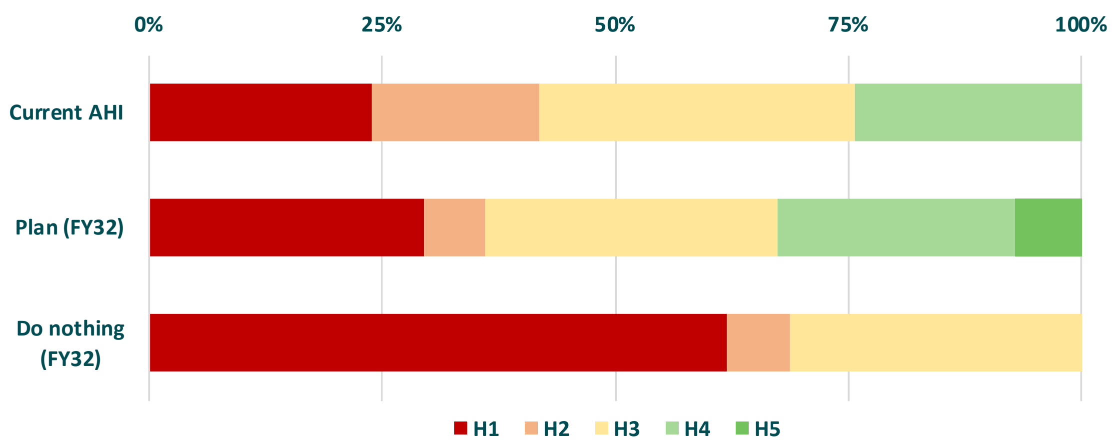
537 Our planned capex is materially higher than FY21-25, as historically renewals have been limited to reactive capacitor replacements only. We have now started a proactive replacement programme, primarily driven by ferro-resonance capacitor replacements. While we are planning to replace only a small number of voltage regulators, these are generally more expensive and represent approximately 75% of the forecast.

6.8.3.1 Voltage regulators and capacitors renewals investment drivers

Asset health and condition risk

538 Figure 6.46 shows the current and forecast AHI for our voltage regulators and capacitors fleet. We have omitted ferro-resonance capacitors and voltage support capacitors from the asset health assessment at this stage due to some data limitations.

Figure 6.46 Asset health modelling for voltage regulators and STATCOMs fleet (as at 31/03/2025)



539 While our planned approach will improve the asset health of the fleet over the CPP period, more work will be required after that time to return the fleet to the desired state of health.

When voltage regulators and capacitors fail, they do not necessarily cause an outage, but can result in a loss of reactive support, which may cause areas of the network to be temporarily outside of voltage limits. As a result, the increased failure risk signalled by poor AHI scores is less of a concern than more critical assets.

6.8.3.2 Forecasting voltage regulators and capacitors renewals volumes and costs

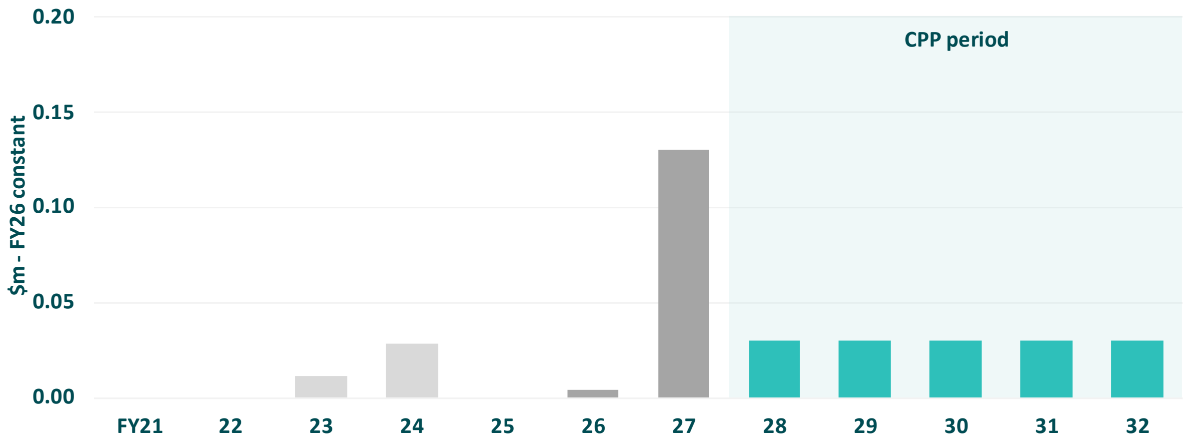
540 We forecast replacement volumes using a repex method (see Box 6.2). Costs are estimated using a volumetric approach. Unit rates are based on the historical average replacement cost.

6.8.4 Generator renewals

541 Our generators supply customers for short periods during fault repairs and/or planned interruptions and provide supply to our building and other essential infrastructure for continued capability in the event of an emergency. This fleet includes mobile generators, building generators, and emergency standby generators.

542 Generators renewal capex over the CPP period is $0.2 million, with annual capex shown in Figure 6.47.

Figure 6.47 Planned renewal capex – generators fleet



543 Our generator fleet is relatively small, we currently only have 14 generators and are planning to only replace 1 in FY27 that has exceeded its expected life. The remainder of the expenditure relates to replacing generator controllers.

6.8.4.1 Generators renewals investment drivers

Asset health and condition

544 We regularly maintain our generators. When they approach end of life, a condition-based assessment will be conducted to see when replacement is optimal. This fleet is in good condition and has had no major mechanical issues. We closely monitor the condition of individual units, in order to extend their useful life.

6.8.4.2 Forecasting generators renewals volumes and costs

545 We forecast replacement volumes using a simple model that compares age to expected life. Costs are estimated using a volumetric approach. Unit rates are based on the historical average replacement cost.

6.9 Secondary systems portfolio

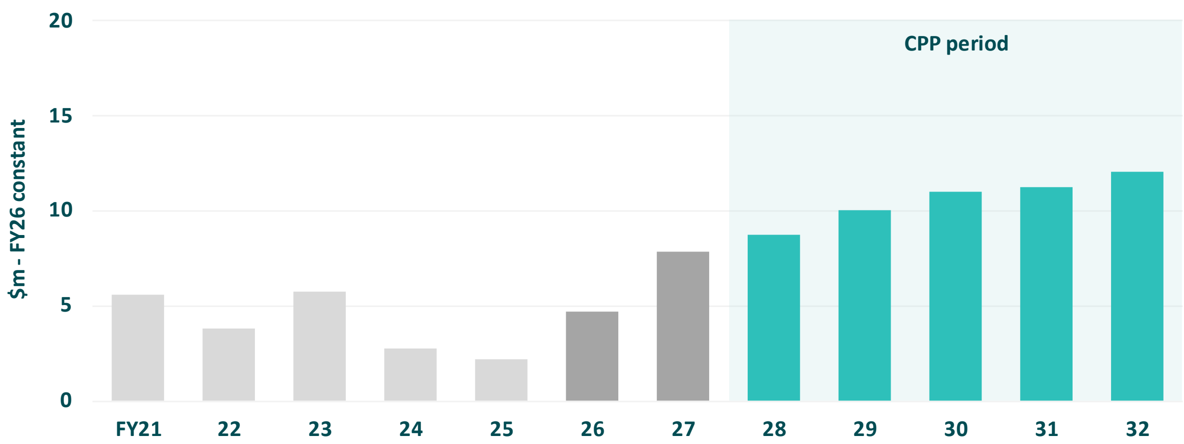
546 Secondary systems are essential for enabling the safe and reliable operation of our network. This portfolio includes 6 asset fleets:

- protection
- batteries and DC supplies
- communications
- signalling/communication cables
- SCADA
- metering.

6.9.1 Secondary systems renewal capex

547 Secondary systems renewal capex over the CPP period totals $53 million, with annual capex as shown in Figure 6.48.

Figure 6.48 Planned renewal capex - secondary systems portfolio



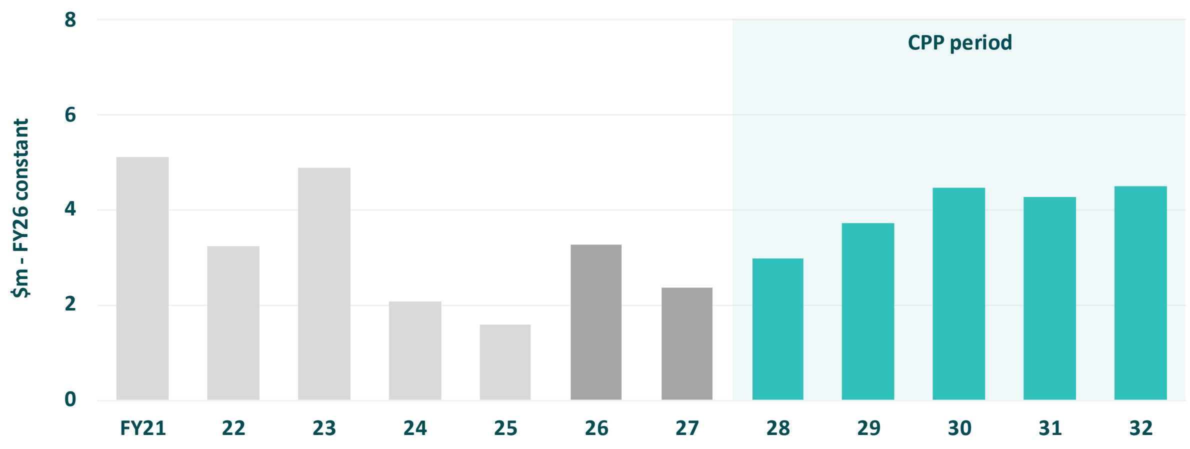
548 The main reason for the increase in investment is replacement of obsolete signalling/communications cables and ageing relays and microprocessor-based numerical relays). We have not previously replaced any signalling/communications cables. However, they are approaching their end of life, poor performing, and non-compliance risks. Normally, replacement of protection relays is done with primary equipment renewal as this is more cost effective, but the shorter life of numerical relays means they often need to be replaced independently of other assets.

6.9.2 Protection renewals

549 Our protection system assets are essential for the safety, security, and reliability of the network. Their primary function is to detect abnormal operating or fault conditions so that they can be interrupted by switchgear assets. The fleet is made up of electromechanical and numerical devices.

550 Protection renewals capex over the CPP period is $19.9 million. Annual capex is shown in Figure 6.49.

Figure 6.49 Planned renewals capex – protection assets



551 Forecast renewal of protection assets is broadly consistent with historical levels. Our forecast includes the renewal of our aging and obsolete fleet of relays. Our forecast gradually increases over the CPP period, as more protection relays become due for replacement. Historically, protection renewals have been undertaken as part of wider primary equipment renewal projects. This was possible because the lives of electromechanical relays (approx. 50 years) were similar to primary equipment, and combining the works was cost effective. However, the shorter life of numerical relays (approximately 25 years) means they need to be replaced within the lifetime of the primary equipment.

6.9.2.1 Protection renewals investment drivers

Asset health and performance risk

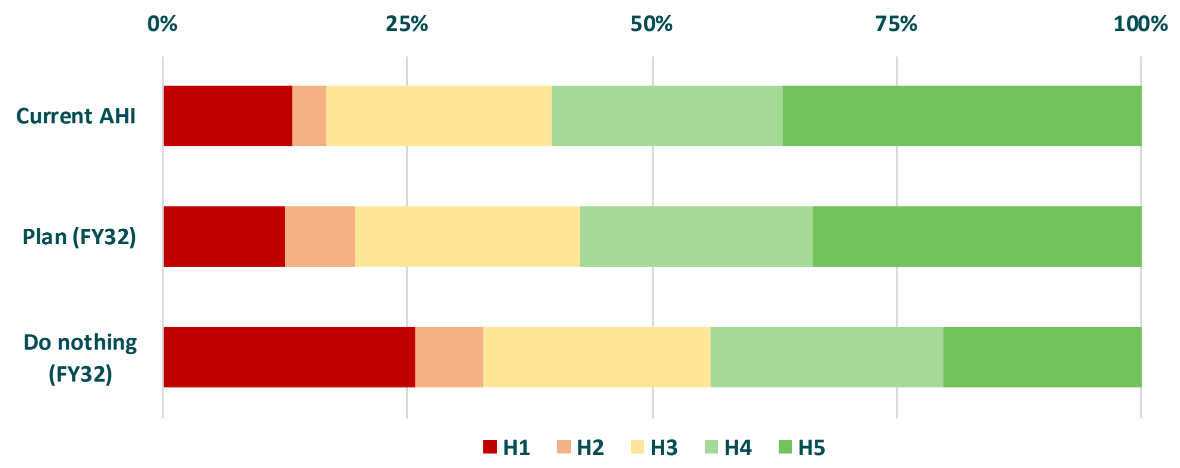
552 The condition of protection assets is difficult to assess as there are no physical signs of deterioration or component ageing on visual inspection. Testing requires simulating actual fault conditions which is difficult and disruptive to the network. During maintenance rounds existing settings are compared against Stationware (protection database) and a binary pass/fail assessment is done to check their operation.

553 We aim to proactively replaced protection assets before failure as they have a significant impact on the performance and safety of our network, making them highly critical. Protection failure can lead to longer fault durations with further potential for asset damage, larger outages with more customers affected, and injury to our people and the public as the faulted equipment may still be live. Protection failure can also cause spurious tripping leading to unwanted isolation of circuits, impacting our reliability.

554 Some faults are due to human error, which are primarily due to the increasingly complexity of protection systems. To mitigate these incidents, we have an ongoing training programme for our technicians, including training on standard designs for protection schemes and maintenance best practice.

555 Figure 6.50 shows the current and forecast AHI for our protection fleet. Many of our electromechanical relays have exceeded their expected life. Some models are also becoming difficult to maintain as manufacturers withdraw support of obsolete types. In the numerical relay population, the oldest devices have recently exceeded their expected life.

Figure 6.50 Asset health modelling for protection fleet (as at 31/03/2025) [update]



6.9.2.2 Forecasting protection renewals volumes and costs

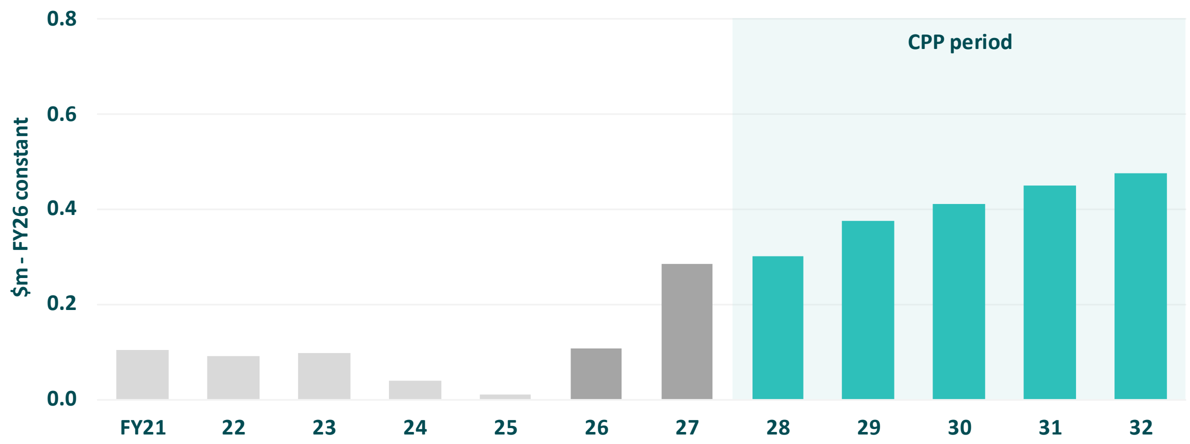
556 We forecast replacement volumes using an age-based model, assuming an expected life of 50 years for electromechanical relays and 25 years for numerical relays. Costs are estimated using a volumetric approach. Unit rates for protection schemes represent an average for each type of protection scheme: transformer, bus zone. feeder, ripple plant, subtransmission, and distribution.

6.9.3 Batteries and DC supplies renewals

557 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. This fleet includes batteries and related chargers.

558 Batteries and DC supplies renewal capex over the CPP period is $2.0 million. Annual capex is shown in Figure 6.51.

Figure 6.51 Planned renewal capex – batteries and DC supplies fleet



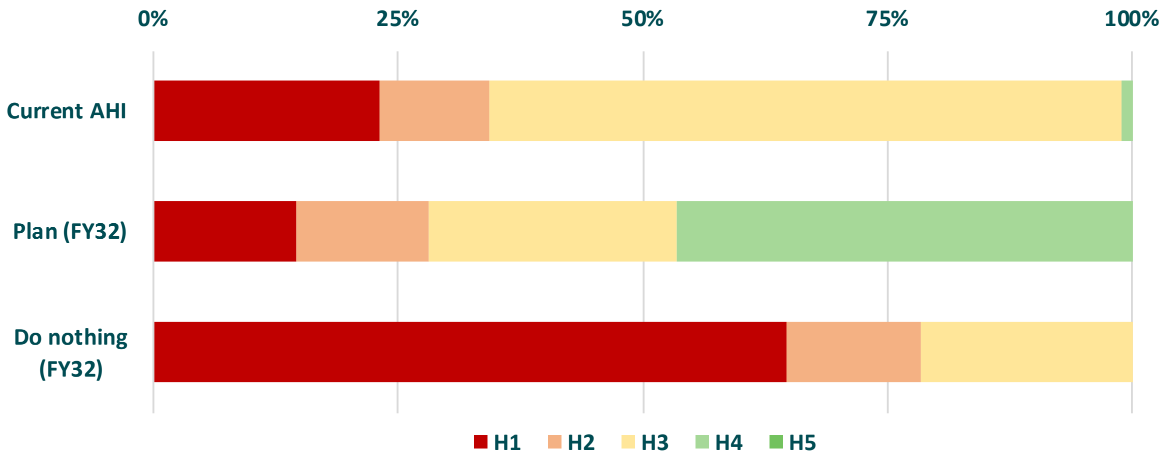
559 Historical renewals of batteries and DC supplies was limited to reactive battery replacements. We plan to initiate a proactive renewal programme of both batteries and chargers, to address the renewal backlog.

6.9.3.1 Batteries and DC supplies investment drivers

Asset health and condition risk

560 Failure of a battery or DC supply can lead to an interruption or unplanned outage. Figure 6.52 shows the current and forecast AHI for our batteries and DC supplies fleet. These assets have relatively short lives (8-15 years), so most of the assets will require replacement in any given 10-year period. A large portion of the fleet have now exceeded their expected lives. Failing to implement our CPP programme would result in very poor asset health by 2032. This would increase network reliability risk as more battery failures would increase the risk that we are unable to properly operate the network and isolate faults.

Figure 6.52 Asset health modelling for batteries and DC supplies fleet



6.9.3.2 Forecasting batteries and DC supplies renewals volumes and costs

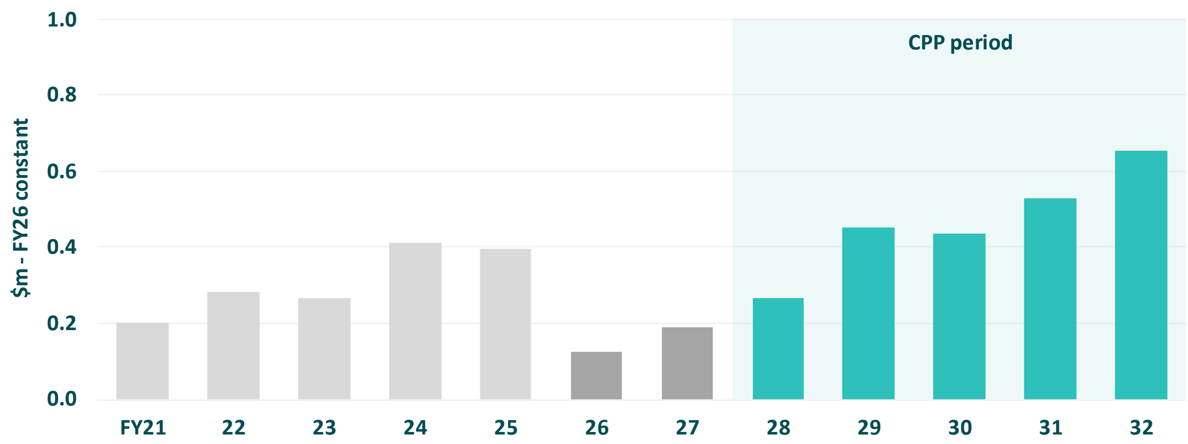
561 We forecast replacement volumes using a simple asset-health driven model. This reflects expected lives of 8, 12, and 15 years for <48V and 110V batteries and chargers, respectively. Costs are estimated using a volumetric approach. Unit rates for batteries and DC systems are an average depending on the operating voltage.

6.9.4 Communications renewals

562 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. We use our signalling/communication cables (see below) as well as a public cellular network for data communications. This fleet includes modems, radios, antennae, routers and masts.

563 Communications renewal capex over the CPP period is $2.3 million, with annual capex as shown in Figure 6.53.

Figure 6.53 Planned renewal capex – communications fleet



564 Our planned renewal of communications assets over the CPP period is in line / slightly higher than historical. The majority of the CPP forecast is driven by radio replacements, followed by modems, routers and antennas respectively. We are not currently planning to replace any masts.

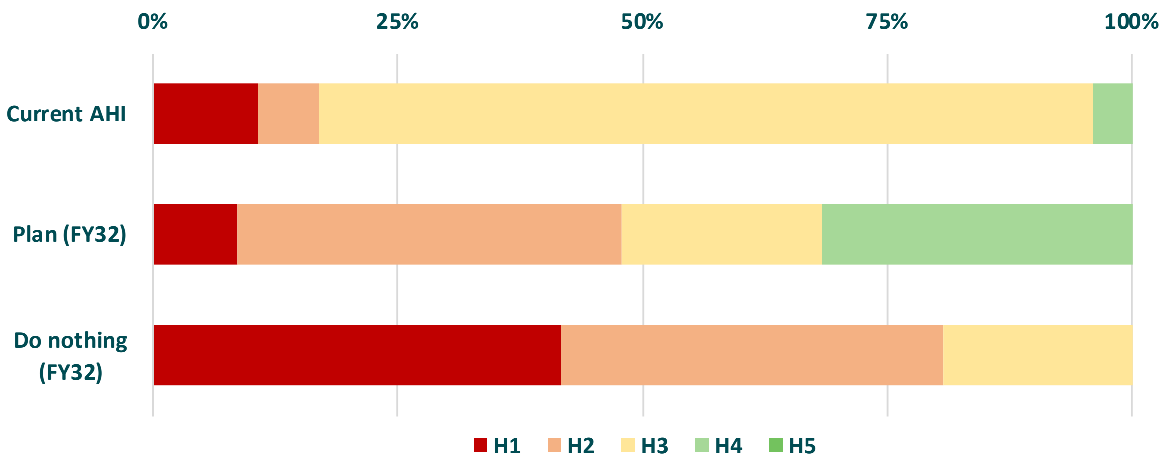
6.9.4.1 Communications renewals investment drivers

Asset health and condition risk

565 We carry out regular inspections of sites and functional testing to ensure reliable operation of the communications system. Our communication systems are largely maintenance free. Because equipment is monitored, with faulty items identified remotely and repaired quickly, failure consequences are generally low.

566 Figure 6.54 shows the current and forecast AHI for our communications fleet. These assets have relatively short lives (8-15 years), so most of the assets will require replacement in any given 10-year period. Most of these assets are within their expected lives, as we aim to replace them based on age. We have retained some assets in service past replacement age due to budgetary/delivery constraints. A substantial number of our modems have exceeded their 8-year expected life; we have a programme in place to replace this equipment.

Figure 6.54 Asset health modelling for communications fleet



6.9.4.2 Forecasting communications renewals volumes and costs

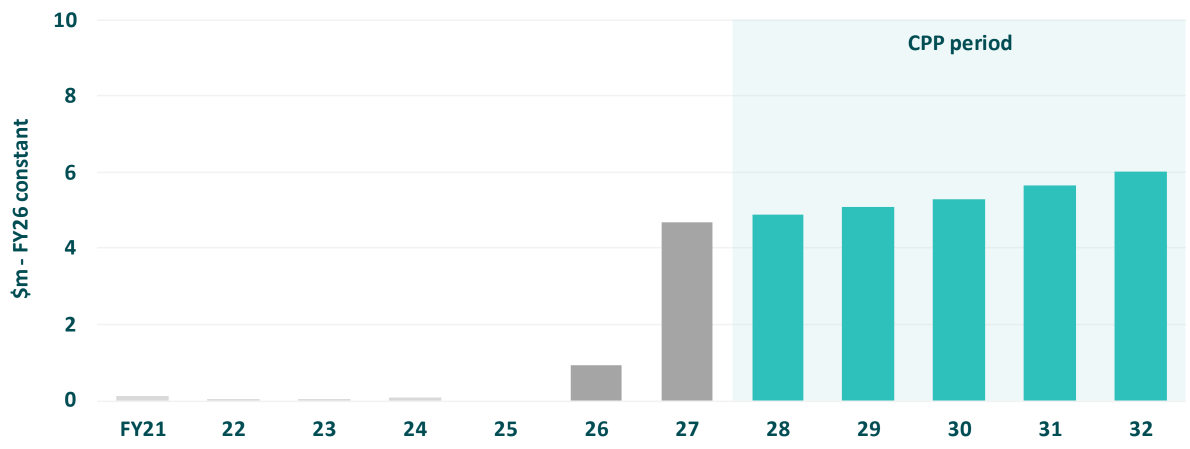
567 We forecast replacement volumes using an age-based approach as age is a reasonable proxy for communications equipment failure and obsolescence. Costs are estimated using a volumetric approach. Unit rates represent an average replacement cost for the equipment type (e.g. antenna, radios, modems).

6.9.5 Signalling/communication cables renewals

568 Our signalling/communication cables (SC cables) provide network operation communication to coordinate safe isolation of primary plant during a fault, and for protection signalling. The cables also support ancillary services between substations and our main control centre. This fleet includes pilot cables (approximately 90%) and fibre optic cables. Fibre optic cables are the modern technology, while pilot cables are a legacy technology, with some of our fleet being 75 years or older.

569 SC cables renewal capex over the CPP period is $26.9 million. Annual capex is shown in Figure 6.55.

Figure 6.55 Planned renewal capex – signalling/communication cables fleet



570 We intend to replace an average of 12km per year during the CPP period. This equates to a very small percentage of the population per year. Some pilot cables (multi-twisted-pair copper) 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 cores.

Box 6.7 Signalling and communications cable renewal approach

Our approach to renewing signalling and communications cables includes a range of options. These options will be chosen to suit the circumstances of individual works to help ensure we achieve the best outcomes. These renewal options include

- **combined with distribution cable renewals:** distribution cables and signalling / comms cables often share the same trench. When we replace signalling cables, if the distribution cable is also due for renewal we will undertake both replacements together. Also, when we replace distribution cables, we generally install spare ducts to support future signalling cable installs
- **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.

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.

6.9.5.1 Signalling/communications cables renewals investment drivers

Asset health and condition risk

571 Failures caused by asset condition 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.

572 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. We coordinate pilot cable replacements with other renewals to minimise required planned outages and the impact on customers.

573 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.

574 Copper 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.

575 During the 2011 Christchurch earthquake, many pilot cables were damaged and spare copper strands were quickly used up to return the protection system into service. Our data shows our spare pilot cable cores were nearly 90% utilised, we are likely to have very few spares left by now. Additionally, vehicle braking at road crossings can cause ongoing damage to cable cores.

Compliance risk

576 We are subject to certain legislation on protection clearance times.[32] Most of our 11 kV network, particularly around urban / suburban Christchurch, is a meshed network. This means that time-grading protection is not feasible, if we are to meet legislative requirements. Instead, our protection system uses SC cables to enable differential protection for our 11 kV network.

577 These cables play a crucial role in our network enabling safe, fast, discriminative, and reliable isolation of faults, as well as being used for SCADA communication to distribution substations and ring main units (switchgear), using DLS modems. Any breaches and/or safety incidents will be investigated, and possibly prosecuted, by WorkSafe.

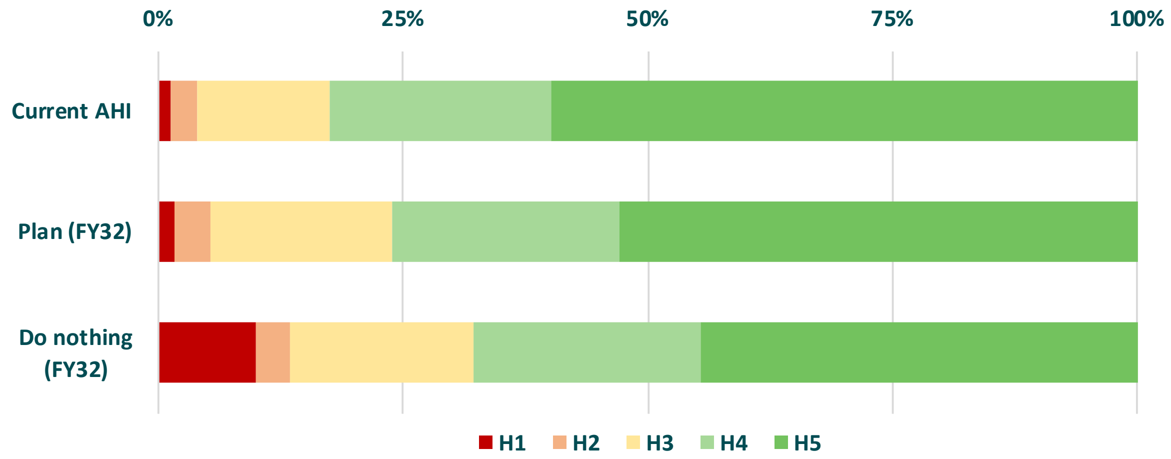
[32] Namely the Electricity (Safety) Regulations 2010 (ESR) and the Electricity Industry Participation Code 2010 (EIPC). The ESR (regulation 33, clause 3a), states that clearance times must not exceed 0.5 seconds, while the EIPC (schedule 12.6, clause 4.2e) states that design clearance times should be 200 milliseconds (bus) to 1 second (feeder) for 11 to 33 kV. Our protection design standard aligns to the EIPC.

Resilience risk

578 Earthquake stress can further weaken aging pilot cables, increasing the likelihood of failure. We plan to replace pilot cables with fibre optic cables as this will make them more resilient against earthquakes as fibre optic cables are more flexible than pilot cables.

579 Figure 6.56 shows current and forecast AHI for our SC cables fleet. The population is ageing and a small percentage of the pilot cable assets have exceeded their expected life (H1).

Figure 6.56 Asset health modelling for signalling/communication cables



6.9.5.2 Forecasting signalling/communication cables renewals volumes and costs

580 We forecast replacement volumes using a repex method (see Box 6.2). 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 approximately 33% of signalling cable renewals will be in shared trenches with distribution power cables which also require renewal. The incremental costs of these distribution cable renewals are included in this portfolio (and excluded from the Distribution Cables portfolio to avoid double counting).

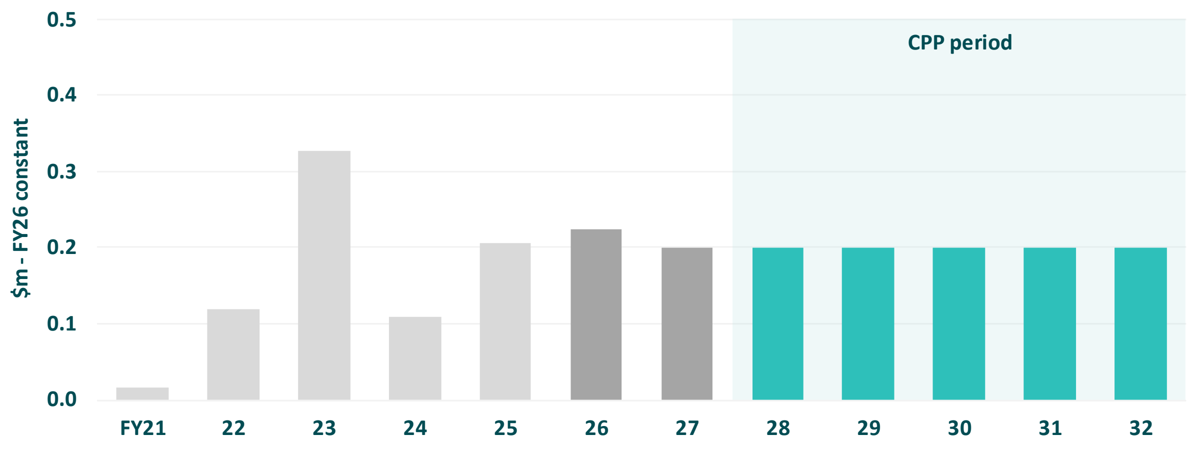
581 When replacing signalling cables, we either install fibre through leased ducts or a new trench with ducts with the former incurring an ongoing leasing cost. Not all leased ducts would route near our equipment – we anticipate 40% of our replacements will use this method while the remainder will require a new trench.

6.9.6 SCADA (RTUs) renewals

582 Our System Control and Data Acquisition (SCADA) system provides control and visibility of our distribution network in real time. We have SCADA assets in zone substations and in the field. This fleet comprises remote terminal units (RTUs), and associated assets.

583 SCADA renewal capex over the CPP period is $1.0 million. Annual capex is shown in Figure 6.57.

Figure 6.57 Planned renewal capex – SCADA fleet



584 Historical renewals for RTUs were ad-hoc or done only with Zone Substation projects. We plan to initiate a more stable programme of proactive RTU renewals, in line with FY25 expenditure while ensuring renewal needs are met and achieving stable delivery at the same time.

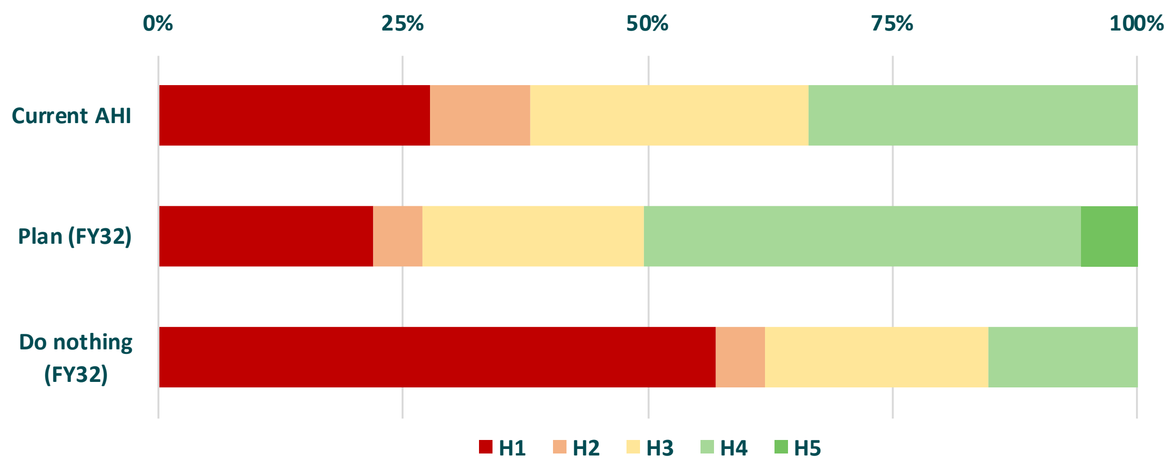
6.9.6.1 SCADA renewals investment drivers

Asset health and condition risk

585 Our SCADA assets are performing adequately at present, despite obsolescence.

586 Figure 6.58 shows the current and forecast AHI for our SCADA fleet. Nearly half of the RTUs have exceeded their expected age and are no longer supported by their manufacturer. We are progressively replacing them as we undertake other projects at zone and distribution substations or during substation maintenance rounds. Undertaking this investment will significantly improve the fleet's health. If SCADA assets fail, they do not generally lead to significant safety or reliability risks. As a result, the increased failure risk signalled by poor AHI scores is less of a concern than for primary asset fleets.

Figure 6.58 Asset health modelling for SCADA fleet



6.9.6.2 Forecasting SCADA renewals volumes and costs

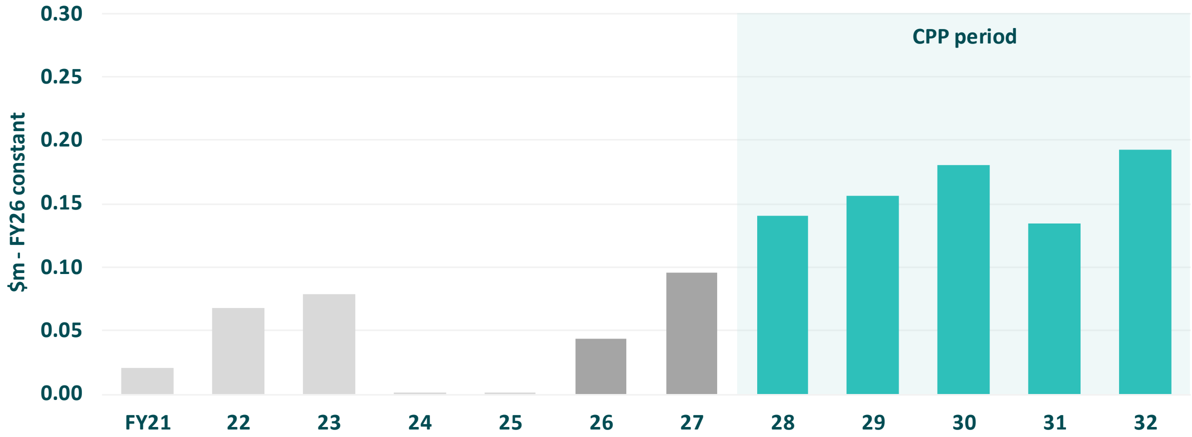
587 We forecast replacement volumes using an age-based approach. Costs are estimated using a volumetric approach. Unit rates are based on an estimated average, covering hardware replacement costs over a wide range of brownfield conditions.

6.9.7 Metering renewals

588 Our monitoring assets are high voltage (11 kV) grid exit point metering equipment and power quality meters. This fleet covers high voltage customer metering, Transpower grid exit point metering, power quality monitoring, and LV monitoring.

589 Metering renewal capex over the CPP period is $0.8 million, with annual capex as shown in Figure 6.59.

Figure 6.59 Planned renewal capex – metering fleet



590 Monitoring assets are considered non-critical, and typically, a reactive approach is used to identify necessary replacement work. However, we are moving to a more proactive approach of replacing them, starting with those that exceed their expected lives over the AMP period which is the reason for the increased investment. About half of our power quality meters are at end of life. Approximately half of our HV meters have already or will reach end of life in the next decade. The majority of LV monitors are within their expected life.

6.9.7.1 Metering renewals investment drivers

Asset health and condition risk

591 We regularly inspect metering sites, carry out appropriate calibration checks, and witness the calibration checks on Transpower's metering.

6.9.7.2 Forecasting metering renewals volumes and costs

592 We forecast replacement volumes using a simple age-based approach. Costs are estimated using a volumetric approach. Unit rates are based on an estimated average cost covering metering replacement costs over a wide range of brownfield conditions.

6.10 Network capex – renewals capex justification

593 We consider the planned network capex for renewals to be prudent and efficient for the following reasons:

- **Customer perspective**: customers and stakeholders consistently told us that a safe, reliable and resilient network is a priority. They expect us to manage our assets prudently and efficiently over their lives and recognise the importance of investing to ensure safe outcomes and maintain reliability at current levels. Customers supported targeted resilience investment to strengthen the network including the 66 kV cable and wildfire pole programmes.
- **Clear, prudent drivers:** our planned renewals programs will help manage safety risks associated with our assets, including overhead assets, type issue RMUs, skeleton panels and oil-filled switchgear. By managing the health of assets, our planned renewal works

reduce asset-failure risk and will help maintain appropriate reliability levels. Other programmes will support improved resilience and manage seismic and environmental risks.

- **Pricebook review:** our unit rates have been independently reviewed and is found to be consistent with the wider New Zealand electricity sector. The review included challenging a number of unit rates, resulting in a combination of upward / downward adjustments during the review process.
- **Cost effective:** we plan to increase volumes of proactive renewal on the network, i.e. aiming to replace assets before they fail. Proactive renewals are generally more cost effective compared to replacing assets reactively. Proactive renewal works are typically higher-volume and programme-managed, enabling more cost-effective delivery through economies of scale.
- **Good Electricity Industry Practice:** our lifecycle and investment approach is aligned with Good Electricity Industry Practice. For example, we are refurbishing our tower assets through our tower painting programme, consistent with approaches adopted across the New Zealand transmission and distribution sector, including Transpower. We also plan to refurbish our zone substation and distribution buildings to address their seismic vulnerabilities, in accordance with relevant building codes and practices. Our planned investments also include remediating overhead conductor clearance violations in compliance with NZ Electricity Code of Practice (NZECP34).
- **Review and moderation:** our forecasts have been reviewed by executive management and the Board. The forecasts have been moderated as a result of these top-down challenges.
- **Standardisation**: we use standard equipment with standard sizes to minimise lifecycle costs, including by reducing contractor training needs and streamlining the range and volume of major plant spares required.
- **Business cases**: planned major renewals projects are supported by full business cases, and have been subject to options analysis, including risk assessments and economic analysis. The tailored cost estimates are derived from our central unit rate price book.
- **Independent verification:** 8 renewal programmes were reviewed by the Independent Verifier with 6 being fully accepted, equating to approximately 95% of the renewal expenditure. The verifier did not accept parts of our wider poles programme including our approach of not reinforcing poles. While pole reinforcements are common practice in Australasia, there is a lack of sufficient evidence that they can perform adequately during seismic movements and/or in liquefied soil conditions. We believe that pole replacement is the most appropriate solution for our network.
- **Expected benefits**: the planned investment will deliver value to customers and the community, including supporting ongoing safety, reliability, and resilience in our network (see Box 6.8).

Box 6.8 Expected benefits of the network capex renewals programme

Our network capex renewals programme supports ongoing safety, reliability, and resilience in our network, enabling us to meet customer and stakeholder expectations. Key benefits expected to be delivered include:

- **Risk management**: the planned activities will reduce risk and maintain/improve asset health and performance of the fleets.
- **Ensuring reliability**: a reduced number of unplanned faults and failures on the overhead and underground network due to asset failures will improve overall reliability.
- **Improved safety**: a reduced risk of exposing staff, service delivery partners, and members of the public to safety risks associated with failures.
- **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
- **Improved data**: by collecting more data, and analysing historical data, for the asset health and performance of our fleets we will improve our understanding of these fleets, resulting in better decision making.
- **Improved efficiency/flexibility:** replacing legacy assets with modern alternatives will increase network control, visibility, and automation. Faster network restoration will also be enabled following a fault.
- **Compliance**: we will meet our obligations with respect to regulations and legislation.
- **Cost effective**: planned renewal work is generally more cost effective than reactive maintenance. Refurbishment of some asset fleets, before significant degradation occurs, is also cost effective.

7

7 Network capex – system growth

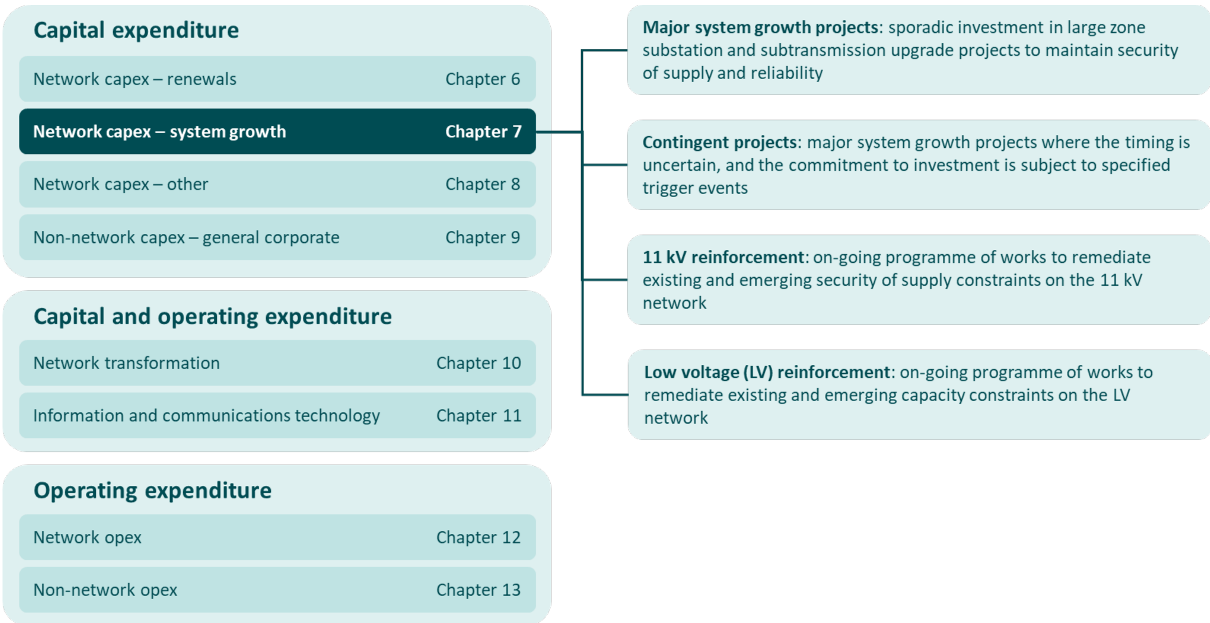
594 System growth capex includes investments to extend and upgrade the network to ensure sufficient capacity to meet peak demand and sufficient security to meet customer preferences for reliability of supply – in both the short and longer term. This expenditure is necessary when:

- network capacity is insufficient to accommodate forecast growth in customer numbers and demand, while maintaining compliance with voltage/power quality regulatory obligations and avoiding asset overloads
- growth has degraded security of supply to a point where reliability is likely to decline below customers' preferred level, and/or the economic cost of an upgrade is lower than the economic cost of outages to customers.

595 As Chapter 2 discussed, our network area has experienced strong population growth and urban development over the past 5 years, and this is forecast to continue over the CPP period and beyond. The nature of this growth is also evolving. Alongside greenfield development in the Selwyn district, the relaxation of infill housing rules across Christchurch and the post-earthquake resurgence of a vibrant CBD – with expanding recreational amenities – are driving higher-density development. Supporting this ongoing and changing pattern of growth is one of the strategic priorities underpinning our CPP application.

596 Figure 7.1 shows where system growth capex sits within our overall expenditure and the portfolios it includes.

Figure 7.1 System growth capex portfolios



597 The projects and programmes in our system growth portfolios interact with 3 other investment categories:

- **Network capex – renewals**: a programme of work to maintain a safe and reliable network and strengthen the network's resilience to earthquakes and severe weather events. This work will contribute to network reliability and security-of-supply by reducing the risk of asset failure and major outages associated with natural hazards. Chapter 6 provides more details.
- **Network capex – other**: a programme of work to connect new customers to the network, and maintain network reliability of supply, safety, and the environment. Chapter 8 provides more detail.

- **Network transformation**: a programme to build capability, tools, and processes to use non-network solutions to moderate peak demand (and thus avoid or defer some system growth capex), investigate alternative network solutions and manage the uptake of distributed energy resources (DER). Chapter 10 provides more detail.

598 The rest of this chapter outlines:

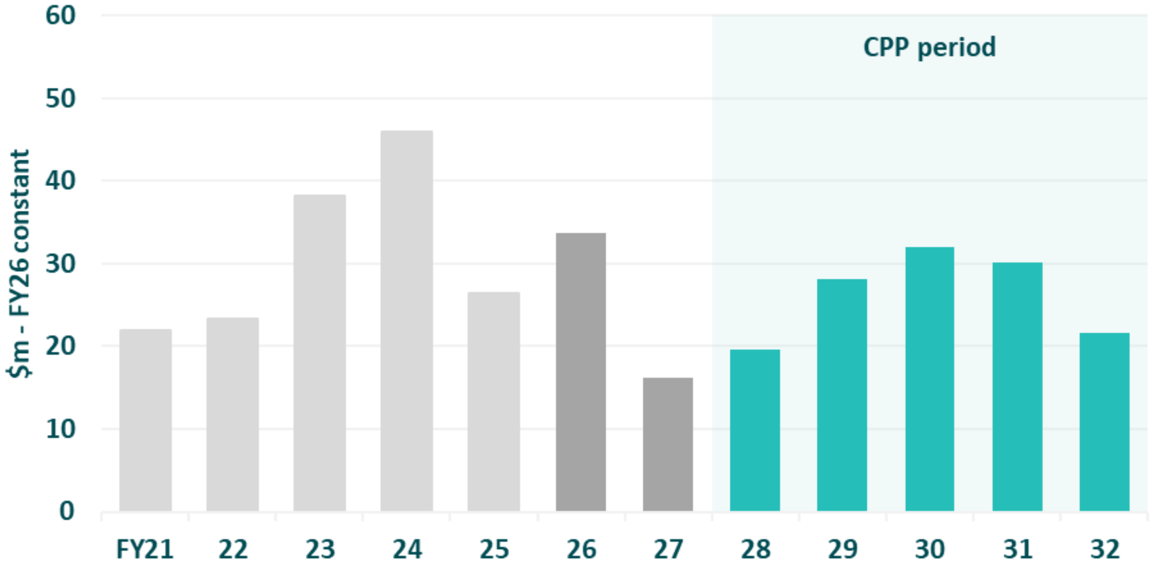
- our planned system growth capex over the CPP period
- its key drivers
- our forecasting approach
- the planned expenditure for each portfolio
- why the planned capex is prudent and efficient.

7.1 Planned system growth capex

599 Our total system growth capex over the CPP period is $131.4 million.[33] It is our second largest expenditure category, representing 14% of planned capex and 9% of planned totex for the CPP period. The planned capex is slightly lower than actual system growth capex in FY21–25.

600 Figure 7.2 shows the planned system growth capex per annum compared with our historical spend.

Figure 7.2 Planned system growth capex per annum

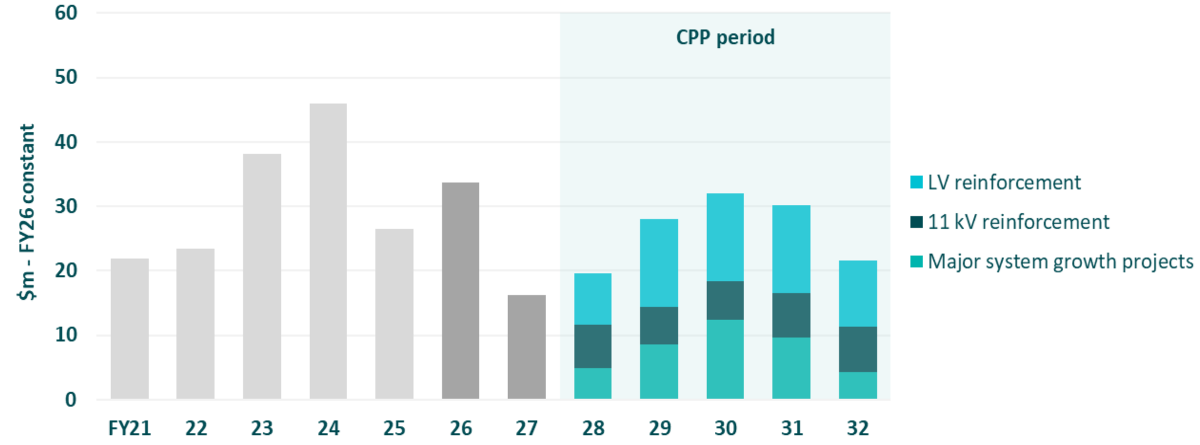


601 Planned system growth capex in the CPP period is broadly in line with the average level of actual capex in FY21–26, though the historical spend was more variable with higher peaks. This is because major growth projects are relatively large and are required intermittently, when growth in a particular location causes a constraint. The planned annual capex trend peaks during the middle of the CPP period, primarily because 2 high-value major projects overlap during FY30.

[33] Excluding expenditure related to the Network Transformation programme.

602 Figure 7.3 shows the planned system growth capex per annum, broken down by portfolio.

Figure 7.3 Planned system growth capex per annum, by portfolio



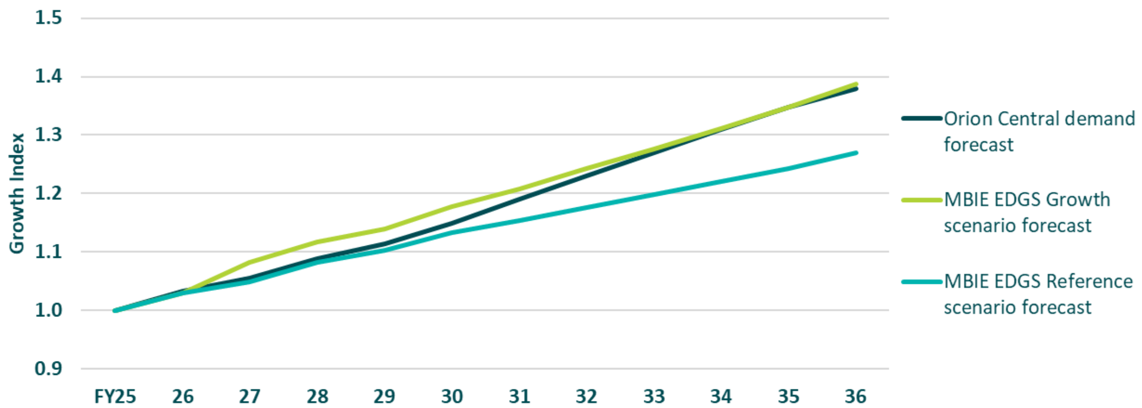
7.2 Key drivers

603 System growth capex is primarily driven by forecast increases in peak demand. On our network, peak demand occurs in the early morning, and this pattern is expected to persist over the CPP period. Evening demand is also high, with some areas experiencing peaks in the early evening.

604 Our long-standing peak demand management has flattened the daily demand profile on cold winter days, deferring the need for growth-related investment over several decades. The value of this demand management varies by location and time, delivering benefits at all levels of the power system. Recent analysis by Concept Consulting found that, in addition to benefits on our network, peak demand management across our network area and the wider upper South Island delivered transmission deferral savings of approximately $11 million per annum since 2021.[34]

605 Over the CPP period, we forecast peak demand to grow by 16.5% – from 741 MW in FY28 to 838 MW in FY32 – or a compound annual rate of 3.1%. Our forecast is comparable to those produced by the Ministry of Business, Innovation and Employment (MBIE) under its Electricity Demand and Generation Scenarios (EDGS), which we used for benchmarking (Figure 7.4).[35]

Figure 7.4 Orion's forecast peak demand growth compared with forecasts under MBIE's Growth and Reference scenarios



606 The sections below outline how we forecast growth in peak demand, and the main drivers of this forecast growth.

[34] See this report for further detail on the analysis: https://www.oriongroup.co.nz/assets/Be-prepared/Managing-load/Valuing-USI-load-control-v4-2026.pdf

[35] MBIE's Growth Scenario provides the most appropriate benchmark, due to the strong population growth expected in our network area.

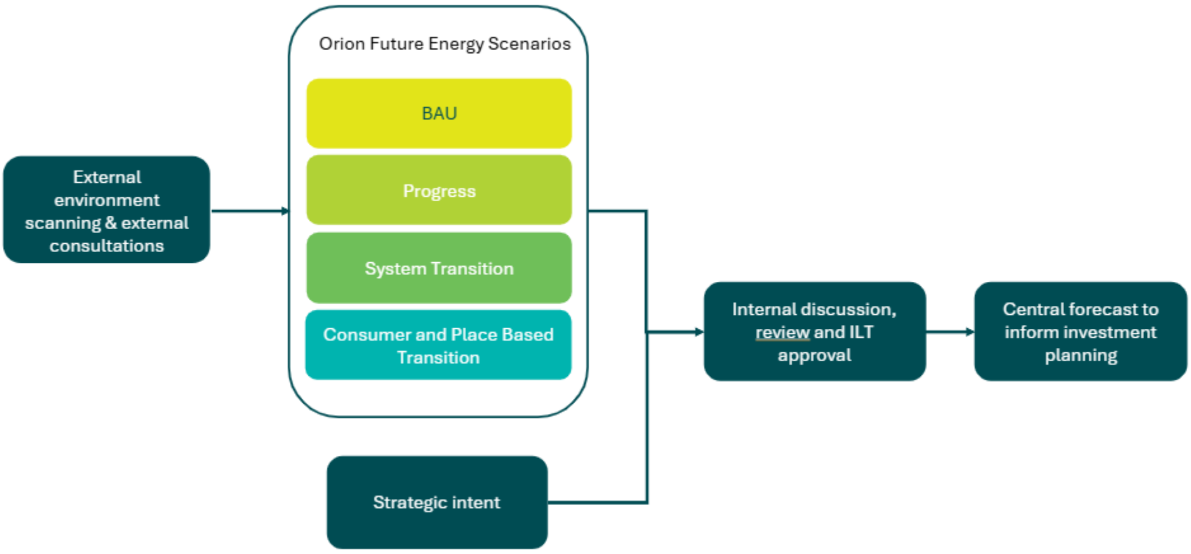
7.2.1 How we forecast peak demand growth

607 To forecast growth in peak demand, we use a driver-based Future Energy Scenarios model developed with Frontier Economics.[36] This model allows us to test a range of plausible futures by varying key assumptions about technology, behaviour and policy, and to assess the implications for demand and investment.

608 We then develop a Central forecast by selecting the most relevant and credible inputs for our region. These inputs, together with our strategic intent (reflecting demand-side levers we can directly influence, such as hot water load control and time-of-use pricing), form the basis of the forecast used for planning.

609 This process is summarised in Figure 7.5 and described below.

Figure 7.5 Central forecast development process



610 We first set forecasting inputs through a structured process combining external referencing, internal analysis, and targeted stakeholder engagement. This ensures assumptions are evidence-based, reflect local conditions, and support long-term planning.

611 For example, inputs were informed by our reviews of recent scenarios used by MBIE, Transpower and UK Power Networks, and workshops with internal and external stakeholders. We also engaged with Transpower, Christchurch City and Selwyn District councils, ChristchurchNZ and Ngāi Tahu.[37]

612 We used the inputs to build on the plausible scenarios in our Future Energy Scenarios report (Business as Usual, Progress, System Transition and Consumer and Place Based Transition) and a Central scenario.[38]

613 We then model peak demand under each scenario using a framework with 4 components:

- **baselines**: location-specific demand baselines (weather-normalised) and driver baselines to avoid double counting
- **drivers**: 5 main drivers – growth and urban development, transport electrification, process heat conversion, solar PV generation, and flexibility

[36] Frontier Economics reviewed and enhanced the demand forecasting process, including development of a weather normalisation model to aid the development of PoE10/50 forecasts.
[37] ChristchurchNZ is the economic development and city promotion agency for Christchurch and the wider Canterbury region in New Zealand. Ngāi Tahu is the principal Māori iwi (tribe) of the South Island of New Zealand (Te Waipounamu).
[38] For example, these inputs included historical data sourced from the network or external providers, information nationally consistent trends (e.g. on EV uptake), information on local trends (e.g. population growth and process heat electrification).

- **location**: forecasts at both zone substation and SA2[39] level to capture network-wide and localised impacts
- **time**: a 25-year forecast with seasonal and half-hourly resolution.

614 The model produces location-specific load profiles, which are combined to form total demand. Peak demand growth is calculated by comparing the peak of the baseline load profile with the peak of the stacked driver-adjusted profiles for each year. This approach captures the diversified impact of individual drivers, with each driver's contribution to peak demand reflected in the coincident system peak rather than as a simple sum of individual effects.

615 A Central forecast is then selected through cross-functional workshops, combining the most appropriate inputs with our strategic intent for planning purposes. Once reviewed and approved by our Integrated Leadership Team, this forecast is used to inform growth-related investment decisions across the network.

616 The independent verifier found that our approach compares favourably to those used by other network utilities in New Zealand and Australia. It observed that the inputs and assumptions we used align with national scenarios used by MBIE and Transpower, and that our forecast for the CPP period is consistent with recent historical growth.

617 For further detail on how we develop our Central forecast, see our Asset Management Plan 2026, Section 10 – Network development approach.

7.2.2 Main drivers of forecast peak demand growth

618 As noted above, we forecast peak demand growth of 16.5% (or 98 MW) over the CPP period. Across all the future energy scenarios and our Central forecast, the primary driver is urban residential and commercial development, linked to population growth across Christchurch and Selwyn – accounting for 81.6% (80 MW) of total growth. The next most significant drivers are process heat conversion and transport electrification, which add 16 MW and 3 MW, respectively. The main drivers of this growth are summarised in Table 7.1. Our population forecasts are outlined in Box 7.1.

619 We considered a range of electric vehicle (EV) uptake scenarios and their impact on peak demand. We expect private EVs to initially affect the low voltage network where clustering may occur, with a smaller overall impact than urban development across all scenarios.

620 We also considered a range of EV charging behaviours in response to retail electricity pricing, as well as the potential for active management by Orion, retailers, or flexibility providers. Our central forecast assumes that time-of-use pricing will materially reduce the contribution of EV charging to peak demand. Further smoothing of the EV charging profile may be achievable in constrained areas through targeted procurement of non-network solutions, including smart EV charging.

621 In relation to the uptake of DER and flexibility, rooftop solar alone has minimal impact on winter peak demand. We assessed combinations of solar and batteries and the potential for vehicle-to-grid exports. However, the uptake over the CPP period is unlikely to match the scale of population growth or the level of storage and flexibility currently available through hot water management. Overall, we expect a small net reduction in peak demand from generation and flexibility over the CPP period. We intend to influence the location and pace of uptake through procurement of non-network solutions in areas of network constraint.

[39] Statistical area 2 (SA2) is a new output geography that provides higher aggregations of population data than can be provided at the statistical area 1 (SA1) level. SA2 areas are smaller than zone substation areas and therefore enable a more granular forecast for application to the 11 kV and 400 V networks.

Table 7.1 Contribution to peak demand change over the CPP period (FY28-32) of each driver and sub-driver

Driver	Sub-driver	Contribution (MW)
Growth and urban development	Residential building (population driven)	29
	Residential energy efficiency	-4
	Industrial and commercial growth (GDP driven)	46
	Residential electrification	0
	Industrial and commercial electrification	2
	Major connections	7
	Total	**80**
Transport electrification	Light electric vehicle charging	3
	Heavy electric vehicle charging	0
	Total	**3**
Process heat conversion	**Total**	**16**
Solar PV generation	Residential	-2
	Commercial	0
	Utility	-6
	Total[40]	**-2**
Demand-side flexibility	Orion peak hot water	3
	Fixed hot water	-1
	Retailer controlled hot water	-3
	Major customer control	3
	Residential battery energy storage system	-2
	Commercial battery energy storage system	0
	Vehicle-to-grid export	-1
	Solar hot water	0
	Total	**-1**
Total		**98**

[40] Utility solar generation is not calculated in the solar PV generation total amount, as recommended by the Frontier Economics review of our approach to demand forecasting.

Box 7.1 Forecast population growth in the Orion network area

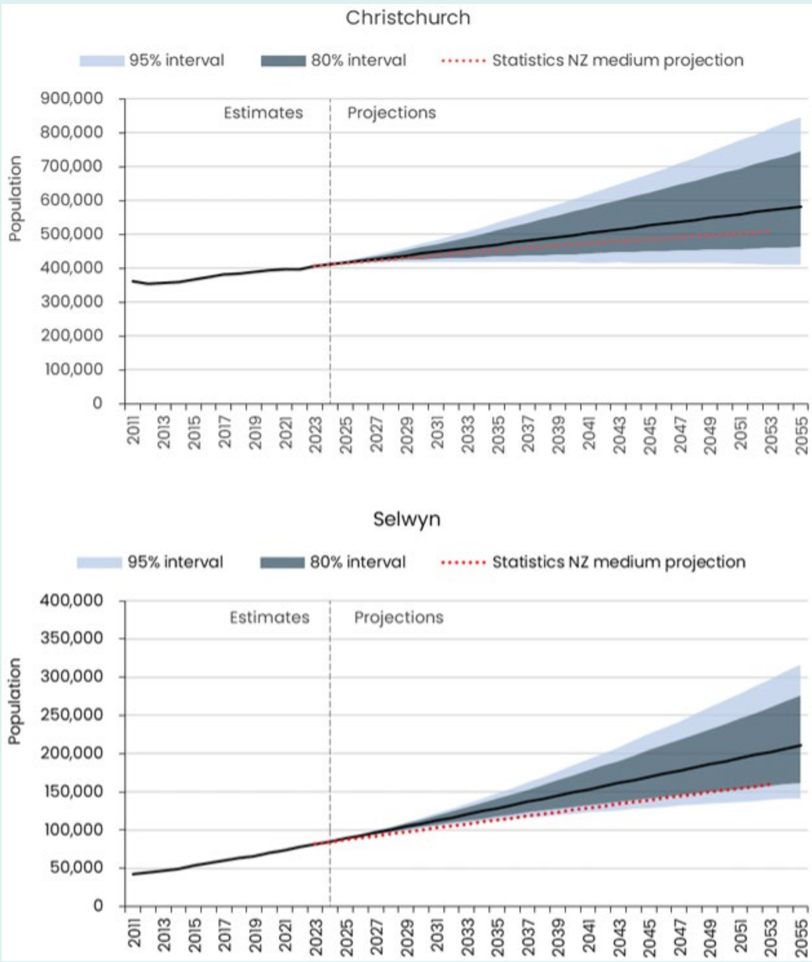
Population projections are a critical input for our peak demand forecasts, as population growth underpins demand growth in the residential sector. It also underpins forecast GDP growth, which drives demand growth in the industrial and commercial sectors.

MBIE uses Stats NZ's medium-growth projections for its demand forecasts. However, since the growth projections made in 2013, Stats NZ's projections have under-estimated actual population growth in our network area. For this reason, we commissioned Geografia – an economics, demography, and spatial analysis consultancy – to prepare independent long-term population projections for our area.

We used Geografia's base population forecast for our peak demand forecast. The base forecast indicates the population in our area will continue to grow strongly over the CPP period and beyond. From 2025 to 2032:

- Christchurch's population is projected to increase by 35,000, representing average annual growth of around 1.1%
- Selwyn's population is projected to increase by 30,000, representing average annual growth of around 4.3%.

The figure below shows Geografia's base population projections for the Christchurch and Selwyn areas (the black line) to 2055, along with the probabilistic uncertainty ranges for these projections, and Statistics NZ's medium population projections.



7.3 Forecasting approach

622 Our Network Development Strategy provides the 'tramlines' that guide development of our system growth expenditure forecasts. It sets out our high-level objectives and focus areas for developing the network to support growth in line with levels of capacity, security-of-supply, and resilience that reflect customer preferences, and our related business and Strategic Asset Management Plan objectives. It also sets out how we will achieve these objectives, including our subtransmission network architecture, our Security of Supply Guide (Box 7.2), optioneering approach (including non-network solutions), the value of reliability in economic assessments, and planning horizon timeframes for each network layer.

Box 7.2 Security of Supply Guide

Our Security of Supply Guide sets out target levels of network security across the network. The Guide identifies all network locations, the type of area or customer they supply, and their load size. For each location, it defines the target level of performance when different types of network fault occur. For example, as the extract below shows, location B2 supplies a metropolitan area with a load of 15 to 200 MW. The Guide states when a fault occurs – a single cable, line or transformer fault – there should be no interruption to supply.

The performance targets are set to replicate the likely point where improvement in security-of-supply can be economically justified: that is, when the economic benefit to customers of the improved network security is greater than the cost to upgrade the network. However, the cost to upgrade the network and economic impact to customers varies by network location. For major projects, this cost and impact will be high, so we investigate further, including an economic assessment, before deciding to upgrade.

The Security of Supply Guide is provided in full in our Asset Management Plan 2026, *Appendix F – HV 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
Orion 66kV and 33kV subtransmission network					
A2 (Note 2)	Supplying CBD, commercial or special industrial customers	15-200	No interruption	Restore within 1 hour	No interruption for 50% and restore rest within 2 hours
A3	Supplying CBD, commercial or special industrial customers	2-15	Restore within 0.5 hour	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
B2 (Note 2)	Supplying predominantly metropolitan areas (suburbs or townships)	15-200	No interruption	Restore within 2 hours	No interruption for 50% and restore rest within 2 hours
B3	Supplying predominantly metropolitan areas (suburbs or townships)	1-15	Restore within 2 hours	Restore 75% within 2 hours and the rest in repair time	Restore within 2 hours
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.					

623 The network development strategy objectives contain focus area priorities that guide where and how we invest to achieve each objective. (For further details, see Asset Management Plan 2026, Section 10 – Network development approach).

624 Within these tramlines, we apply different forecasting approaches depending on the characteristics of each portfolio:

- **For the major system growth projects portfolio,** we use a rigorous tailored approach that involves developing a full business case for each potential project. Once the preferred option is selected, we use the project scope and a price x quantity (P × Q) approach to forecast capex.
- **For contingent projects,** we use the same forecasting approach as for major system growth projects, and also identify the events that will trigger the need for the investment.

- **For the 11 kV reinforcement portfolio**, we use a base-step-trend approach to forecast capex for reconfiguration works, and feeder peak utilisation modelling combined with a P × Q approach for capacity-driven reinforcement.
- **For the LV reinforcement portfolio**, we use a P × Q approach, where constraints are identified through power-flow modelling and assigned a severity with a corresponding cost to resolve.

625 For all portfolios, our scoping process includes actively seeking opportunities to align planning and construction works across system growth with renewal needs. This ensures, where possible, we deliver solutions that not only address network constraints but also replace end-of-life assets, making the most of each investment and enhancing our efficiency.

626 More detail on the portfolio-specific forecasting approaches is provided in sections 7.4 to 7.7 below.

7.4 Major system growth projects portfolio

627 The major system growth projects portfolio includes 4 large zone substation and subtransmission upgrade projects to maintain the security and reliability of supply. It also includes the purchase of additional power transformer emergency spares to ensure we can respond quickly if a major transformer failure should occur. In all cases, we have established through detailed analysis and business cases that the forecast growth will create significant capacity constraints on the network during this period, and that these constraints are most efficiently addressed by upgrading the network. We have also incorporated provision in our non-network solutions programme (see Chapter 10) to defer 2 projects (Lincoln and Lyttelton) and 1 contingent project by one year.

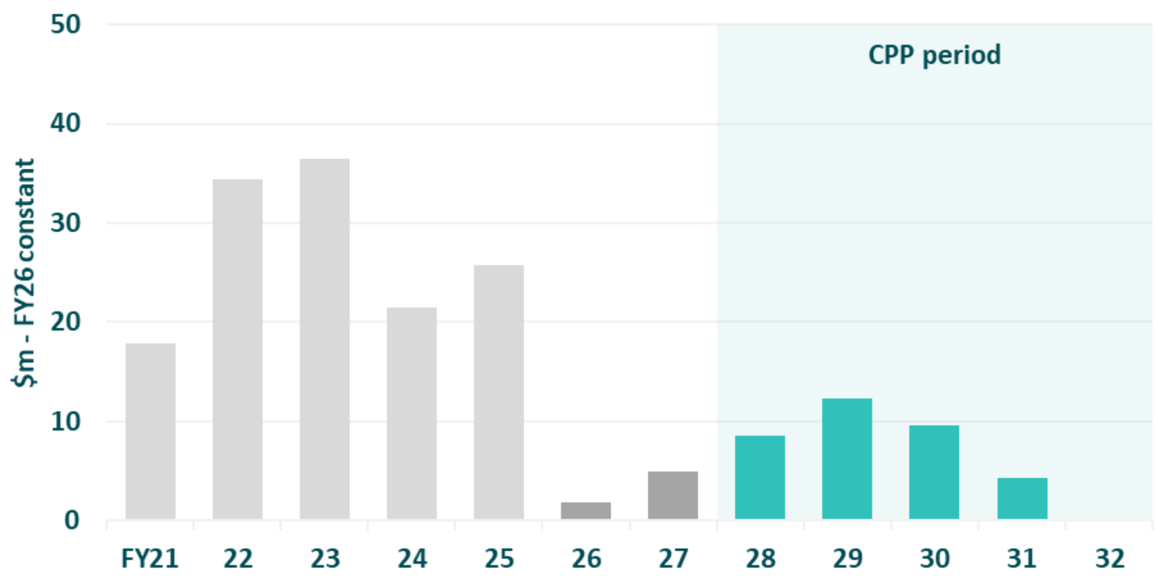
628 The sections below outline:

- the planned major system growth projects capex over the CPP period
- the approach we used to forecast this capex.

7.4.1 Planned major system growth projects capex

629 Our planned capex for the major system growth projects totals $39.6 million over the CPP period. Figure 7.6 shows the annual capex, compared with our historical spend.

Figure 7.6 Planned major system growth projects capex per annum



630 As noted above, the planned major system growth projects capex is lower than our historical spend. This is because between FY21 and FY26, we delivered several major 66 kV cable urban development projects primarily driven by the need to maintain security of supply. Accordingly, these projects were included in the network capex – system growth expenditure category. Although we propose further 66 kV cable replacement projects over the CPP period, these projects are primarily driven by the age and condition of these assets (with resilience improvement influencing the timing) and are therefore included in the network capex – renewals expenditure category, discussed in Chapter 6.

631 Table 7.2 shows the planned capex per year for each major system growth project. These projects are outlined below. More detail is provided in our 2026 Asset Management Plan, Section 12 – Network development programme.

Table 7.2 Planned major system growth projects capex per annum ($m, FY26 constant)

Project	FY28	FY29	FY30	FY31	FY32	CPP Total
Lincoln township growth	0.8	6.6	6.6			**14.0**
Templeton zone substation		0.7	5.3	5.3		**11.3**
Lyttleton major supply upgrade			0.5	4.3	4.3	**9.1**
Malvern industrial growth	1.1	1.1				**2.2**
Emergency spare transformers	2.9	0.1				**3.0**
All projects						**39.6**

7.4.1.1 Lincoln township growth project

632 Lincoln township is one of the main centres in the fast-growing Selwyn district and functions as a commuter satellite town to Christchurch. The district's population is forecast to grow by around 16% over the CPP period, and significant new housing developments are expected to be built. For example, a pipeline of greenfield developments has progressed through planning approvals in recent years, including Earlsbrook (Lincoln South). This multi-stage, mixed-use subdivision of around 2,100 lots is expected to be delivered over the next decade.[41]

633 **The need**: the network's capacity needs to keep pace with the forecast growth in Lincoln township, while maintaining the current level of reliability and supporting the increasing use of EVs for commuting to Christchurch. The existing Lincoln zone substation has undersized, aged primary assets located on a space-constrained site. It is no longer ideally positioned, given the new subdivision is located on the township's fringe.

634 The substation exceeded its firm capacity on several days in winter 2025, and this is expected to occur more often as demand increases. Under our Central forecast, we forecast peak demand on the Lincoln substation to increase by more than 53% in the next decade. Without additional capacity, the risk of a cascade asset failure and associated outages will increase as the Lincoln substation is reliant on the aged power transformers operating further beyond the site's firm capacity.

635 **The solution**: we will establish a new 33 kV Greenpark zone substation on the eastern fringe of Lincoln township to fully replace the existing Lincoln zone substation and provide greater capacity. This solution will be supplemented by a non-network solution, enabling deferment of one year.[42] This option was selected as it resolves the capacity and asset renewal issues and provides the highest net benefit, while de-risking the timing sensitivity associated with the demand forecast through the supplementary use of a non-network solution. To the extent

[41] https://earlsbrook.co.nz/house-land

[42] The forecast investment in this and other non-network solution included in major system growth projects is included in the network transformation portfolio, discussed in Chapter 10.

possible, this project has been staged where appropriate, by undertaking tactical 11 kV upgrades from Springston zone substation in the first instance.

636 The other short-listed options considered were:

- Do nothing: this option was ruled out as it would lead to load shedding following a fault on the network, which is inconsistent with the screen test guidance provided in our Security of Supply Guide, economic analysis, and customer reliability preferences.
- New 33 kV Greenpark zone substation without a non-network solution: this option was considered inferior to the selected option, as it would not enable the potential for deferment with a more economical non-network solution to be tested.
- New 66 kV Greenpark zone substation: this option was ruled out as it brings forward 66 kV-related costs that are not yet needed.

7.4.1.2 Templeton zone substation project

637 Templeton is a small township on the western outskirts of Christchurch. The Christchurch men's and women's prisons are both located in the largely rural area surrounding the town.

638 **The need**: both prisons are currently supplied by a lengthy 11 kV distribution feeder with few interconnections from the Moffett Street zone substation. Both currently use mostly diesel and LPG for space heating and hot water. The Department of Corrections has indicated it intends to expand the men's prison and switch to electricity for space and water heating, increasing its electricity demand. It is likely the women's prison will follow the same path. The existing feeder is not suitable to supply this additional demand due to inadequate reliability and insufficient capacity.

639 **The solution**: we will establish a new 66/11 kV single 23 MVA transformer rated substation immediately next to the prisons, with an in-and-out connection into the adjacent Islington GXP-Weedons zone substation 66 kV line. This solution was selected as the new substation will provide new capacity directly to the prisons, removing load from the sparse 11 kV feeder. It is also close to a new vertical farm that proposes to connect to the same feeder. This solution also has the highest NPV of the options considered (taking account of all network costs and customer benefits) and addresses the business/customer need case including managing risks to an acceptable level.

640 The other short-listed options considered were:

- Do nothing: this option was not selected as it did not address the business/customer need case.
- Strengthen the 11 kV network with a new cable supply: this option was not selected as it had a lower NPV and did not meet the long term needs to strengthen supply in the area.
- A simpler 66 kV T-off connection for the zone substation: this option was not selected because it provided a lower level of reliability for the customer, and a corresponding lower NPV.
- Defer the zone substation with a non-network flexibility solution: this option was not selected as it is unlikely to be able to be delivered at the scale required. Although we selected the fully capex option, we intend to re-engage with the Department of Corrections to determine whether its initial position on a non-network solution that incorporates solar PV and battery storage systems on its land can be used to defer the development of the new substation.

7.4.1.3 Lyttelton major supply upgrade project

641 Lyttelton is a suburb of Christchurch, and the location of Lyttelton Port – the South Island's largest port and container terminal operation.

642 **The need**: Lyttelton is in an isolated part of our network that has limited capacity. It is supplied by 3 dedicated 11 kV feeders from the Heathcote zone substation, around 4.5 km away. No viable/consented alternative supply pathways are available except for the installation of an additional cable installation in the Lyttelton tunnel.

643 Lyttelton Port Company (LPC) plans to substantially expand its port facilities and electrify its port and ship-side movements, resulting in significantly higher total forecast load on the 3 feeders. Without additional capacity, we expect a breach in the firm supply capacity in FY31. (See our Asset Management Plan 2026, Section 11 – Network demand, distributed generation and constraint forecasts for more information.)

644 **The solution**: we will install a fourth 11 kV circuit from Heathcote to Lyttelton and reinforce one of the existing feeders to support LPC's growth plans. This solution will be supplemented with a non-network flexibility solution that defers the investment by one year, delaying commissioning from FY31 to FY32. This option is the most cost-efficient, as it utilises the existing second cable space allocation in the Lyttelton road tunnel. It has the lowest NPV when all network costs and customer benefits are accounted for. It addresses the business/customer need case, including managing risks to an acceptable level.

645 The other short-listed options considered were:

- Do nothing: this option was ruled out as it would lead to load shedding and/or an inability to connect new customers or increased demand at the Port, which is inconsistent with our objective to ensure sufficient, scalable capacity to support growth and electrification, our Security of Supply Guide, and customers' reliability preferences.
- Install a fourth 11 kV circuit and reinforce an existing feeder without a non-network solution: this option is viable and economically comparable to the selected option and will be utilised once the opportunity to utilise non-network solutions has been fully exhausted.

7.4.1.4 Malvern industrial growth

646 Malvern is a rural area to the northwest of Rolleston township containing an abattoir supplied via approximately 11 km of overhead conductor from Highfield zone substation.

647 **The need**: the abattoir in Malvern proposes a 3.7 MW staged upgrade to its operation between 2026 and 2029. This extra demand on the network will exceed the available capacity at Highfield zone substation, and cause excessive voltage drop on the 11 kV overhead feeder.

648 **The solution**: we will establish a new Norwood 11 kV supply point at the recently constructed Norwood 66 kV zone substation. The Norwood site is only 3 km from the abattoir and site establishment works were undertaken as part of commissioning the new zone substation. The solution will resolve the Highfield substation and line constraints and provide additional capacity to the wider area. The capacity constraint (as opposed to a security of supply constraint), the scale of the demand increase, the urgency and the relatively low per MW cost of the preferred solution makes tactical solutions including non-network solutions impractical to meet the technical need at a comparable cost.

649 The other short-listed options considered were:

- Upgrade Highfield substation and install a new voltage regulator: this option was not selected as it did not align with the strategy to utilise Norwood as a zone substation site and had a higher installation cost and lower NPV than the selected solution.
- Establish a new zone substation at the abattoir site: this option was not selected as it had a higher installation cost and lower NPV than the selected solution.

7.4.1.5 Emergency spare transformers project

650 Power transformers are high-value, critical network assets required to ensure a resilient and reliable electricity supply. Their failure has the potential to impact many thousands of customers and procuring replacements takes a long time (12–18 months).

651 **The need**: we have insufficient spare transformers to cover all voltages, ratings, and connection configurations. This is inconsistent with good industry practice, and creates a high risk of extensive or prolonged outages in several catastrophic transformer failure scenarios. This outcome is beyond our risk tolerance, and inconsistent with the Electricity Engineers' Association of New Zealand's *Resilience Guide* (which lists readiness or availability of critical network asset spares as a key risk control). In addition, the power transformer fleet contains a number of transformers in the latter half of their life and transformer spares provide support over their 50+ year lifetime.

652 **The solution**: we will procure 2 spare transformers – one 11.5/23MVA, 66/22/11 kV spare transformer, and one 7.5/10MVA, 33/11 kV transformer to be installed at Motukarara substation (as a hot spare). The 11.5/23 MVA transformer covers both 66 kV and 33 kV primary winding transformers so it reduces the total number of spare transformers we require. This option is selected as it brings the residual risk scores associated with transformer failure in line with our risk tolerance. It ensures we have a spare transformer available for all transformer asset fleet ratings and voltages in case of the loss of a zone substation transformer where there is either no second (N-1) transformer, or no 11 kV back-up supply available.

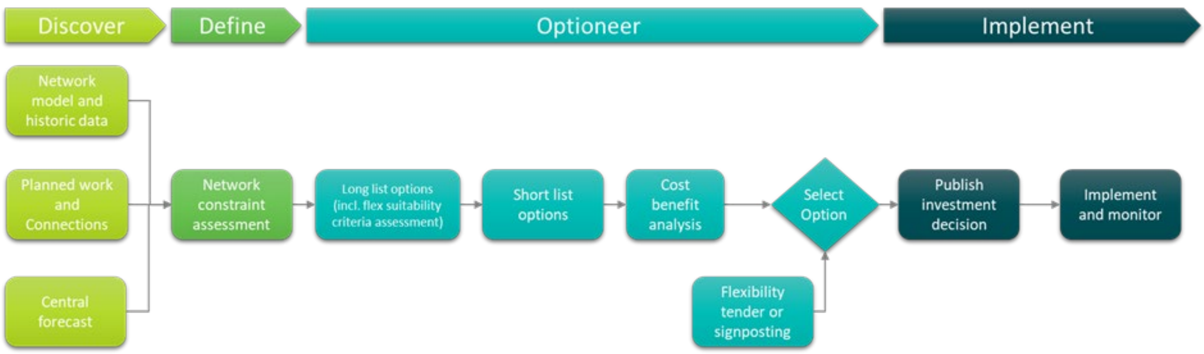
653 Other short-listed options considered were:

- Do nothing: this option was ruled out as it does not reduce the residual risk scores sufficiently under all transformer failure scenarios.
- Procure one 7.5/10 MVA, 33/11 kV spare transformer only: this option was ruled out as it does not reduce the residual risk scores sufficiently under all transformer failure scenarios.

7.4.2 Forecasting major projects capex

654 To forecast the system growth major projects capex, we used a rigorous approach that involved developing a full business case for each potential project. This approach is set out in our Investment Decision Framework, and includes 3 stages: Discover, Define, and Optioneer (Figure 7.7).

Figure 7.7 Discover, Define, and Optioneer



655 These stages guide us in identifying, shaping, and prioritising the major projects necessary to accommodate forecast growth and maintain appropriate security of supply, and in forecasting the efficient capex required.

7.4.2.1 Stage 1: Discover – Identifying potential network constraints

656 In the Discover stage, the first step is to understand the key growth drivers across the network. We draw on a range of inputs, including customer connection requests, forecasts from our Future Energy Scenarios model (discussed in section 7.2 above), and local growth data and insights. Then we consider the likely impact of each driver to identify the location and nature of potential network constraints.

7.4.2.2 Stage 2: Define – Assessing network constraints

657 In the Define stage, we look more closely at the potential network constraints that may affect security of supply, reliability, capacity, or resilience. For major projects, this includes assessing the network's ability to keep meeting the relevant reliability performance targets as the forecast growth occurs. We seek to understand the need case (problems and opportunities in the area), identifying all the drivers related to customer preferences, and our associated business and network objectives.

7.4.2.3 Stage 3 – Optioneer: Evaluating solution options

658 In the Optioneer stage, we explore a range of potential options for addressing the potential constraints. These may include network augmentation, network build, network non-wires solutions, or non-network solutions. They may also include a combination of these solutions or doing nothing and (for example) allowing target levels of security to be breached.

659 Next, as part of our business case, we develop a short list of options based on safety, feasibility, risk reduction, potential cost, and other factors. For each short-listed option, we undertake a residual risk assessment, lifecycle cost analysis, and sensitivity testing to validate the robustness of each option under various scenarios.

660 We also assess the economic justification for investing in a solution by applying standardised equipment failure rates and the value of customer reliability metrics. These tools allow us to quantify the expected benefits of reducing outages and service disruptions, supporting data-driven and transparent investment decisions.

661 Once the preferred option is selected, we use the defined project scope to prepare a P × Q estimate of forecast capex. The scope is used to determine the quantity (Q) of each asset type required (e.g. number of power transformers or kilometres of cable), which is multiplied by the relevant unit rate (P) from our building blocks cost estimation tool.

7.5 Contingent projects portfolio

662 This portfolio includes one system growth major project for which the timing is uncertain – the Lower Selwyn growth project. This project is currently forecast to be delivered outside the CPP period, with one of 3 identified trigger events having the potential to bring the expenditure forward into the CPP period.

663 We forecast the capex for this project by developing a full business case, using the same approach as for major system growth projects (see section 7.4.2 above).

664 Table 7.3 sets out our forecast contingent projects capex over the CPP period.

Table 7.3 Orion's forecast contingent projects capex per annum ($m, FY26 constant)

Project	FY32	FY33	FY34	FY35	FY36	Total
Lower Selwyn Growth – stage 1		0.2	1.7	1.7		**3.6**

665 The Lower Selwyn is a rural area currently supplied by 3 zone substations at Killinchy, Brookside, and Hills Road. The Killinchy zone substation supplies 2 large meat processors (ANZCO and Mountain River) with a combined capacity of 2 MVA. According to the 2023 North Canterbury Regional Energy Transition Accelerator report, ANZCO could decarbonise its current fossil-fuelled boilers, which could add up to another 0.95 MVA of load.[43]

666 **The need**: a capacity and security of supply constraint is emerging in this area. The latest load forecast shows the Killinchy zone substation will exceed its capacity[44] from FY34. This could occur sooner if ANZCO decarbonises. We already use seasonal load shifting between zone substations, customer flexibility services, and voltage regulators to maintain sufficient security of supply, and have limited further options.

667 **The trigger events**: the trigger events below are driven by increased consumer demand, net of existing demand management (e.g., ripple control), and are therefore out of Orion's control.

1. General demand growth, or confirmation of the ANZCO decarbonisation project, causing a revised forecast demand at Killinchy zone substation to exceed 10 MVA by FY32.
2. Stronger than forecast demand across Killinchy, Hills Road, and Brookside zone substations leads to a revised forecast demand across the 3 zone substations exceeding 30 MVA.
3. Stronger than forecast demand across Killinchy, Hills Road, and Brookside zone substations leading to a non-interruptible demand forecast across the 3 zone substations exceeding 20 MVA.

668 **The solution**: we will install a second power transformer at Killinchy, along with the associated switchgear. This allows the peak load of the zone substation to exceed 10 MVA and simplifies contingency arrangements for Killinchy, Brookside and Hills Road. It has the lowest NPV cost, taking account of all network costs and customer benefits. The installation can potentially be deferred by a year by procuring a non-network solution.

669 The other short-listed options considered were do nothing and an option the same as the chosen solution but without the deferral provided by the non-network flexibility solution. More detail on the Lower Selwyn growth project is provided in our Asset Management Plan 2026, Section 12 – Network development programme.

670 Note that in addition to this contingent project, we have identified several potential ('listed') system growth projects that may become necessary during the CPP period, giving rise to a reopener application. For more information, see Box 7.4.

Box 7.4 Potential system growth projects that may become necessary during the CPP period ('listed projects')

Forecasting growth in demand on the network, particularly in specific locations, is uncertain. For example, we can't be certain if and when a large customer will electrify its load, or when and how quickly a new subdivision will be developed.

To address the uncertainty in our forecasting, we have identified a range of nascent (listed) projects. These are potential major system growth projects that may become necessary during the CPP period, if growth or demand is higher than we forecast. As they cannot be fully scoped or costed until further information becomes available, they are excluded from our proposed system growth capex. In conjunction with our CPP proposal, we have requested that the Commission agree to creation of a 'listed project' reopener that would allow us to apply to have our CPP reconsidered to include these uncertain projects

Table 7.4 below identifies the location of the 'listed projects' and their potential investment range. The size of this range reflects the uncertainty of the preferred solution at this stage. The exact location and size of the demand increase will influence the scope and cost of the preferred solution.

[43] https://www.eeca.govt.nz/assets/EECA-Resources/Co-funding/RETA-North-Canterbury-Spare-Capacity-and-Load-Characteristics.pdf
[44] Killinchy is a single transformer site with a capacity of 10MVA

Table 7.4 Orion's identified 'listed' projects capex ($m, FY26 constant)

Project	Potential investment range
Rolleston area growth	2 – 30
Region B subtransmission	10 – 20
Shands Rd zone substation upgrade	10 – 20
Darfield area growth	15 – 25
Malvern industrial growth – stage 2	8 – 12
All projects	**45 – 107**

7.6 11 kV reinforcement portfolio

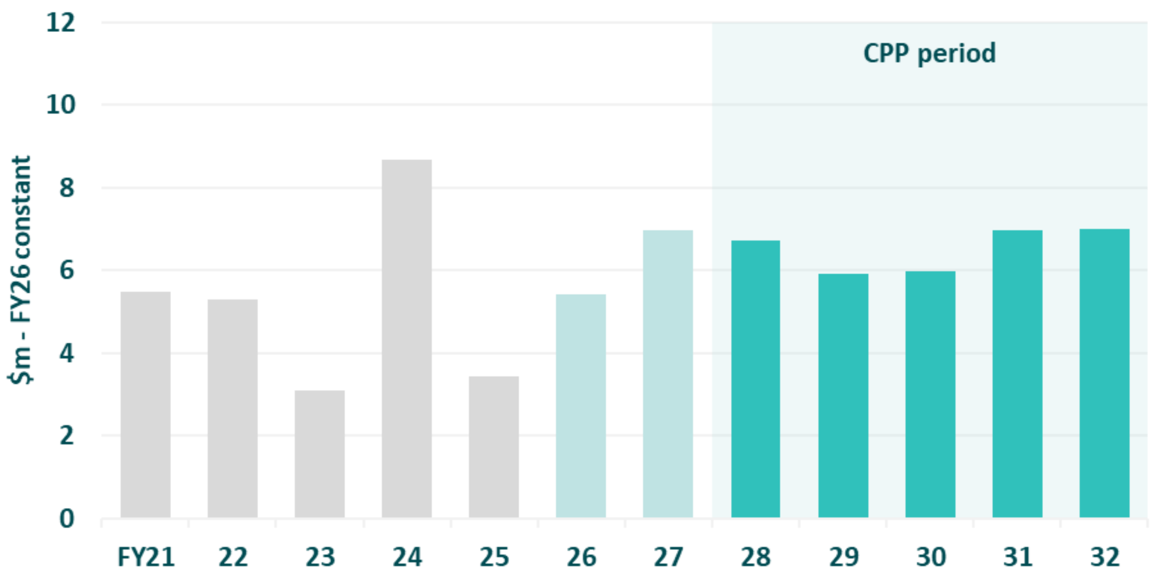
671 The 11 kV reinforcement portfolio is an ongoing programme of work to ensure sufficient 11 kV network capacity to connect new customers or upgrade existing customers' connections to the network, while continuing to meet the targets in our Security of Supply Guide. The sections below outline:

- our planned 11 kV reinforcement capex for the CPP period
- the approach we used to forecast this capex.

7.6.1 Planned 11 kV reinforcement capex

672 Our planned 11 kV reinforcement capex is $32.6 million over the CPP period. Figure 7.8 shows the annual capex compared with our historical spend.

Figure 7.8 Planned 11 kV reinforcement capex per annum



673 The variation in our historical expenditure, particularly over FY23–25, was due to prioritisation of other work, and major 11 kV reinforcement in FY24 to address constraints between Rolleston and Springston. Our planned expenditure aims to return to steady levels and address the backlog of capacity and security-of-supply constraints.

674 At a high level, the 11 kV reinforcement portfolio includes 2 categories of work – reconfiguration and capacity-driven reinforcement. Approximately 48% of our planned capex is for reconfiguration works, and the other 52% is for capacity-driven reinforcement projects (Table 7.5).

Table 7.5 Planned 11 kV reinforcement capex ($m, FY26 constant)

Category	FY28	FY29	FY30	FY31	FY32
Reconfiguration work	3.0	3.1	3.1	3.2	3.2
Capacity-driven	3.7	2.9[45]	2.9	3.8	3.8
Total	**6.7**	**5.9**	**6**	**7**	**7**

Note: For the latter half of the CPP period, projects are not yet individually scoped but are forecast based on network constraint modelling. This forecast will be refined through annual AMP planning cycles as specific projects are identified and scoped.

675 Reconfiguration works are typically reactive, often triggered by small-scale, localised changes like infill housing, load redistribution, or customer-driven upgrades. Our planned capex for reconfiguration works reflects our historical expenditure on these works, escalated broadly in line with forecast expansion of the 11 kV network. (Section 7.6.2 below provides more detail on our forecasting approach.)

676 Capacity-driven reinforcement projects are proactive, triggered when our zone substation and 11 kV contingency planning identifies that network upgrades are required to accommodate concentrated growth or resolve specific capacity constraints. For FY28 and FY29, the 11 kV reinforcement portfolio includes forecast capex for 4 scoped, capacity-driven reinforcement projects.

677 For FY31 and FY32, the portfolio includes planned expenditure of $3.8 million per year for capacity-driven, un-scoped reinforcement projects. This allows for 2 projects per year, in line with the number of 11 kV feeders reaching a 90% utilisation level and the average number of 11 kV reinforcement projects delivered over the past 5 years.

678 From FY29, we forecast that we will defer one capacity-driven project every 2 years using non-network solutions, and hence the reduction in capex in FY29/30 which delays $0.95m per annum reflecting the cost of one $1.9m reinforcement project spread over 2 years. The opex cost of providing non-network solutions is included in our network transformation programme (see Chapter 10).

7.6.2 Forecasting 11 kV reinforcement capex

679 As noted above, we used a base-step-trend approach to forecast our planned capex for reconfiguration works, and a P × Q approach for the planned capacity-driven reinforcement work.

7.6.2.1 Base-step-trend for reconfiguration works

680 Reconfiguration works typically comprise a relatively large number of small projects per year. These works are inherently reactive in nature, typically triggered by small-scale, localised changes like infill housing, load redistribution, or customer-driven upgrades. They involve reconfiguring existing 11 kV feeders to ensure existing latent capacity can be released to meet new demand, and sufficient contingency switching is available to achieve our security-of-supply objectives.

681 Analysis of historical data shows that our expenditure on reconfiguration works is reasonably steady year-on-year, so a base-step-trend approach is appropriate. Our approach for forecasting reconfiguration capex over the CPP period involved:

- **Establishing the base capex**: we used the historical average from FY21 to FY25 escalated to FY26 dollars as the base. Given the year-to-year variability in this reactive work, the forecast is based on a 5-year average rather than a single year such as FY25.

[45] From FY29 onwards the forecast incorporates an ongoing two-year deferral of $0.95m per annum associated with non-network solutions.

- **Adjusting for step changes**: we did not identify any step changes.
- **Applying trend changes**: we applied an output growth factor of 1.42% to the base capex. This is consistent with the final DPP4 trend in the total network scale growth factor analysis prepared by the Commerce Commission. The underlying assumption is that as the network expands, the volume of reconfiguration work will grow in proportion.

7.6.2.2 P x Q for capacity-driven reinforcement work

682 Capacity-driven reinforcement works tend to comprise a smaller number of relatively large projects each year. These projects involve installing additional feeders to accommodate concentrated growth or resolve significant capacity constraints.

683 Historically, we have undertaken these projects reactively. However, given the strong historic growth and continued forecast new demand on our network, we will take a proactive approach over the CPP period so we identify and address emerging reinforcement needs before they impact customers.

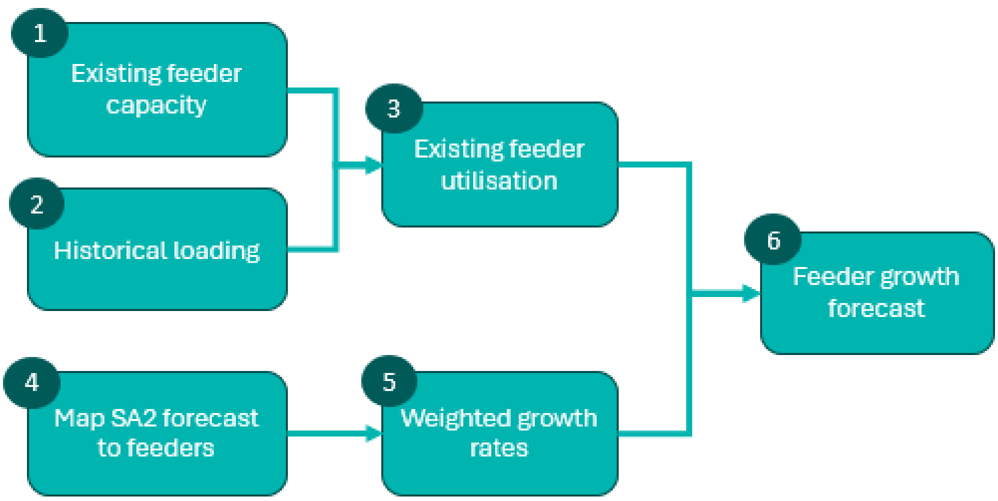
684 The primary driver for capacity-related 11 kV reinforcement is our zone substation contingency planning preparedness, which ensures we meet the Security of Supply Guide objectives under credible failure scenarios. This planning defines where and when network upgrades are needed to enable effective back-feeding between substations, via the 11 kV network, to maintain supply in the event of asset outages.

685 For the CPP period, our contingency planning analysis was undertaken in 2 stages – the existing network (today's topology and loading conditions) and the future network (projected to FY32). This analysis incorporated spatial load growth by applying SA2-level growth factors to the existing load of every distribution transformer.

686 Through this process, we identified several areas where current capacity and security margins are not sufficient and need to be addressed early in the CPP period. We have scoped and P × Q costed solutions for these areas using a simplified version of the business cases used to forecast capex for major projects (see section 7.4.2). These costings form the basis of our forecast capex over FY28–FY29 (and FY26–27).

687 For the remainder of the CPP period, we forecast our capex needs using forward-looking analysis based on peak feeder utilisation. This approach recognises that future 11 kV constraints often arise when there are insufficient feeders in an area to redistribute load or provide contingency support. The utilisation model estimates where future reinforcements will likely be required based on spatial demand growth, peak loading trends, and feeder capacity thresholds (Figure 7.9). The quantity (Q) of forecast constraints is then multiplied by an average historical unit price (P) to resolve the constraint.

Figure 7.9: Peak utilisation model



7.7 Low voltage reinforcement portfolio

688 Our LV reinforcement portfolio is an ongoing programme of work to remediate existing and emerging constraints on this network. For example, it includes upgrading or installing new distribution transformers, overhead conductors, and underground cables, as well as non-network solutions to avoid or defer reinforcement capex.

689 The sections below outline:

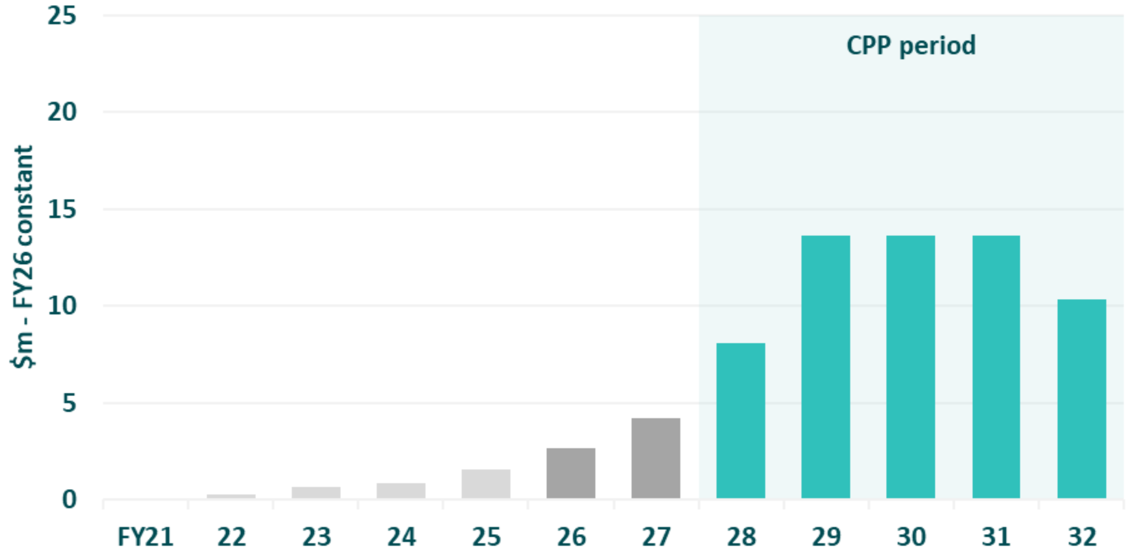
- our planned LV reinforcement capex over the CPP period
- our approach for forecasting this capex.

7.7.1 Planned LV reinforcement capex

690 We plan to invest approximately $59.3 million in LV reinforcement over the CPP period. As Figure 7.10 shows, the planned capex per annum is materially higher than recent levels. This step change is driven by increased infill housing and electrification, together with a growing number of LV networks reaching full capacity utilisation, resulting in a remediation backlog. In response, we are shifting from a reactive to a more proactive LV reinforcement approach.

691 While the uplift in LV investment is significant relative to historical spend, it is proportionate in the context of annual new connections expenditure, after customer contributions, exceeding $29 million. It is also comparable to the investment that would otherwise be required to support continued urban expansion.

Figure 7.10: Planned low voltage reinforcement capex per annum



692 The shift to proactive investment is required to:

- accommodate the forecast demand growth without limiting our ability to connect new infill customers
- maintain compliance with the voltage regulations
- understand constraints early, enabling us to understand the value proposition of non-network solutions and seek alternatives to network investment in advance of needing an urgent reactive response
- prevent outages associated with asset and fuse overloads.

693 It also enables us to clear the backlog of unresolved constraints that have accumulated due to our reactive investment approach. Without this change, the backlog will grow, constraining

timely response to new customer connection requests, as we reach the limits of what can be managed effectively through reactive investment alone.

694 Our planned expenditure will keep the LV network compliant with power quality related regulations and fit-for-purpose as electrification, emerging technologies, and changing customer behaviours reshape demand. It reflects customer expectations for us to provide a reliable electricity supply, invest in targeted improvements in local areas, and ensure sufficient capacity to support continued regional growth.

695 The planned expenditure also enables us to continue to respond reactively to areas of higher than forecast growth and associated power quality issues raised through customer complaints.

7.7.2 Forecasting LV reinforcement capex

696 Our LV network comprises 11,800 individual LV networks, each of which serves a small group of customers (from 1 to approximately 300). The LV reinforcement portfolio typically includes many relatively low-value works to remediate existing or emerging capacity constraints on this network.

697 To forecast our planned capex for this portfolio, we used a P × Q approach as follows:

- **Forecast demand on LV networks**: we generated 20-year demand projections for each LV network, using historic data on LV network demand and applying our peak demand forecast for each SA2 area to LV transformers within the SA2 boundary.
- **Identify existing or emerging constraints on LV networks**: we created a model for each LV network and conducted load flow simulations to assess how asset loading and voltage levels will evolve over the 20-year forecast period.
- **Assess these constraints**: we identified the quantity (Q), type and severity of each existing and emerging constraint over the forecast period.
- **Identify and estimate cost of solution options**: we assigned the appropriate solution options, including non-network solutions, to each constraint according to its type and applied associated cost estimates (P).
- **Forecast the LV reinforcement capex**: we prioritised the constraints based on the number of customers they will affect and their impact on service levels, then developed a programme of works and associated P × Q expenditure forecast to address the highest priority constraints over the CPP period.

698 We also considered the independent verifier’s assessment of our LV reinforcement programme. The verifier’s finding concluded that the forecast capex was based on an overly conservative demand forecast and would lead to over build of LV network capacity. We sought customer input on whether we should plan for a 1 in 2, or a 1 in 10 year winter weather event. Customers supported planning for a 1 in 10-year weather event noting that reliability of power supply is very important in cold winter conditions. In line with customer preferences, our demand and expenditure forecasts retain the 1 in 10 year winter forecast.

699 However, we acknowledge that using a high demand scenario across all LV networks may overstate the expenditure requirements for some networks. We therefore adjusted the forecast expenditure to reflect a medium/central growth assumption. To ensure that we still meet customer preferences for a safe and reliable supply, we added provision to reinforce a proportion of LV networks that may exceed the central forecast level of growth.

700 In response to the verifier’s observation that we could also consider operational measures, we modelled and incorporated the impact of an improvement to our operational voltage management practices at times of peak demand.

701 The combined impact of reverting to a central forecast with provision for high growth areas and improved voltage management reduced the forecast capex by approximately $16.9 million.

7.8 Network capex – system growth capex justification

702 We consider the planned system growth capex to be prudent and efficient for the following reasons:

- **Business cases**: all planned major and contingent system growth projects are supported by a full business case, and have been subject to options analysis, including risk assessments and economic analysis. Individual business cases have been signed off by General Managers. Our scoped 11 kV reinforcement project forecasts are derived using a short-form business case to test options against meeting the need at lowest NPV cost.
- **Routine forecast process**: the LV network reinforcement forecasts are derived by applying a consistent process to each LV network, including demand forecasts, power-flow analysis, constraint trigger thresholds, and a criticality framework.
- **Formalised cost estimation**: all our tailored cost estimates are derived from our unit rate book, which in addition to verification by the verifier has undergone an independent review by Ergo and was found to be consistent with New Zealand electricity sector-wide benchmarks.
- **Non-network solutions**: the potential to defer investment through non-network solutions has been consistently considered, and we have forecast deferred investment wherever feasible.
- **Challenge rounds**: our project and programme forecasts were tested by our integrated leadership team at several stages during their development. The portfolio-level forecasts were scrutinised by the Board at a structured challenge session.
- **Customer perspective**: customers and stakeholders consistently told us that reliability is a priority. They expect reliability to be maintained at current levels and for the network to keep pace with population and demand growth to support regional development. Customers expressed a preference for a proactive approach to LV reinforcement that anticipates high demand growth and very cold winter conditions. Customers also emphasised the importance of affordability, and in response to both this feedback and the independent verifier's assessment (see below), we refined the LV reinforcement programme to adopt our Central demand forecast while adding targeted allowances for higher-growth or higher-risk areas. This approach better balances reliability and affordability and is expected to meet customer expectations for a safe and reliable supply.
- **Standardisation**: we use standard equipment with standard sizes to minimise lifecycle costs, including by reducing contractor training needs and streamlining the range and volume of major plant spares required.
- **Independent verification**: the verifier assessed the following projects and programmes:
    - For major system growth projects, the Lincoln township growth project and the business case format and associated economic calculator used to develop all major and contingent system growth project capex forecasts. It accepted the planned capex for the Lincoln project in full, and concluded that the business case and associated economic calculator are fit for purpose. The verifier also accepted the full network transformation opex provision for a non-network solution to defer or avoid system growth capex.
    - For the 11 kV reinforcement programme, the entire programme. It accepted the planned capex in full.

  - For the LV reinforcement programme, the entire programme. As outlined in section 7.7.2, it accepted $50.5 million of the $76.2 million included in our draft plan. We reconsidered and adjusted the programme in light of the verifier's findings, reducing the forecast capex to $59.3 million in our final plan.
  - For contingent projects, the Lower Selwyn growth project. It found the project to be prudent and efficient, subject to one or more of the identified triggers.
- **Expected benefits**: the proposed expenditure will deliver value to customers and the community, including supporting growth and electrification in our network area (see Box 7.5).

Box 7.5 Expected benefits of the system growth capital expenditure programme

Our system growth capex programme supports population growth and electrification across Central Waitaha Canterbury, enabling us to meet customer and stakeholder expectations. Key benefits expected to be delivered include:

- **Timely and efficient connections:** new customers can connect to the network, and existing customers can upgrade their connections, in a timely manner – regardless of location – without compromising the reliability or quality of supply for other customers.
- **Supporting regional growth:** the network will keep pace with population growth, urban development, and economic activity across Central Waitaha Canterbury, including the fast-growing Selwyn district.
- **Enabling electrification and future energy use:** the network will have sufficient capacity and appropriate configuration to support the electrification of homes, businesses, industrial processes, and transport, and to integrate distributed energy resources and 2-way energy flows, in line with our network transformation roadmap.

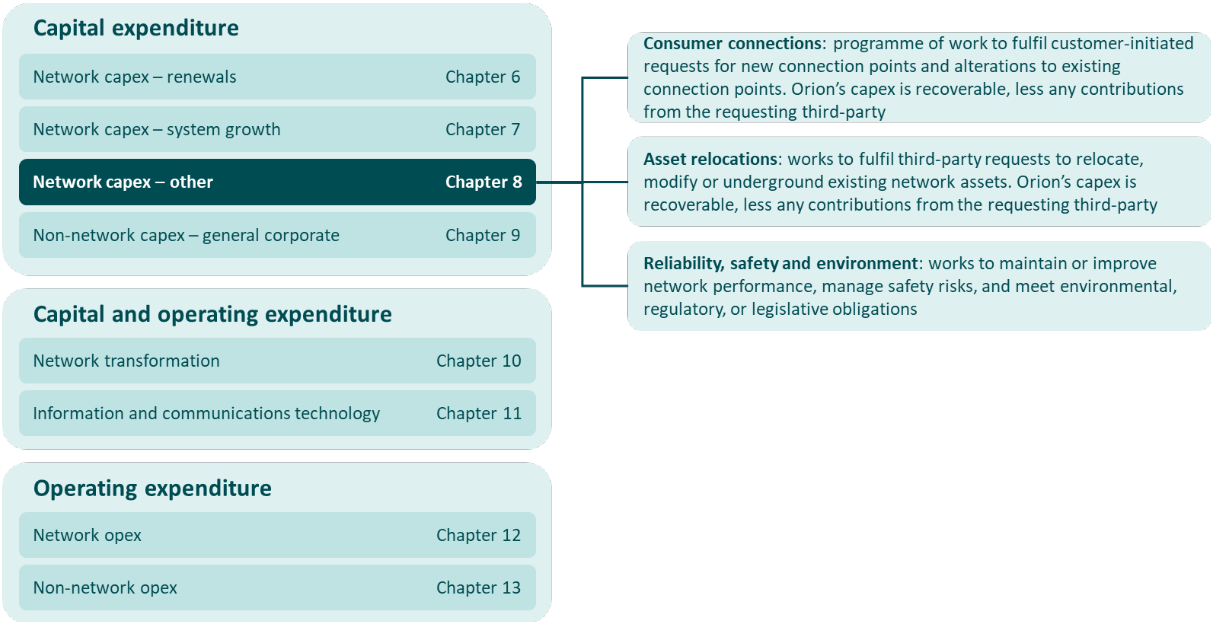
8

8 Network capex – other

703 The other network capex category sits alongside our core renewals and system growth programmes. It comprises capex for customer connections, asset relocations, and reliability, safety and environment (RSE). These portfolios enable us to meet customer connection needs, respond to third-party requests to relocate our assets, and undertake targeted work related to quality of supply, legislative or regulatory requirements, or other reliability, safety and environmental outcomes.

704 Figure 8.1 shows where this category sits within our overall expenditure and the portfolios it includes.

Figure 8.1 Network capex – other and its portfolios



705 The rest of this chapter provides an overview of:

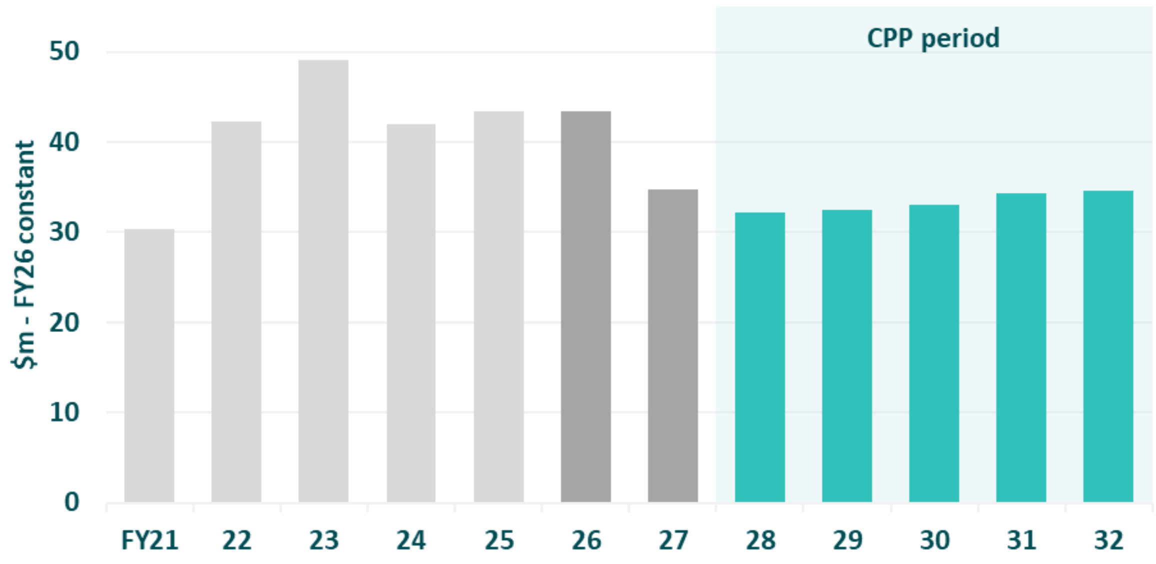
- our planned other network capex for the CPP period
- its key drivers
- the planned expenditure in each portfolio, including how it was forecast and why it is prudent and efficient.

8.1 Planned other network capex

706 Our planned other network capex over the CPP period is $166.5 million, or an average of $33.3 million per annum. This represents 18% of our total capex and 11% of our totex over this period.

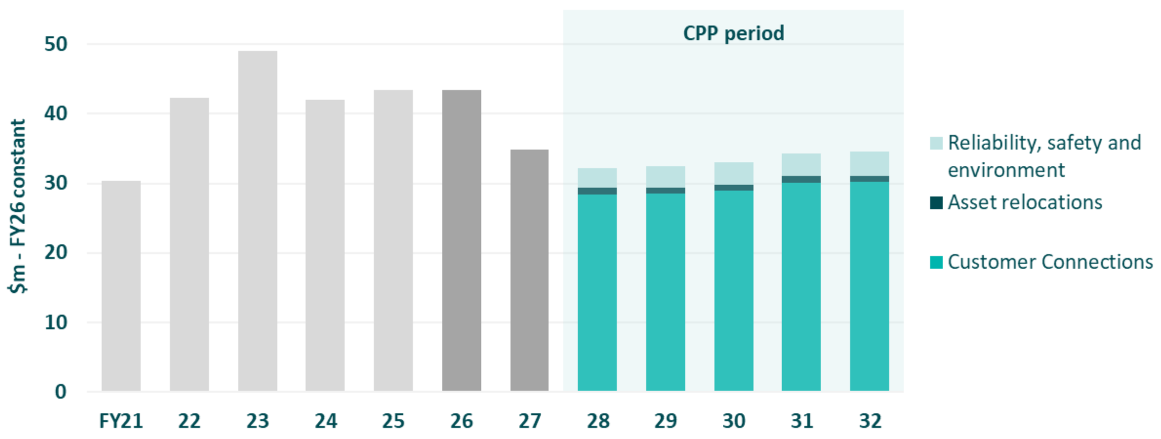
707 In the customer connections and asset relocations portfolios, the planned expenditure is recoverable less any contributions from the requesting third-party. Figure 8.2 shows other network capex per annum net of these contributions compared with our historical net spend.

Figure 8.2 Planned other network capex per annum (net of contributions)



708 Figure 8.3 shows the net other network capex per annum by portfolio. Planned expenditure on customer connections makes up the bulk of this capex, and increases slightly over the CPP period. However, it is lower than recent historical expenditure. Planned expenditure in the other portfolios is broadly stable across the CPP period.

Figure 8.3 Planned other network capex per annum by portfolio (net of contributions)



8.2 Key drivers

709 **For customer connections**, the primary driver is the volume of requests for new connection points or alterations to existing connections. These volumes are influenced by:

- **Population growth and urban development**: residential connection requests are largely driven by new housing construction, which reflects population growth, land availability, and government policy settings.
- **Economic activity**: commercial and industrial connection requests are driven by business expansion, electrification, and process heat conversion.

710 **For asset relocations**, expenditure is driven by third-party requests to relocate or underground our network assets to enable external projects, including road widening, utility upgrades, subdivisions, and other development initiatives. The volume and timing of this work is closely linked to broader urban development activity.

711 **For RSE**, expenditure is driven by the need for targeted investments to improve safety outcomes for our staff, service delivery partners, and the public; maintain appropriate quality of supply; and ensure compliance with applicable safety, legislative, regulatory, and environmental standards.

8.3 Customer connections portfolio

712 This portfolio comprises the cost of fulfilling customer requests for new or upgraded connections to the network. This includes the costs of installing new 11 kV and low-voltage connection assets, but excludes 11 kV reinforcement required to maintain reliability for existing customers (which is classified as system growth capex, see Chapter 7).

713 As noted above, this expenditure is recoverable through prices, net of any capital contributions from the requesting customer or third party. Contributions are determined in accordance with the Electricity Authority's (EA's) regulations and reflect the principle that existing customers should not subsidise new customers.

714 The following sections outline our planned net customer connections capex, our forecasting approach, and the basis on which we consider the planned expenditure to be prudent and efficient.

715 Information provided to the verifier used FY25 as the base year. For our submission to the Commerce Commission, we have updated this to use unaudited FY26 figures.[46] We consider FY26 to be more representative of our future customer connections costs than FY25. In addition, since verification, elements of our contributions policy have changed in response to recent EA regulatory changes. Those contribution policy changes have also been incorporated into the forecasts provided to the Commission.

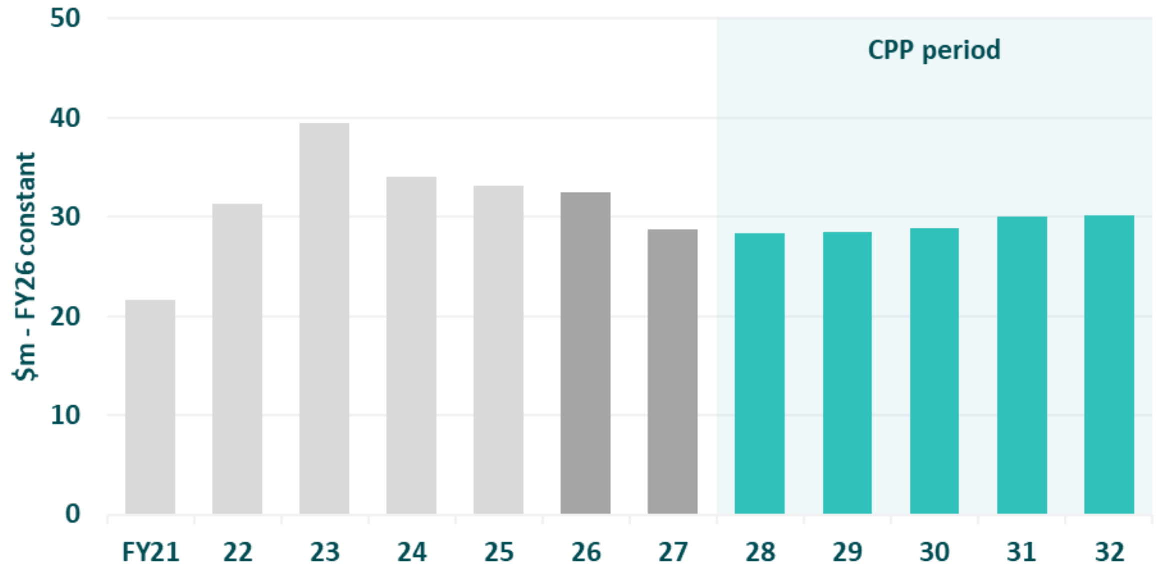
716 We will continue to work through elements of the recent EA regulatory changes. We intend to discuss with the Commission over the coming months our findings and any update of our forecasts to reflect audited FY26 results.

8.3.1 Planned net customer connections capex

717 Our planned customer connection capex over the CPP period, net of estimated capital contributions, is $146 million. Figure 8.4 shows this capex per annum compared with our historical spend.

[46] The FY26 figures used in our Customer Connections portfolio forecasting are unaudited and may not include all accruals that will ultimately be allocated to FY26.

Figure 8.4 Planned customer connections capex per annum (net of contributions)

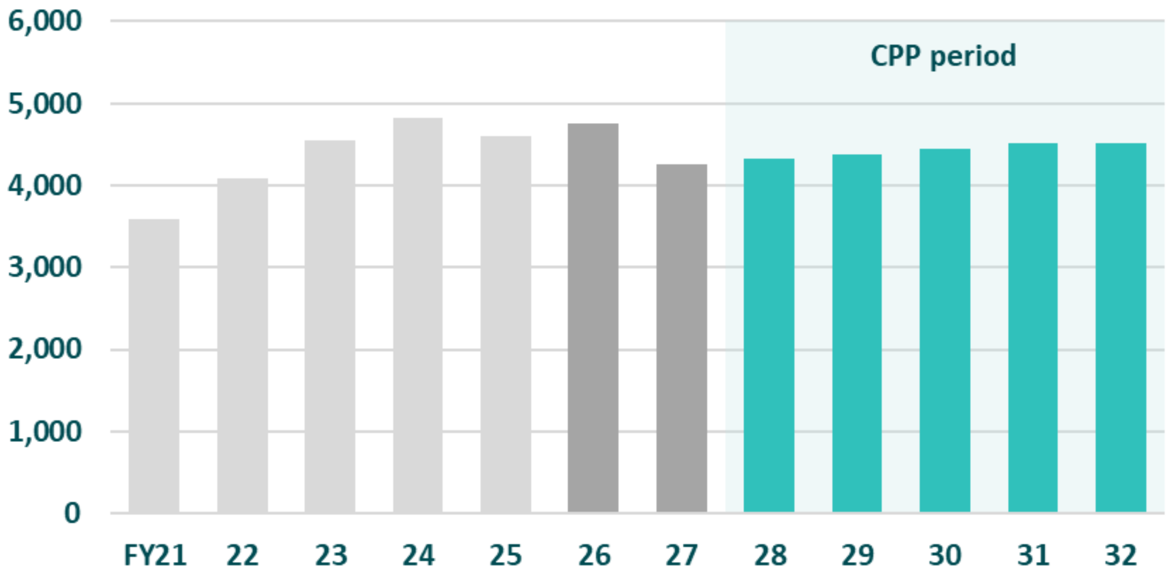


718 On average, the planned net customer connections capex is $29.2 million per annum. This is lower than actual FY26 net customer connections capex ($32.6 million).

719 The variation in actual net capex over FY21–26 reflects changes in the annual volume of net new installation control points (ICPs),[47] as well as historical changes to our customer contribution policy and the cost to connect customers.

720 The forecast annual volume of net new ICPs over the CPP period ranges between 4,318 and 4,521 (Figure 8.5). This is lower than in FY26 (when this volume was 4,747) and in each of the preceding 3 years. Box 8.1 explains how we forecast net new ICP volumes over the CPP period.

Figure 8.5 Forecast net new ICPs per annum



[47] Net new ICPs means additions minus disconnections.

Box 8.1 How we forecast net new ICPs over the CPP period

We forecast new residential and business connections separately, using the projected population and dwelling growth rates in our network area developed by specialist consultant, Geografia (see Box 7.1 in Chapter 7).

For residential ICPs, we applied the projected dwelling growth rates over the CPP period to the existing residential ICP base in each Statistical Area 2 (SA2). For every SA2, we multiplied the current ICP number by the projected annual dwelling growth rate, and the resulting net change became the forecast number of net new residential ICPs each year.

For business ICPs, we applied the projected population growth rates to the existing business ICP base. Historically, population growth has aligned closely with observed business connection trends.

Geografia's population and dwelling growth projections started below the rates seen in the previous 3 years – which it treated as short-term fluctuations – and then increased steadily over time. However, actual growth rates depend on uncertain future migration activity, births and deaths, and economic conditions.

This uncertainty means that actual net new ICPs could differ materially from the forecast. To illustrate the potential impact, we note that the actual volume of net new connections in the 12 months to 31 March 2026 was more than 10% higher than Geografia's forecast, which it made in mid-2025 (4,747 actual compared with 4,187 forecast).

We regularly update our ICP forecasts based on the latest information available. We have requested updated forecasts from Geografia, and will share these updated forecasts with the Commission when available.

8.3.2 Forecasting customer connections capex

721 To forecast our net customer connections capex, we first forecast the gross capex, then deducted forecast customer contributions.

8.3.2.1 Gross customer connections capex

722 To forecast gross capex, we used a base-step approach (no trend factor was applied). This is appropriate as recent expenditure provides a reasonable starting point for forecasting demand-driven connection activity over the CPP period. Our approach involved:

- establishing the base capex by identifying a representative level of historical gross capex
- applying step adjustments to reflect forecast net new ICPs and process heat conversions.

Establish base gross capex

723 To identify a representative level of historic gross capex, we analysed our actual gross cost per net new connection in the 7 years from FY20 to FY26 (converted to constant FY26 dollars to ensure comparability). This showed that our average gross cost per net new connection changed significantly over this period.

724 In FY20 and FY21, our gross cost per net new connection was approximately $6,500. Following the COVID-19 pandemic, it increased annually, peaking at approximately $9,300 in FY23. While initially easing back to under $8,000 after this peak, the average gross cost per net new connection has increased again, reaching approximately $9,050 in FY26.

725 Based on this analysis we selected FY26 as the base year, as it represents the most recent data and is therefore most reflective of expected costs over the CPP period. Cost volatility over FY20–25 makes those years less reliable as reference points.

726 As noted above, the forecast submitted for independent verification used FY25 as the base year. Our decision to update to FY26 reflects the availability of more recent data, which we consider more representative of future costs.

Adjust base for step changes

727 We applied 2 step changes to the base-year capex:

- changes in forecast net new connections, or ICPs, relative to FY26
- upgrades associated with forecast business process heat conversions.

728 To reflect changes in forecast net new ICPs relative to FY26, we applied the forecast ICP volumes shown in Figure 8.5 and scaled the base-year capex using the FY26 average gross cost per net new connection. This adjusts capex in proportion to the difference between forecast and FY26 connection volumes.

729 For process heat conversions, we engaged with large customers to identify potential electrification projects over the CPP period that may require connection upgrades. We sought information on the likelihood of each conversion proceeding, expected timing, and anticipated electrification load.

730 Using this information, we developed a probability-weighted estimate of additional demand from process heat electrification. For each year, the probability-weighted MW impact was converted into forecast connection capex using a standard unit cost (excluding upstream network reinforcement).

731 Costs associated with upgrading the core upstream network are excluded from customer connection costs and instead captured in system growth capex (see Chapter 7). Depending on scale and location, process heat conversions may trigger major projects, 11 kV reinforcement, or be accommodated within existing network capacity.

8.3.2.2 Net customer connections capex

732 Once the gross customer connection capex was forecast, we deducted expected customer contributions to derive the net recoverable capex. All new connections and connection alterations require customer contributions.

Residential and smaller commercial ‘standard’ connection contributions

733 For standard connections, forecast contributions are based on fixed charges per connection, multiplied by forecast net new standard connection ICPs. These fixed charges are set out in our customer contributions policy.

734 The fixed charges used in the independently verified forecast were those in effect at the time of the verifier’s assessment. Since that assessment, and in response to EA distribution connection pricing reform, we updated these fixed charges effective 1 April 2026, with a further update planned for 1 April 2027. The impact varies by customer class.

735 Single-phase urban connections and brownfield multi-unit developments account for most standard connection volumes. Changes in fixed charges for these categories have increased total forecast contributions relative to the verified forecast, resulting in a corresponding reduction in net customer connections capex.

Larger ‘non-standard’ connections contributions

736 For larger non-standard connections, delivery is typically managed by the developer’s electrical contractor, who initially incurs connection costs and invoices Orion and the developer their respective shares.

737 The EA is implementing a regulated ‘incremental cost less incremental revenue’ methodology to determine contributions for large connections. This approach involves detailed, connection-specific cost assessments. We are currently assessing the impact of these changes.

738 As this work progresses, we will share our findings with the Commission. Based on our initial assessment, the revised methodology is expected to further reduce forecast net customer connections capex. The independent verifier noted that the Commission “should check for consistency between Orion’s planned approach to capital contributions during the CPP period with the Electricity Authority’s reformed connection pricing rules and guidelines.”

8.3.3 Customer connections capex justification

739 We consider the planned customer connections capex represents a prudent and efficient level of expenditure for the following reasons:

- **Customer-driven demand**: expenditure is driven by customer requests to connect new loads or alter existing connections, meaning scope and timing of investment are externally driven rather than discretionary.
- **Base-step forecasting approach**: gross capex has been forecast using a base-step methodology, consistent with established electricity industry practice for demand-driven connection expenditure.
- **Capital contributions framework**: expenditure has been adjusted to reflect contributions expected to be received from customers. For standard connections, these contributions are set using an approach consistent with recent EA pricing reforms. For non-standard connections, we intend to discuss the impact of these reforms with the Commission as we assess them.
- **Robust internal challenge:** forecasts were tested through multiple review stages with our integrated leadership team and Board, and refined in response to feedback and scrutiny.
- **Independent verification**: in assessing our approach to forecasting customer connections the verifier noted our "underlying policies, planning standards, the basis of aggregate unit cost estimates, contestability for large connection works and other variables (ICP counts, asset types etc.) . . . meet the expenditure objectives."
- **Expected benefits**: the planned expenditure enables timely connection of new customers and modification of existing connections, supporting ongoing urban development, population growth, and economic activity within our network area.

8.4 Asset relocation portfolio

740 This portfolio covers expenditure in response to third-party requests to move or alter our existing network assets. These parties are typically the owners of infrastructure (such as roads or stormwater pipes) located alongside or near our network assets that need us to move our assets as they undertake their own activities.

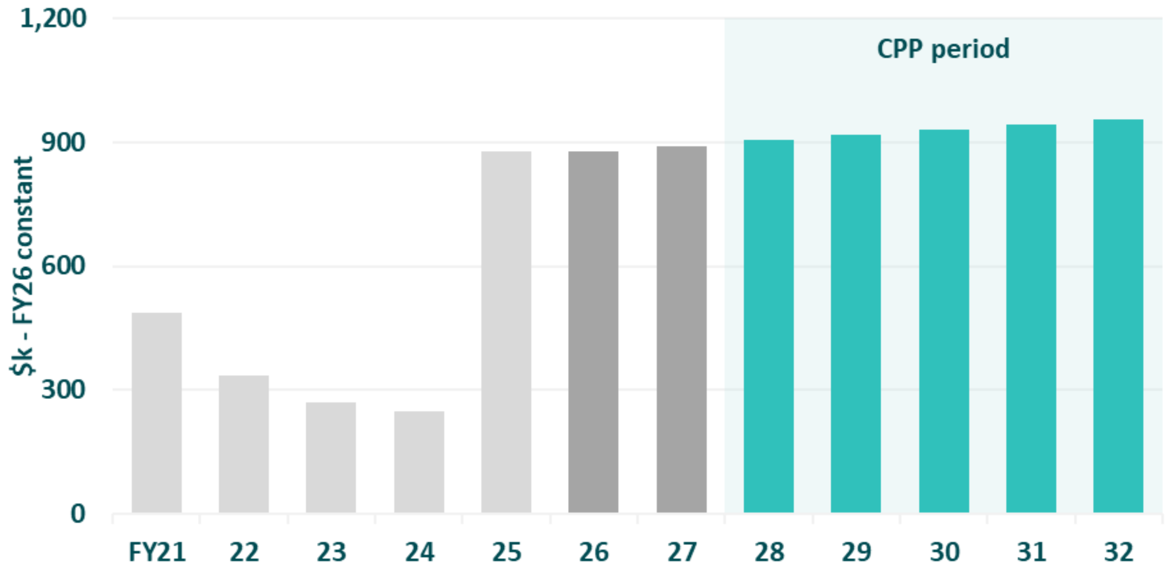
741 Expenditure in this portfolio is recoverable in total or in part through capital contributions from the requesting parties. This ensures appropriate cost sharing between customers and the parties directly benefiting from the relocations. Historically, we have seen year-on-year variation in both asset relocations capex and related capital contributions.

742 The sections below outline our planned net asset relocation capex over the CPP period, our forecasting approach, and why the capex is prudent and efficient.

8.4.1 Planned net asset relocation capex

743 Our planned asset relocation capex over the CPP period, net of capital contributions, is $4.6 million. Figure 8.6 shows this planned expenditure per annum, compared with our historical spend.

Figure 8.6 Planned asset relocation capex per annum (net of third-party contributions)



744 The planned expenditure is broadly in line with spend in FY25. The year-on-year variation in prior years reflects the variable nature of third-party projects.

8.4.2 Forecasting asset relocation capex

745 To forecast our net asset relocation capex, we used a base-step-trend approach. This methodology is appropriate given the recurring nature of the work and the inherent difficulty in forecasting third-party-driven volumes. This approach involved:

- **Establishing the base year:** we selected actual FY25[48] asset relocation capex (net of customer contributions) as the base. Although historical expenditure shows year-on-year variability, the most recent audited year provides the most representative and reliable starting point for forecasting.
- **Step adjustments**: we did not identify material, discrete relocation projects requiring specific step adjustments.
- **Trend application:** we projected the base capex forward using an annual growth factor, consistent with the DPP4 trend. This reflects a reasonable assumption that relocation volumes will be broadly proportional to network scale.

746 We have not included any allowance for large-scale relocation projects, as we are not currently aware of any major developments or third-party initiatives over the CPP period that would require material asset relocation.

8.4.3 Asset relocation capex justification

747 Our forecasting approach results in a prudent and efficient level of investment. This conclusion is supported by the following factors:

- **Base-step-trend methodology**: we have applied a base-step-trend forecasting approach, which is consistent with industry good practice. The FY25 base year reflects activities expected to continue over the CPP period.
- **Externally driven**: asset relocation expenditure is largely driven by requests from customers, utilities, councils, and other authorities. The scope and timing of works are therefore externally initiated rather than discretionary.

[48] Consistent with base-step-trend based forecasts, forecast asset relocation capex is linked to base-year actuals. Actual net capex in FY26 will depend on eventual contributions received. Variances between FY25 and FY26 may warrant an update of CPP period forecasts.

- **Capital contribution framework**: the contribution amount we receive from a requesting party for asset relocation works depends on whether Orion or the requesting party primarily benefits from the works. In many cases, there is little or no benefit to Orion, and the requesting party contributes most or all of the cost.
- **Customer and community outcomes**: the planned expenditure enables third-party infrastructure projects and new developments within our network area, supporting regional growth while maintaining network integrity and service continuity.

8.5 Reliability, safety and environment portfolio

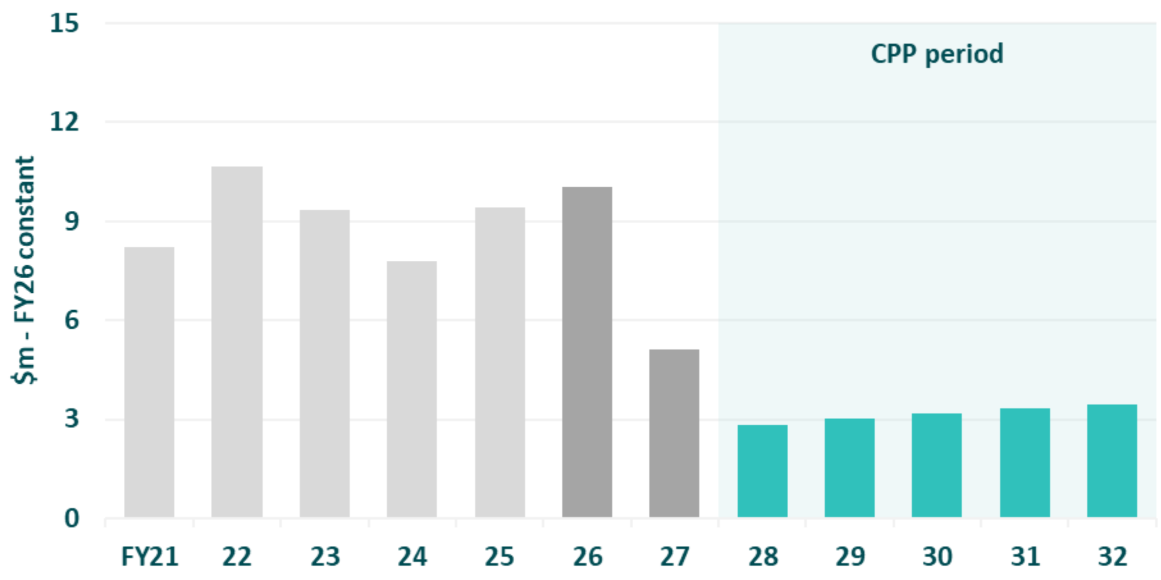
748 The RSE portfolio includes 3 categories of investments: quality of supply; legislative and regulatory; and other RSE investments.[49] These tend to be smaller, targeted investments in new dedicated assets in response to safety risks, localised reliability issues, and compliance needs.

749 The sections below outline our planned RSE capex over the CPP period, our approach for forecasting this capex, and why the capex is prudent and efficient.

8.5.1 Planned RSE capex

750 Our planned RSE capex over the CPP period is $15.8 million, or an average of $3.2 million per annum. Figure 8.7 shows planned expenditure per annum, compared with historical spend.

Figure 8.7 Planned RSE capex per annum



751 The planned annual capex is lower than historical RSE capex, primarily because a large safety-focused programme for fuse relocation is scheduled for completion in FY27.

752 Over the CPP period, planned capex falls into 2 categories – quality of supply and other RSE. The planned programmes in each category are outlined below, including the continuation of established programmes and new programmes.

[49] As defined under Information Disclosure.

8.5.1.1 Quality of supply investments

753 Customers expect a reliable electricity supply, and a consistent service quality over time. Our quality of supply investments focus on managing localised network performance to maintain an appropriate level of service for customers.

754 Table 8.1 provides an overview of planned investments in this category.

Table 8.1 Planned quality of supply investments ($m, FY26 constant)

Programme	Description	Capex
Rectifying poor performing feeders	We plan to install reclosers on overhead lines that frequently trip due to temporary faults (e.g. due to vegetation or wildlife). Reclosers can clear these temporary faults and reduce their impact	0.85
Magnefix switching units (MSU) fault indicator units	We will install fault indicator units on MSUs to enable faster identification of faulted equipment. This will reduce outage durations and improve restoration efficiency, including reducing the need for multiple fault crews	1.25
Online dissolved gas analysis (DGA) monitoring of power transformers	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 sudden changes in gas levels as they occur, allowing operators to respond quickly, and reducing failure risk. It also provides data to support predictive analytics	0.55
Increasing communications resilience	Our rural comms network is mainly low bandwidth radio links. To meet increased requirements for interconnected comms, we will replace existing radio links with fibre. Benefits include improved protection operation (safety), more reliable comms, enhanced security (CCTV), and support for drone stations and drone surveillance and inspections	5.89
Overhead lines remote control switches / network automation	Our planned programme will retrofit comms-enabled switches on compatible overhead equipment and replace some manually operated switches with new comms-enabled versions, enabling backfeed switching to reduce the impact of outages	1.24
Total		**9.78**

8.5.1.2 Other RSE investments

755 Orion has responsibilities to protect staff and the public from electrical hazards and to manage environmental impacts from our operations. Our other RSE investments support safety improvements and environmental initiatives. These investments help ensure we maintain safe working conditions and support meeting our environmental commitments.

756 Table 8.2 outlines our planned investments in this category.

Table 8.2 Planned other RSE investments ($m, FY26 constant)

Programme	Description	Capex
High impedance fault detection	Many of our rural feeders traverse areas at risk of wildfires. While our protection and fuse systems clear the majority of faults on these feeders, they may not be able to clear high impedance faults (HIF). To address this, we plan to install HIF detection systems to help prevent wildfire ignition	1.6
Zone substation fire risk remediations	The planned work addresses an identified fire risk at zone substations. We use AS 2067:2016 as the standard for the design and construction of HV substations. This standard requires minimum separation distances between transformers, and between transformers and combustible buildings, based on the volume of insulating oil. Where these distances cannot be achieved, mitigation measures such as fire walls are required Some of our zone substations are not compliant with these requirements. In particular, certain sites have 2 transformers sharing an oil bund that should be segregated, as well as insufficient separation between adjacent transformers.	1.28

Table 8.2 Planned other RSE investments ($m, FY26 constant)

Programme	Description	Capex
Zone substation seismic remediations	The planned work addresses identified seismic risk at zone substations Following the 2010–2011 earthquakes in Christchurch, changes to the Building Code, through the Building Amendment Act 2016, introduced requirements to identify and remediate potentially earthquake-prone buildings In response, we adopted a standard to ensure all zone substation buildings comply with 67% of the New Building Standard (NBS) for importance level 4 (IL4) buildings. Following required assessments, we identified a number of buildings below 67% NBS. Some of these are modular buildings where seismic strengthening is not always possible. Of the others, most are concrete or cement block construction and can be reinforced by installing steel bracing based on a structural analysis and design Although the NBS scoring system is expected to be replaced, the identified reinforcement works are expected to be required under the new regulations.[50]	1.15
Earth Potential Rise (EPR) issues	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 high voltages. This can create potentially dangerous 'step and touch' voltages for staff and risks to the public near our towers EPR tests conducted on our towers have indicated touch voltages that do not comply with safety standards. Our planned rectification work will address this through mitigations such as earth mats, new earth-wires and barriers around our towers	2.0
Total		**6.03**

8.5.2 Forecasting RSE capex

757 We forecast most of our planned RSE capex using a bottom-up approach, consistent with our method for volumetric forecasts. This involves:

- defining the risks, issues and scope of each programme and forecasting the scope of the solution and required volumes
- applying unit rates based on historical costs, vendor pricing and high-level estimates.

8.5.3 RSE capex justification

758 Our planned RSE capex represents a prudent and efficient level of expenditure. This conclusion is supported by:

- **Standards compliance**: the planned investments are necessary to meet NBS requirements and relevant fire standards.
- **Clearly identified need**: the programme is driven by defined needs including meeting external standards and the mitigation of safety and environmental risks. This includes mitigating EPR public safety risks posed by our towers in public areas.
- **Review and moderation**: the forecasts have been reviewed by our integrated leadership team and the Board, and moderated as a result of these top-down challenges.
- **Pricebook review**: our unit rates have been independently reviewed and found to be consistent with the wider New Zealand electricity sector.
- **Customer perspective**: customers and stakeholders consistently told us that having a safe and reliable network is a priority. Our planned RSE investments support this outcome.

[50] The primary impact of the new system relates to the safety risk assessment methodology, specifically, how the risk of injury from building failure in an earthquake is assessed. Canterbury remains in the high seismic zone and is not exempt under the signalled changes. Gazettal is expected in May 2027 and further information may become available later in 2026.

- **Expected benefits**: these investments will support our ability to manage reliability issues, reduce safety risk, support compliance, and address environmental risks (see Box 8.2).

Box 8.2 Expected benefits of the RSE programme

Our RSE programme supports ongoing safety, reliability, and resilience in our network, enabling us to meet customer and stakeholder expectations. Key benefits expected to be delivered include:

- **Risk management**: the planned activities will reduce reliability, safety and environmental risk associated with our assets.
- **Ensuring reliability**: fewer and shorter duration unplanned faults will help maintain appropriate reliability. Installing reclosers on lines will reduce overall number of temporary faults.
- **Improved safety**: a reduced risk of exposing staff, service delivery partners, and members of the public to safety risks associated with EPR and building related seismic risk.
- **Greater resilience**: ensuring appropriate fire segregation of power transformers will improve overall resilience of the network.
- **Improved network control:** installing or retrofitting comms-enabled switches will enhance network control, visibility, and automation.
- **Environmental impact and compliance**: these investments support our efforts to address environmental risks and meet NBS requirements and relevant fire standards.


9

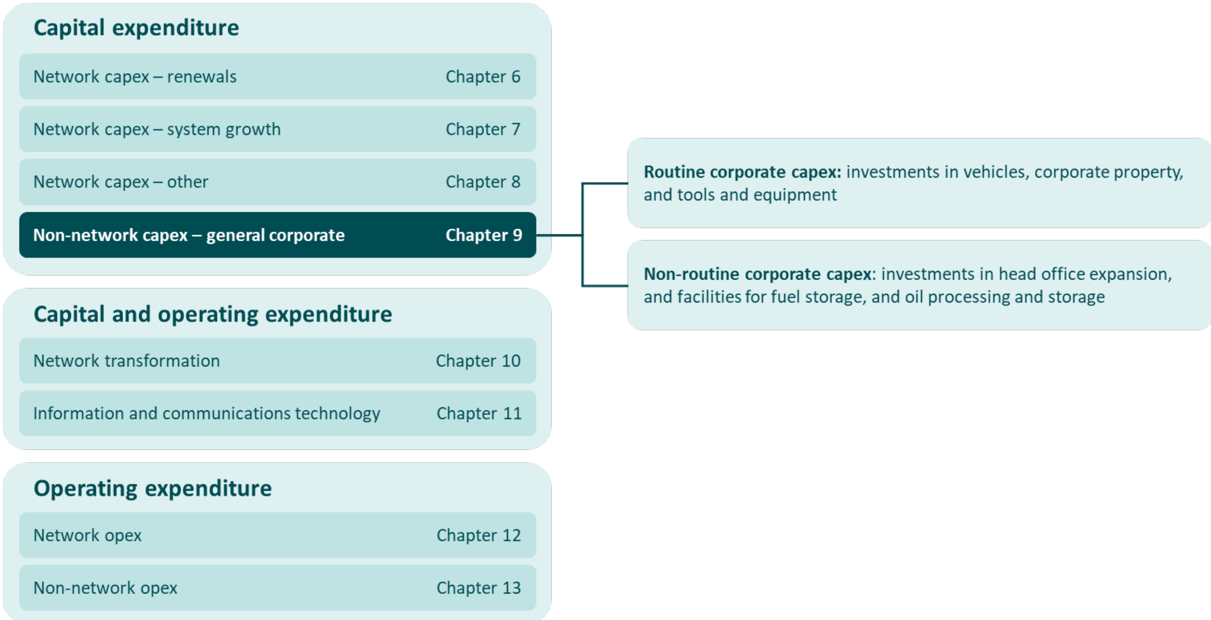
9 Non-network capex – general corporate

759 Non-network capex – general corporate covers expenditure on assets required to support Orion’s network and other non-network activities, including corporate property, tools and equipment, fuel storage facilities, and vehicles. This expenditure ensures our workforce has the facilities and resources required to operate efficiently and effectively.

760 While the non-network capex category includes 3 portfolios, this chapter focuses on the general corporate capex portfolio. The other portfolios, network transformation capex and information and communication technology (ICT) capex, are discussed in Chapter 10 and Chapter 11, respectively.

761 Figure 9.1 shows where general corporate capex sits within our overall expenditure and its components.

Figure 9.1 Non-network capex – general corporate



762 The remainder of this chapter outlines:

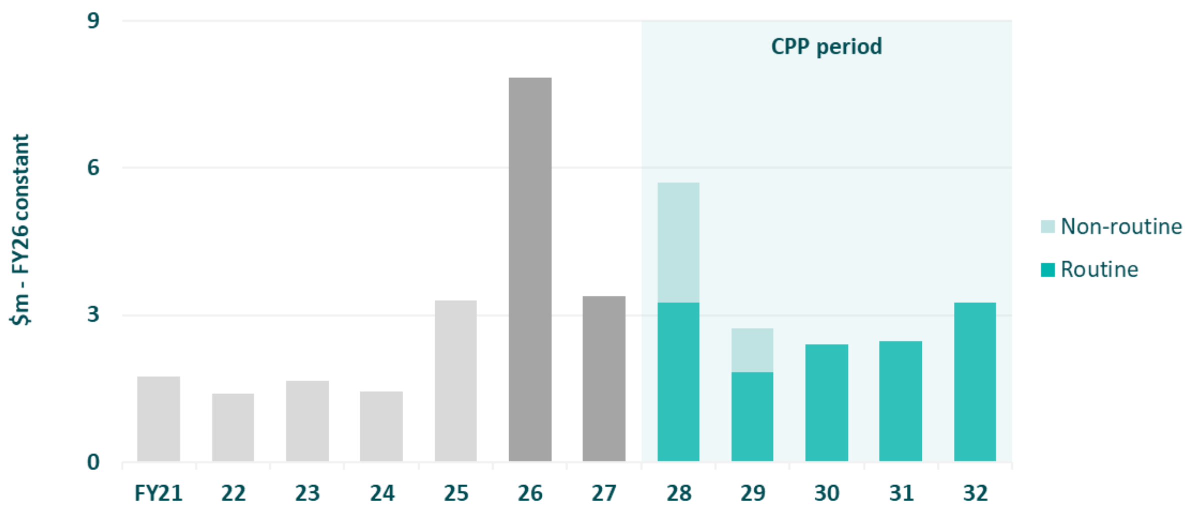
- our planned general corporate capex
- its key drivers
- our forecasting approach
- the planned routine and non-routine components
- why the planned capex is prudent and efficient.

9.1 Planned general corporate capex

763 Orion's planned general corporate capex over the CPP period totals $16.5 million, or an annual average of $3.3 million. This represents approximately 1.8% of capex and approximately 1% of totex for this period.

764 Figure 9.2 shows the planned capex per annum, split into the key components, compared with our historical spend.

Figure 9.2 Planned general corporate capex per annum, by component



765 Actual and forecast annual capex over the FY21–25 and FY26–27 periods vary considerably. The peak in FY26 reflects our decision to deliver all 3 phases of a scheduled head office fitout refresh that year, rather than over FY26–28 as originally planned (see section 9.5).

766 Planned annual capex over the CPP period also varies, but on average is $1.4 million higher per year than over FY21–25. This reflects a step change in the scale of Orion's delivery programme, increased resilience expectations, and the need to operate with contemporary workforce and operational standards. That is, it reflects future delivery requirements rather than changes in underlying cost efficiency. The additional investment ensures the business has the facilities and physical resources required to efficiently deliver the CPP programme.

9.2 Key drivers

767 The key drivers of the planned general corporate capex are:

- **Growth in business scale**: the planned step change in investment and works over the CPP increases the demand for vehicles, workspace, and other physical resources. Without investment, this would constrain delivery and reduce operational efficiency.
- **Delivery model changes**: bringing the project management office (PMO) function back in-house and increasing internal capability requires additional vehicles, workspace, and supporting infrastructure.
- **Age and condition of vehicles, corporate property, tools and equipment**: these assets deteriorate over time and require replacement to maintain operational efficiency.
- **Risk management**: ongoing efforts to improve our network resilience to natural disasters, such as earthquakes and flooding and reduce fire risk.

9.3 Forecasting approaches

768 We forecast the components of this portfolio separately, using bottom-up approaches. For routine corporate capex, we forecast vehicles, corporate property, and tools and equipment capex individually. For non-routine capex, we developed forecasts for 3 discrete projects: head office capacity expansion, a fuel storage facility, and an oil storage and handling facility.

769 Although a base-step-trend approach is often used to forecast this type of expenditure, we consider it is not appropriate in this case due to the material increase in delivery activity over the CPP period. A bottom-up approach better reflects the underlying cost drivers and links forecasts to identifiable assets, programmes, and delivery requirements.

770 We regularly compare actual and forecast year-to-date expenditure, and prepare updated forecasts and take corrective action when required to ensure we keep costs under control. The overall effectiveness of this process is evidenced by benchmarking analysis undertaken for this CPP proposal, which shows that our average non-network capex levels over 2021–25 were generally low compared to the other Big 6 on a per-customer, per-MW and per-km basis (see section 9.6 below).

771 Further detail on how we forecast specific components is provided in sections 9.4 and 9.5 below.

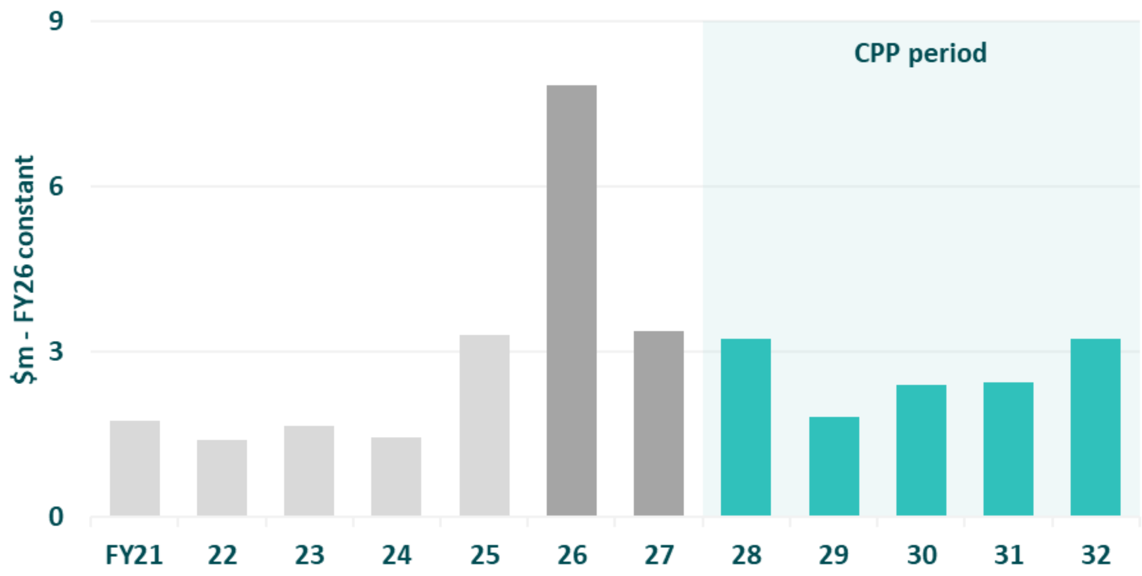
9.4 Routine corporate capex

772 Routine corporate capex covers vehicles, corporate property, and tools and equipment. These investments ensure staff have the resources and facilities necessary to perform their duties effectively.

9.4.1 Planned routine corporate capex

773 Planned routine corporate capex over the CPP period is $13.2 million. Annual planned capex is shown in Figure 9.4.

Figure 9.4 Planned routine corporate capex per annum



774 The planned capex is broadly consistent with the historical spend, with a modest increase reflecting business scale and workforce growth.

775 As noted above, the peak in FY26 largely reflects the accelerated head office refresh. It also reflects a slightly larger-than-normal year for vehicle replacements, due to expansion associated with bringing the project management office function back in-house.

9.4.2 Forecasting routine corporate capex

776 To forecast our routine corporate capex, we developed and combined separate bottom-up forecasts for vehicle costs, corporate property costs, and tools and equipment costs. We chose this approach as the necessary data was available, and because a bottom-up approach generally provides a more accurate forecast than a base-step-trend approach.

9.4.2.1 Vehicle costs

777 Our vehicle fleet is used by staff and contractors to maintain, operate and invest in our network, with costs covering acquisition, fit-out and replacement of vehicles. The fleet is owned, not leased.

778 We forecast vehicle costs by projecting replacement and fit-out requirements based on vehicle age, distance travelled, expected utilisation, and operational requirements. Replacement timing is aligned to defined lifecycle thresholds for each vehicle type (e.g. age and mileage limits), ensuring vehicles are neither replaced prematurely nor retained beyond their efficient service life. Projected volumes were combined with like-for-like replacement costs and average fit-out costs derived from historical data and market analysis.

779 We included forecast fleet growth of 7 operational vehicles and 2 utility service vehicles over the CPP period to reflect increased workforce requirements and delivery activity. These additions are aligned with forecast full-time equivalent staff growth (Chapter 13) and assessed operational needs.

780 This approach ensures replacement timing and fleet growth assumptions are grounded in asset condition data and operational need, providing a prudent and efficient basis for forecasting.

9.4.2.2 Corporate property costs

781 Our properties are used to house our people and equipment. They include our head office building, operational depots and other essential facilities, with costs covering fit-out and refurbishment of existing properties.

782 Following the major refresh of the head office building in FY26, corporate property expenditure over the CPP period is primarily focused on ongoing upgrades and modernisation to maximise utilisation of existing space. This represents a return to steady-state expenditure following completion of the one-off refresh programme.

783 We forecast corporate property costs based on our historical spend and input from our property managers. These investments ensure existing facilities continue to be used efficiently and remain fit-for-purpose, avoiding the need for more significant capital investment in new premises.

9.4.2.3 Tool and equipment costs

784 Our workforce requires tools and specialised equipment to perform their duties safely and efficiently, supporting productivity and service quality. We forecast tool and equipment costs by trending historical expenditure, supplemented with input from line managers. These costs are relatively stable over time.

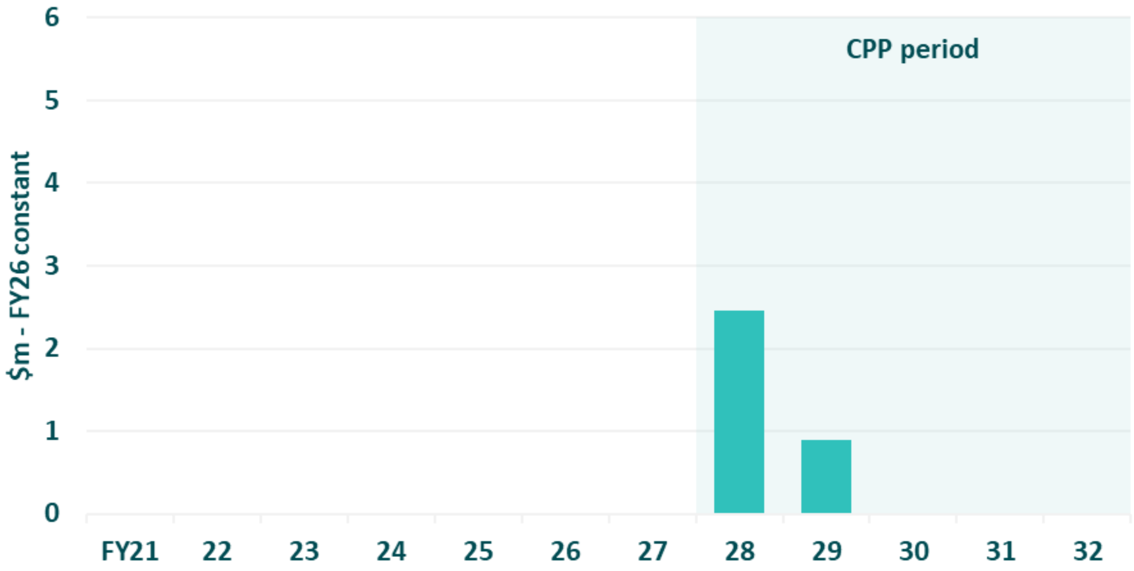
9.5 Non-routine corporate capex

785 Orion's non-routine general corporate capex over the CPP period includes 3 projects: head office capacity expansion; a fuel storage facility, and an oil storage and handling facility. These investments address discrete operational constraints that would otherwise limit our ability to efficiently deliver our CPP programme and maintain safe and reliable services. They also support improved operational resilience, workforce enablement, and risk management across our network and support functions.

9.5.1 Planned non-routine corporate capex

786 Our planned capex for all 3 projects is $3.4 million, comprising $2.5 million in FY28 and a further $0.9 million in FY29 (Figure 9.5).

Figure 9.5 Planned non-routine corporate capex per annum



9.5.2 Forecasting non-routine corporate capex

787 We forecast non-routine general corporate capex by developing separate project-level forecasts for head office capacity expansion, the fuel storage facility, and the oil storage and handling facility, and consolidating them.

9.5.2.1 Head office capacity expansion

788 In FY28, we will invest $2.4 million in expanding our head office capacity to accommodate the additional workforce required to deliver our CPP programme. Current capacity is not sufficient to support the forecast staff increase to deliver our capex and opex programmes. Without additional capacity, this would create inefficiencies, coordination challenges, and potential delays to programme delivery.

789 We forecast the costs of expanding our head office capacity using a structured business case process. This included assessment of alternative options, including a ‘do nothing’ option. Cost estimates were informed by market data, and options were evaluated using a cost-benefit framework incorporating both quantified and qualitative factors. This approach is appropriate for a large, one-off investment.

790 This process identified that leasing satellite office space as delivering the greatest overall value. We plan to lease space for up to 50 staff from the beginning of FY28. This is a flexible and cost-effective solution for addressing our short to medium term capacity constraints that can be implemented quickly, with minimal disruptions to operations. It preserves optionality while

longer-term workforce requirements and delivery models are assessed, avoiding committing to a long-term property solution ahead of demonstrated need.

9.5.2.2 Fuel storage facility

791 In FY29, we plan to invest $0.6 million in establishing a diesel storage facility at our Papanui zone substation to strengthen our fuel resilience during emergency events. Diesel is essential for Orion's operational recovery and mobility. Recent severe weather events, including Cyclone Gabrielle, have demonstrated that fuel access can be significantly limited by infrastructure disruption. In these events, road closures, power outages, and regional isolation constrained the ability of fuel distributors to supply critical users, exposing a reliance on just-in-time fuel delivery that is not resilient under emergency conditions.

792 We assessed alternative options for addressing the identified gap in our current fuel storage capability, including combined diesel and petrol storage. While our response vehicles and generator trucks operate on diesel, some support vehicles use petrol. We assessed the incremental cost of petrol storage against its additional benefits and risk mitigation value. As this option did not meet value-for-money thresholds, a diesel-only solution was selected.

793 A dedicated diesel storage facility will materially strengthen our ability to maintain operations and support emergency response activities. We plan to install 2 diesel fuel tanks (16,000 litres and 10,000 litres) and establish a set-down area for 4 fuel cube mobile units (3,000 litres each). This investment provides a secure, on-site fuel supply for critical functions, including our Emergency Operations Centre, generator fleet, and field response vehicles. It also reduces operational delays associated with refuelling at congested or unavailable service stations during emergency events.

9.5.2.3 Oil storage and handling facility

794 Over FY28 and FY29, we plan to invest $0.5 million in an oil storage and handling facility with increased capacity to refurbish transformer oil, and capability to store and handle ester oil. Our current oil handling capability is limited, which constrains our ability to efficiently reuse transformer oil and adopt alternative insulating fluids. As a result, we currently dispose of approximately 24,000 litres of transformer oil each year, representing an avoidable cost and environmental impact.

795 We estimated the oil storage and handling facility costs using information from equipment suppliers and by referencing the costs of comparable existing assets. We incorporated anticipated savings where the project overlaps with the fuel storage project – for example, through shared consent requirements.

796 This investment will enable us to reuse all our transformer oil, reducing lifecycle costs and environmental impacts relative to disposal and replacement. It will also allow us to replace certain larger ground-mounted transformers in kiosks and customer premises with ester-oil-filled units at the end of the transformer life. Ester oil provides improved fire safety and environmental performance, mitigating risks associated with these installations, particularly in higher consequence locations. This aligns with our Distribution Transformers Asset Class Strategy, which identifies fire risk mitigation for these assets as a priority.

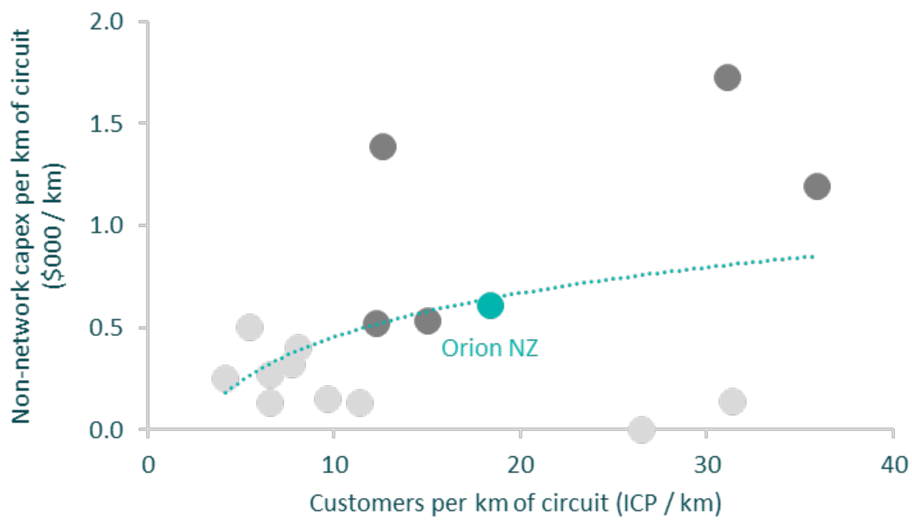
9.6 General corporate capex justification

797 We consider our general corporate capex forecasts are prudent and efficient. This is supported by:

- **Benchmarking**: farrierswier benchmarked our historical non-network capex against comparable New Zealand EDBs. This analysis found that Orion's average non-network capex over 2021–25 is generally low compared to the other Big 6 EDBs on a per-customer, per-MW and per-km basis. Against the full set of non-exempt peers, it sits very close to the trendline when plotted against customer density (see Figure 9.6). These findings provide independent evidence that our forecasts are grounded in an efficient starting point.

- **Bottom-up methodology**: the forecasts were derived using a bottom-up process, based on asset condition, replacement needs, and current market pricing. They reflect future delivery requirements rather than a continuation of historical spending patterns.
- **Alignment with delivery requirements**: the forecasts reflect the facilities, tools, and infrastructure required to support a materially larger capital and operational programme, ensuring efficient delivery and avoiding operational constraints.
- **Customer perspective**: customers and stakeholders expect a safe, reliable and resilient network that can accommodate growth and is future-fit. They also expect assets and supporting capabilities to be managed prudently and efficiently. This planned expenditure will ensure we have sufficient resources to deliver this.
- **Challenge rounds**: the forecasts have been subject to multiple internal challenge rounds, including review by senior management and the Board, and have been tested from a customer perspective through our Customer Advisory Panel and consultation on our draft investment plan.
- **Expected benefits**: the planned expenditure will ensure Orion staff have sufficient physical resources to do their jobs effectively, and a supply of fuel to ensure we can keep vehicles and generators operational following emergency events (when normal fuel supplies can be disrupted). It will also mitigate fire risk, and reduce the environmental impact of our use of transformer oil.

Figure 9.6 Non-network capex[51] per km v customer density (average FY21 to FY25)



Source: farrierswier analysis

[51] This includes ICT expenditure.

10

10 Network transformation

798 The way distribution networks are used is fundamentally changing. Consumers are increasingly generating, storing, and actively managing their own electricity, while demand continues to grow and become more dynamic. Maintaining reliable, affordable and equitable access to electricity and our network requires us to transform how we plan, operate, and invest. Network transformation is therefore a strategic imperative for Orion and customers. It will enable faster and more flexible connections, support electrification, improve customer engagement, and reduce the long-term cost of meeting demand through more efficient use of existing capacity.

799 The network transformation portfolio funds investments to investigate, trial, and implement advanced network technologies, systems and processes to build the capabilities required to plan and operate the network in this changing environment. It focuses on developing and integrating new tools and ways of working across the organisation to enable this transition. We will adopt a fast-follower approach to minimise the risk of overspend or technology lock-in, reflecting a key concern for our community.

800 These investments deliver tangible benefits across operations, customer connections, and network planning. They improve our ability to understand and use new technologies, platforms, and processes, with direct implications for how we reinforce and operate the network to support growth and changing customer behaviour. Benefits are expected to include faster connection approvals, reduced long-term reinforcement costs, and increased customer export capability.

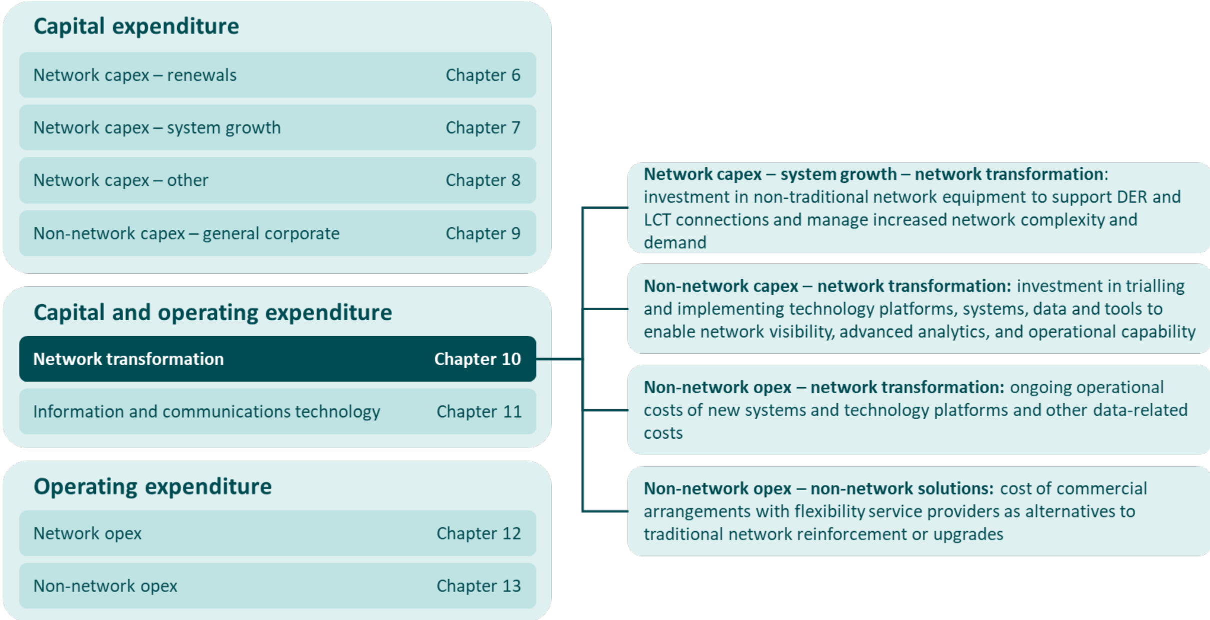
801 This work is being delivered through 2 complementary programmes:

- **The network transformation programme**: improving our understanding of the network and updating our operational, connections, and planning systems and processes to better facilitate the connection and efficient use of distributed energy resources (DER) and low-carbon technologies (LCT).
- **The flexibility and markets development programme**: enabling greater use of demand-side flexibility and other non-network solutions to moderate peak demand on the network, where this is more cost-effective than traditional network capacity upgrades.

802 Together, these programmes position our network to meet the future needs of customers and the energy system – one of the strategic priorities underpinning this CPP proposal (see Chapter 2).

803 Figure 10.1 shows where the network transformation portfolio sits within our overall expenditure and its components. While these components are typically included in other expenditure categories, we have grouped them as a discrete portfolio for the purposes of this proposal to facilitate more holistic assessment.

Figure 10.1 Network transformation expenditure components



804 The remainder of this chapter outlines:

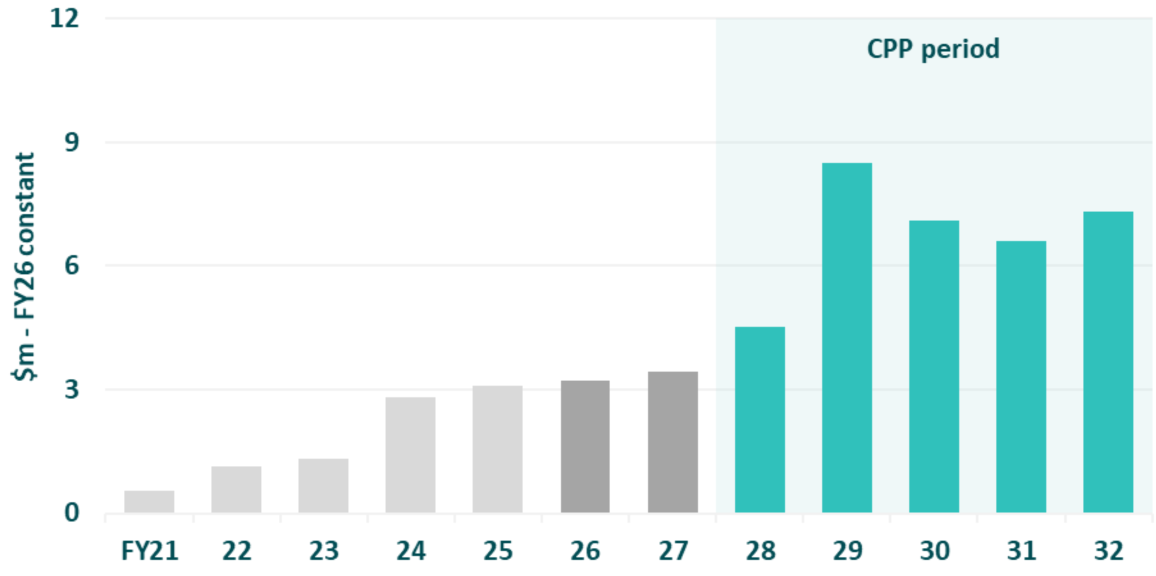
- our planned network transformation expenditure
- its key drivers
- its interactions with other expenditure categories
- our forecasting approach
- the network transformation (NT) programme and flexibility and markets development (FMD) programme expenditure in further detail
- why the planned expenditure is prudent and efficient.

10.1 Planned network transformation expenditure

805 Our planned network transformation expenditure over the CPP period totals $34 million, or an annual average of $6.8 million. It represents approximately 2% of our planned totex in this period.

806 Figure 10.1 shows the planned network transformation expenditure per annum, compared with our historical spend.

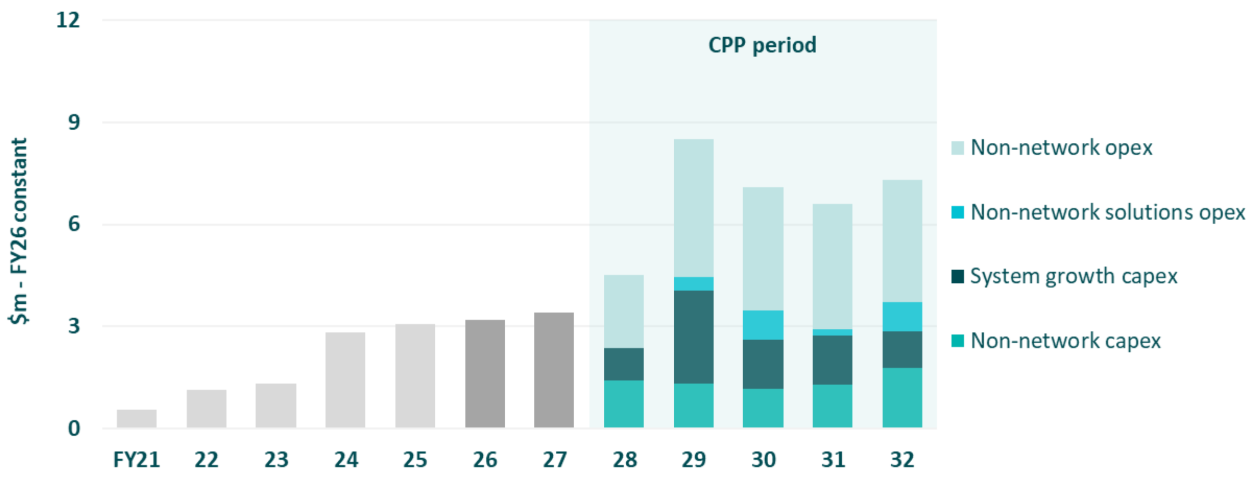
Figure 10.1 Planned network transformation expenditure per annum



807 Expenditure on network transformation activities began in FY21, initially focussed on installing low-voltage (LV) monitoring equipment. The NT and FMD programmes were formally established in FY23, with smart meter data acquisition beginning in FY24, and trials and analytics uplift following in FY25 and FY26. During the CPP period, planned expenditure increases as the programmes shift from set-up to delivery. This means historic expenditure is not a good indicator of future requirements.

808 Figure 10.2 shows the planned network transformation expenditure per annum broken down by component. Three of these components – non-network opex, system growth capex and other non-network capex – are part of the NT programme. The fourth, non-network solutions opex, is part of the FMD programme.

Figure 10.2 Planned network transformation expenditure per annum, by component



809 Roughly half the expenditure over the CPP period is non-network opex, reflecting the cost of acquiring third-party smart meter data. Non-network solutions opex varies year-to-year, aligned with the timing of major system growth projects that incorporate non-network solutions (see Chapter 7).

810 The FY29 peak reflects higher spending in system growth capex, driven by planned investment in delivering a microgrid. FY29 also reflects increased acquisition of third-party smart meter data, and funding the first year of non-network solutions.

10.2 Key drivers

811 As outlined above, the way customers use our network is changing, requiring new capabilities to plan and operate in a more dynamic and decentralised energy system. The key drivers of this change, and of our planned network transformation expenditure, are:

- **Customers**: expectations are changing, relationships with electricity providers are evolving, and the focus on electricity equity is increasing. New technologies and retail offerings are reshaping behaviour, with more customers participating in decentralised generation and energy markets. This requires new approaches to network operation, customer connections, and customer engagement.
- **Demand and decarbonisation**: the transition to low-carbon energy is changing both demand patterns and the supply mix. Orion must enhance the network's capacity to integrate DER and manage more variable, less predictable demand and two-way energy flows.
- **Regulatory**: New Zealand's regulatory framework sets requirements for how EDBs operate and is informed by government policy. The framework is evolving to encourage innovation and support the transition to a low-carbon future. For example, EDBs are now expected by all regulators to consider efficient non-network solutions in network planning.
- **Business**: a focus on improving asset utilisation, optimising investment, and lifting operational efficiency requires new tools, data, and processes to support more informed planning and decision-making. Network transformation investment enables these capabilities, allowing us to make better use of existing assets and deliver more efficient outcomes for consumers.
- **Technology**: the availability and uptake of DER and LCT is increasing. These technologies create both challenges and opportunities for EDBs. Ongoing digitalisation also provides a significant opportunity to improve network visibility and understanding, deliver better customer outcomes at the lowest cost, and support timely and efficient connections.

10.3 Interactions with other expenditure categories

812 The network transformation portfolio interacts with 2 other investment categories – network capex – system growth and information and communication technology.

813 Network transformation initiatives provide a direct alternative to traditional system growth investment by enabling non-network solutions that manage peak demand and network constraints. These solutions are systematically assessed alongside network options through our optioneering and business case processes and are embedded in both individual major projects and portfolio-level forecasts (see Chapter 7).

814 They are expected to defer the timing of some major projects and reduce the volume of reinforcement required, with associated costs treated as opex within the network transformation portfolio. This reflects an intentional application of the totex framework, under which opex and capex are considered together to support efficient trade-offs and least-cost outcomes for customers.

815 Network transformation initiatives are enabled by, and in some cases depend on, planned ICT investment (see Chapter 11). Enhanced data and new operational technology control systems support the deployment of non-network solutions, integration of DER, and more active network management. In turn, network transformation initiatives increase the value derived from ICT investments by embedding these capabilities into planning and operational decision-making. This alignment supports more efficient utilisation of existing assets and reduces the likelihood of defaulting to traditional network investment where lower-cost alternatives are available.

816 Together, these interactions enable a more coordinated and long-term efficient approach to network investment. By combining enhanced data, visibility, and system control with the use of non-traditional solutions, we can make better-informed planning and operational decisions, optimise the use of existing assets, and defer or avoid some traditional network investment. This reduces the risk of inefficient, reactive responses to emerging constraints and supports delivery of safe, reliable, and cost-effective outcomes for customers.

10.4 Forecasting approach

817 As noted above, both the NT and FMD programmes are in their early stages. Their relatively emergent and bespoke nature means limited historical cost data is available. As a result, a traditional base-step-trend forecasting approach is not appropriate. Instead, we used a combination of approaches and information sources for each programme. We also considered the independent verifier's assessment before finalising our forecasts.

10.4.1 Forecasting network transformation programme expenditure

818 To forecast expenditure for the NT programme, we adopted a bottom-up estimating approach, supported by reference class forecasting and supplier validation:

- We defined the activities to be delivered over the next 5 years and specified clear outputs for each. Where activities involved identifiable units, we applied a P × Q methodology to build estimates from first principles.
- Given the limited historical cost data for transformation activities in New Zealand, we engaged an independent consultant to undertake reference class forecasting. This benchmarked our planned scope and budgets against comparable programmes delivered by EDBs in New Zealand, Australia and the UK, establishing a prudent and evidence-based cost range. Expenditure was scaled to align with our relative network size, scope and deliverables.
- We incorporated supplier cost estimates (where available) to reflect New Zealand's regulatory and operating environment and our specific delivery context.

819 Combining bottom-up costing, independent reference class benchmarking, and supplier validation provides a robust triangulated estimate. This approach tests planned expenditure against credible national and international comparators, reduces optimism bias, and supports identification of an efficient cost allowance for each activity.

820 As the NT programme involves exploratory and evolving initiatives for which there is limited historical cost evidence in New Zealand, some cost refinement is expected over time, particularly toward the end of the CPP period.

10.4.2 Forecasting flexibility and market development programme expenditure

821 To forecast expenditure on the FMD programme, we used 2 methods:

- **Neutral cost benefit analysis**: for major systems growth projects, we increased the non-network solutions operating cost in our economic calculator until the cost-benefit ratio equalled that of the traditional capex option. This established a ceiling price for procuring non-network solutions.
- **Equivalent capex and opex**: for the 11 kV and LV programmes of work, we set an annual ceiling price for non-network solutions at a level approximately equivalent to the line charge impact of the traditional network option. This ensures customers are no worse off when a non-network solution is used, while allowing potential savings if the market can deliver it at a lower cost.

10.4.3 Considering independent verifier's assessment

822 The independent verifier assessed all of the forecast expenditure in this portfolio. It accepted the majority of this expenditure, but did not support $5 million of opex associated with the planned purchase of third-party data (and a corresponding reduction to network analytics expenditure).

823 The verifier considered that data is not required for all ICPs on the network at this stage. While it recognised that we are compelled to purchase data for all ICPs under "all or nothing" commercial arrangements, it considered this unnecessary and inefficient. Its position is that data volumes should be reduced, as the current cost–benefit case is insufficient and investment appears premature. It also uses DER uptake as a key indicator, suggesting the scale of the planned data acquisition exceeds near-term needs.

824 We have considered the verifier's assessment but do not agree that data volumes should be reduced. As the verifier acknowledges, our primary provider's commercial offering requires us to purchase data from all connected smart meters, with no ability to select a subset. These terms reflect the monopoly characteristics of the current smart meter data market.

825 In addition, purchasing a lower volume of data would reduce network visibility. This would limit our ability to identify where non-network solutions are viable and increase the likelihood that investment decisions default to traditional network capex where a lower cost alternative may exist. Without sufficient data, we cannot reliably assess network performance, determine the most appropriate solution, or have confidence that non-network solutions will deliver the required outcome.

826 Further, we consider tying data acquisition rates to DER and LCT uptake is a flawed assumption. While DER uptake is an important driver of change, enhanced visibility supports a broader set of core network functions, including capacity management for infill growth, fault detection and response, voltage management, and identification of latent capacity. These benefits are not contingent on DER volumes and are required to maintain service quality and efficiency as the network evolves.

827 Finally, we have reassessed the planned expenditure on acquiring third-party data and confirmed that it remains NPV-positive, indicating that the benefits outweigh the costs.

828 For these reasons, Orion has not reduced the planned expenditure in this portfolio in response to the verifier's assessment.

10.5 Planned network transformation programme expenditure

829 The NT programme focuses on network-based transformation – investigating, developing, and implementing new technologies, systems and processes to support continued delivery of line services in a changing energy environment.

830 Its objective is to prepare our distribution network for a more distributed, low-carbon future, while maintaining safety, reliability and affordability. This includes ensuring we do not become a barrier to the rapid uptake of DER and LCT by customers on our network.

831 The programme is the delivery vehicle for our internal Network Transformation Roadmap, which is based on the industry-wide transformation roadmap published by Electricity Networks Aotearoa.[52] It consists of 6 workstreams, summarised in Table 10.1.

[52] Network Transformation Roadmap | Electricity Networks Aotearoa

Table 10.1 Overview of our Network Transformation Roadmap	
Workstream	**Focus**
1. Intelligent distribution network operator (iDNO) enablement	Evolving operational capabilities, control systems, and market interfaces to operate in a high-DER future. This includes exploring new distribution control systems (like DERMS) and procedures for managing bi-directional power flows and engaging with emerging flexibility markets
2. Scaling DER and LCT connections and conversions	Streamlining and upgrading the customer connection process to manage an expected increase in DER and LCT applications. This includes updating connection standards, automating the approvals process, and developing innovative solutions, both technical and procedural, so customers can connect what they want, when they want, and how they want, without undue delays. It also includes pilot projects to understand the impact of EV fast-charger clusters, vehicle-to-grid, and other new technologies on the network
3. Power system insight enablement	Developing advanced analytical capabilities and tools to interpret new data from smart meters, sensors, and other sources. This includes building network simulation models, especially at the LV level, and applying analytics or AI to derive actionable insights (such as identifying emerging constraints, predicting equipment failures, or optimising asset use). In essence, this workstream is about turning raw data into enhanced network understanding to inform planning and real-time operations
4. System visibility and network data integration	Expanding visibility of the LV network, particularly in previously blind spots like residential feeders. This involves deploying field instrumentation – such as feeder monitors and Internet of Things (IoT) voltage sensors – and integrating these into our IT systems. This will provide a far more detailed, real-time picture of network conditions, which is foundational to enabling DER and maintaining power quality
5. Network transformation business change and enabling services	Internal change management to ensure our people, processes, and culture keep pace with the technical transformation. This workstream covers training staff in new skills (e.g. data science and new engineering practices), updating business processes, and securing stakeholder buy-in. It leverages internal resources and leadership to drive mindset and skillset shifts
6. Network transformation strategic planning and design	Ongoing strategic alignment, industry engagement, and programme design refinement to ensure our network transformation roadmap remains aligned with our corporate strategy, and with external developments such as regulatory changes or technology trends. Activities include stakeholder engagement, communicating with regulators, refining the roadmap as new information arises, and ensuring interdependencies with other Orion initiatives are managed

832 Over the CPP period, we plan activities and investments in 4 areas to progress delivery of this roadmap:

- **network visibility**, which primarily relates to workstreams 3 and 4 of the roadmap
- **growth and connections**, which primarily relates to workstream 2
- **operations**, which relates to workstream 1
- **business change**, which relates to workstreams 4 and 5.

833 The sections below outline our planned expenditure in the network visibility, growth, connections, and operations areas. Business change activities are being undertaken internally, leveraging existing resources and leadership, so planned expenditure is included in the SONS portfolio (Chapter 13).

10.5.1 Network visibility

834 Network visibility is the ability to monitor and understand the condition and performance of the network, including power flows, voltage levels, constraints and asset status. It is increasingly important to have real-time visibility of the LV network as the energy system becomes more dynamic and decentralised due to the growing uptake of rooftop solar, batteries, EVs and other DER. Improved network visibility supports safe and efficient operation, enables more flexible customer connections and non-network solutions, and helps target investment to where it is most needed (Box 10.1 provides further information).

835 Over the CPP period, we will progress initiatives to improve network visibility by establishing foundational structures that support enhanced connection and operational processes. This will involve acquiring data from multiple sources and across different network levels, then using it to develop more accurate network models and apply analytical tools to generate actionable insights and improve workflows.

836 Our planned network visibility expenditure over the CPP period is $22.3 million. Table 10.2 outlines the key initiatives and associated expenditure.

Table 10.2 Key network visibility initiatives and expenditure during the CPP period ($m, FY26 constant)

Initiative	Network capex – system growth	Non-network capex	Non-network opex	Total
Deploying network-based monitoring equipment, which involves installing measuring devices on the network in strategic locations to provide insights to both operational and planning functions. This also includes licensing to support LV network monitoring, allowing network data to be retrieved via the cellular network to inform better investment decisions	2.0	-	1.1	3.1
Developing an LV model to improve our understanding of the LV network and inform better decisions at the LV level	-	-	1.1	1.1
Acquiring network data, including smart meter data, from third parties[53] to obtain insight into customer electricity usage and network power quality and performance	-	5.4	5.3	10.7
Improving IoT device telemetry and communications including trialling new systems and tools to lower the cost of data retrieval on the network	1.9	-	0.1	2.0
Increasing network analytics capability to properly utilise the data we will receive, and allow the business easy access to valuable information to improve decision making	-	-	5.0	5.0
Other	-	-	0.4	0.4
Total network visibility	**3.9**	**5.4**	**13.0**	**22.3**

837 Five of these key initiatives were considered and costed through Project Investment Papers (PIPs). Each PIP defined the underlying need, evaluated alternative options, and compared cost and benefits on a Net Present Value (NPV) basis to identify the most prudent and efficient solution. Together, these PIPs account for around 98% of network visibility expenditure.

[53] The bulk of this data will be acquired from Bluecurrent, as it supplies more than 80% of the meters on Orion's network.

838 Much of this planned expenditure was forecast using a P x Q approach, due to the strong influence of New Zealand-specific cost drivers. Third-party data acquisition costs, which are largely fixed, make up a significant share of total expenditure (approximately 48%). As more than 80% of the smart meters on our network are supplied by a single provider (Bluecurrent), access to this critical data is subject to its commercial terms. These terms reflect the monopoly nature of the metering equipment provider market structure.

839 While increasing network complexity and changing consumer behaviour are the primary drivers of this investment, enhanced visibility also supports safety and reliability through the proactive identification of faults and incidents.

Box 10.1 What is network visibility, and why is it important?

Network visibility refers to the extent to which we can observe conditions across the network, including asset loading, power quality at any given time or location, and faults as they occur. We have strong visibility and control of our HV network through SCADA-enabled devices at most circuit breakers and zone substations. This data underpins our assessment of asset utilisation and informs investment decisions.

Our 400V LV network is a different story. It was designed for stable, passive household loads with one-way power flows. As customers adopt EVs and install generation and battery storage, those assumptions no longer hold. Two-way power flows are now increasingly common, and electricity use is becoming more complex and less predictable. Without granular visibility of LV network performance, we cannot reliability identify where constraints are emerging, or ensure that investment is targeted appropriately in terms of location, timing and scale.

This gap has tangible consequences. Investment decisions in established suburbs – where infill housing development is occurring – have historically been guided by general growth patterns rather than direct evidence of network performance. As electrification accelerates, this approach carriers heightened risk of both under- and over-investment.

Planned work to improve LV network visibility will deliver significant benefits as electrification continues. It will enable us to maintain service levels, target investment more efficiently, and support evidence-based decision-making across the LV network – which has a higher reinforcement cost per ICP than any other part of the network.

Visibility of the LV network is also critical to ensuring that third-party control of electrical devices is managed safely and equitably, without triggering premature investment by the wider community for the benefit of a small number of early adopters.

10.5.2 Growth and connections

840 Growth and connection activities focus on developing and testing new technologies, systems and processes to enable efficient connection of DER and LCT at scale and pace, and to support population and demand growth using cost-effective alternatives to traditional network reinforcement (see Box 10.2).

841 Our planned growth and connections expenditure over the CPP period is $4.9 million. Table 10.3 outlines the key initiatives and associated expenditure.

Table 10.3: Key growth and connections activities and expenditure during the CPP period ($m, 26 constant)

Initiative	Network capex – system growth	Non-network capex	Non-network opex	Total
Exploring battery energy storage systems for capacity management and for improved network utilisation as an alternative to traditional capital build projects, while also enabling us to assess the customer value of participating in the energy storage market	2.1	-	0.3	2.4
Exploring microgrids and community energy hubs for resilience and capacity improvements, to improve service quality for more remote customers and investigate the option of offering these solutions to customers with uneconomic connections	1.2	-	-	1.2
Investigating emerging equipment to improve network automation and optimisation, to understand how it can improve operational outcomes and facilitate better customer experiences, where needed	0.5	-	0.5	1.0
Other	-	-	0.3	0.3
Total growth and connections	**3.8**	**-**	**1.1**	**4.9**

842 This expenditure is driven by the need to prepare the network for changing patterns of demand and generation. It supports more efficient connection processes, improves our ability to integrate DER and LCT safely, and enables targeted use of non-traditional solutions where traditional investment is not cost-effective, such as in constrained or remote parts of the network.

Box 10.2 What are growth and connections improvements, and why do they matter?

Growth and connections improvements relate to how we enable new demand and generation to connect to the network efficiently, while maintaining reliability, service quality, and cost-effectiveness. Historically, network growth has been driven by increases in electricity demand and addressed through reinforcement of network capacity.

This is changing. Growth is now also driven by the connection of distributed energy resources (DER) and low-carbon technologies (LCT), such as solar PV, batteries, and electric vehicles. These technologies introduce more variable and less predictable patterns of demand and generation, increasing the complexity of network planning and operation.

Our existing connection processes and network design approaches were not developed for this environment. As connection volumes increase and technologies evolve, there is a need to improve how we assess, connect, and manage these assets, and to ensure customers can connect in a timely and efficient way.

To support this, we are trialling and assessing a range of new approaches. These include localised solutions such as battery energy storage systems to manage capacity constraints and improve utilisation, and microgrids and community energy solutions to improve resilience and service quality in remote or higher-cost areas. We are also investigating technologies that improve network automation and optimisation, such as automated switching and self-healing capability — reducing reliance on traditional reinforcement and supporting more flexible, efficient use of the network over time.

10.5.3 Operations

843 Operations activities focus on technology and software improvements to build our capability to operate the network using the improved insights and understanding gained from network visibility, and growth and connections activities. This capability is essential to ensure we support, rather than constrain, consumer choice and decarbonisation, and can efficiently procure and utilise non-network solutions in place of traditional upgrade activities.

844 These activities include considering the level of operational control EDBs require to operate in a changing energy landscape. As retailer participation in control markets grows, and customers gain greater choice over their energy supply, the control environment must evolve. This will require new skillsets, systems and operating processes to manage the network effectively (see Box 10.3).

845 Our planned operations expenditure over the CPP period is $4.7 million. Table 10.4 outlines the key initiatives and associated expenditure.

Table 10.4 Key operations initiatives and expenditure during the CPP period ($m, 26 constant)

Initiative	Network capex – system growth	Non-network capex	Non-network opex	Total
Improving network operational tools to facilitate enhanced operational capability for safety and reliability improvements	-	-	0.8	0.8
Investigating and deploying a DERMS at HV and LV levels to facilitate the connection of DER to the network and maximise the export capacity of those systems through intelligent network management	-	1.6	2.3	3.9
Total operations	**-**	**1.6**	**3.1**	**4.7**

846 The DERMS initiative was considered and costed through a PIP.

847 As demand and generation grow, and customers' use of the network evolves, we require enhanced tools to support informed operational decision-making, underpinned by improved visibility and insights. This investment supports delivery of the systems and processes needed to ensure customers have reliable, optimal access to the network, and to enable the use of non-network solutions.

Box 10.3 What are operations improvements, and why do they matter?

Operations capability determines how effectively we use the visibility we have established. As two-way power flows, distributed generation, and third-party-controlled devices become more common, safe and efficient network operation depends on tools that can respond to a more dynamic system in real time. This investment advances our transition to dynamic control capabilities, which are critical to maximising export from generating connections and enabling earlier connection of load under flexible arrangements.

A central component of this investment is the investigation and deployment of a Distributed Energy Resource Management System (DERMS) across our HV and LV networks. A DERMS enables active coordination of the growing number of devices on the network, supporting export optimisation, constraint management, and power quality. We will also invest in improved operational tools to support safety and reliability as retailer participation in control markets increases and customers gain greater choice in how they use energy.

Together, these investments provide the systems and capability to manage an increasingly dynamic network, ensuring we can continue to operate safely, reliably, and efficiently as new technologies are adopted at scale.

10.6 Planned flexibility and markets development programme expenditure

848 The FMD programme focuses on market and customer-enabled transformation. It involves procuring efficient non-network solutions, such as demand-side responses and flexibility services, to address capacity constraints at a specific location and time. These solutions defer or avoid some capital expenditure required to extend and upgrade the network to ensure sufficient capacity and security (system growth capex).

849 In the near term, much of the investment is directed at enabling (rather than optimising) our use of non-network solutions. The flexibility market is still in its infancy, so we are pursuing practical and efficient options to support its development.

850 Our planned non-network solutions operating expenditure over the CPP period is $2.3 million. This represents the total budget to procure non-network solutions over the CPP period, including those incorporated into the Lincoln township growth project and Lyttelton major supply upgrade project, and assumed in forecasting 11 kV and low voltage network reinforcement expenditure (discussed in Chapter 7).

851 This budget was estimated on a cost-neutral basis, using an equivalent capex/opex approach consistent with the Commerce Commission's totex framework and IRIS incentive mechanisms, which allow efficient substitution between capex and opex. Under this approach, an approximately neutral outcome is achieved where the annual opex incurred to avoid a network capex investment is broadly equivalent to around 10%[54] of the capex avoided.

852 In some cases, the network investment is assumed to be avoided (rather than deferred), and therefore the associated non-network solution expenditure is expected to be ongoing. Based on this methodology, we have allocated budgets using a ceiling price model, under which we will procure non-network solutions whenever the market can provide them at a cost below the calculated ceiling price.

853 The planned non-network solutions expenditure is primarily driven by the need to prepare to meet future needs and maintain safety and reliability. As outlined in Chapter 7, the recent strong population growth and rising peak demand in our network area are expected to continue.

854 Customer behaviour is also evolving, with customers taking a more active role in their energy use and participating in a system they were previously only served by. This creates an opportunity for us to leverage customer engagement to deliver non-network solutions that defer or avoid traditional system growth capex.

10.7 Network transformation expenditure justification

855 We are confident that our planned network transformation expenditure is consistent with the efficient costs a prudent EDB in similar circumstances would incur. This is supported by:

- **Forecasting approach**: we applied a range of forecasting methods tailored to each activity type. This enabled us to estimate unit costs and quantities where available, benchmark against national and international peers, and adjust for Orion-specific factors where necessary. Together, these elements provide a robust, evidence-based forecast in an uncertain environment.
- **Challenge rounds**: we tested our forecasts with our integrated leadership team and Board at several stages and moderated them based on feedback and discussion.

[54] In general the opex equivalent is less than 10% of capex but to aid development of the NNS market we have made a 10% provision for 11kV and LV NNS, and utilised NPV analysis to determine an exact equivalent opex for major system growth projects

- **Customer perspective**: customers and stakeholders expect the network to be future-fit, accommodate new technologies and enable greater use of non-network solutions. They recognise that future-focused investment is necessary, and they expect this to be strategic, support affordability, and deliver tangible benefits for customers. Views on the appropriate level of investment varied; with some supporting the planned approach, others favouring acceleration, and some emphasising affordability.
- **Independent verification**: the verifier assessed all planned expenditure for the NT programme and at a high-level concluded[55] it is "strategically sound and forward-thinking" with a "focus on network visibility, operational innovation, and customer empowerment [that] aligns with what consumers want in a flexible, modern grid that can accommodate new technologies without compromising reliability or affordability."
- **Expected benefits**: The planned expenditure will provide value to customers and the community, including those described in Box 10.4.

Box 10.4 Expected benefits of planned network transformation expenditure

The planned network transformation expenditure is expected to deliver benefits that align with customer priorities by:

- **Maintaining safety and reliability as uptake of DER accelerates**: through improved monitoring, visibility and active control to detect safety related defects and prevent unsafe asset overloads, outages and power quality issues.
- **Unlocking capacity and optimising existing assets**: enabling better use of the current network, more targeted investment, and greater use of non-traditional alternatives to defer upgrades and maximise available network capacity.
- **Supporting decarbonisation and customer choice**: by enabling smoother, faster connections for EVs, solar PV, batteries and other DER, improving the customer connection experience.
- **Strengthening data-driven decision-making**: using improved models, increased quantities of data, and analytics to better inform planning, operations, and maintenance.
- **Enhancing customer engagement and transparency**: through tools like hosting capacity maps and streamlined connection portals, supported by ongoing stakeholder engagement.
- **Futureproofing the network**: by building a digital, interoperable systems foundation that can integrate future technologies and market models and contribute to sector-wide innovation, thus ensuring Orion does not hinder customers' ability to use our network how they want, with whatever technologies they choose.

[55] In the detail of the independent verifier's feedback they proposed partial procurement (as opposed to full procurement) of the smart meter dataset, but this is not a commercially available option.

11

11 Information and communications technology

856 Information and communications technology (ICT) encompasses digital, data, information technology, and communications systems used across our organisation, including corporate IT systems and operational technology (OT).

857 This technology underpins the delivery of our strategic objectives, supports core business processes, and enables the safe and reliable operation of the network. Critically, it enables access to, integration of, and effective use of network data, without which the analytical tools, forecasting models, and innovative solutions required to operate a modern distribution network cannot function effectively.

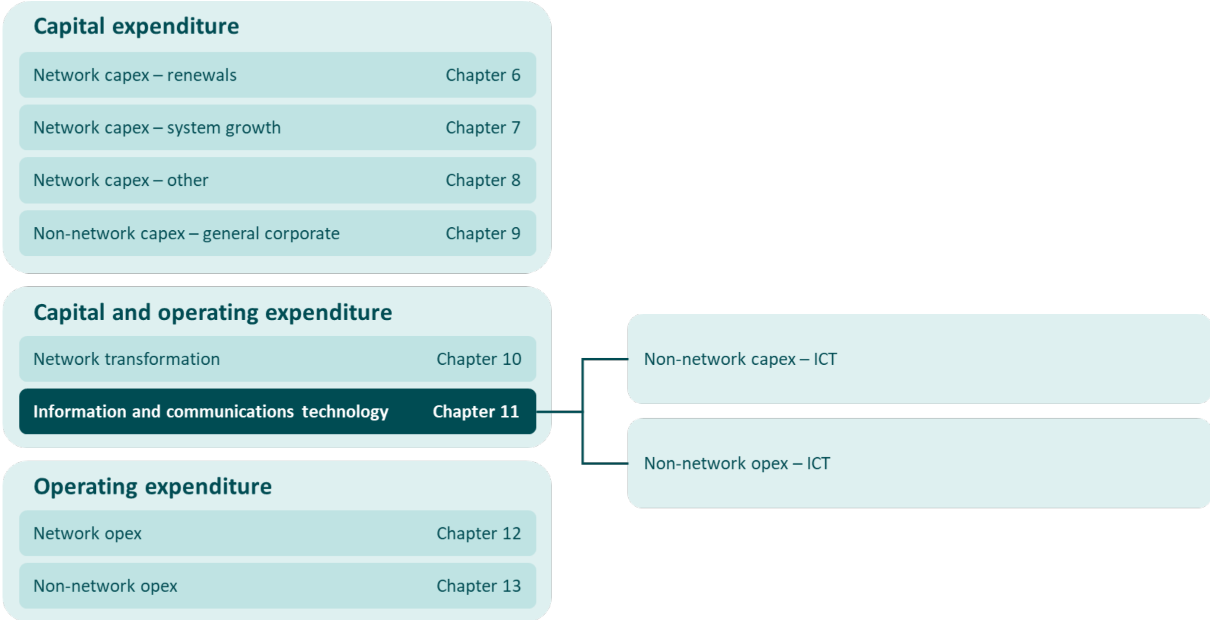
858 Our ICT portfolio includes both capex and opex to deliver, operate, secure, and maintain this technology environment. It covers expenditure related to computing and IP network infrastructure, operating environments, applications, data and integration platforms, and associated services, regardless of hosting arrangements.

859 As outlined in Chapter 2, we will complete the transition to a modern, resilient, and fit-for-purpose ICT environment over the CPP period, supported by a sustained increase in expenditure. This will enable full access to and effective use of network data, and the deployment of innovative tools and solutions that are increasingly central to managing network demands and delivering efficient outcomes for customers. Without this investment, we would be unable to realise these capabilities or meet evolving regulatory and customer expectations.

860 Figure 11.1 shows how the ICT portfolio fits within our overall expenditure profile, while Box 11.1 defines its scope. The rest of this chapter outlines:

- our planned ICT expenditure over the CPP period
- its key drivers
- our forecasting approach
- our planned ICT capex and opex in more detail
- why the planned expenditure is prudent and efficient.

Figure 11.1 Information and communication technology portfolio

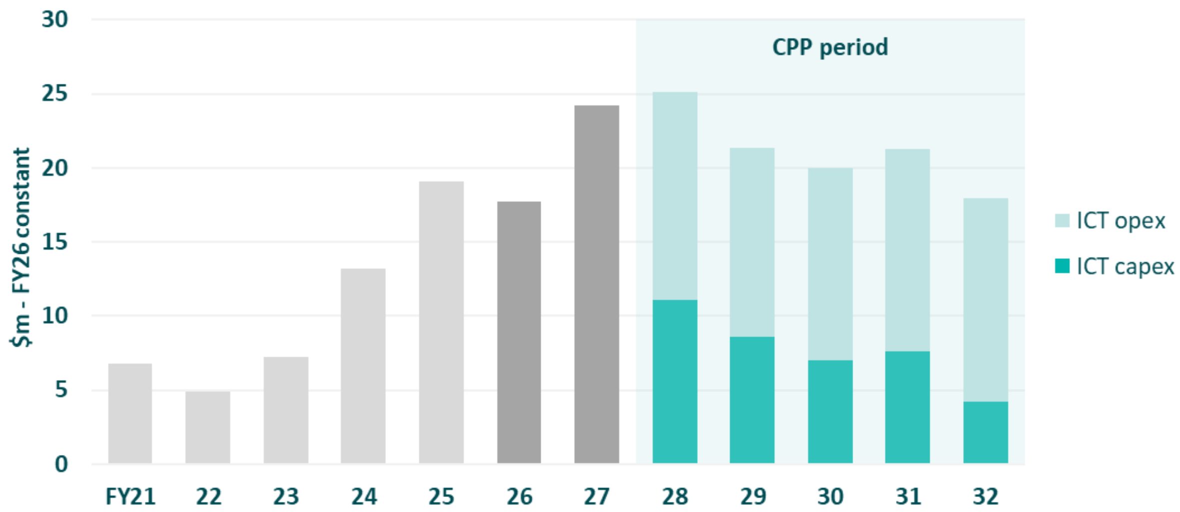


11.1 Planned ICT expenditure

861 Our planned ICT expenditure over the CPP period is $105.7 million, or an annual average of $21.1 million. This represents approximately 7% of planned totex for this period.

862 Figure 11.2 shows the planned ICT expenditure per annum, split into capex and opex, compared with our historic spend.

Figure 11.2 Orion's planned ICT expenditure per annum



863 As outlined in Chapter 2, we deferred system upgrades and opportunities for business improvement through process automation in the years following the Canterbury earthquakes and during the COVID-19 pandemic. Over this period, our ICT strategy prioritised minimising business disruption while we focused on recovery from the earthquakes and on enabling remote work and workforce mobility.

864 While prudent in the circumstances, this approach meant that by FY23 multiple key platforms were late in their lifecycle, and were either not fit-for-purpose, not in a reasonable state of repair, or no longer supported by the vendor.[56] Third-party reviews of key systems confirmed

[56] For example, this included our billing system, works management system, GIS system and finance platform.

that, without significant renewal or replacement, many systems posed increasing risks of failure or performance constraints, and would not support future business requirements or evolving customer and regulatory expectations.[57] In addition, we lacked many of the digital capabilities increasingly required for good practice network management and meeting evolving customer expectations.

865 By FY24, further deferral was no longer prudent. We began a catch-up and capability-building phase, reflected in the increase in our ICT expenditure from FY24 to FY26. Our ICT expenditure is expected to continue to grow in FY27 and FY28 before reducing slightly each year until FY31, by which time most catch-up and capability-building activities will be complete.

866 While nearing the peak of the investment cycle, many of the benefits, particularly those arising from improved asset intelligence, forecasting capability, and integrated data platforms, will be realised over a longer horizon (10+ years). The expenditure planned lays the foundation for that longer term value.

Box 11.1 Scope of ICT portfolio

The ICT investment portfolio includes expenditure on:

- software licensing
- devices and ICT hardware and infrastructure
- external digital platform, application and service costs
- costs associated with data acquisition and/or data management
- cyber security
- artificial intelligence
- external labour (i.e. ICT consultant costs)
- capitalised labour costs (i.e. some staff time spent on ICT projects is capitalised to the extent that it contributes to the creation of an ICT asset, such as software or installed hardware).

For the purposes of our CPP plan, it excludes:

- network transformation expenditure (which is included in the network transformation portfolio, discussed in Chapter 10)
- expensed labour costs (which are included in the SONS and Corporate support opex portfolios, discussed in Chapter 13)
- expenditure on protection and control systems managed directly by SCADA (which are included in network capex and opex portfolios).

11.2 Key drivers

867 The key drivers of our planned ICT spend over the CPP period include:

- **Business change requiring core system renewal**: completing the modernisation of our core ICT systems to support new business capabilities, embed updated business processes, and handle increasing operational complexity. Investment will ensure our platforms remain reliable, resilient, and able to meet the organisation’s evolving needs through modern, integrated solutions.
- **Ongoing lifecycle requirements to maintain ICT continuity**: regular lifecycle upgrades, incremental enhancements, licence renewals, cloud subscriptions, and vendor support arrangements are required to maintain reliable ICT operations. These ongoing investments prevent technology obsolescence, reduce failure risks, and avoid higher reactive costs.
- **Increasing cyber threats and risk exposure**: expanding ICT environments and greater connectivity increase our exposure to cyber threats. Investment is required to enhance

[57] These included an OT cyber security review by PSC Consulting, a cyber security review by Deloitte, an integrated asset management review by PwC, a data and digital strategy assessment by KPMG, and a system interconnectivity review by Deloitte.

monitoring, defence and response capabilities, protect critical operational systems and sensitive data, and meet critical infrastructure security expectations.

- **Expectations for digital engagement**: our service delivery partners (SDPs), suppliers, and customers increasingly expect seamless, convenient digital interactions. Enhancing our digital channels and tools will improve communication, responsiveness, and service delivery for key activities – for example, providing work orders and asset data to SDPs, and information on outages and new connections to customers.
- **Increasing operational complexity and data volumes**: growth in distributed energy resources and more complex operational needs require improved data capability. Investment in modern data platforms, integration services, analytics (including AI), and governance will support improved network operations and data-driven decision-making. Critically, advanced modelling and forecasting capabilities, enabled by ICT investment, will deepen our understanding of our assets and network behaviour. This has a significant risk management benefit, increasing confidence that we can deliver on commitments and plan renewals and investments with accuracy and foresight.
- **Meeting regulatory and compliance obligations:** evolving regulatory requirements around reporting, data provision, and operation of the electricity market require investment in systems that can reliably meet these obligations and automate data exchange with external parties.
- **Need to control costs and improve process efficiency**: ICT-enabled process improvements enable effective cost management without compromising service quality. Investment in system integration and automation will reduce manual effort, minimise errors, accelerate workflows, and support more efficient service delivery (see Box 11.2 for an example).

Box 11.2 Unlocking operational efficiencies through ICT-enabled tools

The transition to a modern ICT environment enables us to deploy innovative tools that improve operational efficiency and service outcomes. For example, as part of our ICT investment programme, we are trialling the use of drones equipped with high-resolution cameras, combined with AI-powered computer vision, to automate inspection of our overhead network.

Traditionally, these inspections are undertaken by field crews, requiring significant time, manual effort, and exposure to safety risks. Under the new approach, drone imagery is automatically analysed using machine-learning models trained to detect fault conditions such as vegetation encroachment, equipment damage, and other asset defects. These defects will then be flagged, classified, and fed directly into our asset management system for follow-up, eliminating the need for manual review of thousands of images.

This approach improves efficiency, by reducing inspection time, labour requirements, and associated costs. It also improves safety outcomes by reducing the need for field-based inspections. Inspections can be completed faster, more safely, and at lower cost. In addition, by enabling earlier detection of emerging faults, it reduces the likelihood of unplanned outages and supports reliable supply for customers. These benefits could not be realised without the modern data platform, system integration, and analytics capabilities delivered through our ICT investment programme.

11.3 Forecasting approach

868 We forecast the individual components of our ICT expenditure separately, using a comprehensive bottom-up approach that combined multiple data sources and methods to ensure accuracy and reliability:

- Historical spend patterns and current contractual expenditure commitments were used to form a baseline for many of our forecasts. By analysing past expenditure trends and accounting for existing contractual obligations, we established a solid foundation that reflects both our operational requirements and committed financial obligations.
- Estimates from external vendors, consultants, and internal subject matter experts also informed forecasts. This specialised knowledge enhanced the accuracy of our forecasts. Vendor quotes provided market-tested pricing for specific solutions and services, while

our consultants and internal experts contributed deep understanding of organisational requirements, technical constraints, and implementation complexities.

869 This multifaceted approach to developing bottom-up forecasts ensures our estimates reflect market realities as well as our organisational context.

870 We prepared 16 Project Investment Papers (PIPs) to consider and cost all major ICT projects and programmes – those with a total forecast value of more than $500,000 of capex or more than $750,000 of opex over the CPP period. Together, these PIPs cover around 85% of total planned ICT expenditure over this period.

871 Each PIP:

- defines the main need or objective for a specific ICT investment
- assesses the costs and benefits of alternative options to meet the objective (including scaling down or doing nothing)
- compares the costs and benefits on a Net Present Value (NPV) basis to identify the most prudent and efficient solution to meet the identified need.

872 All the projects and programmes covered by a PIP were reviewed by the independent verifier, who confirmed the need case for each.

873 Table 11.1 provides an overview of these projects and forecast expenditure. To illustrate the value of these projects, Box 11.3 outlines the need for and benefits of the planned investment in integrated asset management (IAM).

Table 11.1 Major ICT projects and programmes expenditure during the CPP period ($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 future network needs, including renewable energy integration	2.1	6.8
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	4.1	4.1
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	2.9	5.2
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	2.1	4.4
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	2.5	3.6
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	4.5	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	6.1	2.8

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	-	5.7
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	3.0	3.9
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	-	3.8
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	5.2
Integration platform	Expenditure to improve operations and customer service through better system integration. Our current environment still includes a mix of modern service-oriented integrations and legacy point-to-point connections that are increasingly difficult to maintain and pose security risks.	0.5	2.8
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	2.5
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	-	1.8
Total major projects/programmes		**31.4**	**58.4**
% of total ICT capex		**82%**	**87%**

Box 11.3 The need for and benefits of the integrated asset management programme

Our legacy asset management environment has constrained our ability to efficiently assess asset condition and make informed investment decisions. Fragmented systems, manual processes, and limited visibility of asset performance have resulted in a reactive maintenance approach, higher operating costs, and increased risk of unplanned outages.

While the replacement of core systems has occurred with the implementation of a modern platform, it has not in itself delivered all the capabilities required to maintain the network efficiently and proactively. Without further investment, asset condition data would remain incomplete and inconsistent, limiting our ability to forecast asset performance, optimise maintenance, or target investment where it delivers the greatest value.

The IAM programme builds these capabilities, enabling a step change in how the network is managed, and delivering a range of interrelated benefits:

- improved efficiency and cost optimisation through reduced manual processes, better coordination of field activities, and optimisation of maintenance and replacement timing
- maintained reliability and improved resilience by enabling predictive maintenance and earlier identification of emerging asset issues, reducing the frequency and duration of unplanned outages
- enhanced safety and risk management through integration of asset, condition, and safety data, supporting a more systematic and risk-based approach
- more informed investment decisions through improved asset visibility, condition assessment, and scenario modelling across the network
- optimised asset lifecycle management by enabling targeted interventions that extend asset life where appropriate and avoid premature replacement.

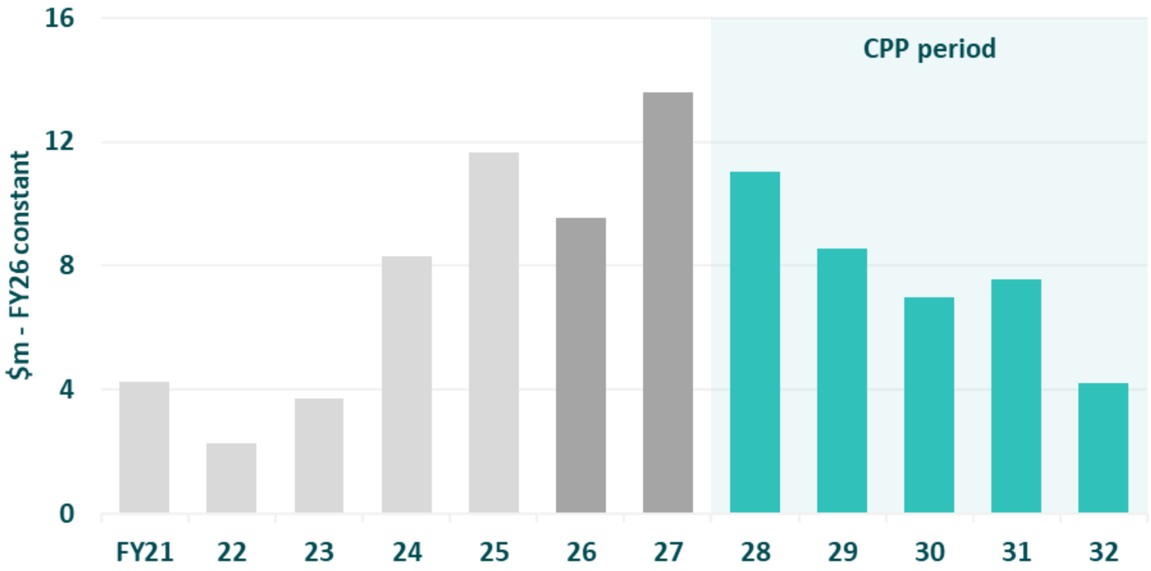
Collectively, these benefits support a transition from reactive to proactive asset management, reducing the cost to operate and maintain the network while improving service outcomes for customers and strengthening our ability to meet our regulatory obligations.

11.4 Planned ICT capex

874 Our planned ICT capex for the CPP period is $38.4 million, or an average of $7.7 million per annum. This represents approximately 4.1% of our planned capex for this period.

875 Figure 11.3 shows the planned capex per annum compared with historical spend.

Figure 11.3 Planned ICT capex per annum



876 ICT capex has increased since FY23, largely reflecting investments to catch up on deferred system upgrades, obtain a more detailed view of and enable richer interactions with customers, and capture opportunities for business improvement through process automation.

877 ICT capex will peak in FY27, before declining through the CPP period to FY31. After this, ICT capex is forecast to follow a cyclical pattern, with peaks every 2 years driven by asset refresh and re-licensing cycles.

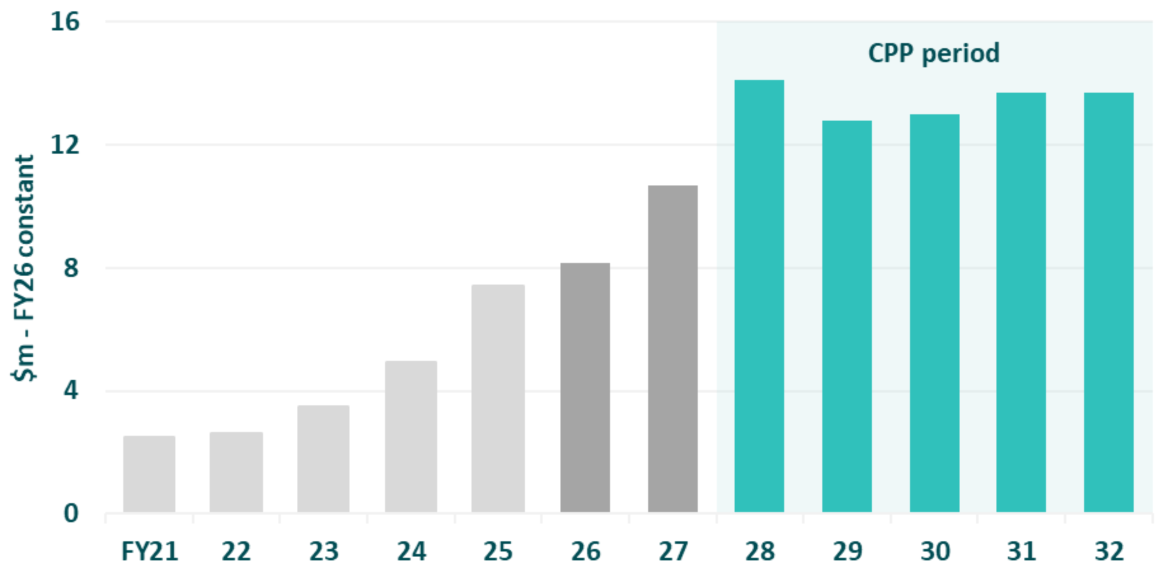
878 As noted above, most of the planned ICT capex over the CPP period is for major projects or programmes, which were considered and costed by developing a PIP. Table 11.1 provides an overview of these investments.

11.5 Planned ICT opex

879 Our planned ICT opex over the CPP period is $67.3 million or an average of $13.5 million per annum. This represents approximately 12% of our planned opex for this period.

880 Figure 11.4 shows the planned opex per annum compared with historical spend.

Figure 11.4 Planned ICT opex per annum



881 Annual ICT opex has more than doubled from FY23 to FY26. Consistent with the capex trend, this reflects investments to address deferred system upgrades, enable improved customer interactions, and capture business improvement opportunities through process automation.

882 This increase is also driven by sector-wide trends, including the shift to software-as-a-service (SaaS) applications, subscription-based software licensing, cloud infrastructure, and increasing cybersecurity requirements. Changes in the accounting treatment of ICT costs – particularly under SaaS models – mean that many costs previously capitalised are now recognised as operating expenditure.

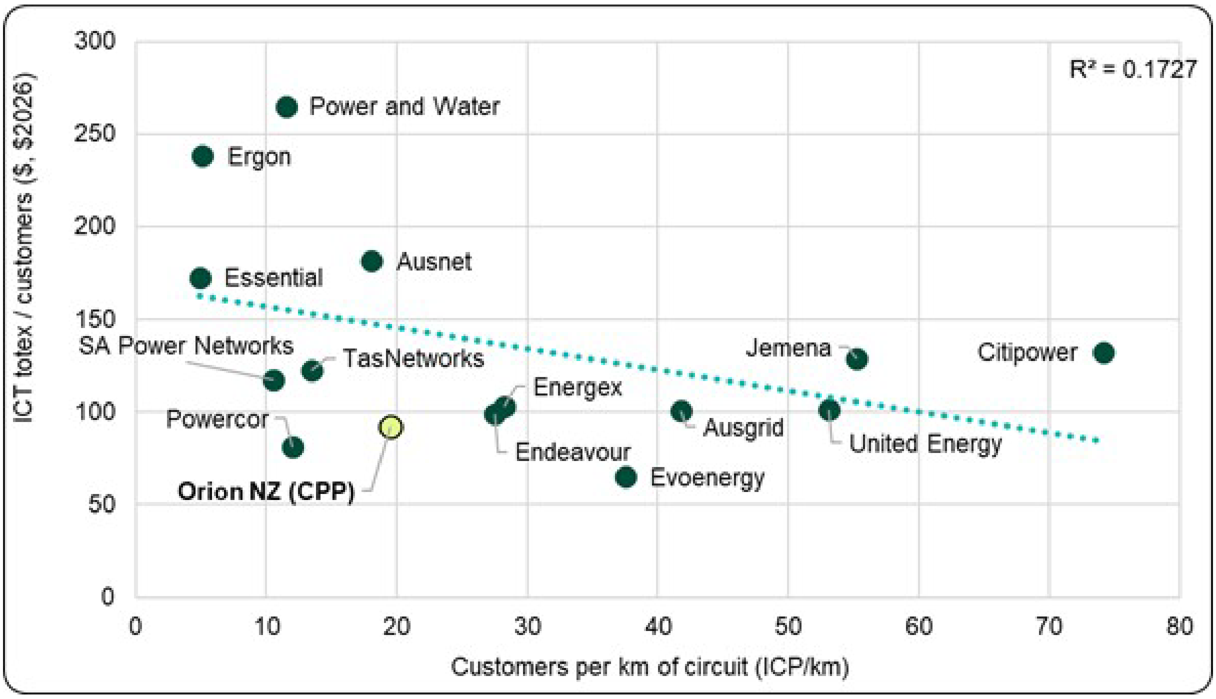
883 Over the CPP period, ICT opex is forecast to peak in FY28, and remain higher than in past years. As noted above, most of the planned opex is for major ICT projects or programmes considered and costed through PIPs (see Table 11.1).

11.6 ICT expenditure justification

884 We consider the planned ICT expenditure to be prudent and efficient, for the following reasons:

- **Bottom-up methodology**: the expenditure was forecast using a comprehensive bottom-up approach, drawing on multiple data sources and analytical methods. PIPs were developed for 16 major projects and programmes, representing around 85% of total planned ICT expenditure, providing a high degree of cost transparency and robustness.
- **Benchmarking**: we engaged farrierswier to benchmark our ICT forecasts against expenditure reported by Australian EDBs (in the absence of comparable standalone ICT reporting on New Zealand). This indicates our planned ICT totex is lower than most Australian peers on a per-customer basis (Figure 11.5) and per-device basis. This supports the reasonableness of our forecast.
- **Governance framework**: our ICT portfolio is managed under a multi-layered governance framework that supports disciplined decision-making and delivery. This includes:
  - strategy and investment governance to provide strategic direction for ICT aligned with organisational objectives and ensure decisions are supported by robust business cases
  - procurement and delivery governance to support effective, timely, and cost-controlled delivery and vendor management
  - technology, data, and security governance to set standards and provide oversight of architecture, cybersecurity, and data management
  - stakeholder engagement to ensure relevant internal and external input into ICT decisions and standards.
- **Customer perspective**: Customers and stakeholders consistently told us they want a safe and reliable network that is future-fit and efficient, supported by effective customer service. Customers supported increased investment in digital systems to deliver this.
- **Challenge rounds**: forecasts for all projects and programmes were subject to multiple rounds of review and challenge by the integrated leadership team and Board.
- **Independent verification**: although the ICT expenditure forecasts have altered since verification, the verifier reviewed all 16 ICT PIPs and accepted the systems they related to needed “to be replaced or updated to maintain network safety, reliability and resilience, and for meeting regulatory and community expectations”.
- **Expected benefits**: the planned expenditure will deliver value to customers and the community, including through improved outcomes and avoided costs (see Box 11.4).

Figure 11.5 Orion's planned ICT totex per customer v customer density benchmarked against Australian EDBs (NZD)



Source: farrierswier analysis

Box 11.4 Expected benefits of planned ICT expenditure

Our planned ICT expenditure is a critical enabler of our strategic priorities for the CPP period and beyond – providing the foundation for reliable, resilient, and customer-focused network operations. It will address our immediate ICT renewal needs while providing the capabilities required in the future, supporting our transition to a more digital, resilient, and adaptive electricity distribution business. While some benefits will be realised during the CPP period, many will accrue over a longer timeframe, reflecting the enduring nature of the ICT foundations being established.

Specific benefits expected to be realised include:

- **Risk reduction and support cost savings:** replacing legacy systems will reduce ICT maintenance requirements and the risk of major failures, supporting reliable service and lowering emergency repair costs.
- **Labour efficiency and productivity gains:** integration, automation, and improved digital tools will improve workforce productivity, allowing staff to focus on higher value activities and helping to contain operating costs.
- **Improved decision-making:** enhanced data availability and analytics will enable faster, more informed decisions across network planning, operations, and customer service.
- **Stronger risk management and network foresight**: advanced modelling and forecasting capabilities will deepen our understanding of asset condition and network behaviour, supporting a more proactive and evidence-based renewals programme and increasing confidence in our ability to deliver on long-term commitments.
- **Enhanced security and risk mitigation**: investments in cybersecurity will reduce the risk of data breaches and service disruptions, protecting customer data and operational integrity.
- **Scalability and flexibility for the future**: cloud-enabled and integrated platforms will provide the flexibility to respond to changing conditions, such EV uptake, new regulatory requirements, or evolving customer expectations, without requiring massive new investments.

12

12 Network opex

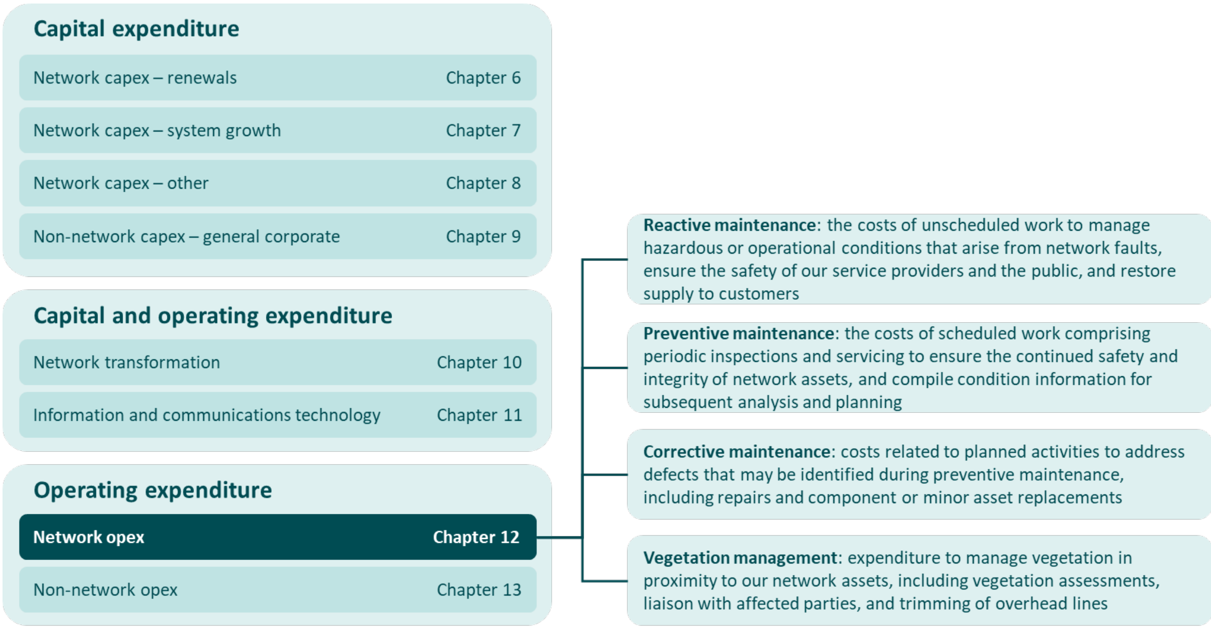
885 Network opex covers activities related to our asset maintenance and vegetation management programmes. These activities are critical for maintaining network safety and reliability and are a key component of effective asset lifecycle management. Vegetation management expenditure also supports compliance with legislative requirements and enhances network resilience by reducing the risk of unplanned outages during adverse weather events.

886 As outlined in Chapter 2, as network assets age, the incidence of defects and condition-related issues increases. Our maintenance programmes are designed to identify and address these issues before they result in safety incidents or unplanned outages, and to respond when outages occur. Similarly, our vegetation management programme aims to prevent the encroachment of vegetation on our assets, which poses a risk to safety and reliability.

887 Together, these activities support our strategic priorities for the CPP period by maintaining network safety and reliability, and strengthening resilience.

888 Figure 12.1 shows where network opex sits within our overall expenditure and the portfolios it includes.

Figure 12.1 Network opex and portfolios



889 The rest of this chapter outlines:

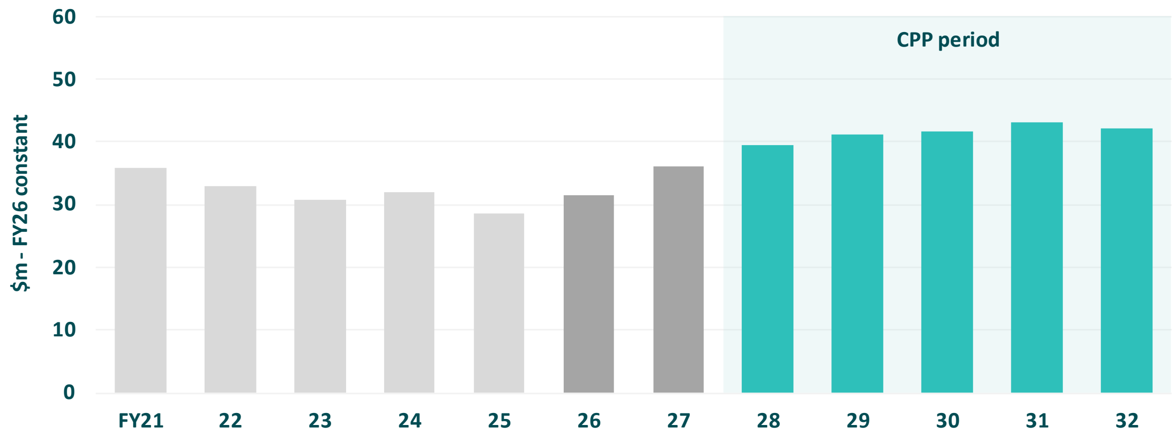
- our planned network opex over the CPP period
- its key drivers
- our forecasting approach
- the planned opex in each portfolio
- why the planned opex is prudent and efficient.

12.1 Planned network opex

890 Orion's total network opex over the CPP period is $207.7 million. This represents approximately 36% of total opex and 14% of totex over this period.

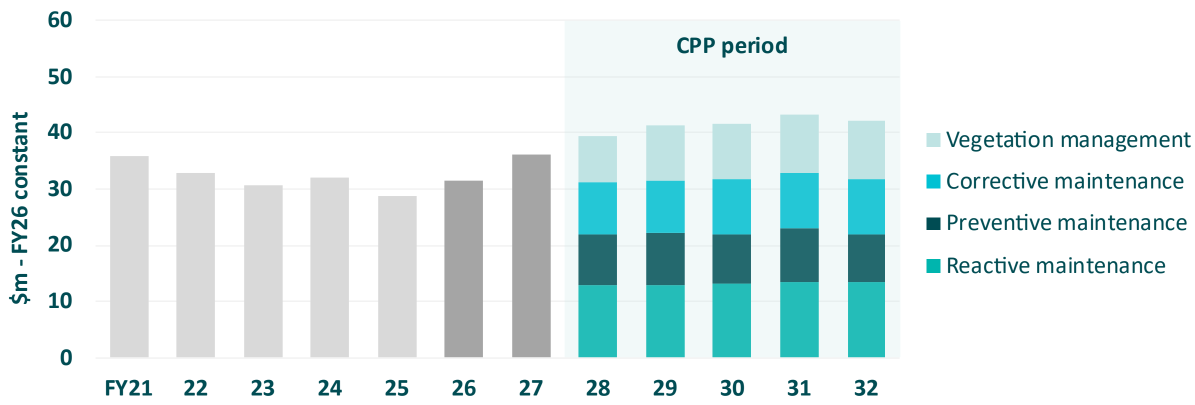
891 Figure 12.2 shows the planned network opex per annum compared with our historical spend.

Figure 12.2 Planned network opex per annum



892 Planned network opex is higher than in the current (FY21–25) and assessment (FY26–27) periods. As Figure 12.3 shows, this reflects modest increases in preventive and corrective maintenance, and vegetation management.

Figure 12.3 Planned network opex per annum, by portfolio



893 In all portfolios, the planned opex largely reflects the costs of external labour provided by our service delivery partners (SDPs). It excludes the costs of Orion employees associated with managing SDP work. These costs are included in our system operations and network support portfolio (see Chapter 13).

12.2 Key drivers

894 The key drivers of the planned network opex are:

- **Increased asset failure risk due to past deferrals and backlog**: to remain within DPP3 and DPP4 expenditure limits, Orion deferred non-critical preventive and corrective maintenance programmes and tasks for some asset classes. We plan to resume these programmes and clear the resulting backlog during the CPP period.
- **Improving our asset data**: addressing limitations in our asset and condition data will improve our ability to proactively plan our renewal works and make better operational decisions. To realise the benefits of our investments in an integrated asset management

system we will collect more comprehensive asset data. Richer asset and condition information will improve our understanding of network risk and support more robust modelling and more cost-effective asset renewal and replacement decisions.

- **Backlog of inspections and aligning our maintenance procedures to best practice**: some overhead inspections have become overdue, for example poles yet to be inspected to our new standard. Some inspection cycles, such as for buildings and grounds assets, are considered to be too long. This can allow defects to worsen before detection (e.g. leaks getting worse) increasing the scale of remediation required. We plan to introduce new or expanded inspection regimes for specific asset categories. In addition, we will update several maintenance procedures to better align with latest industry practice.
- **Increased asset populations**: as outlined in Chapter 6, ownership of a significant number of telecoms poles supporting our overhead network will transfer to us over the CPP period. This will increase the asset base we are responsible for inspecting and maintaining.
- **New vegetation management requirements**: anticipated changes to the *Electricity (Hazards from Trees) Regulations 2003* are expected to require a more proactive, risk-based approach to vegetation management. To meet these requirements, we will expand our vegetation management activities and programmes.

12.3 Forecasting approach

895 We used a base-step-trend approach to develop our network opex forecasts. This approach is appropriate for forecasting recurring expenditure like network opex, and is used by many utilities and economic regulators.

896 For each portfolio, we took the following 3 steps:

- **Established base opex**: we used actual FY25 opex as the base for each portfolio, after testing its efficiency, and escalating the FY25 expenditure to FY26 dollars. To test this, we engaged farrierswier to benchmark our historical spend against our New Zealand peers (see section 12.8).
- **Adjusted for step changes**: we identified required step changes for activities not captured in the base or trend components. We forecast the cost of each step change individually. These step changes were then added to the base opex. More information on this step is provided in the relevant sections below.
- **Applied trend changes**: we applied an output growth factor of 1.42% to the base opex. This is consistent with the total network scale growth used by the Commerce Commission for DPP4. The underlying assumption is that as the network expands, the volume of maintenance and vegetation management work will grow in proportion.

897 Forecasts for the preventive and corrective maintenance[58] and the vegetation management portfolios were reviewed by the independent verifier. It accepted all the assessed expenditure, except for a portion of corrective maintenance expenditure to resume our full overhead defects programme. The verifier's findings are discussed further in section 12.8.

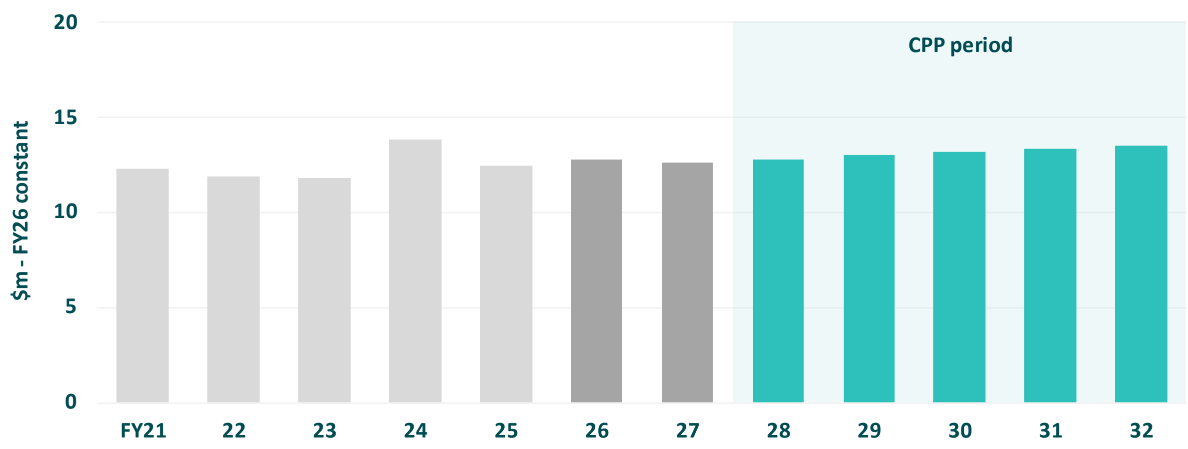
[58] Reactive maintenance was not deemed an identified programme by the independent verifier, and thus was not reviewed.

12.4 Reactive maintenance portfolio

898 The reactive maintenance portfolio covers opex associated with emergency work and fault response arising from unplanned events or incidents that disrupt normal network operations. These activities address hazardous network conditions, manage safety risks, and restore supply to customers quickly and safely.

899 Our planned reactive maintenance opex over the CPP period is approximately $65.8 million. This is broadly in line with historical expenditure, as shown in Figure 12.4.

Figure 12.4 Planned reactive maintenance opex per annum



900 We do not forecast a significant change in this expenditure. This is because our reactive maintenance work volume is primarily driven by the number of faults on the network, and this was relatively flat from FY21 to FY25, except for short-term variations due to weather or other factors. We expect the number to remain stable over the CPP period as asset condition is managed through our renewal programs.

901 The slight increase in planned reactive maintenance expenditure that can be seen in the figure above reflects the 1.42% (DPP4) trend we applied to our base opex. The underlying assumption is that as the network expands, the volume of reactive maintenance work will grow in proportion.

12.5 Preventive maintenance portfolio

902 This portfolio covers opex for preventive maintenance programmes and tasks across our network asset fleets – including inspections, condition assessments and data collection, servicing, and testing.

903 These scheduled programmes are carried out by our SDPs at regular intervals in accordance with our maintenance standards. They help ensure the ongoing safety and integrity of our assets, and provide the essential information on asset condition and other data underpinning our asset management system and wider work programmes.

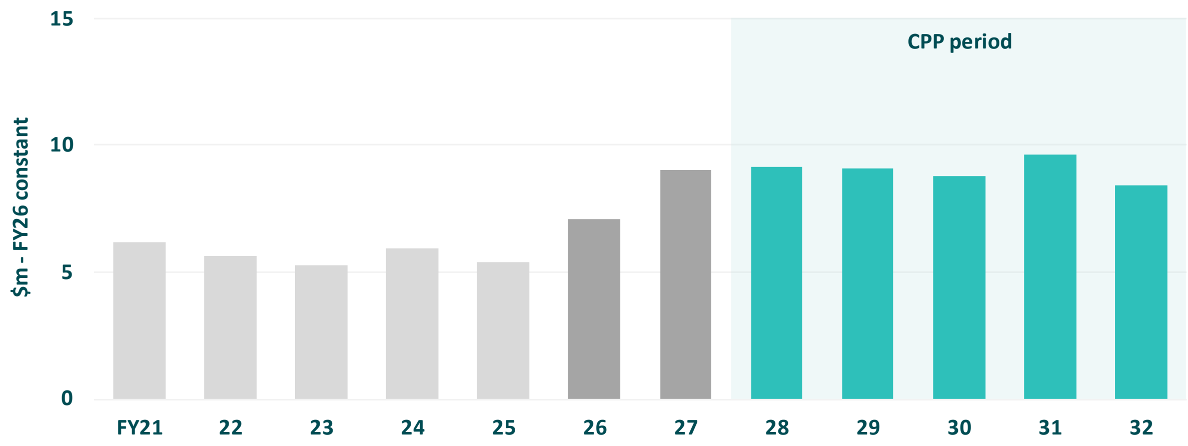
904 As preventive maintenance activities often identify defects or emerging issues, an increase in these activities will lead to higher levels of corrective maintenance and renewal volumes in the short to medium term.

905 The sections below outline our planned preventive maintenance opex and the step changes we included in forecasting this opex.

12.5.1 Planned preventive maintenance opex

906 Our planned preventive maintenance opex over the CPP period is $45 million, or an average of $9 million per annum. This is higher than historical annual expenditure, as shown in Figure 12.5.

Figure 12.5 Planned preventive maintenance opex per annum



907 We have used the BST approach to forecast preventive maintenance opex. The base year is based on actual FY25 expenditure, as it was the latest available audited outturns and there were no identifiable atypical expenditure items. High-level benchmarking indicates that our base maintenance opex is consistent with peer EDBs (see section 12.8).

908 Step changes were added to reflect the need to improve and expand our maintenance procedures, address inspection backlogs, leverage IAM capabilities and collect more comprehensive data. Step changes over the CPP period total approximately $16.4 million.

909 The DPP4 trend component was applied to our base opex. The underlying assumption is that as the network expands, the volume of preventive maintenance work will grow in proportion.

12.5.2 Step changes in preventive maintenance

910 In addition to the recurring work reflected in our base amount, we have identified the need for uplifts in our preventive maintenance activity. We have included these needs in our forecast as step changes, that reflect the following types of drivers:

- improving and expanding our maintenance procedures to further align ourselves with Good Electricity Industry Practice (GEIP)
- ensuring we fully address inspections backlogs
- leveraging IAM capabilities and collecting more comprehensive asset data
- expanding inspections regimes.

911 Table 12.1 summarises the key step changes in each asset class.

Table 12.1 Summary of key step changes in preventive maintenance opex over CPP period ($m, FY26 constant)		
Asset class	**Description**	**Opex**
Overhead structures		**2.8**
Pole inspections catchup	Address the current backlog of pole inspections and ensure all inspection data reflects our recently improved standards	
Telecommunications pole inspection	Ensure all telecoms poles transferred to Orion are inspected against our inspection standard, enabling early identification and remediation of defects and poor condition poles	
Earth potential rise (EPR) testing	Identify EPR safety risk by introducing current injection and step and touch potential testing for steel towers located on public land or near residential properties and schools.	
Overhead conductors		**5.9**
Conductor destructive testing	Confirm conductor expected life settings using targeted destructive testing, strengthening confidence in long-term investment planning and renewal timing	
Overhead survey and data improvement	Undertaking a verification survey to collect better conductor data (type / material / size) to scope and prioritise our conductor replacement programmes.	
Zone substations		**2.1**
New Building Standard (NBS) assessments	Monitor seismic risk and address compliance requirements by undertaking cyclical New Building Standard (NBS) assessments of zone substation buildings	
Power transformer bund leak inspections	Monitor environmental and asset risk by implementing routine inspections of bunded areas for power transformers, ensuring oil containment systems remain effective and compliant	
Distribution switchgear		**2.6**
Distribution kiosks fire risk assessments	Identify non-compliance with AS2067 fire separation requirements by undertaking external fire risk assessments of distribution kiosks and substations, enabling risk-based remediations and targeted fire mitigation renewals	
Soil contamination testing	Assess environmental and health risk associated hazardous substances by introducing a recurring soil contamination testing programme and contamination register for distribution substations, enabling improved work planning, and avoidance of unexpected costs and delays	
NBS assessments	Monitor seismic risk and address compliance risk by undertaking cyclical NBS assessments of distribution buildings	
Distribution transformers		**0.5**
Large ground mounted transformer inspections and testing	Monitor risk of undetected internal transformer faults by introducing dissolved gas analysis for large ground-mounted transformers, enabling early fault detection and reducing the likelihood of costly failures	
Secondary systems		**2.4**
Signalling and comms cable condition assessments	Confirm the condition and configuration of copper pilot cables by undertaking targeted condition assessments, improving data quality to prioritise renewal decisions	
SCADA / RTUs – backlog of testing points and alarms	Increasing the number of intelligent electronic device (IED) points tested to monitor relay/IED health. Currently these are only tested at commissioning.	
Total		**16.4**

912 These step change amounts are forecast based on unit rates using a volumetric approach, multiplying quantities, or increasing levels of work (Q) by the unit rate (P).

913 These step changes will help ensure we address inspection backlogs and maintain compliance with relevant standards. We will collect more comprehensive asset data to fully leverage our investments in our integrated asset management system. They will also enable us to further align our preventive maintenance practices with good electricity industry practice.

914 Box 12.1 provides further detail on selected preventive maintenance initiatives to illustrate why a step change in maintenance expenditure is required, and how increased preventive maintenance activity informs other maintenance activities and programmes.

Box 12.1 Why step changes in maintenance expenditure are needed: preventive maintenance examples

Asbestos survey, testing and remediation

We have many distribution buildings with suspected asbestos-containing materials. When SDPs respond to faults and emergencies in these buildings, they may need to take extra precautions to avoid potential exposure. This not only increases safety risk but may also increase outage duration, as more time is needed to undertake the work.

To mitigate this, we will undertake a survey and invasive testing as part of our preventive maintenance programme. If asbestos is confirmed, we will undertake a risk assessment in accordance with WorkSafe guidelines to determine the best remediation for each building. This may include encapsulation, removal, sealing, and/or enclosing. These remediations will form part of our corrective maintenance programme (see Box 12.2 below).

Earth Potential Rise (EPR) testing and assessments

Our steel towers were constructed between the 1950s and 1970s in areas that were predominantly rural at the time. As Christchurch has expanded, surrounding land has since been developed for residential, commercial, and industrial use. Many of these towers are now located within or adjacent to parks, housing, and commercial / industrial buildings, making them accessible to the public. This has elevated the risk of exposure to EPR during a fault event. A safety incident would require a person to be in close proximity to, or in contact with, a tower at the time of a fault. While the likelihood of such an event is low, the consequences could be severe, including serious injury or death. To manage this risk, we plan to undertake current injection testing and EPR assessments on towers located in publicly accessible areas. These assessments will identify the extent of EPR risk, and any required remediations will be delivered through the RSE programme (see Chapter 8).

Conductor destructive testing

We have used destructive testing on our Bromley-Heathcote conductors, confirming loss of zinc coating and reduced tensile strength see Box 6.4 in Chapter 6 for more details). These are strong indicators that renewal is needed. We plan to roll out similar destructive testing across our wider conductor fleet to better understand degradation rates and to confirm expected lives. We will sample across different conductor types, sizes and multiple locations with varying ages near the expected life. This will help us confirm the degradation rates and asset life assumptions, supporting more effective planning of renewal works.

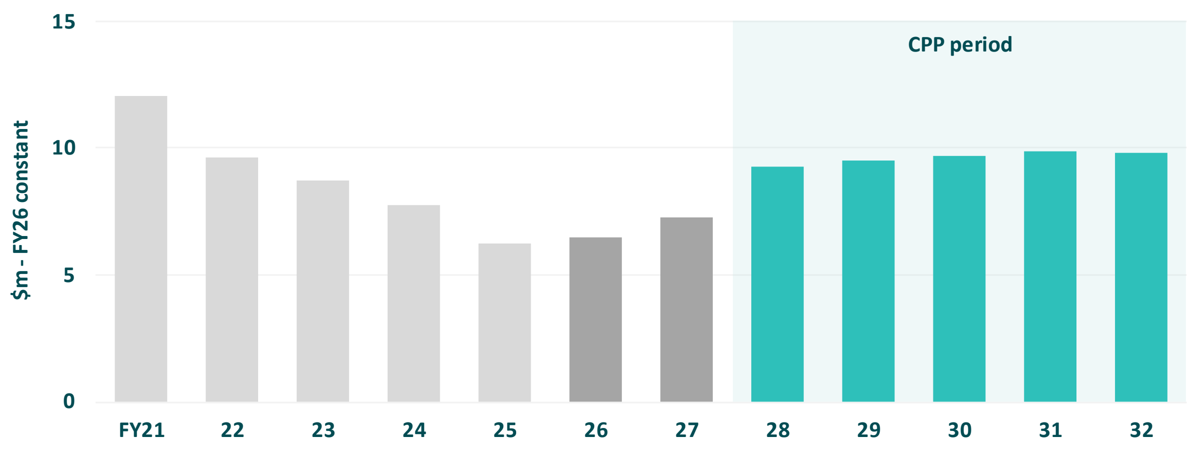
12.6 Corrective maintenance portfolio

915 Corrective maintenance opex covers planned activities to rectify defects identified through preventive maintenance. Most of this work involves small remedial tasks – such as repairing or replacing minor components to restore assets to appropriate condition. Where tasks are not urgent, they are scheduled in advance to ensure they are delivered cost-effectively.

12.6.1 Planned corrective maintenance opex

916 Our planned corrective maintenance opex is $48.2 million, or an average of around $9.6 million per annum. This is broadly in line with our actual expenditure over the FY21–25 period, as shown in Figure 12.6 shows the planned opex per annum compared with historical spend.

Figure 12.6 Planned corrective maintenance opex per annum



917 Historical corrective maintenance opex has trended down, mainly due to deferral of non-critical remediation programmes to manage within DPP opex allowances. Our forecast for the CPP period, reflects the resumption of previously deferred programmes and expected higher levels of defects as a result of new or expanded preventive maintenance activities.

918 Corrective maintenance is forecast using a base step trend approach. The base year is based on actual FY25 expenditure, as this was the latest available audited outturns. High-level benchmarking indicates that our base maintenance opex is consistent with peer EDBs (see section 12.8). Step changes have been added to reflect identified needs including addressing anticipated new defects due to improved and expanded inspection regimes, under preventive maintenance.

919 The DPP4 trend component was applied to our base opex (FY25). The underlying assumption is that as the network expands, the volume of corrective maintenance work will grow in proportion.

12.6.2 Step changes in corrective maintenance opex

920 In addition to the recurring work reflected in our base amount, we have identified the need for uplifts in our corrective maintenance expenditure. Consistent with the 'base-step-trend' methodology, we have included these needs in our forecast as step changes. The total step change in corrective maintenance opex is approximately $15 million.

921 Table 12.2 summarises the changes by asset class.

Table 12.2 Summary of step changes in corrective maintenance opex over CPP period ($m, FY26 constant)		
Asset class	**Description**	**Opex**
Overhead structures		**11.9**
Overhead structures defects programme	Ensure proactive defect management to maintain pole integrity and reduce failure risk. This programme includes addressing cracked insulators, missing or damaged signs or possum guards, and loose or damaged stay wires	
Expected new defects	Address the expected increase in identified defects resulting from expanded condition assessments and the transfer of telecoms poles	
Overhead conductors		**0.9**
Expected new defects	Address the anticipated increase in identified defects resulting from expanded condition assessments of overhead conductors	
Cables		**0.3**
Cable seals	Address water ingress and associated asset deterioration in distribution buildings by implementing a new programme to seal and remediate cable entry points	
Zone substations		**1.6**
Asbestos remediation	Address health, safety and compliance risks associated with asbestos exposure in zone substation buildings by implementing a remediation programme of removal, sealing, enclosing or encapsulation	
Expected new defects	Address the anticipated increase in identified defects arising from more frequent buildings and grounds inspections and the introduction of bund leak inspections	
Distribution switchgear		**0.4**
Asbestos remediation	Address health, safety and compliance risks associated with asbestos exposure in distribution buildings by implementing a targeted encapsulation programme	
Expected new defects	Address the anticipated increase in identified defects resulting from more frequent buildings and grounds inspections	
Total		**15**

922 These step changes will help ensure we proactively address defects in appropriate timeframes and address the increased volume of defects expected due to improved and expanded inspection regimes, while managing safety risks (e.g. asbestos).

923 Box 12.2 provides examples of corrective maintenance we expect to identify through expanded inspection activity, and a step change to address safety risk.

Box 12.2 Why step changes in maintenance expenditure are needed: corrective maintenance examples

Pole defects

A number of poles have not yet been inspected under our latest standards meaning there be defects not captured during previous inspections, which did not consider below-ground conditions. In addition, ownership of telecoms poles is being transferred to us, most of which are not inspected to our latest standards. Our increased inspections and condition assessments will identify additional pole defects. It is important that we address these defects in appropriate timeframes, otherwise they may lead to more costly reactive repairs or asset failures.

Asbestos remediation

If our testing regime confirms the presence of asbestos in our zone substation and distribution buildings, we will deploy appropriate mitigation measures. We will apply a hierarchy[59] of control measures, which include:

- eliminating the risk: complete removal of asbestos material from the building
- engineering controls: encapsulate / coating the asbestos material with a product that hardens.
- isolating the risk: placing a barrier between the asbestos material and surrounding areas.
- engineering control: applying a protective coating that creates a seal.

Where feasible, removal is our preferred remediation, as this eliminates the risk to our workers who may need to work in this hazardous environment during recovery efforts or fault restoration. We only remove asbestos that is friable and at medium or high risk of releasing asbestos fibres into the air. Our assessors consider whether the material is badly damaged, delaminated or are in poor condition. This practice is aligned with WorkSafe guidelines. For asbestos that does not fit the criteria above, we will consider the other three control measures on a case-by-case basis.

12.7 Vegetation management portfolio

924 The vegetation management portfolio includes opex associated with ensuring vegetation does not encroach on network assets. The purpose of this expenditure is to maintain a safe, reliable, resilient network by managing risk associated with vegetation, and to comply with the *Electricity (Hazards from Trees) Regulations 2003* (the Tree Regulations).

925 The level of expenditure required to fulfil this purpose is influenced by the characteristics of our network area (Box 12.3), and expected amendments to the Tree Regulations (Box 12.4).

Box 12.3 Orion's vegetation management operating environment

Vegetation management operating environment

Orion's operating environment presents particular vegetation management challenges that can be more complex than those faced by other electricity distribution businesses. This directly influences the level of activity and expenditure required.

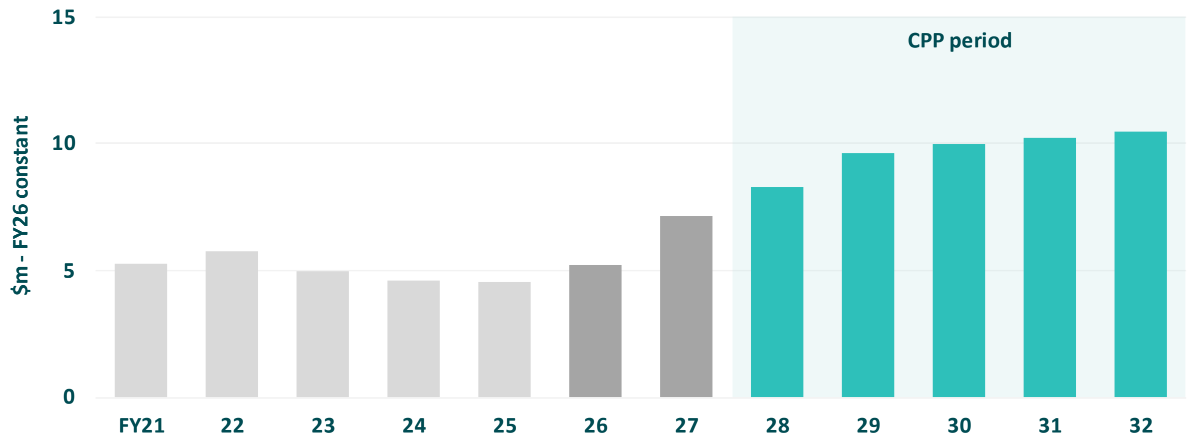
A substantial share of vegetation that we need to manage comprises hedges and shelter belts planted directly beneath or adjacent to our high-voltage lines. These are deeply established and often run the full length of line spans. Maintaining statutory clearances in this environment requires specialised shelterbelt trimming equipment and highly experienced operators to safely manage large cutting heads and associated debris. This work is more complex than standard line clearance and can lead to increased costs.

[59] Consistent with the Health and Safety at Work (General Risk and Workplace Management) Regulations 2016.

12.7.1 Planned vegetation management opex

926 Our planned vegetation management opex is $48.7 million over the CPP period. Figure 12.7 shows this opex per annum compared with our historical spend.

Figure 12.7 Planned vegetation management opex per annum



927 The upward trend in planned vegetation management opex, which begins in FY27 and stabilises by FY32, largely reflects increased vegetation management activity to comply with anticipated changes to the Tree Regulations.

Box 12.4 Expected changes to the Electricity (Hazards from Trees) Regulations 2003[60]

The Electricity (Hazards from Trees) Regulations 2003 set out how tree and vegetation hazards around overhead electricity assets must be managed to protect public safety and network reliability. Following lessons learnt from Cyclone Gabrielle, a set of proposed changes will introduce new obligations for EDBs. All are expected to be in force by the start of the CPP period. These changes include:

Expanded Growth Limit Zone: the growth limit zone around conductors has been adjusted and, for many lines, extended to require a "clear to sky" zone, which may require additional works to ensure vegetation does not overhang the conductor. The proposed changes will extend these requirements to include 11kV and 400V rural lines.

Introduction of treefall hazard risk assessments: EDBs will be required to assess the likelihood and impact of trees falling onto lines, with advice from a qualified arborist. Based on risk assessment results certain tree may need to be removed.

Expanded assessment corridor: includes assessments of trees up to ~24 meters either side of power lines, enabling proactive management of trees that could fall onto lines.

12.7.2 Step changes in vegetation management opex

928 In addition to the recurring work reflected in our base amount, we have forecast likely required work to meet the expected amendments to the Tree Regulations. We have included these needs as step changes. We have identified 4 step change in vegetation management opex, with the forecast cost of the step changes totalling $24.6 million over the CPP period.

929 The step changes have been developed using a volumetric approach, whereby required opex is forecast by applying unit rates – such as cost per span or per tree (for trimming, assessment, or removal) – to forecast work quantities . Work quantities have been estimated based on the results of a LiDAR scan of our non-urban network. We will continue to use LiDAR to improve identification of encroachments, target work more effectively, and monitor compliance.

[60] Signaled amendments to the Electricity (Hazards from Trees) Regulations (2003) were made to Cabinet on 29 May 2025. However, at the time of writing, they have not provided any timeframes for gazetting them. See: https://www.mbie.govt.nz/dmsdocument/30749-a-secure-network-amendments-to-the-electricity-hazards-from-trees-regulations-proactiverelease-pdf

930 Table 12.3 summarises the key step changes in vegetation management opex.

Table 12.3 Summary of step changes in vegetation management opex over the CPP period ($m, FY26 constant)

Step change	Description	Opex
'Clear to sky' requirements	Address compliance risk associated with the extension of 'clear to sky' requirements by expanding our vegetation management activities to meet these obligations	10.5
Initial treefall hazard risk assessments	This step change is in preparation for treefall hazard risk assessments for certain vegetation.	1.9
Ongoing treefall hazard risk assessments	We will need to continually assess vegetation as it grows to the height requirements for assessment.	6.2
Removal of treefall hazard trees	Removal of trees assessed as presenting moderate or high treefall hazard risk, reducing the likelihood of tree-related outages and safety incidents	5.9
Total		**24.6**

931 These step changes will also strengthen network resilience during adverse weather events. A large portion of the faults on our network related to vegetation are caused by wind (e.g. trees fall onto lines, broken branches blown into lines). The frequency of these events is likely to increase in the future because of climate change. Given the large volume of work required, we propose to phase delivery of this work beyond the CPP period to FY36.

12.8 Network opex justification

932 We consider our planned network opex to be prudent and efficient, based on the following:

- **Clear, prudent drivers**: we will introduce new or expanded inspection to better identify potential network risks and improve our asset information. Our corrective maintenance programmes will address increased volumes of defects and address safety risk, such as remediating asbestos. We will increase vegetation management activity over the CPP period to strengthen resilience and comply with the signalled regulations.
- **Base-step-trend approach**: this approach is considered good practice for forecasting recurring expenditure. The applied trend aligns with the total network scale growth factor used by the Commerce Commission for the DPP4 period.
- **Efficient base year spend**: benchmarking by farrierswier indicates that our historical network opex is consistent with our New Zealand peers, and so appears to be an efficient starting point for forecasting purposes. See Figure 12.8 for further details.
- **Good electricity industry practice**: planned step-changes reflect current good practice. This includes detailed seismic assessments for buildings, asbestos identification and remediation programmes will bring us further in alignment with WorkSafe New Zealand guidelines. We are also testing our towers to quantify our EPR risks, consistent with Electricity Engineers' Association earthing guide.
- **Customer perspective**: when discussing risk tolerance, customers favoured a proactive maintenance approach that supports reliability, rather than a more reactive approach that increased the likelihood of unplanned outages.
- **Review and moderation**: we tested our forecasts with our integrated leadership team and Board at several stages, refining and moderating them based on feedback and scrutiny.
- **Independent verification**: the independent verifier assessed our planned expenditure on preventive and corrective maintenance and vegetation management. It accepted preventive maintenance and vegetation management in full. It largely accepted corrective maintenance, other than a portion of our overhead lines defect programme. Overall, the verifier accepted approximately 96% of the network opex assessed.

- **Expected benefits**: the planned expenditure will deliver value to customers and the community, including supporting ongoing safety, reliability, and resilience in our network (see Box 12.5).

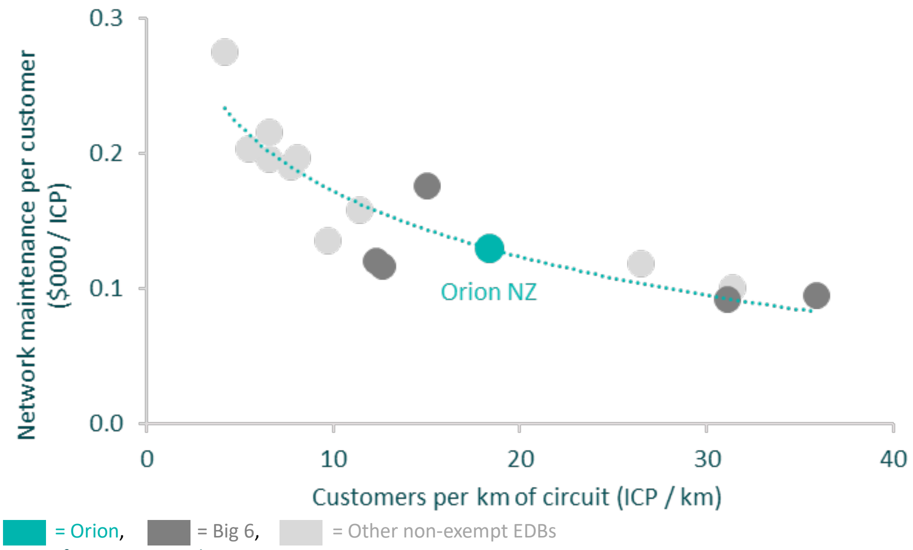
Box 12.5 Expected benefits of network opex

Our planned network opex will deliver the following benefits, which are aligned with the strategic drivers of our CPP plan:

- **Improved safety**: reducing risk of exposing staff, service delivery partners, and members of the public to safety risks associated with asset failures, EPR, asbestos, and seismic issues.
- **Greater resilience**: ensuring our overhead network is more resilient in severe weather conditions will support overall network resilience. This is increasingly important due to the growing influence of climate change. Vegetation management will support network safety, reliability, and resilience outcomes by reducing the risk of tree-related asset damage.
- **Good practice**: allows us to resume maintenance programmes and expand inspections to align with good electricity industry practice.
- **Cost-effective**: planned maintenance work is generally more cost effective than reactive repairs. Identifying and remediating soil contamination and asbestos issues in advance will help reduce cost prior to undertaking work at those sites.
- **Support improved decision-making**: allows us to gather better asset data and fully leverage our IAM system to make better asset management decisions.
- **Improved customer experience**: reducing the number of unplanned faults on the overhead network due to vegetation will improve service quality experienced by customers.
- **Compliance**: we will meet our obligations with respect to regulations and legislation.

933 We benchmarked historical network opex across our portfolios to test its relative efficiency. As Figure 12.8 shows, our network maintenance opex appears to be comparable to that of our New Zealand peers on a per customer basis.

Figure 12.8 Network maintenance opex per customer v customer density (average 2021–25)



Source: farrierswier analysis

13

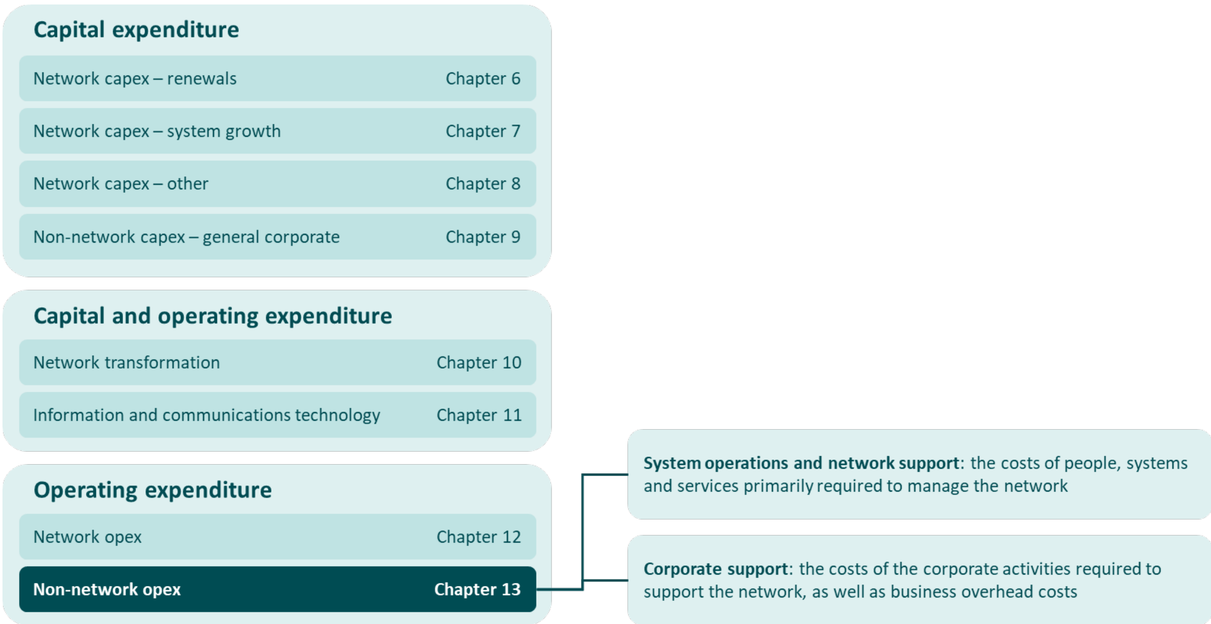
13 Non-network opex – SONS and corporate support

934 Non-network operating expenditure covers the resources required to manage, operate and support the business, including people, tools, systems and other support activities. It enables the safe, reliable and efficient delivery of network services and ensures we operate as a well-managed electricity distribution business.

935 While planned non-network opex comprises 4 portfolios, this chapter focuses on system operations and network support (SONS) and corporate support only. The network transformation and ICT portfolios are discussed in Chapter 10 and Chapter 11, respectively.

936 Figure 13.1 shows where these non-network opex portfolios sit within our overall expenditure.

Figure 13.1 Non-network opex portfolios



937 The remainder of this chapter provides an overview of:

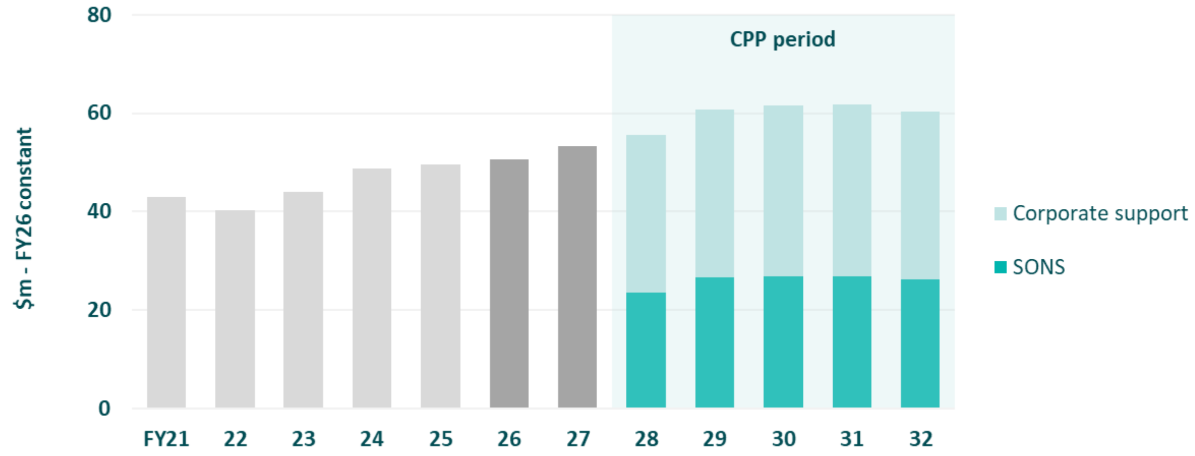
- our planned non-network opex for SONS and corporate support
- its key drivers
- our forecasting approach
- the SONS and corporate support portfolios
- why the opex is prudent and efficient.

13.1 Planned non-network opex

938 Orion's planned opex for SONS and corporate support over the CPP period is $283.7 million. This represents 49% of total opex, and approximately 19% of totex for this period.

939 Figure 13.2 shows this planned opex per annum compared with our historical spend for these portfolios.

Figure 13.2 Planned non-network opex per annum, by portfolio



940 Historically, Orion has managed non-network opex within regulatory allowances, constraining spending where possible. This has been supported by internal budgeting discipline, regulatory incentives (including IRIS), and active cost management, including deferral of non-critical expenditure where required. However, since FY23, expenditure has trended upwards across both portfolios, in part driven by sector-wide cost pressures.

941 In SONS, this also reflects Orion's greater emphasis on enhanced asset management (including investments in integrated asset management), resilience planning and regulatory compliance, which has driven higher people costs across engineering, network and field response. In corporate support, it reflects our response to an evolving energy operating and regulatory environment, including growing our capability in energy futures.

942 Looking forward, we expect our expenditure to increase across both portfolios in the first 2 years of the CPP period, as resourcing is scaled up in advance of and alongside the ramp-up in capital delivery, and then stabilise in FY30–32 as work volumes level off and efficiency improvements begin to be realised.

13.2 Key drivers

943 The primary drivers of growth in SONS and corporate support opex over the CPP period are:

- **Business scale growth**: the planned work programmes outlined in Chapters 6–8 increase capital expenditure and network scale, supporting growth in new customer connections. This drives growth in SONS and corporate support opex, as delivery of these programmes requires additional operational, engineering and commercial resources, resulting in higher salary and contractor costs across both portfolios and asset storage costs in SONS.
- **New capability requirements**: realising the benefits of planned investments in network transformation and ICT (Chapters 10–11) requires new and enhanced capabilities, including disciplines such as artificial intelligence (AI), operational technology (OT) and cyber security, as well as strengthened expertise in reliability engineering, scenario modelling, asset information management, and regulatory strategy. This increases salary and consulting costs across both portfolios and represents a step change to support a more data-driven, technology-enabled network.
- **Changes in the nature of work**: completing our transition to a modern ICT environment (Chapter 11), combined with rapid skill obsolescence and emerging skill requirements, increases the need for workforce training, change management and integration. This drives growth in corporate support salary costs and reflects a broader shift towards a more digital, technology-enabled operating model.

944 Existing SONS and corporate support teams have limited spare capacity to absorb the increased volume of work associated with the planned CPP programmes. As a result, additional resourcing is required to maintain service levels, safety, and delivery efficiency. This reflects the labour-driven nature of these portfolios and the limited headroom within existing teams to increase work volumes without additional support.

13.3 Forecasting approach

945 We forecast SONS and corporate support expenditure separately using a base-step-trend methodology. This is appropriate because our current expenditure provides a reasonable starting point for forecasting what we expect to need over the CPP period. We also considered the independent verifier's findings and conclusions where the verifier did not accept all forecast expenditure. The key steps of our approach are outlined below.

13.3.1 Establishing the base

946 We established the base opex by identifying ongoing activities and associated efficient costs in a representative base year. FY25 was selected as it is the most recent full year with audited expenditure. We adjusted actual FY25 opex to remove non-recurrent costs and expenditure attributable to the network transformation and ICT portfolios to ensure the base reflects steady-state, business-as-usual activity.

947 To test the efficiency of this base, we benchmarked our non-network opex performance in FY24 and FY25 against other price-regulated New Zealand EDBs, primarily using Information Disclosure data. This analysis shows that on consistent basis, our non-network opex compares favourably with our peers. In addition, recent increases in this opex align with sector-wide cost pressures and do not indicate inefficiency.

Given that SONS and corporate support opex is largely labour-driven, we also benchmarked:

- our total full time equivalent employees (FTEs) against those for Australian EDBs (as data for New Zealand EDBs is not publicly available)
- average salaries for those employees against New Zealand median salaries for equivalent roles (as collated by Strategic Pay).

948 This analysis shows that we have fewer FTEs than many Australian EDBs, especially those that are more directly comparable,[61] suggesting we are not employing more staff than is efficient. It also shows that average salaries are consistent with the national medians, suggesting that we are not overpaying those staff. The benchmarking did not identify evidence of structural inefficiency in base labour costs.

949 Subsequent independent benchmarking of our historical non-network opex supports these findings and conclusions (see section 13.6).

13.3.2 Adjusting for step changes

950 We identified step changes not compensated for in the base or trend components, and added them to the base. Four step changes were identified in each portfolio. These changes are driven by capability requirements to:

- strengthen asset, investment and risk management
- realise the benefits of network transformation and ICT investments
- respond to changes in the nature of work requiring workforce capability uplift.

[61] For example, when headcount per 100,000 customers is plotted against customer density, Orion has approximately 12 FTEs compared with SA Power Networks' 19, TasNetworks' 21 and Essential Energy's 29.

951 For each step change, we considered 3 to 4 options for meeting the defined need, including a 'do nothing' option. Options were evaluated on cost, risk and expected benefit to ensure selection of the lowest-cost, least-risk pathway to achieving the required capability.

Table 13.1 summarises these step changes and the planned SONS and corporate support opex associated with them.

Table 13.1 Summary of step changes over CPP period ($m, FY26 constant)

Step change	Description	SONS	Corporate support
Alignment to ISO55001 (global asset management standard)	We are implementing ISO-aligned asset management practices internally (without external certification) to strengthen governance, improve decision-making, and support cost avoidance through better risk targeting and investment timing. This step change reflects the estimated cost of additional internal resources to implement and embed these changes, ensure coordination, and sustain the new system	0.5	0.8
Advanced investment and risk management	We are deliberately shifting to a structured, scenario-based investment and risk management model to improve targeting, transparency, and long-term customer value. This model will strengthen investment governance, support the deferral of low-priority expenditure, and reduce regulatory risk. This step change reflects the estimated cost of establishing a dedicated, appropriately skilled in-house team to embed and operationalise the new model. The team will include reliability engineers, scenario analysts, asset information specialists, and a regulatory advocate. This expenditure is closely aligned with our planned investment in integrated asset management and is necessary to realise the full benefits of this investment	2.0	2.5
AI and operations technology expansion	To complete our transition to a modern ICT environment, we are investing in AI, OT and cybersecurity (see Chapter 11). To realise the benefits of these investments, we are establishing a cross-functional, appropriately skilled internal team to lead digital OT operations, AI integration, and cybersecurity governance. For example, this team will include OT engineers, AI data engineers and cybersecurity engineers	1.1	4.8
LV network data and operations transformation	We are building capability to model and operate the LV network with the same accuracy, responsiveness, and visibility as the HV network, in preparation for higher DER, electrification, and customer participation (see Chapter 10). To benefit from this investment, we require additional resources. We are establishing a dedicated team to support the modelling, planning, and real-time operation of the LV network	2.7	-
Capability shift	Orion is implementing a skills-first strategy to uplift workforce capability, enabling efficient CPP delivery and long-term resilience. This responds to changes in the nature of work, which mean the useful life of skill sets is shortening. We will upskill our workforce with future-ready capabilities while phasing out legacy roles and behaviours. This step change reflects the estimated cost of establishing dedicated in-house training roles to supplement existing resources, which lack capacity given the pace and scale of change	-	1.9
Total		**6.3**	**10**

13.3.3 Applying the trend

952 Our approach to forecasting the trend builds on the Commission's DPP4 econometric approach, incorporating scale drivers and a productivity adjustment.

953 We made 3 deliberate refinements relative to the DPP4 approach:

- using forward-looking forecasts for all scale growth factors rather than historical averages
- forecasting growth relative to the base year
- retaining year-by-year volatility rather than smoothing.

954 These refinements are consistent with the deeper cost-driver assessment appropriate under a CPP framework, where allowances are tailored to the specific circumstances of the business rather than applied on a light-touch basis. They align with the approach used by other economic regulators under similar frameworks, such as the Australian Energy Regulator.

955 We also included a 0.5% annual productivity adjustment to reflect realistic efficiency gains from other initiatives, including our planned ICT spend. This goes beyond the Commission's DPP4 assumption of 0%, while recognising that Orion is operating at or near the efficient frontier for New Zealand EDBs (see Chapter 5 for further detail on our considerations regarding this productivity adjustment).

956 The resulting trend equates to 1.9% over the CPP period. This trend growth (net of productivity assumptions) will provide approximately 15 additional SONS FTEs and 9 additional corporate support FTEs from FY28 through FY32.

957 The specific roles associated with these additional resources have not yet been identified. However, they will be spread across most SONS and all corporate support functions, given the limited headroom and capacity within teams to increase work volumes. From FY32 onwards, we expect modest reductions in FTEs as project volumes ease and efficiency benefits materialise.

13.3.4 Considering independent verifier conclusions

958 The independent verifier reviewed all forecast SONS and corporate support opex, and accepted the forecast base and trend allowances in full. However, it only accepted 50% of the forecast step change allowances. The basis for this appears to be its view that elements of the expenditure associated with our planned capability uplift are already provided for through the trend allowances, and/or that existing staff involved in the CPP application process will have capacity to absorb some of the planned additional functions once this process is completed.

959 We understand the intent of the verification process and the need to ensure that forecasts do not double-count costs. However, for the reasons explained below, we consider that these conclusions rest on assumptions that are not aligned with:

- how the trend allowance is constructed under the Commission's DPP4 decision; or
- the evidence available on Orion's existing capability and resourcing position.

960 We forecast scale growth for Corporate Support and SONS using the econometric model adopted by the Commission in its DPP4 decision for non-network opex. In simple terms,

- an econometric model is specified that assumes relationships between opex and three observable growth drivers: line length, ICPs, and capex;
- that model is then fitted statistically using historical data across non-exempt EDBs to derive elasticities the represent how opex changes in response to changes in the growth drivers; and
- finally, the model is applied by multiplying forecasts of the growth drivers by the elasticities to determine the projected change in opex due to scale growth.

961 The allowance therefore captures scale related growth associated with those drivers and does not, by construction, provide funding for increases in organisational capability, new functions, or capacity uplifts that are unrelated to scale growth. Any year-on-year changes in opex that do not correlate with those drivers are, by design, excluded from the elasticities estimated through the statistical fitting process. We do not believe that the step changes proposed are reflected in the econometric elasticities underpinning the trend allowance.

962 It is also important to understand what the Commission has said about what its growth trend allowances cover. In its DPP4 decision, for instance, the Commission explains that this allowance covers growth associated with line length, ICPs and capex. We are not aware of the Commission having previously stated that trend allowances are intended to fund increases in business capability or organisational transformation, for instance.

963 Our proposed step changes seek to align our asset management with ISO 55001, realise the benefits from significant ICT and network transformation investment over the CPP period, and uplift our human resource capability. These are not driven by scale growth.

964 Absent a link between the proposed step changes and the growth drivers, it is inappropriate to imply that there is one by suggesting that the scale growth forecast is sufficient to cover half of our proposed step change costs. Logically, for instance, even if the three growth drivers that underpin our scale growth forecast were projected to remain flat over the forecast period – such that scale growth was $0 – the need for the step changes would remain.

965 The independent verifier does not appear to have concluded that there is a link (i.e., that step changes correlate with the growth drivers). There is no discussion in the independent verification report of how the costs underpinning the step changes would be reflected in the estimated elasticities.

966 If they do not, then the only basis for concluding that the step changes could be compensated for within the scale growth forecast is if the econometric model adopted by the Commission in the DPP4 decision overstated the impact of growth, leaving headroom to cover step changes. And we are not aware of any evidence that supports that view.

967 To support its assumption that trend growth funds step changes, the independent verifier cites examples, such as roles associated with maintaining Orion’s asset management and risk management systems. GHD states that these roles would have been funded through approved trend growth.

968 We don’t agree with this view. Opex allowances have only applied to Orion since 2009, prior to which price-quality paths were not determined using a building block approach. Roles that existed prior to 2009, therefore, cannot have been funded by opex allowances. It is also not obvious from the Commission's decisions for DPP1, DPP2, DPP3 and DPP4 that the trend growth allowances were determined to fund capability uplifts (or other such step changes). And, as noted earlier, the econometric models fitted by the Commission seek to identify relationships between growth factors and historical opex. Any opex not correlated with those factors will be excluded from the estimated elasticities by design.

969 The independent verifier also appears to assume that staff currently involved in preparing the CPP application will have capacity following completion of the process to address some of the planned capability increases.

970 We don’t agree with this view either and this assumption was not supported by further explanation in the independent verification report. The independent verifier does not appear to have recognised that Orion has engaged backfill and other temporary resources, or otherwise deferred some activities, so that existing staff could support the CPP application. Once the CPP activities reduce, those temporary resources will no longer be required and deferred activities will be picked up again. At the same time, the one-off costs related to the CPP were removed from base opex, so do not form part of our Corporate Support or SONS opex forecasts over the CPP period.

971 Orion's operating expenditure forecast has been developed as an integrated package, comprising: scale growth, step changes and assumed productivity improvements. For both Corporate Support and SONS, Orion has planned an annual productivity improvement of 0.5% over the CPP period. In part, this reflects efficiency gains expected to flow from the capability uplift enabled by the planned step changes.

972 Reducing the step changes without reassessing the associated productivity assumptions risks creating inconsistency within the overall forecast by assuming efficiency gains that are dependent on capability uplift, alignment with ISO 55001, and realising benefits associated to ICT and network transformation investment, while removing the funding required to deliver those outcomes.

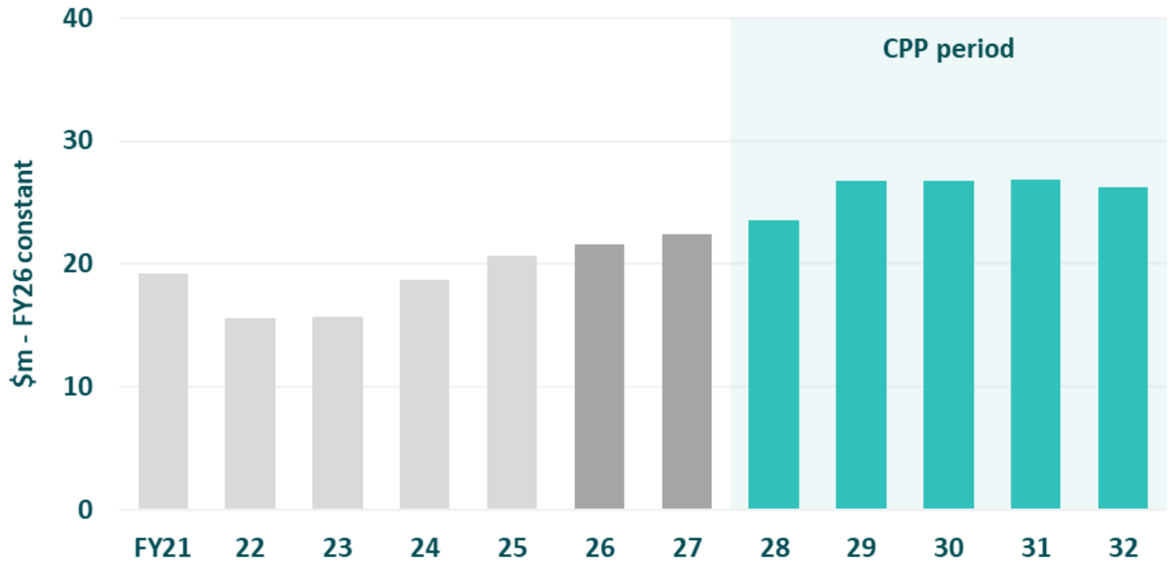
973 The independent verifier also recommended an efficiency factor of 1%, rather than our planned 0.5% be included in the trend. However, as discussed in Chapter 5, we have not adopted this recommendation. Our benchmarking indicates Orion is operating at or near the efficient frontier of New Zealand EDBs. In this context, the relevant question is not how fast Orion should catch up to peers, but what sector-wide productivity gains are realistic over the CPP period. A 1% factor is more consistent with a catch-up efficiency scenario than one applying to a business already at the frontier.

13.4 SONS portfolio

974 The SONS portfolio covers salary and other operating expenditure where the primary driver is managing the network (see Box 13.1). The purpose of this expenditure is to ensure the teams associated with operating and growing the network – including engineering, connections, network operations, health and safety, and asset management functions – have sufficient, appropriate resources to efficiently complete and support the volume of work being undertaken on the network. These functions span real-time network control, engineering standards and system design, connection of new customers, asset lifecycle planning, and safety and compliance activities.

975 Planned SONS opex is $113.3 million over the CPP period. Figure 13.3 shows this opex per annum compared with our historical spend.

Figure 13.3 Planned SONS opex per annum



976 On average, the planned annual SONS opex is $22.7 million. This is $3.3 million higher than the base year (FY25), and around $5.2 million higher than the annual average over FY21–25. Most of the increase is driven by forecast business scale growth, with the remainder reflecting new capability requirements.

977 SONS expenditure is a critical enabler of our planned capital programme over the CPP period. The planned increase in opex ensures that sufficient engineering, operational, and delivery capability is available to support the higher volume of work during the CPP period, while also embedding the specialised skills required to operate and manage increasingly technology-enabled network systems. This includes capability in areas such as operational technology, data analytics, cyber security and advanced asset management, reflecting the changing nature of network operations.

978 Without this uplift, resource constraints would reduce the efficiency and timely delivery of planned network investments, while also limiting the benefits that can be realised from investments in integrated asset management, AI, OT, cybersecurity and network visibility). Existing SONS teams have limited spare capacity to absorb the increased workload, meaning additional resourcing is required to maintain service levels, safety and delivery efficiency.

979 The 0.5% annual productivity adjustment included in our forecasting approach reduced the planned SONS opex by about $0.4 million per year on average, or a total saving of $1.9 million over FY28–32 relative to a zero-efficiency scenario.

980 SONS expenditure is predominantly labour-driven, with approximately 75% of costs relating to salaries. As a result, changes in forecast opex primarily reflect changes in workforce size and capability required to support the CPP work programme. The forecast includes trend-related increases in baseline resourcing associated with network scale growth, as well as step changes associated with new capability requirements that are not captured by the trend allowance. The balance comprises:

- **Asset storage costs** (6%): the costs of storing network parts and components to ensure repairs and planned work can be undertaken in a timely manner. The stores are held and managed by Connetics, with a charge back to Orion to recover its holding and storage costs.
- **Network support vehicle costs** (3%): the operating costs associated with the fleet of Orion-owned vehicles. We do not lease any vehicles.
- **General support costs** (15%): including consultancy costs (e.g. specialist health and safety advice), contract staff costs (e.g. supporting the connections team to deal with high volumes of new applications), and generator fuel costs, for example.

Box 13.1 SONS primary functions

For the purposes of this CPP plan, SONS includes following functions:

- **Engineering**: establishes technical standards and specifications for network design and equipment selection; ensures the 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 the network, responds to faults and maintains system security; includes control centre operations, field response capabilities, and coordination of network access for maintenance and construction activities.
- **Connections**: plans and facilitates the connection of new customers to the network, and the alteration of connections for existing customers in response to customer requests
- **Network portfolio**: Develops detailed work packages and specifications for contractor execution, ensuring all works meet our technical standards and are delivered efficiently.

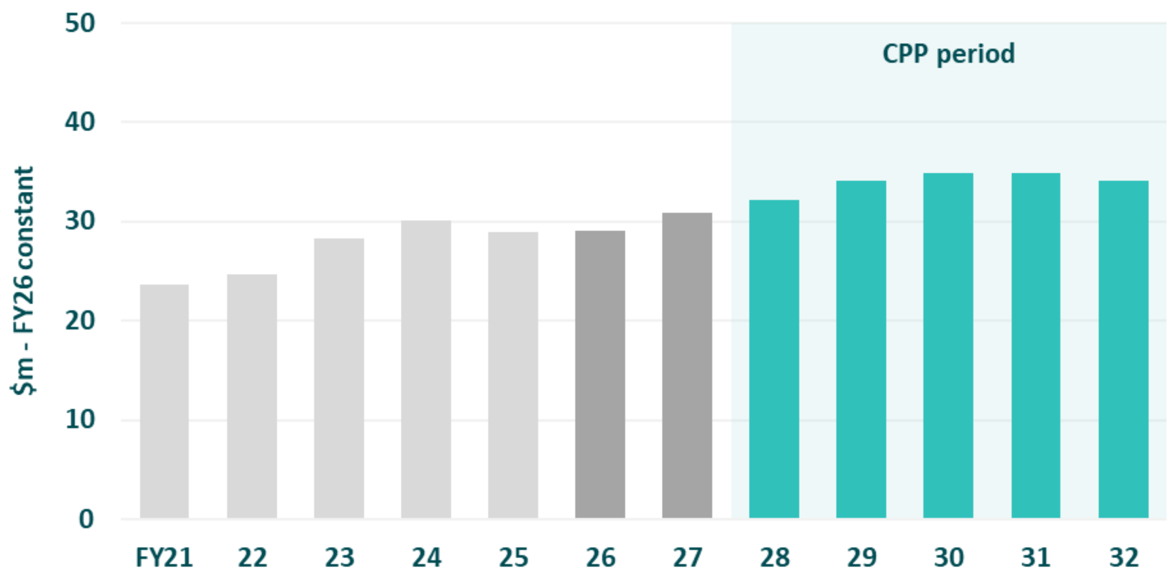
- **Asset management**: focuses on long-term network needs through strategic planning, condition assessment, and development of maintenance and replacement programmes; produces our Asset Management Plan and ensures investment decisions are optimised across the asset lifecycle.
- **Health and safety**: ensures Orion staff and contractors operate in accordance with best practice health and safety requirements.
- **Asset information**: maintains network records.
- **Land / Legal**: maintains grounds and properties associated with the network, and deals with required compliance and easements etc.

13.5 Corporate support portfolio

981 Corporate support covers the operating expenditure associated with the corporate activities required to support the network, as well as business overhead costs. It ensures that our corporate support functions are appropriately resourced and can efficiently support the business as its scale grows and its operating environment continues to evolve. These functions include executive leadership, finance, regulatory and compliance, people and capability, and customer and stakeholder engagement, as well as core business overheads such as insurance and audit (see Box 13.2).

982 Our total planned corporate support expenditure over the CPP period is $170.4 million. Figure 13.4 shows this expenditure per annum, compared with our historic spend.

Figure 13.4 Planned corporate support opex per annum



983 On average, planned corporate support opex is $34.1 million per annum. This is $5.1 million more than the base year opex (FY25), and $6.9 million higher than the FY21-25 average.

984 The primary driver of this increase is the forecast business scale growth over the CPP period. This includes increases in capital delivery, customer connections and network scale, which drive additional demand across finance, regulatory, commercial and people functions. The other key drivers are new capability requirements and changes in the nature of work. These include the need to support a more data-driven and technology-enabled business, respond to evolving regulatory expectations, and embed new organisational capabilities.

985 The 0.5% annual productivity adjustment we included in our forecasting approach reduced the planned opex by about $0.6 million per year on average, or a total saving of approximately $2.9 million over the CPP period relative to a zero-efficiency scenario. This reflects expected

efficiency improvements from initiatives across the business, including investments in systems, processes and capability uplift.

986 Corporate support opex primarily comprises workforce costs. Salaries account for approximately 58% of this opex. The forecast includes both trend-related increases in baseline resourcing associated with business scale growth and step changes to deliver new or enhanced capabilities not captured by the trend allowance. The balance comprises:

- **Insurance costs**: (around 12%): insurance for building property assets (including zone and other substations), vehicles, third-party damage, and general liability. Premiums have increased by 62% since 2018, despite reductions in coverage levels to manage costs. The primary drivers have been global climate-related risk concerns and New Zealand's earthquake exposure, including Alpine Fault risk. These external cost pressures are largely outside Orion's control and reflect broader insurance market conditions. There are early signs that this rapid growth in insurance costs is slowing and potentially stabilising.
- **Consultancy costs**: (around 8%): specialist advice and technical support, primarily supporting finance, regulatory, and revenue functions, where work is complex and regulatory requirements frequently change.
- **Property maintenance costs**: (around 3%): costs associated with Orion's corporate building, the Connetics building and site, smaller leased office spaces for alternative work locations, and residential properties adjacent to substations.
- **External audit costs**: (around 1%): fees paid to Audit NZ for annual financial statement and regulatory Information Disclosure audits.
- **Governance costs**: (around 2%): Directors' fees and direct Board costs, including travel.

Box 13.2 Corporate support primary functions

For the purposes of this CPP plan, corporate support includes the following functions:

- **Leadership**: Orion's integrated leadership team and people leaders (i.e. heads of the business divisions).
- **Accounting and finance**: responsible for the financial aspects of the business, such as budgeting, monthly reporting, year-end reporting, accounts payable and receivable, regulatory disclosures, and treasury.
- **Revenue and regulatory**: sets revenue / pricing based on regulatory settings and manage Orion's relationship with the Commerce Commission.
- **People and capability**: responsible for the human resources functions of Orion.
- **Customer and stakeholder**: responsible for external and internal communication and engagement.
- **Insurance**: premium costs associated with what Orion considers to be a prudent level of insurance coverage.
- **Board and governance**: Director costs and external audit fees.
- **Property maintenance**: maintenance costs of corporate and residential properties owned by Orion.

13.6 SONS and corporate support opex justification

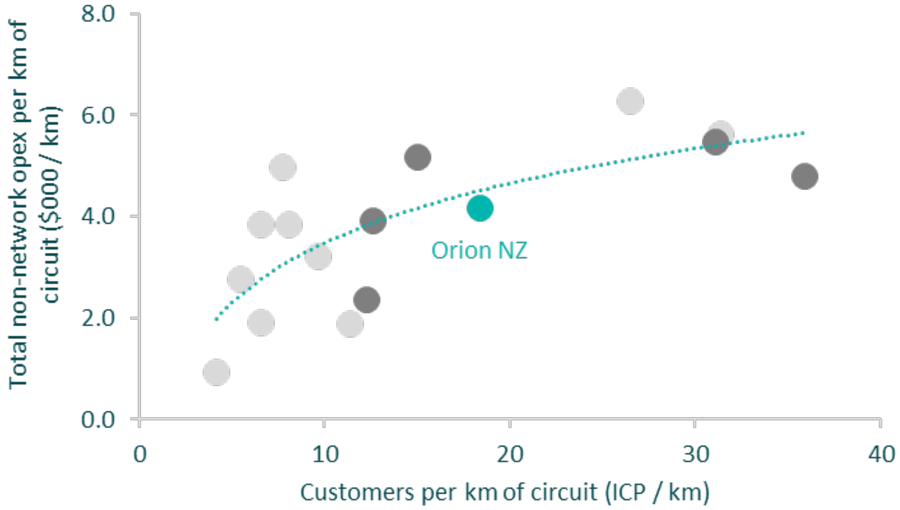
987 We consider our planned SONS and corporate support opex to be consistent with the efficient costs a prudent EDB in similar circumstances would incur for the following reasons:

- **Base-step-trend approach**: this approach is industry good practice for forecasting operating expenditure of this nature and is consistent with the Commerce Commission's regulatory framework for non-network opex.
- **Benchmarking**: farrierswier benchmarked our historical non-network opex against comparable New Zealand EDBs. It found that our combined SONS and business support opex sits broadly in the middle of the Big 6 on a per-km, per-consumer and per-MW basis, averaged over 2021–25. Across all non-exempt peers, it sits close to or below the trendline

when plotted against customer density (Figure 13.5). It also noted that the combined non-network opex measure is likely to be more informative than individual SONS and business support measures, as it reduces the impact of differences in cost allocation between those categories. These findings support our view that our forecasts are grounded in an efficient starting point.

- **Headcount and salary benchmarking**: we benchmarked total FTEs and salaries against comparable networks (as outlined in section 13.3.1). We found that we operate with relatively lean staffing levels relative to comparable Australian EDBs, and that our average salaries are broadly aligned with New Zealand market medians. Together, these findings indicate that the labour inputs underlying our forecasts are consistent with efficient industry benchmarks.
- **Trend aligned with Commission methodology**: in forecasting the trend, we largely applied the method used by the Commerce Commission for its DPP4 decision, with minor refinements to reflect the detailed forecast approach appropriate for a CPP application. The trend captures only scale-related growth associated with capex, network size and customer connections, consistent with the Commission's econometric framework.
- **Clear distinction between trend and step changes**: costs associated with new or enhanced capabilities are not driven by scale growth and are therefore not captured in the trend allowance. These costs are included as step changes to avoid underfunding required capability and to ensure there is no double counting within the forecast.
- **Efficiency improvement**: for both corporate support and SONS, we have planned an annual productivity improvement of 0.5% over the CPP period. This increases each year and reduces planned opex by approximately $1 million per year on average, or a total of around $5 million over the CPP period relative to a zero-efficiency scenario. As outlined in Chapter 5, a 0.5% annual productivity assumption represents a credible and achievable efficiency target for these portfolios. It reflects expected benefits from planned system, data and process improvements, as well as embedding scale increases over time. It also aligns with expected sector-wide productivity gains observed by the Australian Energy Regulator and is consistent with intended role of the productivity assumption in a base-step-trend framework.
- **Challenge rounds**: we tested our forecasts with our integrated leadership team and Board at several stages, refining and moderating them in response to feedback and scrutiny.
- **Customer perspective**: customers and stakeholders consistently told us they want a safe, reliable and resilient network that can accommodate growth and is future fit. They also expect us to manage our assets prudently and efficiently. This planned expenditure will ensure we have sufficient resources to deliver this.
- **Independent verification**: the verifier assessed 100% of the forecast SONS and corporate support expenditure and accepted the base and trend allowances in full. It recommended reducing forecast step change opex by 50%, and increasing the efficiency factor to 1%, which we have not accepted or adopted for the reasons outlined above and in section 13.3.4.
- **Expected benefits**: The planned expenditure will provide value to customers, including supporting the safe, reliable and efficient operation of the network, enabling delivery of the CPP programme, and ensuring Orion has the capability required to operate in an evolving, technology-enabled environment (Box 13.3).

Figure 13.5 Non-network opex[62] per km v customer density (average 2021–25)



Source: farrierswier analysis

Box 13.3 Expected benefits of the SONS and corporate support opex

Our planned SONS and corporate support expenditure ensures that the teams responsible for operating and growing the network, as well as our head office support functions, are appropriately resourced. This underpins Orion's ability to deliver its strategic priorities for the CPP period and beyond, including maintaining efficient network operations. Key benefits include:

- **Efficient delivery of the CPP programme**: adequate resourcing supports effective planning and execution of the planned work programme, reducing the risk of inefficiencies or increased turnover arising from staff working beyond sustainable capacity.
- **Maintained safety standards**: network growth and an increasing frequency of natural hazard events require sufficient people, equipment and systems to maintain the safety of our workforce, contractors and the public.
- **Productivity and efficiency gains**: the forecast includes an allowance for efficiency improvements above the standard level applied to New Zealand EDBs, reflecting the benefits expected from increased investment.
- **Future-ready workforce**: the business will be better able to retain, develop and attract the expertise needed to operate the network effectively into the future, enabling customers to benefit from new technologies and improved ways of working.
- **Responsiveness to regional growth**: our region is one of the fastest growing in New Zealand. Appropriate resourcing ensures connection requests and network upgrades can be processed and delivered in a timely manner, ensuring the network has sufficient capacity to keep pace with regional development without becoming a constraint on growth.
- **Timely response and recovery**: sufficient staffing levels and improved systems maintain timely restoration of normal operations following incidents.

[62] This includes all non-network opex categories, including ICT and Network Transformation.

14

14 Revenue requirement and price impacts

988 Our proposed revenue requirement reflects the prudent and efficient expenditure required to deliver our CPP plan over FY28–32. As set out in previous chapters, this plan has been robustly developed, tested, and scrutinised. The associated expenditure forecasts have been prepared on a consistent basis to ensure they reflect the level a prudent and efficient electricity distributor would reasonably require, in Orion's circumstances, to meet expected demand and deliver required service quality in the long-term interests of consumers.

989 Once approved by the Commerce Commission, the revenue requirement sets the maximum revenue we may recover to fund our operations in each year of the CPP period and therefore places an upper limit on our prices.

990 This chapter outlines:

- our total revenue requirement for the CPP period
- its expected impacts on customer electricity bills
- how we have smoothed revenues to avoid price shocks
- our estimate of total revenue over the CPP period.

14.1 Total revenue requirement

991 Our proposed total revenue requirement for the CPP period is $1,761 million. It is derived from the planned capex and opex summarised in Chapter 5, using a financial model compliant with the Input Methodologies (IMs) (Table 14.1). The model was developed with support from PwC (see Chapter 3) and has been independently audited, providing assurance of its robustness and compliance.

Table 14.1 Revenue requirement and building block components for the CPP period ($m, nominal)

	FY28	FY29	FY30	FY31	FY32	CPP Total
Return on investment	135	144	154	166	178	**778**
Return of investment (depreciation)	70	74	76	82	87	**388**
Return of investment (revaluation)	-38	-40	-43	-47	-51	**-219**
Forecast operating expenditure	115	124	129	134	135	**637**
Regulatory tax	32	33	35	37	39	**176**
Revenue requirement pre-smoothing (BBAR[63] before tax)	**313**	**334**	**351**	**372**	**389**	**1,761**

[63] Building Blocks Allowable Revenue

992 Box 14.1 summarises the key factors influencing the level of the revenue requirement. The Financial and Modelling Information document, included as part of our CPP application, provides a detailed explanation of how the revenue requirement was derived and the assumptions used to derive it. The CPP financial model we used to calculate the revenue requirement is also included in our application.

Box 14.1 Key factors influencing our revenue requirement

Orion's revenue requirement is driven by 3 primary factors:

- Regulatory framework: the requirements of Part 4 of the Commerce Act 1986 and the IMs, which define how revenue is calculated, including the cost of capital and asset valuation methodologies
- Expenditure forecasts: the level of prudent and efficient capex and opex required to deliver the CPP plan, outlined in Chapters 6-13
- Building block inputs: key assumptions – such as the value of the regulatory asset base (RAB), inflation, tax settings, and financial parameters – that are specified in, or determined in accordance with, the IMs.

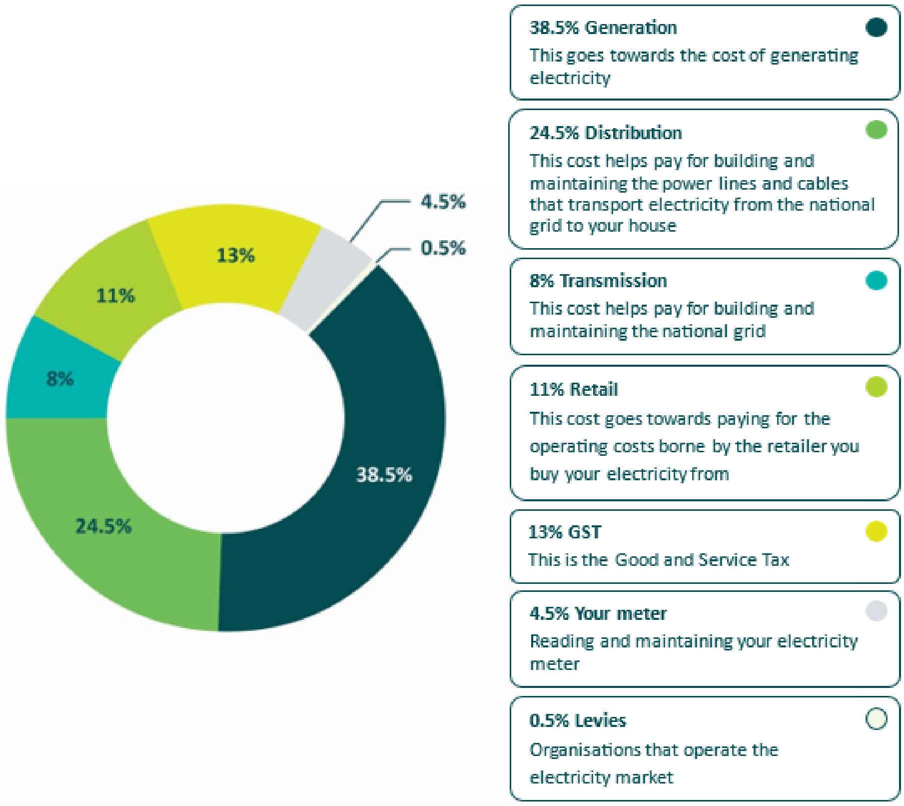
The resulting revenue requirement is subject to uncertainty, including demand, cost escalation, and macroeconomic factors such as inflation and interest rates. These uncertainties are discussed further in Chapter 5.

14.2 Expected impact on customer bills

993 Following the Commission's determination, we will set lines charges for electricity retailers to reflect the approved revenue requirement. Retailers will then determine how these charges are reflected in the tariffs paid by end customers.

994 For this reason, and because electricity bills reflect the costs of all parts of the electricity supply chain (Figure 14.1), we cannot accurately forecast total customer bills over the CPP period under our proposal.

Figure 14.1 What an electricity bill pays for: average breakdown of a typical household bill[64]



[64] Electricity Authority. *What does your power bill pay for?* Retrieved 15 May 2026 from https://www.ea.govt.nz/your-power/bill/

995 However, we have undertaken analysis to illustrate the effect of the proposed CPP on the distribution component of electricity bills for typical residential and small business customers[65] over the CPP period. This analysis involved:

- calculating forecast distribution revenues under our proposed CPP and under a default price-quality path for each year of the period
- allocating the incremental difference in these revenues across customer groups based on expected revenue recovery
- for each group, dividing the allocated revenue by the forecast number of customers to estimate an average annual impact per customer
- converting the annual impact to an average monthly impact per customer, consistent with how distribution charges are typically incorporated in electricity bills.

996 Table 14.2 summarises the results of this analysis. It indicates that we expect the distribution component of a typical residential and small business[66] customer bill to be around $4 per month higher, on average, under our CPP than under a default pathway. Actual impacts for individual consumers will vary depending on consumption, tariff structure, and retailer pricing decisions.

Table 14.2 Estimated impact of total revenue requirement on the distribution component of monthly electricity bills for customers ($, nominal)

Indicative distribution revenue (average / month)*	FY28	FY29	FY30	FY31	FY32	CPP period average
Under our customised price-path						
Residential	72	74	81	88	94	**82**
Small business	84	86	94	102	110	**95**
If we stayed on a default pathway						
Residential	68	73	82	84	85	**78**
Small business	79	85	95	98	99	**91**
Difference resulting from our customised price-path						
Residential	4	1	-1	4	9	**4**
Small business	5	2	-1	4	11	**4**

** Phasing of revenue reflects the proposed X-factor to manage price shock for customers, as discussed in section 14.3.*
Notes: excludes transmission charges passed through in lines charges and all other cost components of electricity bills.

997 We consider this impact to be broadly consistent with customers' willingness to pay. Through our CPP engagement (see Chapter 3), customers consistently identified affordability as a key concern. At the same time, they prioritised maintaining current safety and reliability, strengthening resilience to natural hazards, and ensuring the network keeps pace with growth. When presented with alternative investment options involving different price and service outcomes, customers generally indicated an acceptance of moderate price increases to support the investment to support these outcomes.

998 In response to this feedback, we have sought to balance affordability with the need for timely investment. By ensuring our proposed expenditure is prudent, efficient, and aligned with customer priorities, we have minimised price impacts while maintaining service levels and supporting the long-term resilience and capability of the network.

[65] Residential and small business customers make up approximately 92% of customers connected to our network.
[66] These are our residential and small general connection pricing groups.

999 In developing, testing and finalising our CPP plan, we reduced forecast expenditure by refining programme scope, timing, and delivery assumptions to improve affordability while maintaining the outcomes customers value. As a result, the estimated monthly bill impact for a typical residential customer reduced from around $8 under our initial investment approach, to $6.50 under the draft plan, and to approximately $4 under the final CPP plan. We note that the initial estimate of $8 was slightly conservative (to avoid understating likely impact) and our estimated DPP5 settings have been refined over time which, along with the reduced expenditure levels, have contributed to the reduced impact as we have finalised the CPP.

14.3 How we smoothed revenues to avoid price shocks

1000 The timing of forecast expenditure – particularly step changes in capital investment – can result in volatility in the annual revenue requirement under a standard building block approach. If this volatility were passed directly through to prices, it would result in sharp year-on-year changes in customer bills.

1001 To avoid this outcome, we have applied revenue smoothing to shape the timing of cost recovery across the CPP period. This approach moderates price increases in the near term while maintaining net present value (NPV) neutrality, consistent with the IMs. Customers are therefore no better or worse off over time, but face a more stable and predictable price path.

1002 Our approach to smoothing is aligned with the Commission's established framework, which considers 3 key elements of the revenue path:

- **level** of revenue in the first year (P0)
- **rate of change** in revenue over time (CPI–X)
- **timing of recovery**, shaped through smoothing mechanisms.

1003 In this context, the X-factor is not applied as a measure of expected productivity improvements, but as a tool to shape the revenue path and achieve a smoother and more manageable distribution of price impacts over time.

1004 We have calibrated the X-factor to balance 3 objectives:

- **price stability** to avoid sharp increases, particularly in the early years of the CPP period
- **within-period equity** to ensure that costs are recovered from customers who benefit from the associated investment
- **regulatory consistency** by maintaining alignment with the Commission's price-shock management approach.

1005 In doing so, we have had regard to the Commission's recent practice under DPP4, where explicit consideration was given to limiting both initial and ongoing price increases. While those thresholds do not directly apply to a CPP, they provide a useful benchmark for assessing whether the resulting price path is reasonable from a customer perspective.

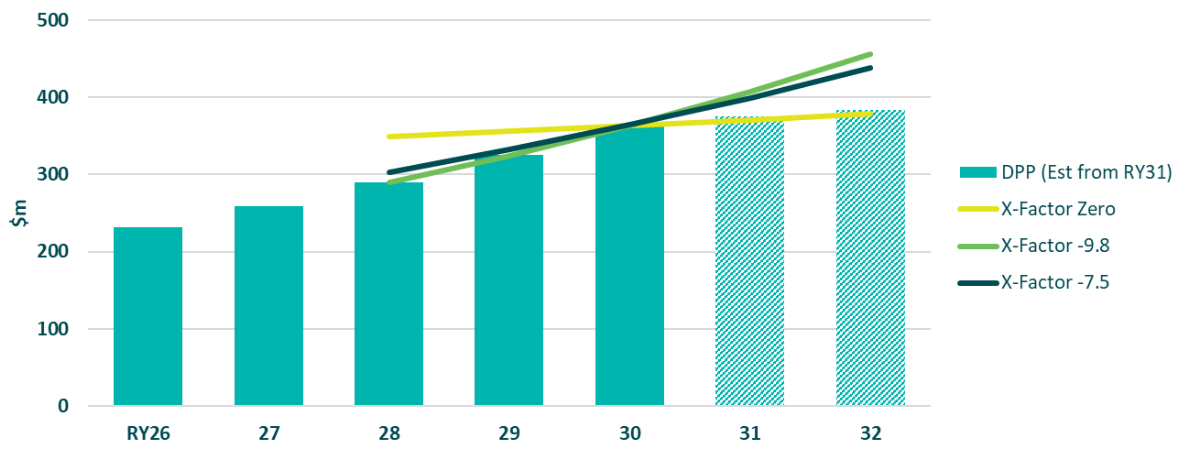
1006 To consider the effect of different smoothing choices, we have assessed three alternative revenue paths using a range of X-factor settings, outlined in Table 14.3.

Table 14.3 Comparison of X-factor settings

X-factor	Description	Pros	Cons
0%	Higher upfront price increase (~35%), then a gentler revenue slope over the CPP period	Smoother later-year impacts; likely closer alignment with DPP5 settings when exiting CPP	Larger Year 1 step into CPP; price shock unlikely to be acceptable to customers
-9.8%	Consistent with DPP4 settings; effectively extends the existing (steeper) DPP4 revenue slope	Smaller Year 1 step (~12%), broadly aligned to the existing DPP4 revenue path	Greater risk of "rate fatigue" in later years; increased revenue at end of CPP likely to be materially higher (~10%) than DPP5 revenue settings when exit CPP
Our proposed X-factor of -7.5%	More balanced and gradual price profile, replicating the Commission's DPP4 approach	Moderated P0 of ~17%, providing a balanced step into the CPP without being as an excessive CPI-X slope as the -9.8% X-factor	Risk of "rate fatigue" remains in latter years (although reduced) and still anticipate revenues will step down upon exit from the CPP.

1007 Figure 14.2 illustrates the impact of re-shaping and smoothing revenue collection by comparing the above three X-factor options.

Figure 14.2 Proposed revenue path under various X-factor options



1008 This analysis indicates that our proposed approach reduces the risk of price shocks while enabling timely recovery of efficient costs, and results in a more even distribution of price impacts across the CPP period.

1009 Customer and stakeholder feedback has been an important consideration in developing our smoothing approach. Customers have indicated a clear preference for gradual and predictable price increases (see Chapter 3), as this allows time for them to adjust consumption and manage household or business budgets. Our proposed revenue path responds directly to this feedback.

1010 Overall, our approach to revenue smoothing supports the long-term benefit of consumers by delivering a stable and transparent price trajectory, while ensuring that efficient costs are recovered in a manner consistent with regulatory requirements.

1011 We have considered how to further smooth the revenue path, using revenue deferral provisions within the revenue wash-up mechanism, to reduce the revenue peak experienced in the final two years of the CPP (RY31 & RY32). This deferred revenue could then be collected over the remaining three years of DPP5 following the CPP (FY33-FY35). This will effectively spread revenue across the CPP and DPP5 periods.

1012 While we are not proposing this deferral as part of our application, we are willing to discuss this possibility with the Commission if further reduction of the peak in revenue, caused by the application of the X-factor and subsequent recovery of this revenue in future years, is considered beneficial to customers. Our pricing impacts detailed above therefore do not include any potential deferral adjustments.

14.4 Total estimated revenue over CPP period

1013 Total revenue recoverable from customers over the CPP period will include Orion's allowed revenue requirement as well as the transmission charges we pass through to consumers as part of lines charges.

1014 Table 14.4 sets out our estimate of total revenue recoverable over the CPP period, assuming the Commission approves our proposed revenue requirement.

Table 14.4 Estimated total lines revenue including transmission charges ($m, nominal)

Indicative lines revenue	FY28	FY29	FY30	FY31	FY32
Distribution revenue	318	334	370	409	445
Transmission revenue	84	88	92	91	99
Total lines revenue	**402**	**422**	**462**	**500**	**544**

1015 Transmission charges are expected to be the same under both DPP4 and a CPP. As a result, they do not affect the incremental impact of our CPP plan on customer bills presented in section 14.2.

1016 Overall, our proposed revenue requirement and resulting price path reflect a careful balance between affordability and the need for timely, efficient investment. The CPP plan has been developed in response to clearly identified network needs, tested through extensive customer engagement and independent scrutiny, and refined to moderate price impacts while maintaining the outcomes customers value. The resulting revenue profile provides for the recovery of prudent and efficient costs in a manner that is stable, transparent, and consistent with the long-term benefit of consumers.

15

15 Service measures and quality standards

1017 As part of our CPP application, we have considered the service measures and quality standards that are appropriate for Orion over the CPP period.

1018 Service measures specify what we will measure and report in our Asset Management Plan, each year of the CPP period, to provide transparency on our service performance. These measures are intended to reflect service attributes that are meaningful and important to customers. Each measure includes an annual performance target.

1019 Quality standards define the reliability performance levels we are expected to maintain over the CPP period. They are set by the Commerce Commission as part of the CPP Determination. Their purpose is to protect customers by ensuring reliability performance is maintained at appropriate levels throughout the regulatory period.

1020 The sections below outline:

- our service measures for FY28–32
- how we developed these measures
- our approach to quality standards, including context and suggested options available to the Commission for setting quality standards for the CPP period.

15.1 Our service measures

1021 We will measure and report on 26 service measures across 7 key service attributes – reliability and resilience, power quality, safety, customer service, environmental impact/sustainability, efficiency and network planning, and energy transition support.

1022 Thirteen of the measures are existing measures[67] from our Asset Management Plan 2024. The remaining 13 are new measures that we propose to begin monitoring and reporting on from FY28.

1023 Table 15.1 sets out these service measures and associated annual performance targets.

Table 15.1 Service measures for the CPP period

Service attribute	Service measure	Annual performance target	Status
Reliability and resilience	Planned SAIDI	≤ 23.83	Existing
	Unplanned SAIDI	≤ 63.14	Existing
	Planned SAIFI	≤ 0.074	Existing
	Unplanned SAIFI	≤ 0.795	Existing
	Unplanned interruptions restored within 3 hours	≥ 60%	Existing
	Percentage of planned interruptions where less than 10 working days' notice is given to electricity retailers	≤ 20%	New
	Number of localised reliability hot spots with an approved corrective action within six months of being identified.	≥ 3	New

[67] The safety measures have been retained, but their wording has been adjusted to improve clarity.

Power quality	Timeframe for when customer complaints relating to network power quality issues are responded to after the issue has been logged.	100% in ≤ 5 business days	New
	Percentage of validated customer complaints relating to network power quality issues that are resolved within one month after the proposed remedy is identified	≥ 90%	New
	Percentage of proactively[68] identified network power quality issues that are resolved within five working days e.g., broken neutrals, high impedance neutrals	≥ 90%	New
Safety	Notified events that result in serious injury to employees	≤ 1 serious event	Existing
	Notified events that result in serious injury to service delivery partners	≤ 1 serious event	Existing
	Events that result in serious injury to the public, excluding car versus pole incidents	≤ 1 serious event	Existing
Customer service	Customer experience: rating of service received	≥ 8 out of 10	Existing
	Customer experience: ease of doing business with us	≥ 8 out of 10	Existing
	Awareness of the Orion website	≥ 50%	New
	Percentage of customers restored within ±30 minutes of the communicated restoration time for planned HV outages	≥ 30%	New
	Percentage of small generation (<10kW) connections approved within 10 business days after receipt of completed applications	100%	New
Environmental impact / sustainability	Sulphur hexafluoride (SF_6) gas lost	≤ 0.8% of total installed SF_6 inventory	Existing
	Grams of carbon dioxide equivalent (CO2e) per MWh delivered – excludes distribution losses	≤ 700g to FY28 inclusive ≤ 580g for FY29 and FY30 ≤ 450g for FY31 to FY36	Existing
Efficiency and network planning	Operational expenditure per MWh	≤ NZ comparator group average	Existing
	5-year rolling average of total network MWh / total expenditure	5-year change in measure exceeds the average change across comparator EDBs	New
	Average load (kW) as a percentage of firm capacity of transformers (weighted by customers supplied by that transformer)[69]	To be determined	New
Energy transition support	Number of commercial and industrial customers supported to understand their flexible capability and report on outcome/learnings	≥ 10	New
	Notification of forecast constraint shared with flexibility providers[70]	≥ 3 years before expected constraints at subtransmission and zone sub level ≥ 2 years before expected constraints at 11 kV and low voltage level	New
	Maximum duration (hrs/ICP) of distributed energy resource export curtailment, per residential customer with DER, due to network constraints	To be determined	New

[68] Proactively identified means the issue has been identified before we receive a customer complaint.
[69] Firm capacity means the N-1 rating for zone substations, or the total transformer rating for distribution transformers.
[70] 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).

15.2 How we developed and tested the service measures

1024 We developed our service measures and performance targets through a structured process designed to ensure they are grounded in customer priorities and capable of providing meaningful accountability and transparency over the CPP period.

15.2.1 Develop draft measures

1025 We developed our draft set of service measures and performance targets using a structured 4-step approach. In step 1, we identified the range of service attributes to be covered. We considered the attributes valued by customers drawing on feedback from our annual customer perceptions surveys, Customer Advisory Panel sessions, and CPP-specific customer engagement. This analysis identified the following attributes that are meaningful to customers:

- safe and reliable energy supply
- network resilience
- affordability
- clear communication and outage information
- easy connections
- support for new technologies.

1026 We also considered the strategic priorities underpinning our CPP proposal – maintaining safety and reliability, supporting population and demand growth, strengthening resilience, preparing for future energy needs, and enhancing efficiency and capability. Finally, we considered our expenditure objective to meet appropriate service standards, and to comply with applicable regulatory obligations.

1027 In step 2, we developed a list of potential service measures to cover the service attributes identified above. For this step, we drew on the measures included in our Asset Management Plan 2024, as well as peer EDB practice and industry guidance.

1028 In step 3, we filtered and shortlisted the service measures by assessing them against the following selection principles:

- **relevant**: the proposed measures are relevant to one of the nominated service attributes, and that is meaningful and important to customers and/or network performance
- **measurable**: the proposed measures can be reliably measured using available data and methods, ideally drawing from established reporting processes
- **controllable**: the proposed measure is within Orion’s control and can be directly influenced by its deliberate action
- **achievable**: the proposed measures (and their proposed service levels or targets) are realistic and can be determined for the CPP period using reliable data and methods.

1029 This assessment was informed by the Commission’s DPP4 decision, which provided a clear benchmark for the types of measures considered appropriate at an industry level.

1030 Finally, we set draft annual performance targets for each measure, drawing on historical performance, customer expectations, regulatory settings and a minimum requirement to maintain performance at levels previously achieved.

15.2.2 Test and refine measures

1031 We tested the draft service measures and performance targets through our internal governance processes, through our customer engagement, and through the independent verification process.

1032 Our customer engagement included:

- Outlining 11 draft service measures and performance targets in our customer summary of the draft investment plan.[71] This summary explained what the measures mean and why they matter for customers, and set out options for measuring additional service attributes. We sought feedback on the draft measures and the additional options.
- Discussing the draft measures at a Customer Advisory Panel session and 2 Powerful Conversations community workshops. At the workshops, we also asked participants to rate the importance of the draft measures.

1033 Feedback from this engagement indicates that customers place the highest value on maintaining reliable supply, particularly minimising outages. When outages occur, clear and timely communication – especially regarding restoration timeframes – is critical. Customers also expect service interactions to be accessible, helpful, and informed.

1034 The independent verifier also assessed the draft service measures and performance targets, examining their relevance to customers, and the quality of our customer consultation process. This assessment also reviewed our 4-step approach for developing the service measures, and considered whether further additional service measures were appropriate.

1035 The independent verifier found the draft service measures were relevant to a complete range of key service attributes that are meaningful and important to customers, and that we had undertaken an appropriate level of engagement on these measures and the proposed performance targets.

1036 It also found that our development approach was logical and appropriate for deriving service measures and targets for the CPP period. However, it identified 2 service measures, related to the service attribute of efficiency and network planning, that it considered required further consideration. We subsequently changed the service measures related to that attribute.

1037 The resulting service measures represent a direct translation of customer priorities – particularly reliability and resilience, safety, affordability, communication, connections, environmental impact, and energy transition support – into measurable commitments that will provide accountability and transparency for our performance throughout the CPP period. In this manner, we consider that our service measures support the 'appropriate service standards' component of the expenditure objective.

[71] See pages 40-41 of our Consultation Document: https://www.haveyoursay.oriongroup.co.nz/cpp

15.3 Our quality standards

1038 Orion does not propose a quality standard variation (QSV) for the CPP period (FY28-32). The Commerce Commission is required to set quality standards and incentives as part of its CPP Determination. To inform this process, we have considered the relevant context and approaches available to the Commission, and set out our preferred approach below.

15.3.1 Context for setting quality standards

1039 We consider the relevant context for setting quality standards, which includes customer preferences in relation to reliability levels, and our recent and forecast reliability performance.

15.3.2 Customer preferences and our response

1040 Unlike other recent CPP proposals, Orion's proposal is not driven by the need to address reliability concerns. As outlined in Chapter 3, throughout our CPP engagement, customers expressed high satisfaction with our current reliability levels and a strong preference for maintaining these levels. They indicated unwillingness to fund additional investment to improve our reliability performance above those levels, except for improving reliability in targeted, localised areas.

1041 Consistent with these preferences, the network renewal and maintenance investments in our CPP plan are designed to maintain our current reliability performance.

15.3.3 Recent reliability performance

1042 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 15.1 and 15.2).

1043 We have complied with our quality standards for the past 2 regulatory periods (2015–2020 and 2020–2025).

Figure 15.1 Orion's historical planned and unplanned SAIDI (non-normalised)

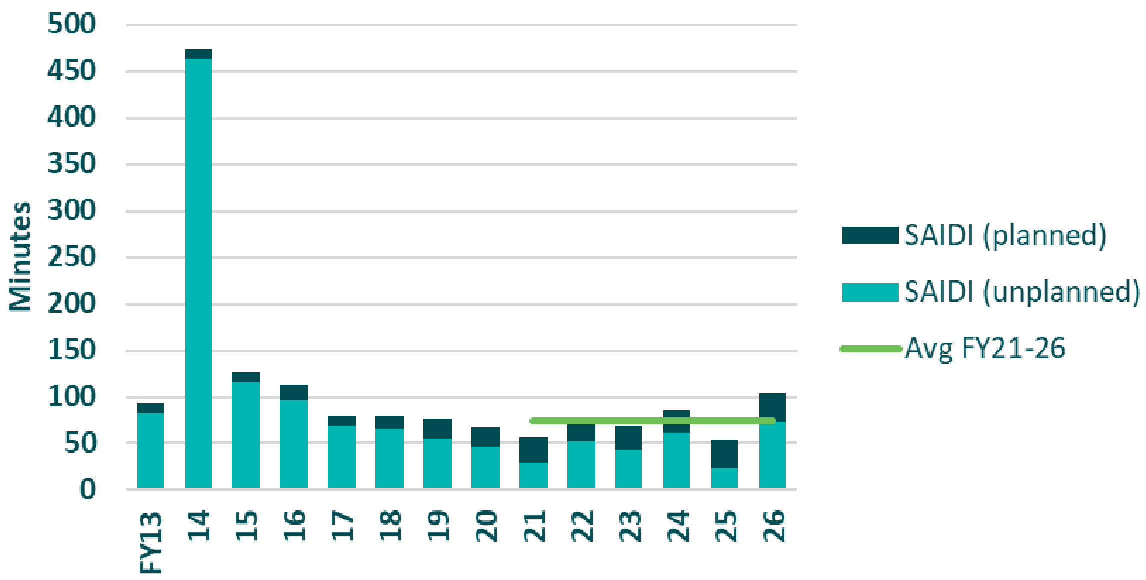
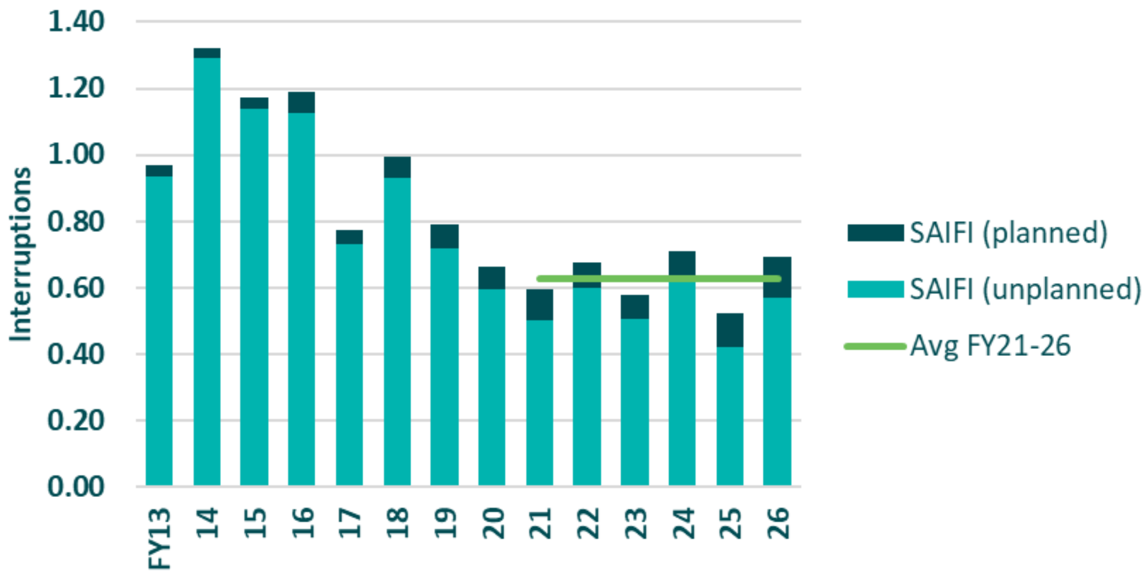


Figure 15.2 Orion's historical planned and unplanned SAIFI performance (non-normalised)



15.3.4 Forecast reliability performance

1044 Forecasting unplanned reliability performance is a complex process, requiring high-quality data and extensive, bespoke modelling.[72] We do not currently have sufficiently robust, granular data to be confident that forecast modelling can accurately reflect reasonably achievable future performance.

1045 Nevertheless, based on our past performance, and our planned asset management strategies and activity levels, we consider the unplanned reliability standards set for the DPP4 period remain achievable over the CPP period. Given the limitations of forward-looking modelling, our sustained historical compliance provides the most reliable basis for assessing what is reasonably achievable.

1046 For planned reliability, increased work volumes associated with our CPP programme are expected to place upward pressure on outage duration and frequency. However, we expect this to be mitigated through larger bundling of work programmes, and more effective outage notification processes.

1047 In this context, we consider retaining the current quality standards provides an appropriate and proportionate balance. It maintains accountability for service performance while recognising the practical constraints associated with delivering an expanded work programme, and avoids introducing more stringent standards that would not reflect customer preferences or expected performance.

15.3.5 Approaches available for setting quality standards

1048 Where a CPP applicant does not include a QSV in its CPP proposal, the regulatory framework provides no guidance on the approach the Commission should take in setting quality standards, leaving this to the Commission's discretion.

1049 We have considered several feasible approaches available to the Commission in exercising this discretion, given the context outlined above. These include a:

- **Maintain option**: the Commission sets the current DPP4 quality standards and incentives for a further 5 years (from 1 April 2027 to 31 March 2032). This is a proportionate approach. However, it would result in quality standards being fixed for 7 years without

[72] We are not aware of any standardised unplanned reliability forecasting tools.

adjustments to reflect more recent performance. In addition, incentive parameters would not be updated to reflect changes in delivery volumes or the value of lost load.

- **Refresh option (our preferred approach)**: the Commission sets 'refreshed' standards incentives for FY28-32. This involves repeating its DPP4 modelling by rolling the underlying reference periods forward by 2 years, to incorporate the most recent reliability performance data (i.e., to 31 March 2026). This ensures that the quality standards and incentives are set prospectively (preserving the ex-ante nature of the quality standards framework), reflecting Orion's most recently achieved performance, and quality incentive parameters are updated appropriately.
- **Follow option**: the Commission sets the current DPP4 quality standards for FY28-30 and the DPP5 quality standards for FY31-32. This would align standards with the most recent regulatory resets. However, it would introduce a split quality standard within the period, reducing certainty and departing from the standard ex-ante approach to setting quality standards. It would also assume that the structure of the quality framework remains unchanged between DPP4 and DPP5.

1050 We propose that the Commission sets our quality standards and incentives for the CPP period using the refresh option, outlined above. We consider this approach to be robust and proportionate, as it:

- is consistent with Part 4 purpose of providing services at a quality demanded by customers
- is consistent with the Commission's principle of no material degradation; by setting standards prospectively using the most recent available performance data, the refresh option ensures quality standards for the CPP period reflect what is reasonably achievable
- leverages a stable and existing regulatory methodology that allows the benefits of quality improvements to be passed through to customers, in contrast to 'modelled' approaches that can suffer from optimism bias (reliability impacts of investment overstated and forecast to appear too quickly)
- ensures standards reflect both recent observable and reasonably achievable future performance without creating an excessive step change that would give rise to unnecessarily high compliance risk
- maintains a degree of stability as Orion transitions back to a DPP from FY2033 (based on prior CPP-DPP transitions, we would expect the Commission to set Orion's quality standards for the remainder of the DPP5 period during the DPP5 reset in disclosure year 2030).

16

16 Enhanced performance reporting

1051 Alongside recent CPP determinations, the Commerce Commission has placed additional information disclosure requirements on EDBs, including the publication of Annual Delivery Reports (ADRs) over the CPP period.[73] The Commission indicated its intention was to improve the visibility of EDB performance and strengthen accountability to customers and other stakeholders, including by making it easier for stakeholders to assess whether CPP commitments are being delivered.[74]

1052 Given the possibility that the Commission chooses to place similar requirements on Orion, the sections below outline:

- the proposed role of ADRs
- the proposed measures to be reported on in ADRs
- how we developed the proposed measures.

16.1 Proposed ADR role

1053 Under our proposal, the ADR will be the primary mechanism for reporting on delivery of the CPP plan over the regulatory period – bringing together information on expenditure, outputs and outcomes in an accessible format to complement existing information disclosure.

1054 The ADR will provide a clear and transparent account of our progress in delivering CPP commitments, including:

- how delivery aligns with the 5 strategic priorities underpinning the CPP plan and the customer preferences identified during CPP engagement
- whether and how we have adapted the CPP plan in response to the CPP Determination, the changing community and technology landscape, and other external conditions.

1055 We will report on key CPP programme and project expenditure, including explaining material variances from planned expenditure where these affect delivery of customer preferences and strategic priorities.

1056 We will support the ADR with stakeholder engagement and communication to ensure the information is accessible, understood and open to scrutiny, using our established customer engagement programmes.

16.2 Proposed ADR measures

1057 Our proposed ADR measures focus on areas where additional reporting will provide meaningful insight beyond existing regulatory disclosures, particularly in demonstrating delivery of CPP commitments and outcomes.

1058 The measures are deliberately high-level and outcome-focused, enabling clear visibility of delivery while maintaining appropriate flexibility to respond to changing conditions over the CPP period. This approach ensures accountability is retained at the level that matters most to customers and stakeholders. We anticipate that the measures will be developed in further detail in coordination with the Commerce Commission as part of its CPP decisions.

[73] For example, Powerco was required to publish an ADR, present this report's findings in public meetings and hold an annual technical meeting with the Commission to discuss progress in delivering its CPP programme. Aurora's requirements were similar but required it to publish additional planning documents.
[74] For example, see https://www.comcom.govt.nz/assets/pdf_file/0018/264240/Aurora-Energy-Limited-Additional-Information-Disclosure-Requirements-Final-reasons-paper-31-August-2021.pdf

1059 Together, these measures are designed to enable stakeholders, including the Commission, to assess whether we are delivering the commitments and outcomes underpinning our CPP (Table 16.1).

Table 16.1 Proposed ADR measures

Objective	Measure	Insight provided	Relationship to existing reporting
Delivery against customer preferences	Report on delivery of CPP-funded programmes consulted on through customer engagement: • 66 kV oil-filled cable replacement programme: delivery against customer-preferred timeframes • Non-network solutions: implementation outcomes, including targeted capex deferral • Network transformation programme: delivery of planned work, realised benefits, and key learnings Report on how overall expenditure has tracked against the plan / CPP Determination, including whether and why expenditure has been reprioritised	Demonstrates whether CPP-funded investment that customers were specifically consulted on is being delivered in line with customer priorities and willingness to pay	Complements AMP and service measures by linking investment delivery to customer preferences and outcomes (not explicitly covered elsewhere)
Delivery against strategic priorities	Report on progress against the CPP strategic priorities: • Maintain safety: development of a network asset safety risk register and, once established, performance against asset safety targets • Maintain reliability: customer-facing summary of Asset Management Plan reliability performance reporting • Support growth: resolution current and forecast LV network constraints • Strengthen resilience: delivery of key programmes (66 kV cable replacement, fire risk poles, vegetation management and fuel storage) • Prepare for future energy needs: integration of non-network solutions and delivery of network transformation initiatives • Enhance efficiency and capability: delivery of IAM programme	Demonstrates delivery of the CPP strategic priorities and associated outcomes	Complements AMP and reliability reporting by focusing on delivery of strategic initiatives rather than operational performance metrics
Changes to CPP programme over time	Report on material variances from programmes or projects: • changes to scope or timing of major system growth projects (>$5m) • cumulative (multi-year) variances between forecast and actual expenditure and delivery across major renewal projects • cumulative (multi-year) variances (>30%) in specified volumetric renewal programmes (volumes or expenditure) Provide explanations of the drivers of the material variances	Enables stakeholders to assess how the CPP plan is evolving, including the management of trade-offs and delivery risks	Extends beyond Information Disclosure by providing forward-looking, programme-level and multi-year variance explanations
Accessibility and transparency	Publish the ADR and support it through stakeholder engagement through our established engagement programme	Ensures information is accessible, transparent and open to stakeholder scrutiny	Enhances accessibility and usefulness of existing disclosures rather than duplicating them

16.3 Approach for developing proposed measures

1060 In developing the proposed ADR measures outlined above, our objectives were to ensure we can:

- demonstrate delivery of the customer priorities and expectations identified through our CPP engagement
- demonstrate delivery of the 5 strategic priorities underpinning our CPP plan (to the extent this is enabled by the Commission's determination)
- clearly communicate any divergence between the CPP plan and actual delivery, and the reasons for this divergence.

1061 We consider that additional information disclosure should add value over existing regulatory reporting, avoid unnecessary duplication and cost, and provide information that is meaningful and accessible to customers and stakeholders.

1062 Therefore, in developing the proposed measures, we assessed our expected reporting and communications over the CPP period to identify gaps against the objectives outlined above. This included:

- our Information Disclosures requirements
- the information we intend to report on in our Asset Management Plan 2026 and future AMPs – including the associated information disclosure schedules, asset management improvement plan, reliability (quality standard) performance reporting, service measures and associated performance evaluation
- Electricity Authority requirements (e.g. connections queue reporting)
- the information we communicate through our routine customer engagement programme.

1063 Based on this review, we developed a targeted set of proposed ADR measures, set out in Section 16.2, to complement existing reporting and provide enhanced visibility in areas where this adds most value to customers and stakeholders. Together, these measures enable transparent assessment of delivery against customer preferences and strategic priorities, and how the CPP plan evolves over time.