Electra

Asset Management Plan 2025 to 2035

Contents

1. Executive summary

1.1 Introduction

We commenced a two-year programme to update our Asset Management Plan (**AMP**) at the beginning of 2024. This document is a significant revision of our previous full AMP, issued in 2023.

This AMP communicates Electra's approach to operating a safe, reliable, and cost-effective electricity network. We are committed to the long-term stewardship of the network, which will allow us to meet the needs of customers and stakeholders and support the livelihoods of the people and businesses throughout Horowhenua and the Kāpiti Coast.

This AMP has been structured in three parts:

- Part 1: The key issues facing the network;
- Part 2: Strategies to address the key issues;
- Part 3: Implementation plans to deliver the strategy and the required level of performance.

Whilst we have changed the structure, this AMP continues to provide all the information to assure our stakeholders that:

- Our assets are being managed for the long term;
- The required level of performance is being delivered (and where there are gaps, improvement plans are being implemented);
- Our business is efficient (so the distribution prices are no higher than need be).

This executive summary highlights the key factors driving investment and performance, the strategies adopted to ensure the network responds to those factors, and the key programmes and projects supporting the strategy. This section overviews the six strategic themes driving the $280 million[1] investment in the network and systems over the next decade.

Over the next 12 months, we will continue working on various improvements outlined in the asset management improvement plan. The AMP published in 2026 will include further updates as we complete our two-year improvement journey.

1.2 The network

Electra's network is spread over the Horowhenua and Kāpiti districts on the narrow strip of land between the Tasman Sea and the Tararua Ranges, stretching from Foxton and Tokomaru in the north to Paekākāriki in the south. The network covers approximately 1,628 km^2.

The Horowhenua district has a population of 36,700, with most people living in Foxton, Shannon, Levin, and several beach settlements. The northern (Horowhenua) network is tied to horticulture, dairy farming, and Levin's urban and commercial areas.

The Kāpiti Coast district has a population of 58,700, with most people living in the towns Ōtaki, Waikanae, Paraparaumu, Raumati, Paekākāriki, and other beach settlements. The southern (Kāpiti Coast) network is

[1] This is total capital expenditure, less capital contribution plus vested assets.

predominantly urban and includes light commercial, rural lifestyle, and agricultural production. Many customers on the southern network commute to Wellington, so daytime demand is considerably less than evening demand.

Our network is electrically contiguous but generally operates as a northern and southern network, with the interconnection between the two being north of Ōtaki. We operate a very secure sub-transmission system, and all zone substations, except Paekākāriki, are afforded N-1 sub-transmission and zone substation transformer security. This is consistent with the semi-urban nature of our customer base.

The 11kV distribution network comprises interconnected radial feeders. This is primarily overhead construction in the northern region and mostly underground in the southern region. Our overhead network is exposed to adverse weather, vegetation, and vehicle damage (when located near the roadway). Our underground network, whilst reliable, has a very low switch density, which constrains our ability to restore faults quickly. This is an area for improvement.

1.3 Recent performance

We monitor our performance against various measures, including customer service, safety, environmental, asset performance, network efficiency and work delivery.

Our overall trend for health and safety is positive, and we continue to improve. Work on auditing and improvement actions has taken a step up in recent years, and we expect to see this benefit in our safety outturn in the coming years.

Overall, our unplanned reliability performance has generally been good, and we perform well against our peers (Figure 1). We have exceeded our target due to one-off events, which are not yet indicators of any current issues (Figure 2).

Unplanned reliability is an area of focus for the business, and a few recent observations are:

- The recent trend in defective equipment outages is static (which is acceptable). However, we see a concentration of defective equipment and adverse weather outages on our worst-performing (overhead) feeders. Improving the performance of the worst-performing feeders through a combination of reliability improvement initiatives and targeted asset renewals in areas where asset health is deteriorating is a focus for this AMP;
- We currently have very few cable outages; however, restoration times are very long when they occur. This reflects the limited switching on the underground distribution network, which extends restoration times. Increasing our ground-mounted switch density is required;
- In recent years, vegetation-related outages have been concentrated on a few feeders, and climate change is likely to exacerbate vegetation contact. Our operational plans have been prioritised to address the worst-performing feeders (for vegetation).

Our planned reliability targets are no longer appropriate due to the increasing work being undertaken on the network. As work on the underground network increases, the limited switching capability will significantly increase the reliability impact. The targets need to increase to accommodate the increasing work volumes required to effectively manage the network.

We have delivered the vast majority of our planned capex and opex works programme. However, some capex projects and some planned inspections have seen delays due to the time taken to select new lines and cable routes (delaying design work) and due to internal staff shortages. We are improving our front-end processes and have recently increased inspection staff numbers. These will assist in resolving the recent issues.

Figure 1: Unplanned outage duration[2]

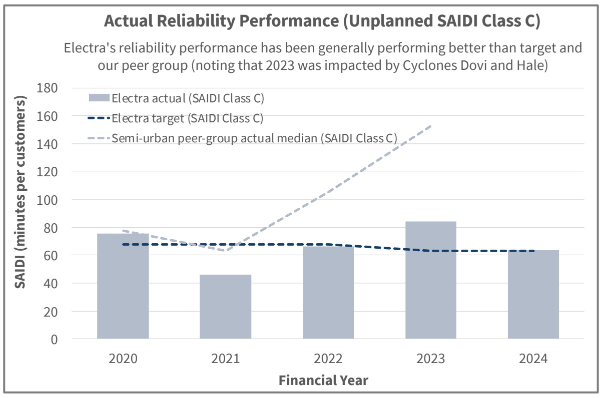
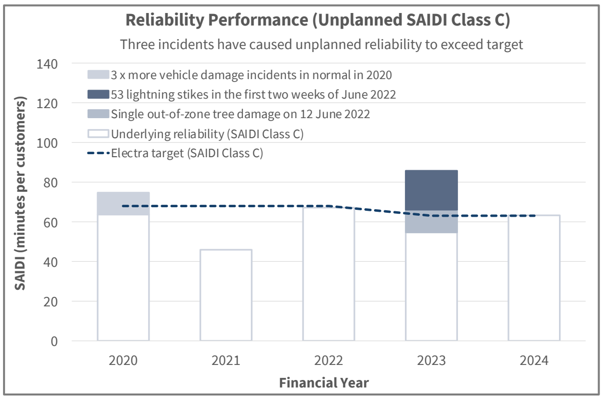


Figure 2: Unplanned outage, reasons for the target being exceeded



1.4 The strategic themes shaping this AMP

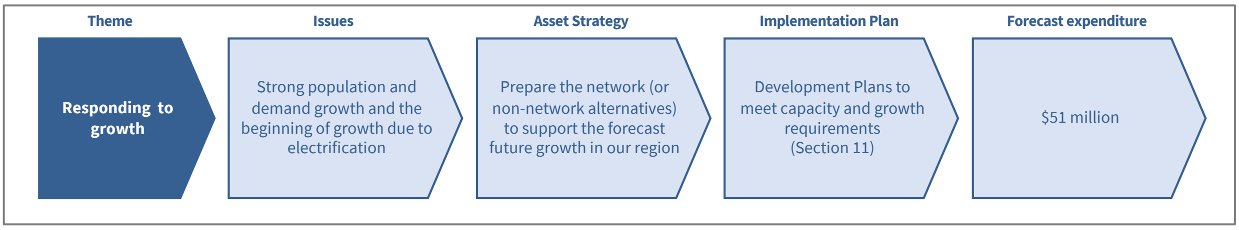
Six strategic themes are driving the investment and performance of the network:

- Responding to growth;
- Responding to the electrification of New Zealand;
- Responding to our aging assets;
- Reducing reliability risk;
- Preparing the business for the future;
- Balancing stakeholder needs.

We discuss the issues, strategy and implementation plans associated with these themes in the following Sections.

1.5 Responding to growth

Figure 3: Responding to growth



Electra is experiencing a period of strong growth (refer to Section 5.2). Horowhenua District Council forecasts the population to grow to 62,000 by 2041. The District's population is projected to grow 1.8% annually over the next ten years[3]. This is much higher than in previous decades. The growth is partly driven

[2] The semi-urban peer group was impacted by major weather events in 2022 and 2023 (Cyclones Dovi, Hale and Gabrielle).

[3] Sense Partners, "Horowhenua Socio-Economic Projections Summary and Methods", May 2020

by the Wellington Northern Motorway project, which improves access to the Wellington region. Plenty of flat land is available in Horowhenua, close to transport links. This land is cheaper than that available in Wellington and Palmerston North, which will likely fuel commercial and light industrial development in the region. Based on our projections, we are forecasting around 9,500 new connections by 2050 in the Horowhenua region.

On the Kāpiti Coast, we are seeing significant progress in land development. The current view suggests land development could be in the order of 600-700 sections per year, which equates to a growth rate of around 1.7% p.a. Based on our projections, we are forecasting around 14,000 new connections by 2050 in the Kāpiti Coast region.

Our view on population growth will see the base demand (before the impact of electrification) grow by 13% by 2035 and 40% by 2050. This indicates an additional 26 MW of demand by 2050, before any effect from electrification.

In response to this growth (and incorporating the early stages of electrification growth), we have identified a range of capacity constraints across the region that need to be addressed. The proposed work includes:

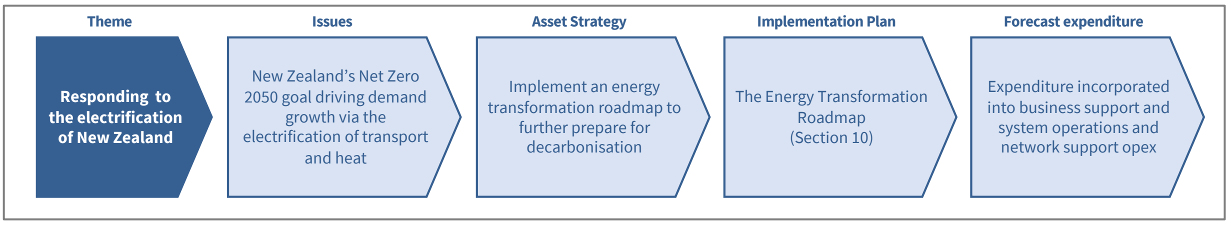
- The development of a new Northern GXP. This project is discussed in Section 11.8. The capacity available from the existing Mangahao GXP will shortly become constrained, and we are analysing the potential options to increase capacity in the region. The project is not yet in the expenditure forecasts;
- Upgrading subtransmission line capacity in the Northern region and constructing two mini-zone substations, with preparatory work for a third (refer to Section 11.9);
- Construction of thirteen new 11kV distribution feeders to supply new developments and additional capacity for growth. Our near-term plans include six specific feeders (most in the Southern region) and provision for a further seven from FY2030 (refer to Section 11.10).

Our development plan has been prepared based on meeting controlled demand growth (see Section 10). Our current plans can efficiently cater for high growth, should this occur. Conversely, we can defer development should demand growth fall below the controlled demand forecasts.

We are also in the early stages of considering non-network alternatives. At this stage, there are no viable alternatives to the proposed projects; however, we will continue exploring options as we work on the projects.

1.6 Responding to the electrification of New Zealand

Figure 4: Responding to the electrification of New Zealand

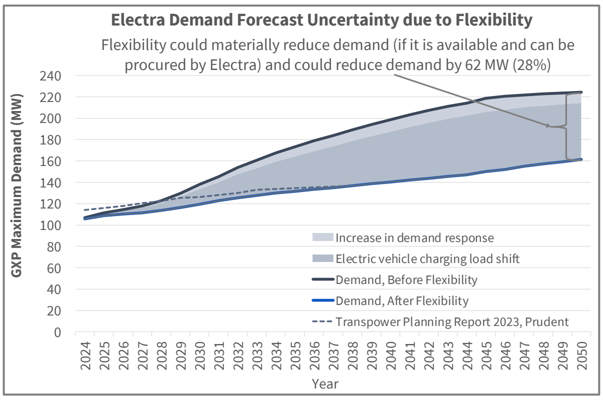


Reducing emissions through electrification and increasing renewable generation are critical to achieving net-zero 2050. In particular, the electrification of transport and heat (both process and general) and the use of distributed energy resources (**DERs**) are central to decarbonisation (refer to Section 5.3).

Our network provides the critical link between customers and energy markets and enables greater customer participation in decarbonisation. We prepared an energy transformation roadmap (**ETR**) in FY2022 and have been monitoring industry developments and progressing with the various actions on the roadmap since then. The ETR ensures we have a pathway to build the capability and capacity to support New Zealand's decarbonisation efforts (refer to Section 10).

We are forecasting a material increase in the connection of controllable DERs (like EVs and solar PVs in combination with batteries). These are expected to reach over 11,000 by 2050. These controllable DERs can provide flexibility (i.e. reducing electricity demand in response to a signal).

Figure 5: Demand Growth and the impact of flexibility

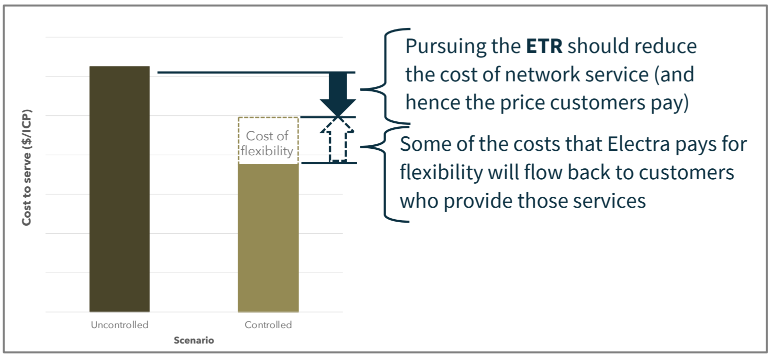


Utilising flexibility is an important aspect of our ETR. It can significantly reduce peak demand on the network and significantly reduce investment in new capacity. Our modelling indicates that flexibility could reduce demand by 62 MW by 2050, which is a 28% reduction (Figure 5).

Our modelling suggests three key benefits of pursuing the ETR (Figure 6). These include:

- Lowering the cost of network services—by utilising non-network alternatives, like flexibility to reduce investment in network capacity;
- Enabling customers to decarbonise through electrification;
- Lowering overall energy costs to customers through electrification and flexibility payments.

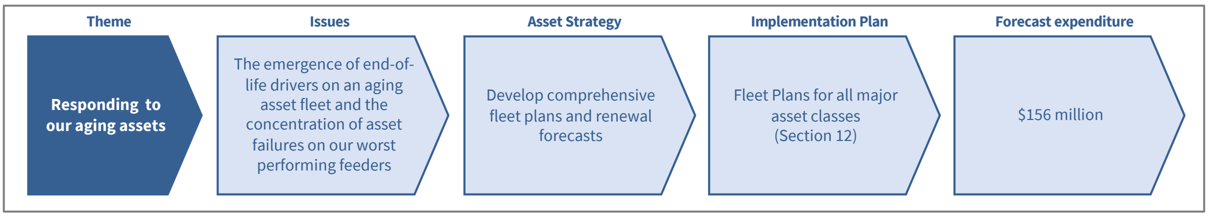
Figure 6: Benefits of the ETR



We have begun to increase the team's capabilities and are forecasting that many of our operational technology systems will need to be upgraded in the future. The ETR is only the starting point for our transformation work. There will be further detailed network modelling and refinement of solutions over the next 12-24 months. We expect the roadmap to evolve (along the direction laid out) as technology evolves and customers and society adapts.

1.7 Responding to our aging assets

Figure 7: Responding to our aging asset fleet



Many of our assets were installed in the 1950s, 1960s and 1970s, and many will reach end-of-life over the coming decades. We expect that end-of-life drivers for replacement could emerge in around 18% of the fleet over the next decade (refer to Section 5.4). How we manage asset-related risks will be a greater focus for the business.

We have an initiative to define asset fleet strategies that are aligned with the quality and availability of asset age, condition, and risk data for each asset fleet. We will be accelerating asset condition inspections where data gaps exist. We will also target asset renewals where asset health is deteriorating, including prioritising pole-top hardware and conductor on the worst-performing feeders (refer to Sections 4.5.9, 12.12 and 12.13).

We have developed a Condition-Based Asset Risk Management Model (CBARMM) to forecast asset risk and renewals. The model is based on the DNO Methodology.[4] CBARMM models have been developed for all network assets. These models apply a risk-based, information-driven approach to asset renewal forecasting. The CBARMM models provide a systematic, data-driven methodology to identify asset renewal needs and enable us to evaluate overall asset fleet risks based on different renewal, refurbishment or maintenance scenarios (refer to Section 12.4).

Fleet risks are increasing most significantly for our zone substation assets, overhead distribution assets, and the low-voltage network. Fleet risks on the underground assets are challenging to forecast, but we are expecting these to emerge mid-way through the planning period.

Fleet risks for zone substation circuit breakers, transformers, and protection systems are increasing. These are critical assets, and we have a lower risk tolerance for failure. Over the planning period, we have a $32 million renewal programme for these assets. We generally plan to replace or refurbish zone substation assets before the risk increases above medium (above risk grade 3). However, we are replacing more assets than indicated by their risk grade alone as some safety-related factors, building resilience issues, and protection scheme vulnerability drivers are not fully reflected in CBARMM (refer to Section 12.6.1). The significant zone substation renewal programmes are power transformers ($13.8 million, due mainly to the presence of end-of-life risks) and protection relays ($9.1m, due mainly to technological obsolescence).

The percentage of distribution assets with increasing risk varies. Forecast high-risk assets are below 5% for our large concrete pole and crossarm fleet and below 10% for a small wood pole fleet.[5] We have a $59 million programme to address these risks over the next ten years (refer to Section 12.6.2).

4 Ofgem, "DNO Common Network Asset Indices Methodology—Version 2.1", April 2021.
This is a common framework of definitions, principles and calculation methodologies published by Ofgem and adopted by all GB Distribution Network Operators for the assessment, forecasting and regulatory reporting of asset risk.

5 Over the next five years.

Forecast high-risk assets and between 0% and 13% for subtransmission and distribution overhead conductor and cable. Most of these risks relate to overhead copper conductors, and there is a $32 million programme to address these assets over the next ten years (refer to Section 12.13 and 12.14).

The $5 million renewal programme for distribution switches addresses type issues identified on our air-break switch and ring-main unit fleets. Due to the lower consequence of failure associated with distribution transformers and pole-mounted dropout fuses, we are operating these assets at a higher risk rating. This approach is typical across the industry (refer to Section 12.15 and 12.16).

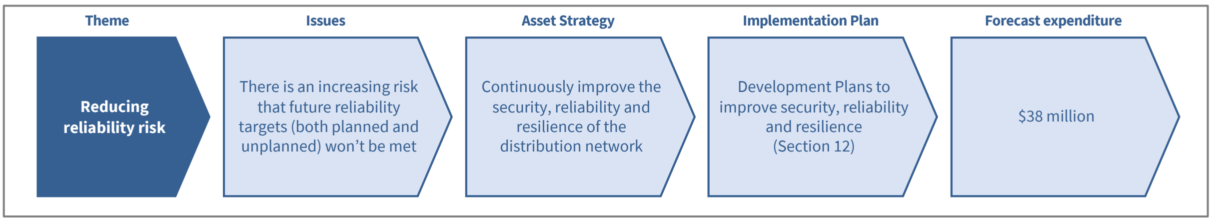
We anticipate increasing end-of-life issues on our low-voltage pillar boxes, and a $15 million asset renewal and safety programme is planned over the coming decade. This programme focuses on steel pillar and link boxes, where we have identified potential safety issues being addressed (refer to Section 12.17).

Our CBARMM process predicts a growing number of high-risk LV conductors and cables. Assessing the health of these assets is inherently challenging, and the performance of these fleets indicates that the need for renewals is not yet required (hence our forecast for renewals is below the projected risk). We are monitoring the fleet's performance to identify emerging health issues.

For all the assets being replaced, where possible, we will use the opportunity to incrementally address resilience—to physical conditions and the energy transformation.

1.8 Reducing reliability risk

Figure 8: reducing reliability risk



Our planned and unplanned reliability performance has generally been good, but without change, there is an increasing risk of deteriorating reliability performance. The risks to reliability performance arise from climate change, population growth, our aging asset fleet and the limited switching points on the underground network (refer to Section 5.5).

Based on a continuation of historical performance, we have a 38% probability of achieving our unplanned reliability (SAIDI) target in any year. Given the risks mentioned above (if left unmitigated), this could deteriorate to less than a 10% probability of achieving the target by the end of the decade.

Given the increase in planned work (and the fact that the current configuration of the underground network does not meet our planning standards), our current planned targets are no longer appropriately set. Our planned work on the underground network will severely impact customers due to the large outage areas required. We believe that this situation will be unacceptable to our urban customer base so we have developed targeted improvement programmes to address the switching point issue.

Managing reliability is increasingly important. Electrification will reduce energy diversity and increase New Zealand's dependence on a reliable electricity supply. Customers need confidence that electricity will be delivered where and when required, and maintaining the reliability of supply will provide this confidence.

Given the increasing reliability risks and the importance of maintaining a reliable network, we are planning a range of improvement projects to increase the network's security, reliability and resilience. These initiatives will improve unplanned reliability performance over what we currently provide and enable us to achieve our recently revised planned reliability target.

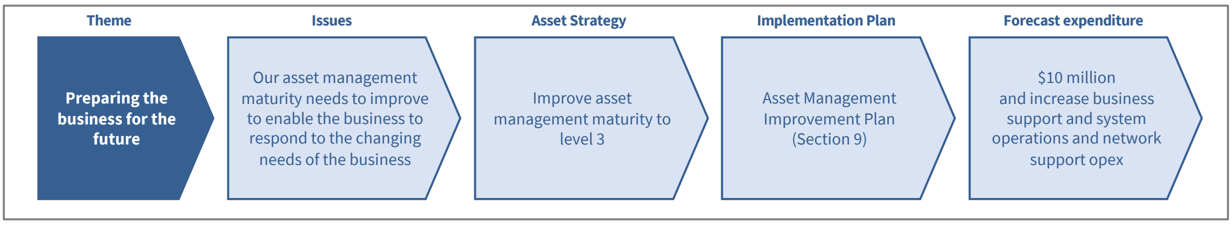
These security and reliability initiatives amount to $38 million over the planning period and include:

- Urban underground network security, automation and protection enhancements (Sections 11.10.3 and 11.10.4);
- Rural overhead network security, automation and protection enhancements (Sections 11.10.3, 11.10.4 and 11.12.3);
- Improvements in resilience (Section 11.10.5[6]).

Our overhead line and conductor renewal programme also targets the worst-performing feeders (Sections 4.5.9, 12.12 and 12.13). We also want to ensure that the vegetation management work focuses on the worst-performing feeders (Section 12.19.2).

1.9 Preparing the business for the future

Figure 9: Preparing the business for the future



Until now, our maturity has been a good fit for the network and business needs. However, we now need to improve our asset management maturity to ensure that we can cater for the changing needs of the network and the increasing complexity of our operating environment (refer to Section 5.6).

We are embarking on an asset management improvement plan that will drive the improvement in asset management maturity (refer to Section 9). The improvement plan comprises three parts:

- Enhancing policies, processes and procedures;
- Enhancing IT/OT systems (Electra's Information System Strategy Plan);
- Enhancing asset management data.

Regarding process improvements, our immediate focus is on condition assessment standards, development planning, front-end engineering design and contingency plans. We will also look to formally establish an asset management group to oversee various asset management actions required to lift maturity and to support the Board's asset management and planning subcommittee. These near-term actions will help the

6 We have a reliability improvement target for our resilience initiative. However, we have not yet specified the resilience projects. We have only recently finalised our resilience strategy, and the projects are being considered over the coming year.

more pressing needs of the business. We have employed a resource to progress these actions in the past year.

We have identified a significant Information technology (**IT**) and operational technology (**OT**) system enhancement programme. The OT developments are focused on our core SCADA and ADMS operational systems. Our SCADA system is reaching end-of-life, and newer systems offer opportunities to increase resilience and cybersecurity. Our current SCADA and ADMS application layers are becoming outdated, with some areas of limited functionality, which we plan to upgrade or replace. These planned upgrades will ensure we keep pace with the evolving operating environment and prepare for the energy transformation.

We are progressing with significant IT upgrades to our financial system and our geospatial information system (**GIS**) and selecting an enterprise asset management system (**EAMS**). Choosing right-sized and least customised technology products, and aligning to good industry practice, we will implement a separate financial and asset management system. A modern EAMS will provide significant industry-standard processes to enhance maintenance and asset management delivery.

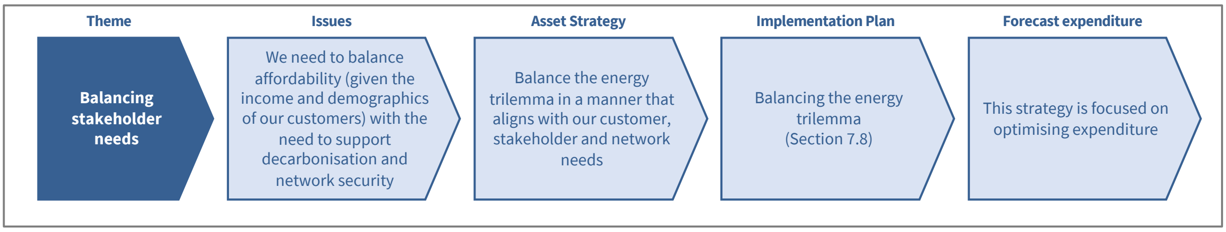
The quantity and use of data is increasing across all business areas, and our need to maintain data quality is also growing. As a result, we have prepared a data transformation roadmap. This roadmap will guide the processes, policies, and technologies for data collection, storage, management, and analysis across the business.

Our data transformation roadmap will deliver significant benefits by creating advanced data products that will enhance our understanding of the network to ensure our infrastructure operates at peak efficiency, improved finance, pricing, and performance forecasting capabilities, better asset health and service delivery optimisation, and the ability to develop customer and community intelligence tools.

This strategy impacts capex by $10 million over the forecast period, but most of the impacts are seen in opex, where there is an increase in personnel (as maturity improves and services increase) and in IT, as many of the new systems are now software-as-a-service.

1.10 Balancing stakeholder needs

Figure 10: Balancing stakeholder needs



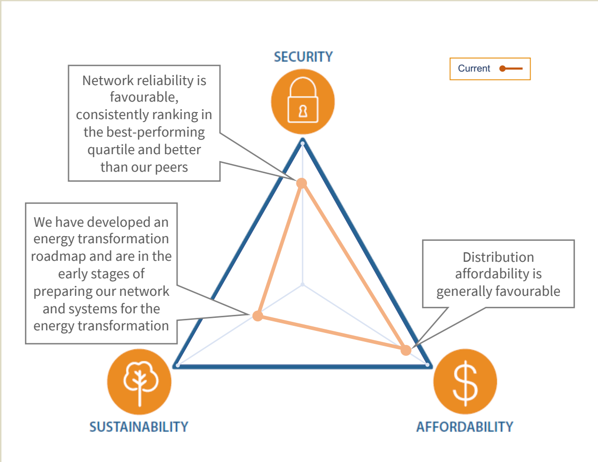
Balancing the needs of stakeholders is essential in all aspects of our business. We have adopted the energy trilemma as a tool to consider this balance (from an asset management perspective). The energy trilemma is a well-recognised model for assessing the optimisation and balance across security of supply, affordability to customers, and sustainability (refer to Section 5.7).

In the energy context, the three limbs refer to:

- **Security** means the ability to meet current and future energy demands reliably, as needed by our customers, including being resilient to external events (reliability is the measurable outturn of security for a distribution business);
- **Sustainability** means supporting New Zealand's energy transformation, minimising emissions, and adapting to climate change. In the AMP, we are principally concerned with supporting the energy transformation;
- **Affordability** means the cost of, and access to, energy (of which electricity is an increasingly important component).

Our current energy transformation balance (as shown in Figure 1) favours security and affordability, as we are only in the early stages of preparing for the energy transformation.

Figure 11: Electra's current energy trilemma balance



- **Security:** Electra's reliability has consistently ranked in the best-performing quartile over the past five years and has been less volatile than the industry and our semi-urban peers. However, we have further work to do to assess and improve resilience. The broader issue of energy security, including electricity generation and wholesale market activity, is outside the scope of our AMP.
- **Sustainability:** We developed an energy transformation roadmap in 2021 and have been progressing with its implementation, which remains in its early stages. We are not yet seeing material impacts from electrification, the uptake of DERs and material changes in customer behaviour. However, our network analysis indicates that constraints will emerge on the network (depending on our ability to control demand through access to flexibility);
- **Affordability:** Since 2013, our distribution prices have declined in real terms.[7] Given the concentration of older people and the generally low income of our customers, affordability is a key strategic consideration for the business.

This AMP will influence the energy trilemma balance over the coming years as we ramp up our investment to address growth, prepare for the energy transformation, and renew our ageing asset fleet. The increase in capital expenditure will ensure that we continue to perform strongly on security and enhance sustainability. However, this will impact affordability in terms of distribution costs. However, as sustainability improves, customers will gain greater access to lower-cost electricity (as a substitute for pricier fossil fuels), thereby enhancing their overall affordability (refer to Section 7.8).[8]

1.11 Future targets

We have comprehensive performance targets consistent with our asset strategies, stakeholder interests and customer expectations (refer to Section 7).

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7 Based on the 2013 to 2023 Information Disclosures.

8 Assessed by Sapere in their recent report for the Electricity Networks Association https://www.ena.org.nz/news-and-events/news/total-household-energy-cost-to-reduce-over-time/

We are committed to ensuring the health and safety of our employees, contractors, customers, and the public. We have a comprehensive health and safety system aimed at achieving zero LTIs (concerning critical risks), and we predominantly measure safety performance using leading indicators—which is the best way to ensure that we influence safety outcomes. We have commented on our prior performance in Section 4.2.

Figure 12 and Figure 13 show our primary reliability performance targets (other targets are included in Section 7).

We have forecast our future reliability performance separately from our target. The future performance is based on a continuation of an “average” year (regarding the impact of weather, third-party damage, and other factors) and incorporates our planned improvements.

Including the planned improvements, we expect a 50% probability of achieving the unplanned SAIDI target in FY2029. Having forecast performance to at least achieve P50, and we think it strikes the right balance between investing more in reliability and accepting that there will be some years (due to weather) that we will exceed the target.

We are forecasting an increase in planned outages, reflecting the planned increase in work volume. Even with this increase, we will perform significantly better than our peers. The new target is a 90% increase from that included in the 2024 AMP; however, our prior targets have been insufficient and exceeded four out of the past five years. Planned outages are notified in advance and generally cause less inconvenience for customers.

Figure 12: Unplanned outage duration

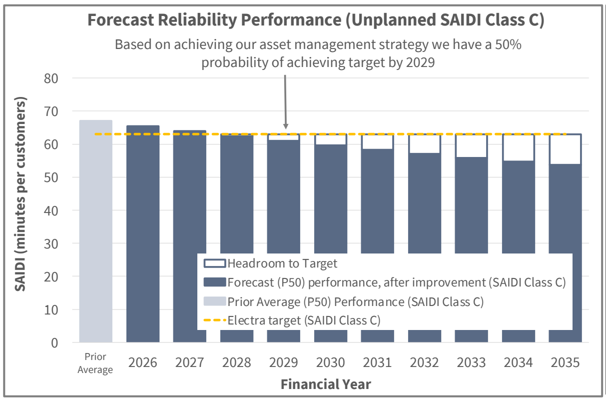
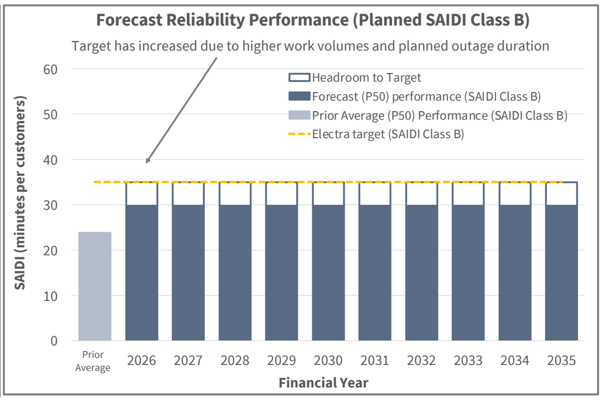


Figure 13: Planned outage duration



We also have a range of asset performance and work delivery targets. We are forecasting improvements in our performance in both these areas over the coming decades.

1.12 Delivery capability

Over the last decade, our resourcing strategy and Electra’s in-house resources have evolved to support the business's needs. Our strategy continues to evolve in response to our corporate and asset management strategies, recent delivery performance, national resource constraints, increasing work volumes, and our aging workforce (refer to Section 13).

Since our last AMP, we have responded to the various resource challenges through a range of initiatives, including:

- Significantly increasing resourcing in asset management and planning, and established a graduate engineer programme;
- Redefining our People, Safety, and Culture operating model to support the business;
- Establishing a Commercial team, bringing expertise in the regulatory, pricing and commercial in-house;
- Establishing an in-house Customer Experience team to support the business with customer engagement, communication, complaints, and community connection;
- Building our information technology and operational technology capabilities to ensure our data is managed appropriately and can deliver business improvements;
- Building our internal field resource capability from within. This included creating 12 new roles for trainee line mechanics, cable jointers, arborists, technicians, electricians, and a control room operator. We continue to pursue a range of other strategies.

1.13 Risk management

Electra is exposed to a wide range of risks, not just those inherent in operating an electrical network but also those from external influences such as legislation and regulation, environmental changes, and stakeholder satisfaction. As a lifeline utility, we recognise our responsibility to ensure the network is safe, secure, and resilient.

We have established a comprehensive risk management policy and framework based on the internationally recognised standard AS/NZS ISO 31000:2018. This system has identified significant business risks, including regulatory change, staff retention and recruitment, climate change and sustainability, decarbonisation, harm to workers and the public, and cyber security. We have developed a range of controls to manage these risks.

Operating and maintaining an electrical network involves hazardous situations with risks that cannot always be eliminated. For this reason, we operate a mature safety management system (refer to Section 13.4). This system includes a comprehensive range of controls, including hazard identification, certification, training and auditing (amongst many others).

Cyber-related attacks continue to increase globally and in New Zealand. We have carried out a series of assessments and undertaken a series of activities on cyber security controls. We continue to develop and enhance our cyber security controls, particularly concerning our operational technology.

1.14 Expenditure forecasts

Our forecast capital expenditure (**capex**) and operational expenditure (**opex**) have increased over the 2024 AMP.

The capex forecast for the next five years is $153 million; for the 10-year planning period, it is $280 million (Figure 14 and Table 1). Compared to the 2024 AMP, this is an increase of $12.3 million (9%) over the next five years and $4.4 million (2%) to FY34[9].

Our commentary relates to the first five years (FY26 to FY30), as our forecasts reflect known projects and programmes for this period. The forecasts beyond the first five years are more general, and the forecasts in

[9] When comparing forecasts to the 2024 AMP, we can only compare to FY34 as this was the extent of the forecasts included in that AMP. Before adding Vested Assets and deducting Capital Contributions.

this period may change if economic conditions, electrification demand, subdivision activity, asset health or asset risk change.

The material drivers of the increase in capex over the first five years relate to developing two mini-zone substations, voltage support at Ōtaki, and two subtransmission line upgrades that are required in response to growing demand (refer to Section 11.9), and an increase in asset renewal (refer to Section 12.8 to 12.18) in response to the increasing asset age and risks. The timing for developing a new Levin depot and office has changed, increasing expenditure in FY27 (refer to Section 13.5.1).

The network opex forecast for the next five years is $131 million; for the 10-year planning period, it is $264 million (Figure 15 and Table 2). Compared to the 2024 AMP, this is an increase of $12.3 million (10%) over the next five years and $20.4 million (9%) to FY34.

The material drivers of the increase in opex over the first five years were primarily due to additional IT costs (refer to Section 9.8). These increases relate to SaaS (Software as a Service) and employee and consulting costs relating to the data transformation roadmap. SaaS is a shift in our cost structure, where IT licence and development costs were traditionally capex. We are also forecasting higher finance, commercial, communication and people and culture costs as we improve the maturity of our operations, risk management, and people support. There is also an increase in service interruption and vegetation management costs to reflect current fault management costs and expand our vegetation management programme (refer Section 12.19.1 and 12.19.2).

Figure 14: Capex Forecast (Real 2025$)[10]

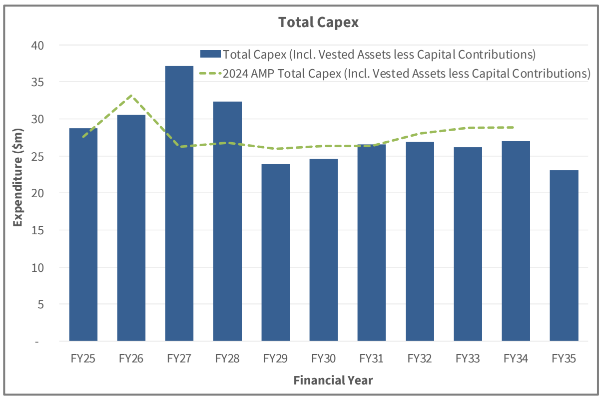


Figure 15: Opex Forecast (Real 2025$)

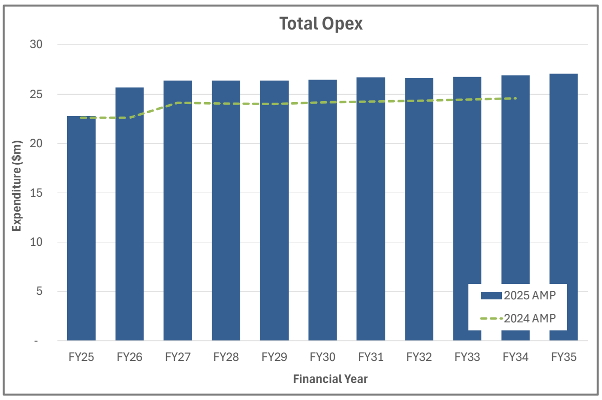


Table 1: Capex Forecast (Real 2025 $000)[10]

Forecast	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Capex 2025 AMP	30,061	37,117	36,459	25,469	24,030	26,025	26,323	25,610	26,392	22,439
Capex 2024 AMP	33,654	27,634	27,557	25,837	26,196	26,222	27,901	28,671	28,747	
Change	**(3,593)**	**9,483**	**8,902**	**(368)**	**(2,165)**	**(197)**	**(1,578)**	**(3,061)**	**(2,354)**	

Table 2: Opex Forecast (Real 2025 $000)

Forecast	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Opex 2025 AMP	25,693	26,888	26,466	26,058	26,218	26,347	26,284	26,395	26,567	26,725
Opex 2024 AMP	22,611	24,138	24,040	24,013	24,169	24,256	24,344	24,432	24,554	
Change	**3,082**	**2,750**	**2,426**	**2,045**	**2,049**	**2,091**	**1,940**	**1,964**	**2,013**	

[10] Total capex Before adding Vested Assets and deducting Capital Contributions.

1.15 Concluding comments

Early in 2024, we embarked on a two-year programme to update our AMP to reflect the uplift in our asset management capability. In this AMP, we have outlined the key issues, strategies, and plans for responding to them. Our work programme will continue over the next 12 months, and the 2026 AMP will include fleet plans on all our significant assets.

This AMP includes some near-term increases in capex (due to growth and our aging fleet) and a long-term increase in opex as we prepare for the business's future needs.

This AMP describes our plans to develop and renew the network and build our business capabilities. It will ensure that the assets are managed for the long term and that the required level of performance can be delivered. We have defined improvement plans to close gaps where they exist.

This AMP defines our resilience strategy, which will ensure that high-impact asset-related risks are understood and managed.

This AMP meets this purpose, and we have included a reconciliation of the AMP content to the Information Disclosure requirements in the appendices.

About this plan

2. Introduction, Purpose and Responsibilities

2.1 Introduction this AMP

This AMP outlines how we intend to manage the network over the next ten years and beyond. It covers the current state of the network, our targets for network performance and customer service and our strategies and plans for the network.

We have been through a period of modest growth with a network that has performed well and has not shown material signs of deteriorating asset health and risk. Things are now changing. Growth, across both the Kāpiti and Horowhenua regions, is accelerating. New Zealand's strategy to decarbonise through electrification could further accelerate growth. Our assets are aging, and the presence of end-of-life drivers is increasing. The capabilities required to manage the network are also changing as we move from steady-state to where our network will become integral to New Zealand's decarbonisation efforts and where greater coordination between networks, customers, generators, retailers, aggregators, traders and Transpower in its role as System Operator is required. In this AMP, we describe how we are responding to these changes.

This AMP is a significant revision over our last full AMP published in March 2023. Given the emerging changes, and our need to demonstrate how we are responding, we have organised the AMP into three parts:

- Part 1: The key issues facing our network;
- Part 2: Strategies to address the key issues and performance;
- Part 3: How we are implementing our strategy.

The planning period for this AMP is from 1 April 2025 to 31 March 2035.

The Board approved this AMP on 27 March 2025, and the corresponding Director Certificate is included in the appendices.

2.2 Purpose of this AMP

The primary purpose of this AMP [11] is to provide information to assure stakeholders that:

- The assets are being managed for the long term;
- The required level of performance is being delivered (and where there are gaps, improvement plans are being implemented);
- Our business is efficient (so the distribution prices are no higher than they should be);
- Asset-related risks, particularly high-impact asset-related risks, are understood and being managed.

This AMP meets this purpose, and we have included a reconciliation of the AMP content to the Information Disclosure requirements in Appendix 1.

2.3 Key changes since our last full AMP

Much of the content included in this AMP is an update of that included in the 2023 and 2024 AMPs. However, there are some key changes in this AMP, including:

[11] Commerce Commission, "Electricity Distribution Information Disclosure Determination", Section 2.6.2.

- A description of the key issues facing the network (Section 5);
- A description of the asset management strategies we intend to adopt over the coming decade to address the key issues and performance (Section 6);
- Details on our asset management improvement plan, which is our plan to improve the maturity of our asset management activities and the quality of our asset data (Section 9);
- A new section on the energy transformation that describes the impact electrification could have on the network and our team (Section 10);
- More detailed development plans that describe how we are responding to growth, security and reliability needs (Section 11);
- New asset fleet plans for our key asset classes (Section 12). These fleet plans describe how we manage our assets for the long term.

2.4 Our stakeholders

Stakeholders are defined as any person or organisation that affects or is affected by Electra's business. These include customers, the Electra Trust, employees, contractors, suppliers, energy retailers, Transpower, Councils, Waka Kotahi, landowners, industry bodies, regulatory authorities, iwi, mana whenua, and the general public. We have identified the relevant interests of these stakeholders and how these link to the management of the network (as shown in Table 3).

Table 3: Stakeholder interests

Primary interest of stakeholders	Linkage to asset management
Safety	• Electra keeps the public safe by keeping all assets structurally sound, live conductors are well out of reach, all enclosures are secure, and all exposed metal is earthed • Our Safety Management System (SMS) provides a structured approach to maintaining the safety of the public, contractors and staff • We provide staff all necessary equipment, safe work practices, and will stop work in unsafe conditions • Motoring safety is assisted by placing above-ground structures as far as practically possible from the carriageway within the constraints of private land and road reserve • We engage with stakeholders providing education, raising awareness about working and living safely near Electra's assets • We offer safety services such as asset location, stand-overs, isolations, and close approach permits
Reliability and supply quality	• Electra accommodates stakeholders' needs for supply quality through its security of supply, management of asset health, resilience strategy and operational practices • We pursue published security of supply standards • We seek opportunities to increase system resilience and have developed a resilience strategy and planning standard. We have a dedicated engineering resource allocated to determine areas where resilience improvement is appropriate • We monitor the condition of our assets and direct our asset renewal and maintenance programmes to maintain asset health and minimise the risk of outages • Our operational practices ensure outages are minimised, and when they occur, they are restored quickly
Financial sustainability	• Electra satisfies stakeholders' needs by providing electricity distribution services at a level of quality that our customers are willing to pay for. Electra balances the cost of providing a more reliable or resilient service, with whether that level of service is affordable. • Electra aims to provide a satisfactory discount to Electra's consumers/owners, balancing the size of the discount with affordability and network investment requirements.
Affordability	• Affordability must be managed in line with regards to our regional demographic and our customers' ability to pay
Environmental sustainability	• Electra ensures it complies with all environmental regulations and requirements • We pursue a sustainability policy incorporating good industry practice

Primary interest of stakeholders	Linkage to asset management
	• We consider sustainability and our impact on the environment in the choices we make about how we operate and invest in the network, the materials we purchase, and our installation methods from cradle to grave • We engage with energy users in our region to coordinate electrification requirements enabling the sustainability and energy transition of stakeholders in our regions
Compliance	• Electra ensures that all safety issues are adequately documented and available for inspection by authorised agencies as well as for learning by the staff and contractors • We operate a robust compliance process to ensure we comply with all regulatory, statutory and consenting requirements • We disclose performance information in a timely and compliant fashion.

Our planning standards, customer survey and performance targets provide the relevant standards for assessing compliance and performance against the primary interests. We report on the customer survey and performance in Section 5, define our targets for coming years in Section 7, and discuss our planning standards in Section 11.4.

Where we have conflicts in stakeholder interests, we prioritise safety above all else. This is followed by supply quality (given its impact on customers and the region), environmental sustainability, compliance, and financial sustainability.

2.5 Our strategy

Electra's business strategy is captured in our Statement of Corporate Intent (**SCI**), which defines our purpose, strategy, and values.

Our purpose is:

> **To operate our region's electricity network safely and effectively, and support the growth and electrification of Kāpiti and Horowhenua**

Our strategy to deliver on this purpose is to:

Operate a safe, efficient, innovative and sustainable business which:

- **Focuses on our core operations,**
- **Delivers the needs of our customers and communities in an affordable way,**
- **Supports the growth and electrification of our region,**
- **Invests for a clean energy future, and**
- **Demonstrates the clear value proposition from local trust ownership**

We have developed this AMP to support this strategy. In particular, this AMP demonstrates our focus on the network to ensure its performance meets the needs of customers and communities over the term (Section 7.3). We have a strong focus in this AMP on supporting growth and electrification (Sections 10 and 11).

2.6 Asset management framework and improvements

We are implementing an asset management framework. This framework includes the key elements within ISO 55001 and guides our asset management activities. The framework provides a structure for the systems and processes to manage network assets effectively. It ensures that our asset management strategies, plans, and actions align with our vision, values, and corporate goals. It also ensures that services are delivered to meet the required standard.

Section 8 describes the asset management framework, and Section 9 describes the asset management improvement plan.

2.7 Accountabilities and responsibilities for asset management

Figure 16 shows our organisational structure. The responsibilities for asset management are shared across the executives and their respective teams; these include:

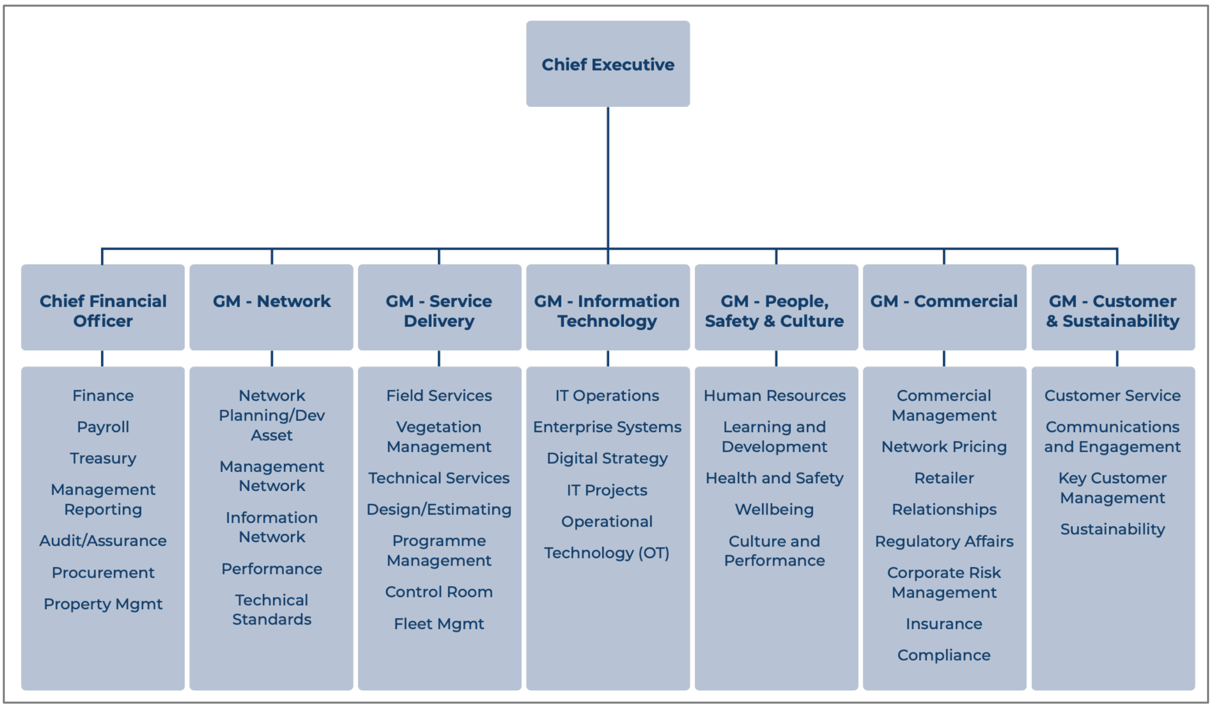
- Corporate strategy is the primary responsibility of the Board, Chief Executive and Senior Leadership Team;
- Strategic asset management is the primary responsibility of the Board Asset Management Committee, Chief Executive and General Manager Network;
- Health and safety is the responsibility of everyone in the business, and is the primary responsibility of the General Manager People, Safety and Culture;
- Asset management planning is the primary responsibility of the General Manager Network;
- Works programme management is the primary responsibility of the General Manager Service Delivery;
- Continuous improvement is shared across the Senior Leadership Team;
- Managing the performance of the network is the primary responsibility of the General Manager Network;
- Risk management is overseen by everyone in the business, and is the primary responsibility of the General Manager Commercial;
- Human resource capability management is the primary responsibility of the General Manager People, Safety and Culture;
- Information management and the development of information systems is the primary responsibility of General Manager Information Technology;

Accountability and assurance that these activities are being undertaken to the required standards are achieved through:

- The Electra Trust have oversight of the company through the SCI, annual reporting, external auditing process, and regular reporting to the Electra Trust;
- The Board oversight of the Chief Executive and the company through the company's management reporting, compliance programme, internal audit programme, asset management and planning committee, audit and risk committee, health and safety committee, and approval of expenditure forecasts, annual budgets, asset management plans, and other tactical and operational plans;
- The Chief Executive and Senior Leadership Team oversee the company's asset management planning, delivery, and operational activities. This is supported by Electra's policies, procedures, standards, and management and operational reporting processes, which cover all aspects of the business's asset management and operational areas.

The delegated authority and position descriptions attached to all roles within the business support the accountability framework.

Figure 16: Organisational structure



2.8 Communication and participation in developing this AMP

This AMP is a key document for Electra and sets the direction for developing and maintaining the network. We communicate the key features of asset management planning and activities to the employees, contractors, and other stakeholders. Key features of our communication approach are:

- The Board undertake an asset management due diligence programme via the Board's asset management and planning committee. This covers the asset management policy, strategy, risks and other material matters;
- For those employees involved in the AMP development, we communicate the asset management policy, strategy and standards at the commencement of the AMP update process;
- For those employees and stakeholders involved in delivering capital projects, inspections and maintenance works, we communicate the plans and projects well ahead of the forthcoming financial year. Our construction, inspection and maintenance standards are available via Electra's contractors portal;
- For those employees involved with managing performance, we communicate the required standards ahead of the forthcoming financial year.

The AMP is communicated to our customers through publishing on our website.

2.9 Linkage to other documents

This AMP is the critical document to ensure that the assets deliver the required performance consistent with the needs of our stakeholders, the Statement of Corporate Intent, our strategy, and business plans. Within this document, the key link to stakeholders and strategy is through the asset management policy and asset management strategy (which are set out in Section 6). We achieve this through:

- Ensuring there is alignment between the strategies, plans and actions in this AMP and Electra's strategy, vision, values and corporate goals, where these goals are aligned with our stakeholder needs;
- Ensuring services are delivered to meet service levels and resilience to respond to high impact low probability events;

- Continuous improvement;

The linkage between the asset management plan and other corporate documents is shown in Section 8.3.

2.10 Significant assumptions

The significant assumptions used in this AMP are summarised in Appendix 2.

Part 1:

The key factors driving our asset management strategy

3. Network and Customer Overview

3.1 Introduction

In this section we discuss the general characteristics of our customers and the network and consider the implications for our asset management strategies and plans. In summary, the implications are:

- Affordability is a key factor when we assess the energy trilemma balance given the age and income demographics of our customers (and beneficiaries);
- Customer behaviours are changing, which will have an impact on demand profile and control;
- Customers are presently afforded a high level of security at a sub-transmission and zone substation level. This supports reliability and is consistent with the semi-urban customer base;
- Parts of our underground distribution network have a legacy architecture which features a very low number of switching points, which restricts the timely restoration of faults;
- Historical LV design standards have been conservative, which means we generally have good LV capacity headroom;
- Our demand profile has significant morning and evening peaks, which may present the opportunity to shift demand to daytime and overnight as electrification demand (particularly from EVs) increases;
- Firm capacity at Mangahao GXP is exceeded, and we rely on Mangahao Generation to manage peak demand.

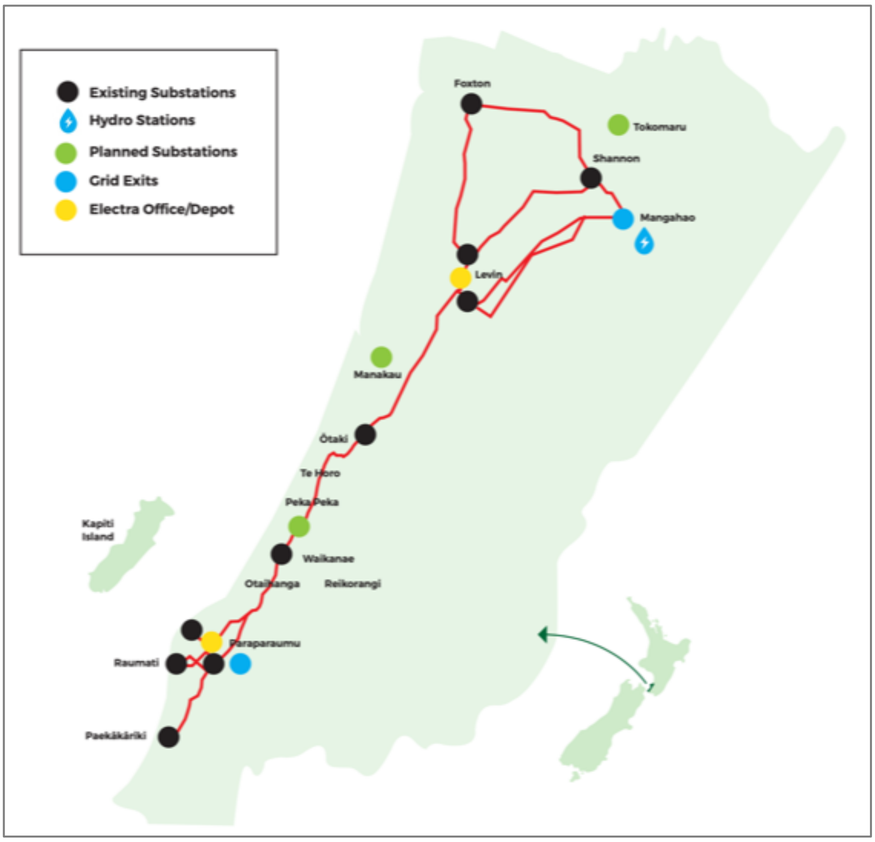
3.2 Network Area

As shown in Figure 17, Electra's network is spread over the Horowhenua and Kāpiti districts on the narrow strip of land between the Tasman Sea and the Tararua Ranges, stretching from Foxton and Tokomaru in the north to Paekākāriki in the south. The network covers approximately 1,628 km^2.

The Horowhenua district has a population of 36,700, with most people living in Foxton, Shannon, Levin, and several beach settlements.

The Kāpiti Coast district has a population of 58,700, with most people living in the towns Ōtaki, Waikanae, Paraparaumu, Raumati, Paekākāriki, and other beach settlements.

Figure 17: Network supply area



3.3 Customer overview

Our network supplies around 47,000 customers, with over 80% being domestic customers using less than 6,500 kWh per year. We have a higher proportion of low users than other networks (nationally, around 68% of domestic customers use less than 6,500 kWh). The number of low users is higher in our region due to the low household occupancy, gas reticulation, the high proportion of people aged over 65 and the low average income.[12]

A further 18% are larger domestic and small commercial customers. These customers are also relatively low users and consume 10,870 kWh per year on average.

A notable absence in our region is any single very large industrial user. Of the small industrial and larger commercial customers , eight use around 6% of the electricity conveyed on the network. These customers are in food processing and production, manufacturing and retail trade.

Given the low industrial consumption, Electra faces a low revenue risk from its large industrial customers.

Given the concentration of older people and the generally low income of our customers (refer to Figure 18 and Figure 19), affordability is a key strategic consideration for the business. We discuss this further in Sections 5 and 7.8.

[12] Horowhenua and Kāpiti have 2.4 and 2.3 occupants per house, compared to the national average of 2.6. Source: Stats.nz
Horowhenua and Kāpiti have 26% and 27% of people over the age of 65, compared to the national average of 17%. Source: Stats.nz
Horowhenua and Kāpiti have average household income of 75% and 88% of the national average. Source: Infometrics

Figure 18: People over the age of 65 in our Region[13]

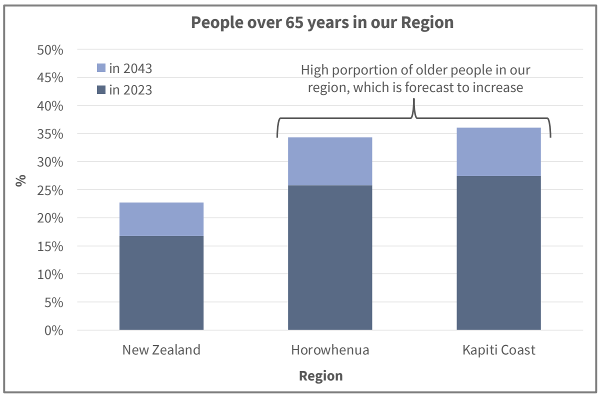
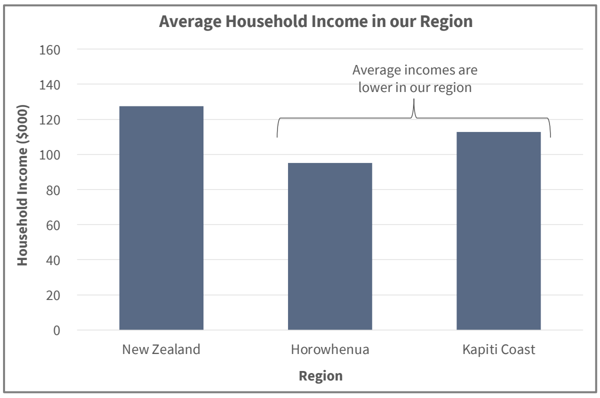


Figure 19: Average Household Income in our Region[14]



Since 2013, new connections have grown by around 0.8% p.a. Connection growth has increased in recent years, and we are now connecting over 400 customers p.a. As mentioned in the introduction, we expect growth to accelerate further, and our forecasts are discussed further in Sections 5, 6 and 10.

3.4 Network Demand Profile and Historical Growth

In FY2024, the network delivered 428 GWh of electricity and had a peak demand of 111 MW (85 MW supplied from the Mangahao and Paraparaumu GXPs and 26 MW supplied from distributed generation).

The northern (Horowhenua) network is tied to horticulture, dairy farming, and Levin's urban and commercial areas. The Horowhenua demand profile has a very slight morning peak and more daytime demand (compared to the Kāpiti Coast), which reflects the greater commercial and light industrial customers in the region (refer to Figure 20).

The southern (Kāpiti Coast) network is predominantly urban and includes light commercial, rural lifestyle, and agricultural production. Many customers on the southern network commute to Wellington, so daytime demand is considerably less than evening demand, leading to a low load factor. Working-from-home arrangements have reduced this impact in recent years. The southern region's demand profile reflects the high number of domestic consumers, which has resulted in strong evening winter peak demand (refer to Figure 21).

Our evening peak has been growing faster than total consumption, reflecting more energy consumed in the early evening. We expect this to relate to greater use of electricity for heating, greater use of electrical appliances and devices, and a deterioration of the effectiveness of hot water load control.

The amount of control through ripple control of hot water load is slowly decreasing. We assume that customers' replacement of resistive heated hot water cylinders with more efficient heat pump technology will occur. Also, as the energy transformation evolves, we expect to see hot water control combined with electric vehicle charging and offered in flexibility markets (discussed further in Section 10).

Around 21% of our customers use reticulated gas or LPG bottles. The likely transition from gas to heat pumps will have a small impact on demand and profile over the planning period.

[13] Stats NZ. Subnational family and household projections, population by living arrangement type, and age, 2018(base)-2043

[14] https://www.infometrics.co.nz/product/regional-economic-profile

Both regional demand profiles are materially "peakier" than the national demand profile. This may present an opportunity to shift demand from the morning and evening peak to daytime and overnight, which could be used to reduce demand growth from electrification.

Figure 20: Horowhenua Load Profile

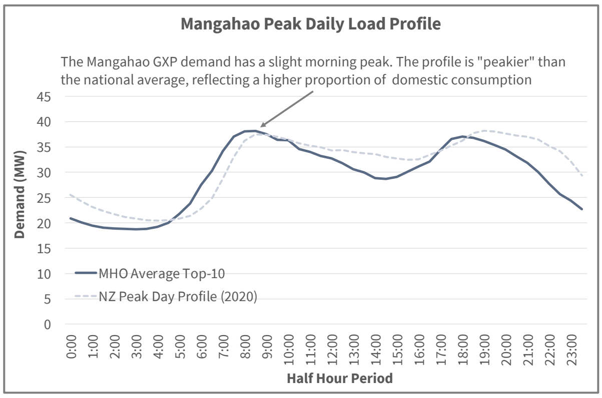
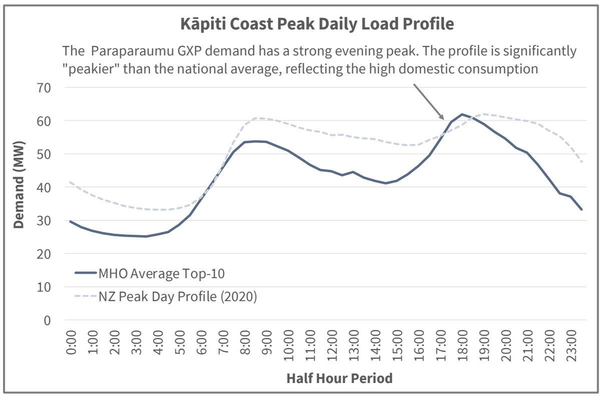


Figure 21: Kāpiti Coast Load Profile



We have begun to see the impacts of changing consumer behaviour on our load profile and expect this to increase over time. We are seeing the impact of retailers' price signals (e.g. the "free hour of power" and other incentives to shift usage), where our peak demand is shifting later in the evening on some days when these incentives are offered (this is known in the industry as consumer herding). Given our relatively low EV and solar PV penetration rates, we are not yet seeing any material impacts on our load profile. However, we expect this to change.

Presently, we still utilise hot water ripple control to reduce peak demand. The impact of hot water control is included in Figure 20 and Figure 21 and amounts to around 3.9 MW on the northern (Horowhenua) network and 6.1 MW on the southern (Kāpiti Coast) network. The impact of consumer herding on the peak demand is reducing the effectiveness of our hot water load control.

About 41% of energy is conveyed through the northern network and about 59% through the southern network.

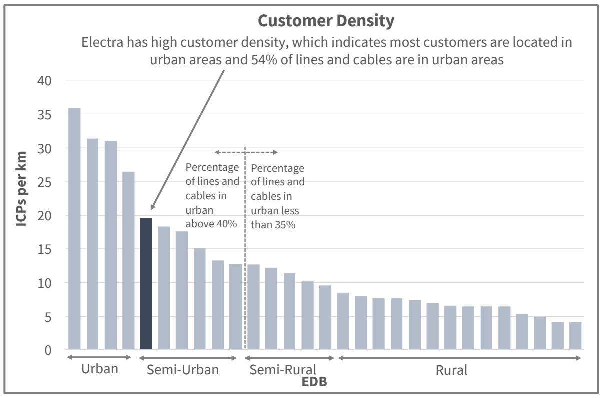
The changing consumer behaviour will likely impact peak demand, and our asset management strategies and network planning need to incorporate this uncertainty. We discuss this further in Sections 6, 10 and 11.

3.5 Network Configuration

3.5.1 Customer density

Figure 22 indicates that our customer density is higher than most EDBs and consistent with other semi-urban networks. Around 54% of our lines and cables are in urban areas. Most customers are in Paraparaumu, Waikanae, Raumati, Ōtaki, Levin, and Foxton.

Figure 22: Customer Density Benchmark[15]



3.5.2 Sub-transmission network

Our network is electrically contiguous but generally operates as two separate networks:

- The northern network is supplied from the 110 kV Mangahao GXP and Mangahao generation and supplies Levin, Foxton and Shannon substations in a ring configuration (refer to Figure 23);
- The southern network is supplied from the 220 kV Valley Road Paraparaumu GXP and supplies Paekākāriki, Paraparaumu East and West, Raumati, Waikanae and Ōtaki substations in a double spur configuration (refer to Figure 24).

All zone substations, except Paekākāriki, are afforded N-1 sub-transmission and zone substation transformer security. This is consistent with the semi-urban nature of our customer base.

The northern sub-transmission network is predominantly overhead construction. It traverses rural areas and flood plains around Foxton and Shannon and is exposed to adverse weather and vegetation. Over 60% of the lines are located away from roadways, which reduces exposure to vehicle damage but can delay repairs due to ground conditions.

The southern sub-transmission network is 73% underground, reducing the exposure to vehicle and vegetation damage. For the overhead sub-transmission lines, over 55% are located away from the roadway, reducing exposure to vehicle damage.

[15] Electra is a semi-urban network. It has 54% of its lines and cables in urban areas and an ICP density of 19.5 ICP per km. This is consistent with other semi-urban EDBs (Aurora, Orion, WEL Networks, Unison and Counties) that have an average proportion of urban lines and cables of 55% and an ICP density of 16.1. Typically, urban networks have an ICP density above 25, semi-rural networks have an ICP density below 13, and rural networks below 8 ICP per km.

Figure 23: Northern 33/11kV network

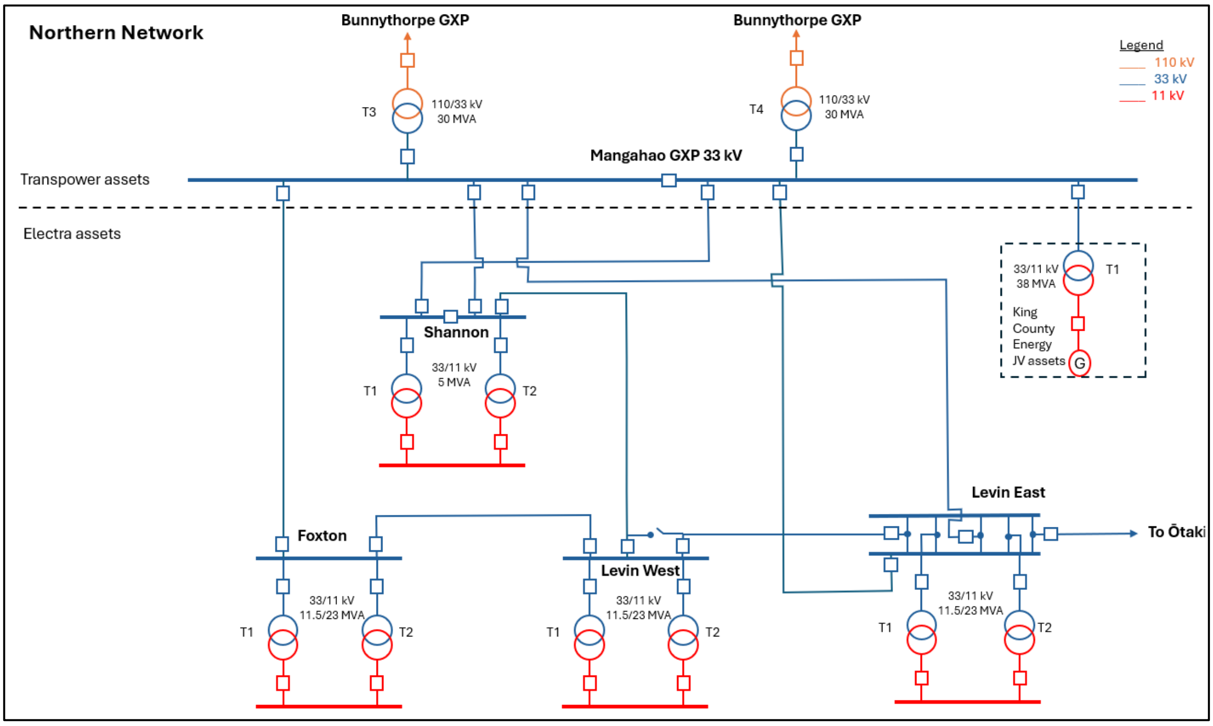
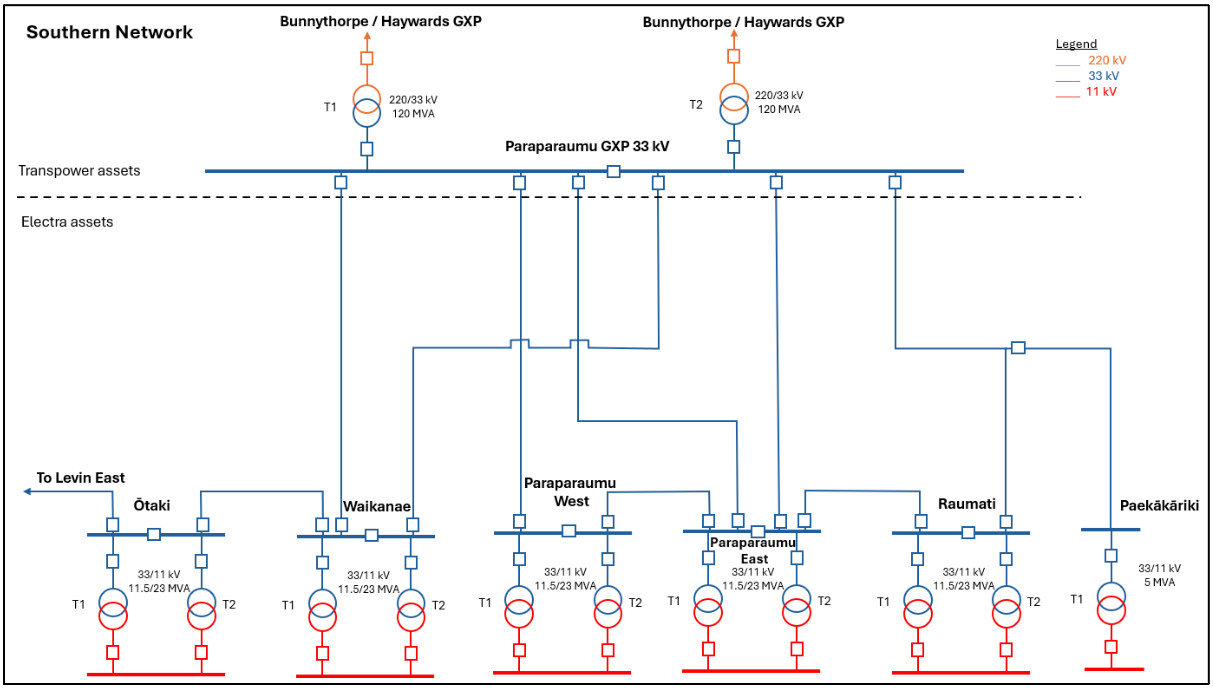


Figure 24: Southern 33/11kV network



3.5.3 Distribution network

The 11kV distribution network comprises interconnected radial feeders. It is overhead in older parts of the urban network, particularly in towns on the northern network and Ōtaki. As the southern region has grown, underground distribution has been installed, and that network is now 66% underground, twice that of the northern network.

Overhead lines are exposed to adverse weather, vegetation, and vehicle damage (when located near the roadway). This is why the fault rate on the northern network is 50% higher than the southern network.[16] Whilst the fault rate is higher on the northern network, the SAIDI contribution is around 45% of the total SAIDI. This is because faults in the southern region impact more customers, reflecting higher customers per feeder and less feeder sectionalisation.

Our overhead network has a reasonable level of recloser and sectionaliser density. Reclosers and sectionalisers allow the network to be segmented in the event of a fault and help improve reliability by reducing the area impacted by an outage.

Where a distribution feeder supplies both urban and rural customers, we have installed electrical protection (a line recloser) at the town boundary to maintain an appropriate level of service to our urban customers (as there are more outages in rural areas due to the length of the line exposed to hazards).

Our underground network has a legacy architecture which features very low ground-mounted switch density. While faults on the underground network are rare, having sufficient switching points allows for quicker network restoration and improves reliability when they do occur. This is an area for improvement, as outlined in Sections 6.3, 11.10.3 and 11.10.4.

Figure 25: Overhead Recloser and Sectionaliser Density

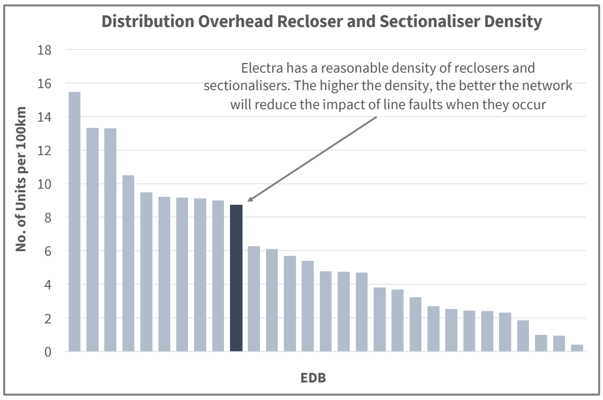
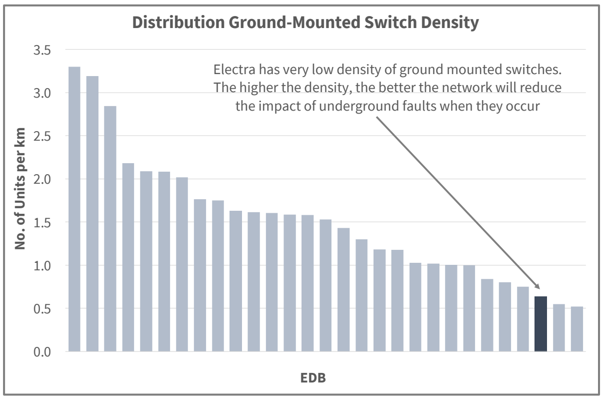


Figure 26: Underground RMU, Ground Mounted CB and Switch Density



Generally, the peak loading of feeders is within the 70% capacity limits to allow headroom for back-feeding during faults. However, there are some feeders where loadings are approaching the 70% capacity limits, and this is discussed further in Section 11.10.2.

3.5.4 Low voltage system

When designing the urban LV network, Electra adopted a standard design ADMD of 3.5 kVA per dwelling (which has been used for decades). This standard exceeds the current (GXP and feeder level) ADMD of around 2.6 kVA per customer and has helped minimise issues with the low-voltage network (e.g., low-voltage complaints). It provides a very good basis for accommodating the forthcoming growth in EVs and solar PV.

The low voltage network is 49% overhead and 51% underground. There is still a significant portion of overhead LV conductors in urban areas. Most of the underground LV cables are in urban areas.

[16] This is the number of faults per 100km.

3.5.5 Mobile generation

Electra has owned a 500kVA mobile diesel generator since 2008. It is primarily used to maintain supply during planned and unplanned outages. We have contracts for using a small fleet of generators ranging from small single-phase units to larger 880kVA units. The use of generation to minimise the impact of outages is based on an economic and customer assessment—that is, the cost of the generation needs to be less than the value of the loss load that is avoided.

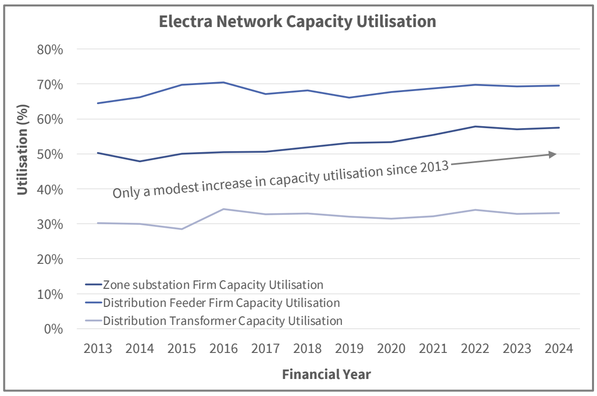
3.5.6 Standardisation

Over the preceding decades, Electra has adopted standardisation in the configuration and aspects of design. This standardisation means that the breadth of different technologies has been minimised, and the economics of spare holdings have been enhanced. This has improved our ability to maintain staff competency, reduced the risk associated with unfamiliar equipment, and reduced the cost of spares.

3.6 Network Utilisation

Over the past decade, Electra's network has had largely stable firm capacity with modest demand growth, which has resulted in a modest increase in capacity utilisation. The capacity utilisation across zone substations, distribution feeders, and distribution transformers is generally within security limits. However, there are some specific locations where growth is reaching capacity limits, and these are discussed in Section 11.

Figure 27: Network Capacity Utilisation



Significant capacity is available at GXP supplying the southern network. However, the capacity of the Mangahao GXP (at 44 MVA N-1-g firm, which includes firm generation)[17] is close to the current demand of 42 MVA.[18] The 38 MW Mangahao hydro generator supports supply security at peak times. This is discussed further in Section 11.8.

3.7 Distributed Generation

We have two large distributed generators embedded in the network: the 38 MW Mangahao hydro station and the two 0.96 MW diesel gensets at a customer site in Paraparaumu (although the site is not currently occupied). There are also 1,540 other small distributed generation sites with a combined capacity of about 6.9 MW[19]. We estimate that around 11% of these have batteries.[20]

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17 The firm capacity of the GXP transformers is 30 MVA.

18 42 MVA is the peak ½ hour demand at the Mangahao GXP. The average of the top-10 peaks is 38.5 MVA. Data is as of 31 March 2024.

19 EA EMI, Installed distribution generation trend reports, as of 31 March 2024.

20 Based on the New Zealand average: Source: EA EMI, Installed distribution generation trend reports, as of 31 March 2024

We have recently been approached by several large solar and wind farm projects (over 1MW) for potential embedded connections. We are encouraging these start-ups and aiding them with their planning, equipment requirements, load flow studies, congestion determination, and alternative solutions for the customer to consider. The proximity of these proposed connections to our sub-transmission and substation assets has been advantageous in keeping connection costs down and reducing congestion of embedded generation on the distribution network.

The Mangahao hydro station is an essential generator for Electra. Its output currently supports the security of supply from the Mangahao GXP during peak demand. The current peak support arrangements are mutually beneficial. However, we have commenced discussions with the station owners to formalise them. The Mangahao GXP transformers are reaching end-of-life[21], and the plans for replacing them are discussed in Section 11.8, including the impact on the embedded Mangahao station.

We discuss the future impacts of distributed generation, particularly solar PV, in Section 10.

[21] Transpower have identified these for risk-based replacement between 2026 and 2028 in the 2023 Transmission Planning Report (Table 11.3, page 204).

4. Recent Customer Service and Network Performance

4.1 Introduction

This section reviews our customer and network performance. We monitor our performance against various measures, including customer service, safety, environmental, asset performance, network efficiency and work delivery. The systems described in Sections 9.4.1 and 9.4.2 are used to capture and maintain this data.

Overall, our unplanned reliability performance has generally been good, and we perform well against our peers. Most customers are satisfied with the reliability of supply they receive and are generally happy with our price-quality trade-off.

We have presented a comprehensive analysis of customer and network performance to assess the implications for our asset management strategy and detailed plans. In summary, the implications from the analysis that follows are:

- Our overall trend for health and safety is positive, and we continue to focus on ensuring the health and safety of our employees, contractors, customers, and the public. Work on auditing and improvement actions has taken a step up in recent years, and we expect to see the benefit of this in our safety outturn in the coming years;
- Unplanned SAIFI performance has been particularly favourable against our target, and there is scope to reduce the target;
- Our planned reliability targets (SAIDI and SAIFI) are no longer appropriate due to the increasing work being undertaken on the network. As work on the underground network increases, the limited switching capability will significantly increase the reliability impact. The targets need to increase to accommodate the increasing work volumes required to effectively manage the network;
- The recent trend in defective equipment outages is static. However we are seeing an increase in pole-top hardware failures. This is from a low base, so it is not seen as a material issue but rather as an area for greater inspection, investigation and targeting of asset renewals;
- We currently have very few cable outages; however, restoration times are very long when they occur. This is a product of the legacy network architecture in part of our underground distribution network which features a low number of switching points, which extends restoration times. Increasing our ground-mounted switch density is required;
- There is a concentration of defective equipment and adverse weather outages on our worst-performing (overhead) feeders. Improving the performance of the worst-performing feeders through a combination of reliability improvement initiatives and targeted asset renewals in areas where asset health is deteriorating is a focus for this AMP;
- Adverse weather mainly impacts overhead lines and is likely to increase due to climate change. To minimise the impact of high winds, we must ensure our overhead line designs meet site-specific wind speed requirements;
- We experience a high incidence of vehicle damage outages, and further geographical analysis and assessment of options to reduce vehicle risks is required;
- A few feeders have experienced a high incidence of contractor damage to underground cables. Reducing the probability of further strikes is challenging; however, increasing the penetration of ground-mounted switches will reduce customers' outage duration should further contractor incidents occur. New switch installation will be prioritised together with an increasing public awareness campaign when working near our assets;

- In recent years, vegetation-related outages have been concentrated on a few feeders, and climate change is likely to exacerbate vegetation contact. Our operational plans have been prioritised to ensure the worst-performing feeders (for vegetation) are addressed (to the extent that the tree regulations allow);
- A small number of proposed capex works involving new line and cable routes have taken more time to secure land rights and access than we have in the past forecast and this has now been factored into our revised forecasts;
- Over the past three years, we have exceeded budgets on system interruption and emergency costs due to higher than forecast costs of materials, resources, and traffic management costs. We have revised our forecasts, and will continue to monitor and manage costs efficiently and effectively;
- Lastly, we experienced a short-term resource constraint in our planned inspection programme during FY24. This has being addressed, and an accelerated inspection programme during FY25 has resolved this issue.

4.2 Safety and environmental performance

Electra is committed to ensuring the health and safety of its customers, employees, contractors, and the public. Our people are our greatest assets, and Electra aims for them all to get home from work safely and well every day. Our customers and the public are just as important to us, and we strive to protect them from harm from our assets and work activity. We have three key pillars to achieve these goals: Health and Safety, Wellbeing, and Compliance.

Table 4 shows our safety and environmental performance for the past five years. Overall, we continue improving our performance and achieving our health and safety goals.

Understanding our most critical safety risks, including traffic (moving vehicles and plant), electricity (contact with), height (falls), lifting operations (suspended loads), driving, and work capacity (fatigue, wellbeing), involves developing, reviewing and monitoring the key controls to reduce the likelihood of harm. Our auditing, preventative and proactive improvements, planned inspections and compliance with our public safety management system assist us in ensuring control effectiveness and ongoing improvement. Other than a recent delay in some inspections, these measures are tracking well. We discuss our critical risk, key controls and control effectiveness in Section 14.

Having an active internal safety observation and audit program based on our critical risks is vital. All people leaders have performance measures to ensure regular safety and wellbeing checks on their teams. This extends to our senior leaders and directors, who provide visible leadership and support through site visits. An external auditor comes in annually to audit our field team's safety and compliance, with positive findings to date and opportunities for improvement acted upon.

Our asset inspection program prioritises areas where the public is more likely to be present, especially around schools, shopping centres, and parks. Ad hoc safety audits are conducted more frequently in these locations. Engaging with third parties and contractors working around and on our network is an ongoing task, ensuring the risks of working near our assets are well known and appropriate controls and permissions are in place. We experienced a delay in some inspections in 2023 and 2024 (due to resource constraints). Additional resources have been committed and our programme of inspections is now on track.

Whilst we recorded six staff lost-time injuries (LTIs) in the last three years, all were low severity, and importantly, none were caused by a critical risk. These resulted in 21 days off work to enable a full recovery. Our lost-time injury severity rate currently sits at 3.5, compared with an overall industry rate of 11. All incidents are thoroughly investigated, and lessons learned are shared and applied to our work procedures.

The wellbeing of our team is paramount. This includes health checks, funded health insurance and discounted benefits, employee assistance for them and their immediate families, peer support, wellbeing checks, and simple things like providing fresh fruit, cold water, and electrolytes to our teams working outside in the summer heat.

No customers or members of the public have been harmed from asset failure or our work activity. This result is supported by our public safety management system, which is audited annually by Telarc and certified to the NZS7901 standard. Our audits for the past three years have fully conformed with the standard, with certification through to February 2027.

Table 4: Safety and Environmental Targets

Area	Indicator	Type	Target 2024	Average 2020-2023	Actual 2024	Comments
Safety of staff, contractors, and the public	Staff Lost Time Injuries (LTIs)	Lagging	Zero (for critical risks)	2.0	3.0	Whilst we are seeing an increase in LTIs, they have been of a low severity
	Number of incidents	Lagging	Reporting is encouraged	75	96	Reporting of incidents is increasing, which is a positive trend
	Public safety audits	Leading	60 per year	28	111	We have significantly increased our auditing, which is a very positive trend
	Contractor safety audits	Leading	60 per year	124	247	
	Compliance with our public safety management system	Leading	Compliant	Compliant	Compliant	We are fully compliant
	Completed preventative and proactive actions[22]	Leading	5% annual increase from 2020	989	1,278	This is a very positive result and will lead to long-term improvement in our lagging measures
Asset integrity	Completion of planned Inspections[23]	Leading	>95%	93%	73%	A resource constraint caused and a timing issue with and external contractor impacted our inspection programme. (Now resolved)
Environmental responsibility	Number of environmental incidents	Lagging	Zero	0	0	We continue to achieve no environmental incidents

4.3 Network reliability performance, customer perspective

Our primary customer service measure is network reliability as measured using the internationally accepted performance measures of SAIDI and SAIFI:

[22] This measure captures all of our audits, incidents and all follow-up actions.

[23] This is a composite measure of the completion of planned inspections. Practical completion means the work is completed with the exception of minor omissions (of less than 5%), hence the target is >95%. We take a practical approach as some inspection require access to private property and can have weather restrictions.

- **SAIDI:** System Average Interruption Duration Index, which is the average duration (in minutes) customers are interrupted over a year;
- **SAIFI:** System Average Interruption Frequency Index, which is the average number of interruptions per customer per year.

Within these two measures, we assess unplanned and planned outages separately. Unplanned outages are particularly important because they inconvenience customers due to their unforeseen nature. Planned outages are notified in advance, and customers can alter their plans to accommodate them. We also use raw reliability data in our analysis, which is before any normalisation for major events (as is the case for regulated distribution businesses). We use raw data because this is the reliability that our customers experience.

Electra does not distinguish between customers in different geographical areas; however, the network configuration provides a higher level of reliability to urban customers than rural customers (refer to Section 3.5).

Unplanned reliability performance

Referring to Figure 28 and Figure 29, our unplanned network reliability is consistently better than our semi-urban peers[24] and has been favourable against target for three of the past five years. SAIFI performance has been particularly favourable against our target. One-off events can impact reliability performance, which was why we did not meet targets. As shown in Figure 2, three factors caused the target to be exceeded in 2020 and 2023. These were:

- A significant increase in vehicle damage to the network in 2020. This was three times the normal rate, which has not occurred again;
- A significant weather event in early June 2022 which resulted in 53 lightning strikes in the first two weeks of June;
- During the same June 2022 storm, an out-of-zone tree fell causing significant damage. The Council closed the road due to safety concerns around the potential for a significant land slip meant that we were unable to access the damage and it took an extended period to restore supply.

[24] Electra is a semi-urban network. It has 54% of its lines and cables in urban areas and an ICP density of 19.5 ICP per km. This is consistent with other semi-urban EDBs (Aurora, Orion, WEL Networks, Unison and Counties) that have an average proportion of urban lines and cables of 55% and an ICP density of 16.1. Typically, urban networks have an ICP density above 25, semi-rural networks have an ICP density below 13, and rural networks below 8 ICP per km.

Figure 28: Unplanned outage duration[25]

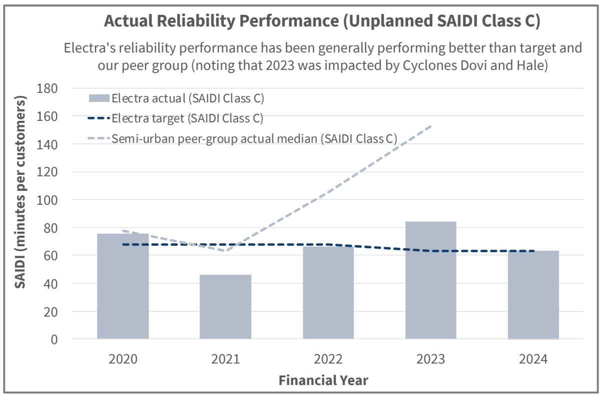


Figure 29: Unplanned outage frequency[25]

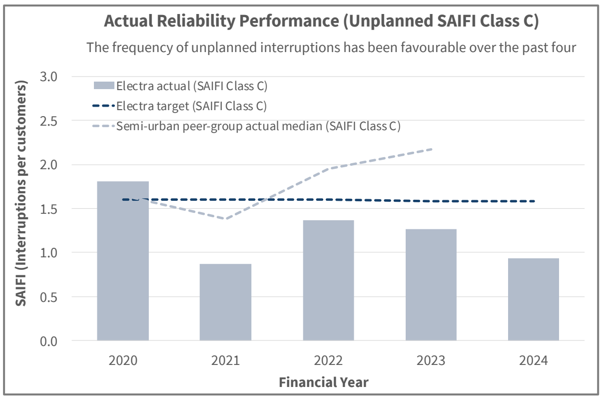
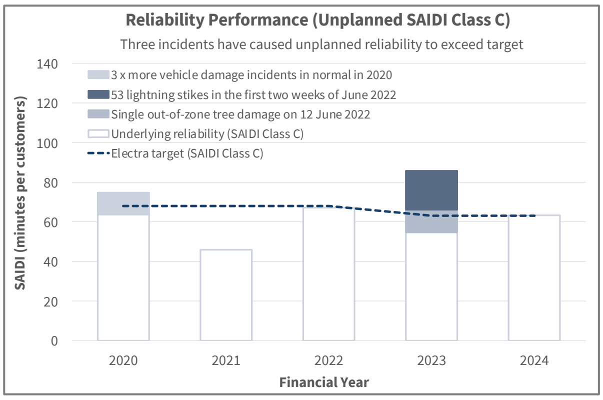


Figure 30: Unplanned outage, reasons for the target to be exceeded



Given the generally good performance, our reliability improvement focuses on continuous improvements and enhancing resilience. This is important given the likely increase in adverse weather events due to climate change.

Planned reliability performance

Referring to Figure 31 and Figure 32, our planned network reliability has been unfavourable against the target in recent years. This is due to the increase in the work we have been undertaking on the network (requiring outages). However, our planned SAIDI is unusually low compared to the industry and our peer group (Figure 33). This reflects our use of live line techniques on the overhead network, the low work volumes on the underground network (which currently comprises 10% of planned outages and 13% of planned SAIDI) and our use of temporary generation. Our planned work programme is set to increase further; hence, a revision to the planned outage target is proposed in Section 7.

[25] The semi-urban peer group was impacted by major weather events in 2022 and 2023 (Cyclones Dovi, Hale and Gabrielle).

Figure 31: Planned outage duration

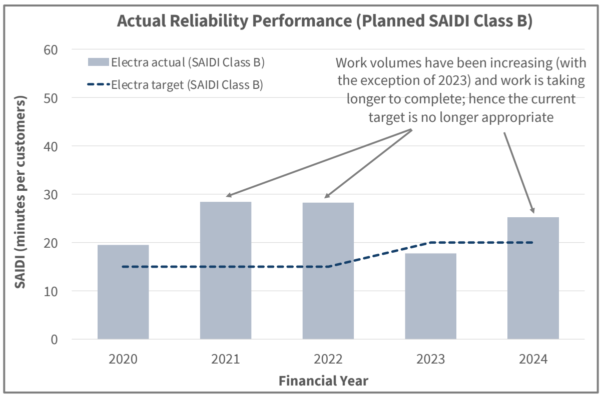


Figure 32: Planned outage frequency

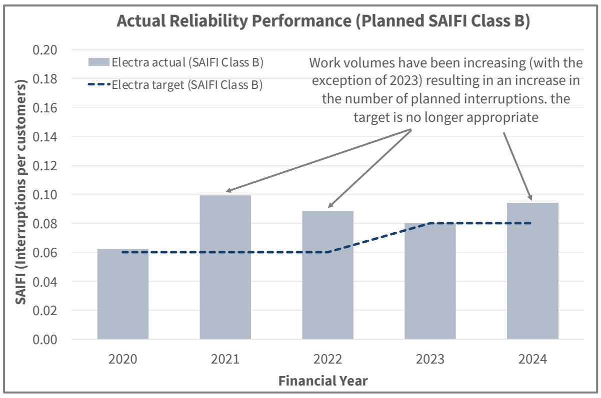
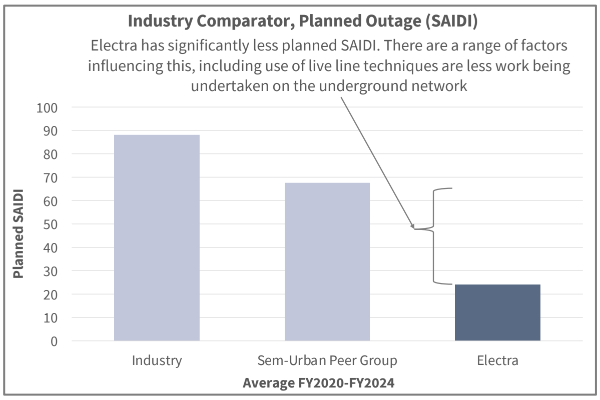


Figure 33: Planned outage benchmark



4.4 Other areas of customer service performance

In addition to reliability, we also measure our performance in other areas important to customers. These include:

- Customers' views on our network reliability;
- Customers' views on our response to unplanned outages;
- Customers' views on price-quality trade-off.

Until 2023, we completed an annual customer survey to seek customers' views on our network reliability and service during faults. The survey was not conducted in 2024 and will be replaced by an industry-standard survey. Based on our prior data, almost all customers are satisfied with the reliability of supply they receive from the network. These views have been consistent over recent years.

When faults occur, we want to be responsive and remedy them as soon as possible. Customers who have had a fault are almost all satisfied with the service they received, which is again a pleasing result.

Figure 34: Customer views on network reliability

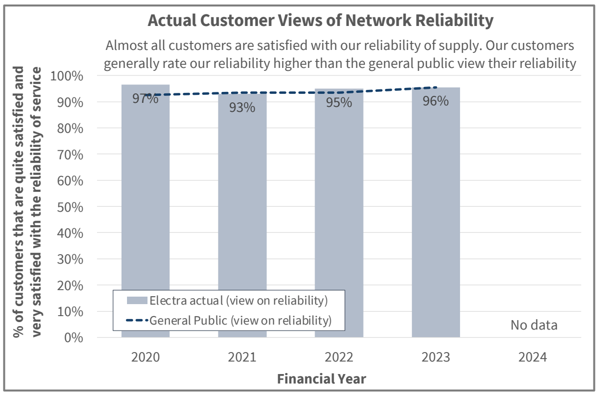
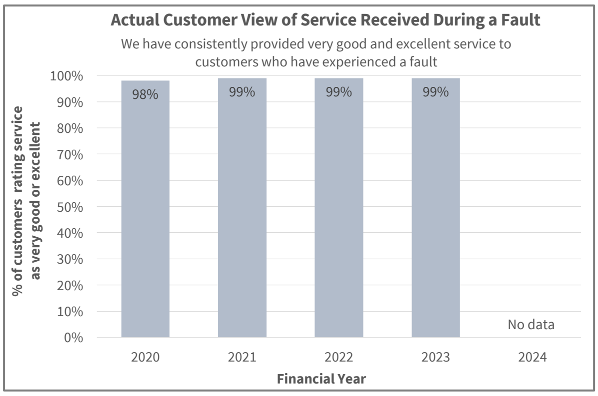


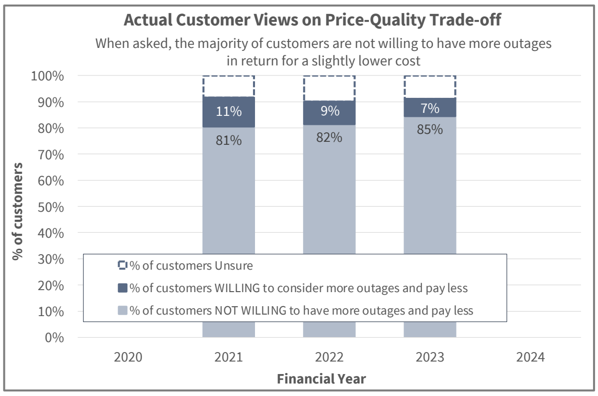
Figure 35: Customer views on service received during a fault



A recent ENA study identified that customers value ease of connection and timely planned outage notification. We have operational oversight in these areas and are developing measurements and targets, which will be included in a subsequent AMP.

Whilst not specifically a performance metric, it is important to understand whether customers are satisfied with our price-quality trade-off. This data helps inform whether our reliability targets are appropriate. The survey results indicate that most customers are not willing to have more outages for a slightly lower price, and this trend is increasing. Customers' views on the importance of reliability reflect their particular circumstances and their recent experiences of outages; however, the survey results consistently indicate that customers are generally unwilling to accept a lower level of service.

Figure 36: Customers' views on Price-Quality Trade-off



4.5 Asset performance

4.5.1 Introduction

This section examines the causes of outages and their impact on overall reliability. We then assess the drivers of the material causes of outages. This assessment shapes our focus areas in the asset management strategies presented in Section 6. The analysis is focused on SAIDI and outages as the drivers (and resolution) of these issues also impact SAIFI.

4.5.2 Material causes of outages

As shown in Figure 37 and Figure 38, defective equipment is the most significant cause of SAIDI, followed by third-party damage, vegetation and adverse weather. These causes contribute 80% of SAIDI and 70% of SAIFI.

Figure 37: Reliability Performance, Unplanned SAIDI

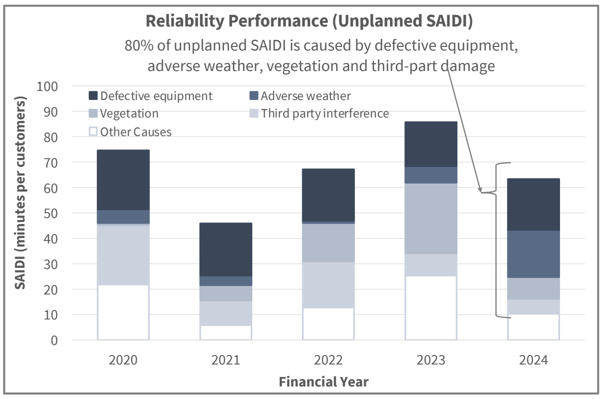
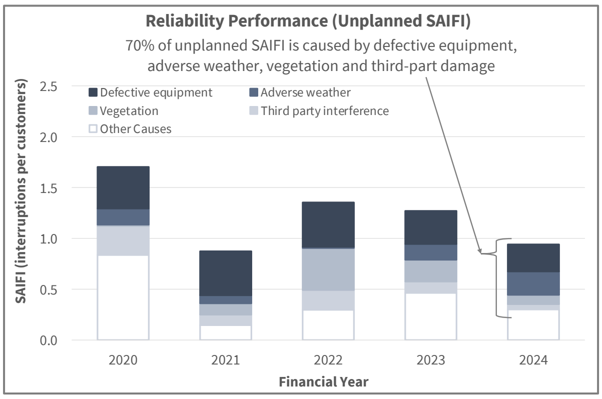


Figure 38: Reliability Performance, Unplanned SAIFI



In broad terms, over the past five years:

- Defective equipment SAIDI was the principal highest cause of outages;
- Third-party damage SAIDI was a result of relatively few outages, but when they occurred, they impacted a large number of customers and took longer to repair;
- Vegetation SAIDI reflected a combination of outage numbers and the outages taking a long time to repair;
- On average, adverse weather is not a material cause of outages but shows high volatility. That is, in the years when weather impacts the network, there are many outages that typically affect many customers.

Almost all outages and SAIDI impacts occur on the distribution network. The sub-transmission network and zone substations assets contribute 2% to total unplanned SAIDI, lower than the industry median (8%) and the semi-urban peer group (5%). This reflects the high network security afforded the sub-transmission network and zone substations.

In the following sections, we assess the four material drivers of reliability. The analysis relates to the distribution network.

4.5.3 Defective equipment outages

Defective equipment is the largest source of outages and SAIDI. The extent of defective equipment outages is consistent with our semi-urban peer group and close to the wider industry (refer to Figure 39).[26]

As shown in Figure 13 and Figure 14, five types of equipment are causing outages. The most significant are conductors and cables, pole-top hardware, overhead fuses and links, and ground-mounted transformers.

There is no material deteriorating trend in defective equipment outages and SAIDI, except for pole top hardware. The increase in pole-top hardware failures is from a low base, so it is not seen as a material issue but rather as an area for greater inspection and investigation.

Except for cables (and their associated joints and terminations), equipment failures are repaired promptly, or supply is restored through network backup. There are significantly fewer outages for cables, but the

[26] The percentage of defective equipment SAIDI looks higher than the comparators only because of a high percentage of defective equipment in 2021. This was a consequence of the low unplanned SAIDI in 2021, not because of an increase in defective equipment SAIDI in that year.

restoration times are materially longer. This reflects the time to locate and repair cable and joint faults and the limited switching on the underground distribution network.[27]

Figure 39: Defective Equipment Benchmark

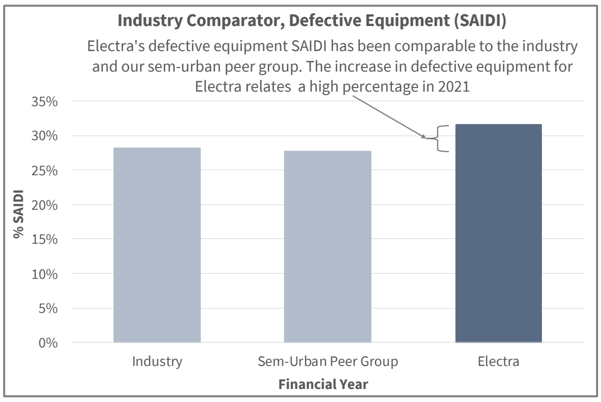
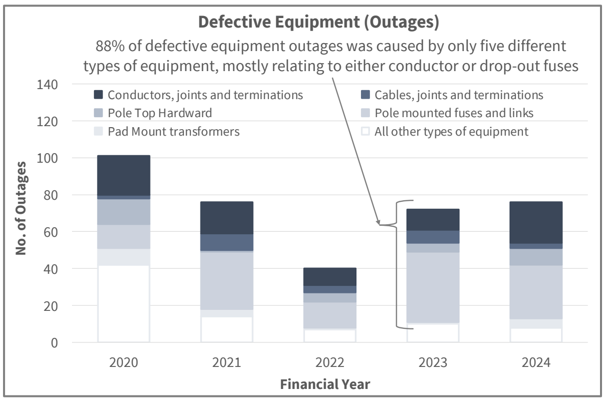


Figure 40: Defective Equipment, Outages



As shown in Figure 41 and Figure 42, defective equipment outages (by number) are concentrated on our worst 15 feeders.[28] These are overhead feeders. Over the past two years, 30% of feeders caused 72% of defective equipment outages (with the worst five feeders causing 40% of the outages).

This AMP focuses on improving the performance of the worst-performing feeders. In the development plan (Section 11.10.3 and 11.10.4), we assess the worst-performing feeders for opportunities to enhance their reliability through reliability improvement initiatives. In the lifecycle plan (Section 12.12 to 12.16), we assess whether there are any asset health drivers concerning the worst-performing feeders.

Figure 41: Worst Performing Feeders, Defective Equipment, SAIDI

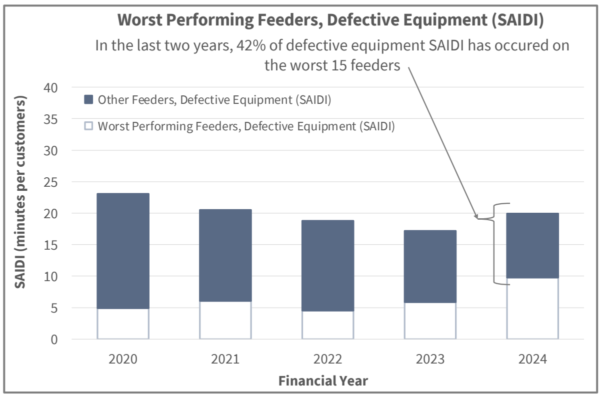
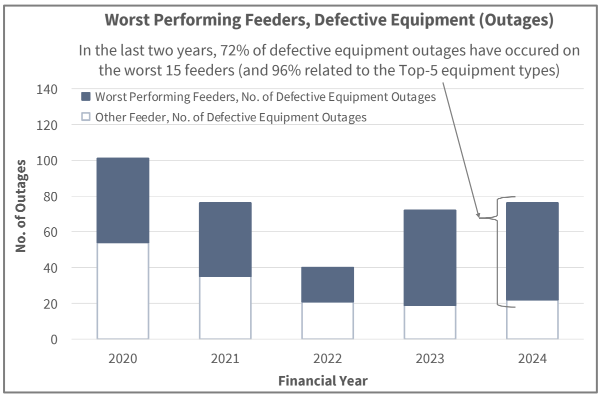


Figure 42: Worst Performing Feeders, Defective Equipment, Outages



4.5.4 Adverse weather outages

Adverse weather outages generally relate to asset failures that occur during adverse weather. These typically occur when weather conditions exceed the design limits of the assets. Over the past five years, we have seen a lower impact from adverse weather than our peer group or the industry (refer to Figure 43 and Figure 44).

[27] The average outage time for cables is 292 minutes, compared to 126 minutes for other equipment.

[28] These feeders have had three or more defective equipment outages over the past two years. These feeders also have the highest number of outages over the past five years.

Figure 43: Adverse Weather Benchmark

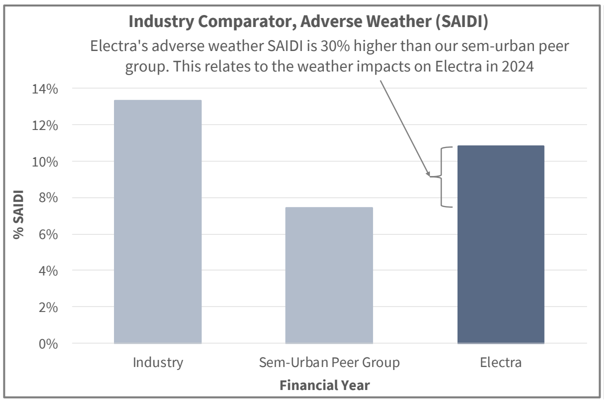
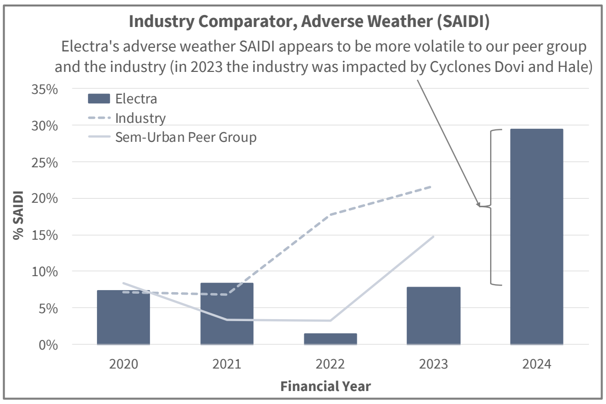


Figure 44: Adverse Weather Volatility



As shown in Figure 45, the impacts of adverse weather outages are volatile and can result in around 30% of total unplanned SAIDI in years when major weather events occur. In normal years, the impact is around 6%.

High winds cause around 80% of all adverse weather outages (refer to Figure 46). As expected, adverse weather mostly impacts overhead lines. Consistent with defective equipment, conductors and associated joints and terminations are mostly impacted (refer to Figure 47). Ensuring our overhead line designs meet site-specific wind speed requirements is important to minimise the impact of high winds.

There is an overlap between the worst-performing feeders for defective equipment and those for adverse weather. This reinforces our need to focus on resolving any issues with our worst-performing feeders (refer to Figure 48).

Figure 45: Adverse Weather, SAIDI

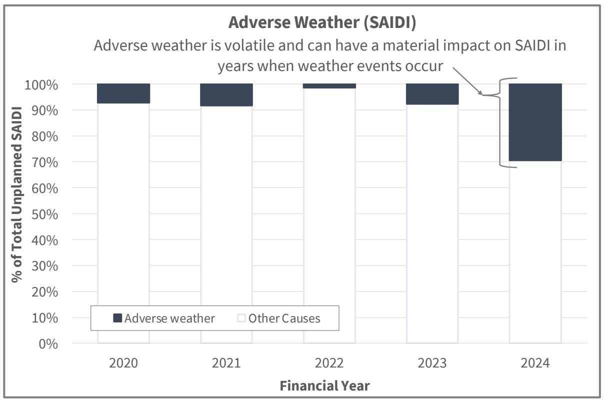


Figure 46: Adverse Weather, Conditions Outages

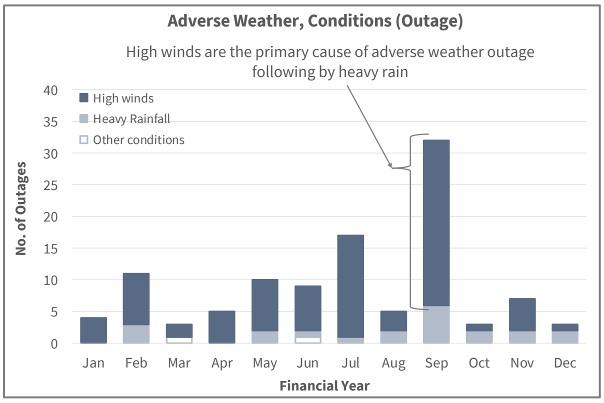


Figure 47: Adverse Weather, Equipment Type, Outages

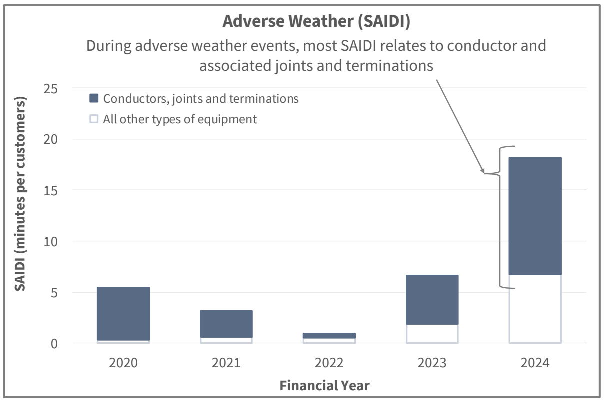
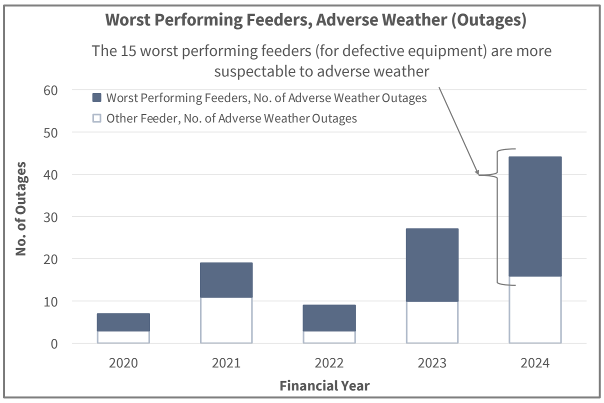


Figure 48: Worst Performing Feeders, Adverse Weather, Outages



4.5.5 Third-party damage outages

Third-party damage has materially impacted reliability over the past five years. For Electra, third-party damage SAIDI was around 30% more than our semi-urban peers. While much of this is related to the very high number of vehicle damage incidents in 2020, after normalising for 2020, it remains nearly 20% higher than our peers (refer to Figure 49).

Third-party damage is primarily caused by vehicle damage (typically to overhead lines) and contractor damage (typically to underground cables). Pleasingly, incidents have declined since the 2020 peak (refer to Figure 50).

Figure 49: Third-Party Damage Benchmark

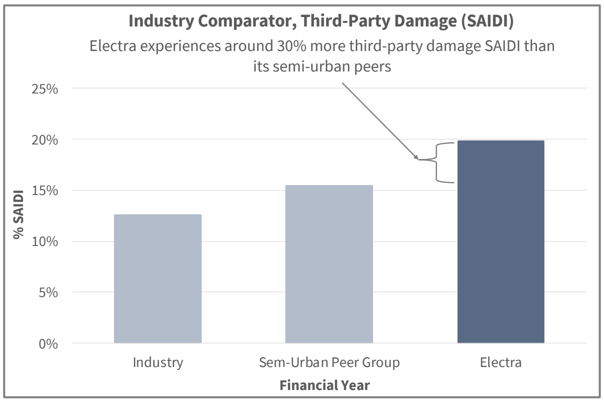
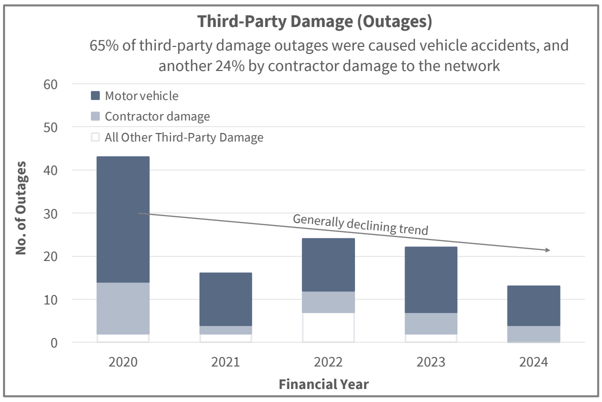


Figure 50: Key Causes of Third-Party Damage, Outages



As shown in Figure 51, vehicle damage is concentrated on a few feeders. Twelve feeders account for 64% of vehicle damage outages, and the worst six feeders account for 40% of outages.

As shown in Figure 52, third-party contractor damage is also concentrated on a few feeders. Over the past five years, three feeders have seen more than three third-party contractor damage outages. We rely on process-based controls to mitigate third-party contractor damage (i.e., the dial-before-you-dig process); hence, reducing the probability of incidents is difficult. However, increasing the underground network's security through increasing the number of ground-mounted switches will reduce the duration of outages for customers. The prioritisation of the installation of new switches considers the location of third-party contractor damage incidents and the areas for significant building and civil work (refer to Section 11.10.3 and 11.10.4).

Figure 51: Vehicle Damage, Outages

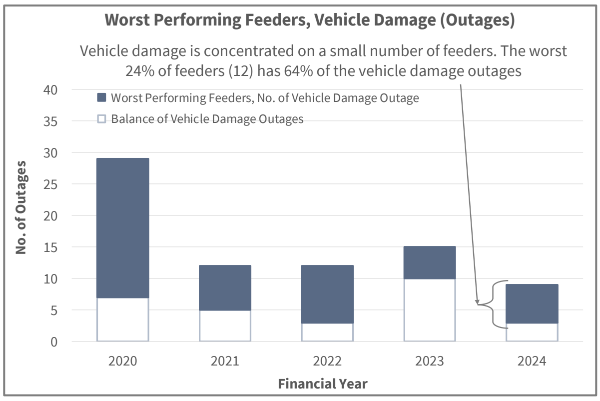
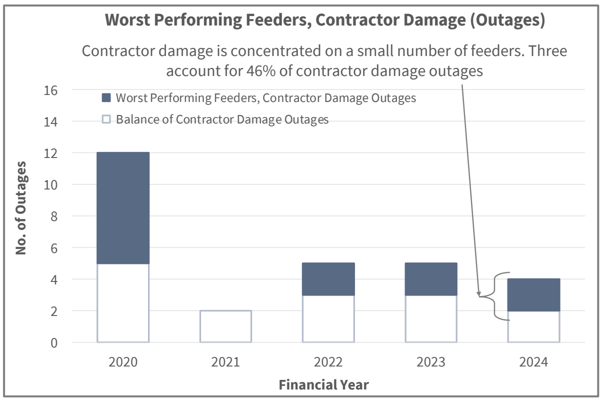


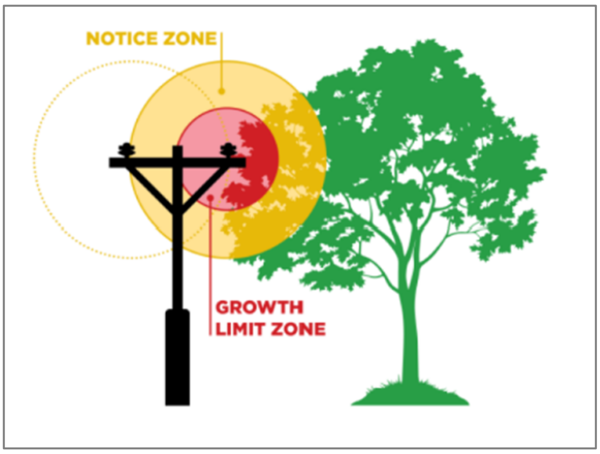
Figure 52: Third-Party Contractor, Outages



4.5.6 Vegetation outages

Our vegetation outage analysis considered the impact of vegetation contacts on the network from inside and outside of the growth limit zone (GLZ), as shown in Figure 53. Management of vegetation outside the notice zone and GLZ zone is difficult and is not supported by regulations.[29]

Figure 53: Vegetation zones



Over the past five years, we experienced a similar impact from vegetation damage as our semi-urban peers (refer to Figure 54). Vegetation originating from outside the GLZ is the predominant source of outages. It has been the reason for increased vegetation SAIDI and outages over the past five years (refer to Figure 55 and Figure 57).

Not unexpectedly, the reliability impact from vegetation contact outside the GLZ occurs due to wind (refer to Figure 56). Ignoring the impact of wind, which creates significant volatility in the number of outages, there is only a slight upward trend in vegetation outages (refer to Figure 57).

In recent years, vegetation-related outages have been concentrated, with the worst eleven feeders resulting in 60% of the outages (refer to Figure 58).

[29] The Electricity (Hazards from Trees) Regulations 2003 specifies minimum distances from overhead power lines that vegetation must be clear from, with distances varying depending on voltage and conductor span length (the GLZ). While these zones provide clearance from interference from branches (although greater clearance would be useful), they are inadequate to manage tree fall risk and interference during storm events, where greater separation is needed.

Vegetation outage management is an ongoing issue exacerbated by climate change, the difficulty of gaining access and approval to trim vegetation, and the narrow GLZ that reduces the effectiveness of trimming work. We have established a vegetation management strategy presented in Section 12.19.2. Our operational plans have been prioritised to ensure the worst-performing feeders are addressed.

Figure 54: Vegetation Benchmark

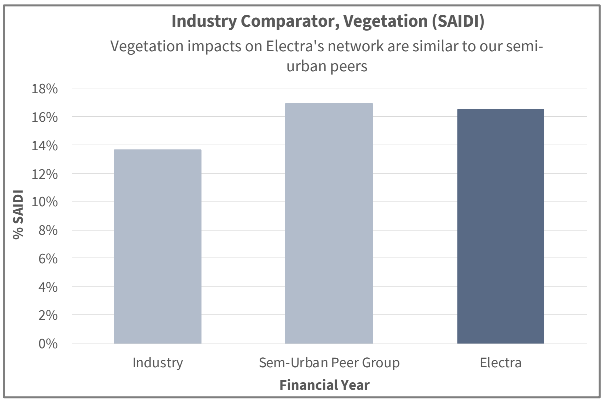


Figure 55: Vegetation Contribution to Unplanned SAIDI

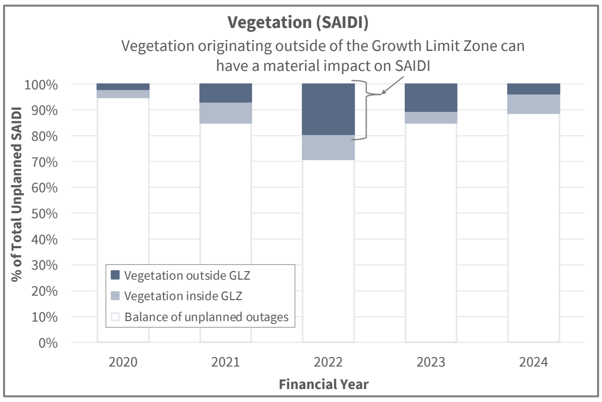


Figure 56: Key Causes of Vegetation Damage, Outages

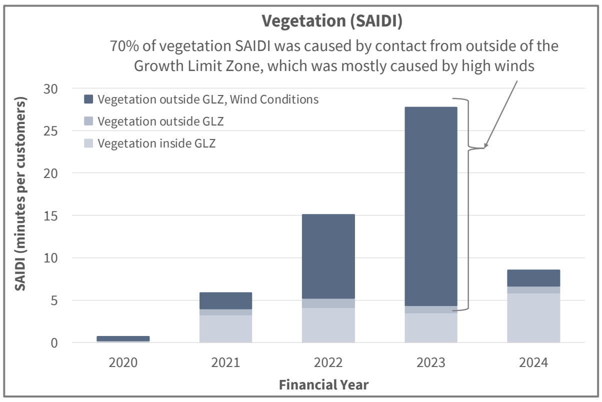


Figure 57: Underlying Vegetation Trend, Outages

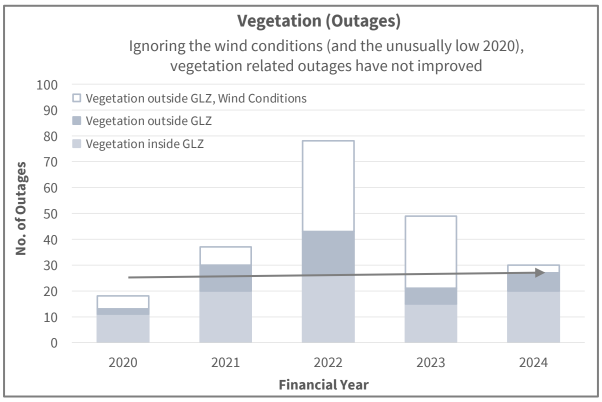
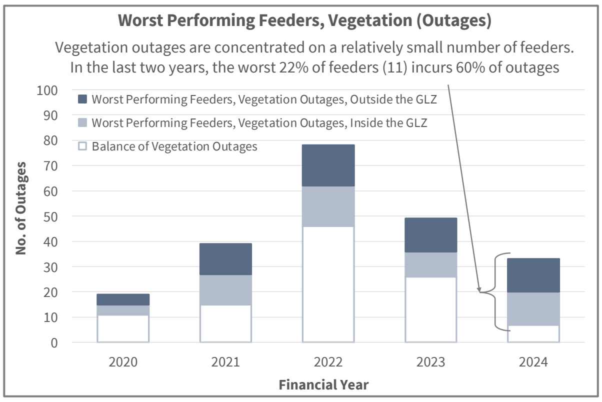


Figure 58: Vegetation, Worst Performing Feeders, Outages



4.5.7 Unknown interruptions

All EDBs experience unknown cause outages. These outages are where, after investigation, we could not determine the cause. These outages are typically of short duration and often occur due to the standdown period required before the control room can attempt to restore supply. Over the past five years, these have averaged around 6% of SAIDI, well below the industry average.[30] We have well-defined procedures for post-fault investigation, which has led to good results in this area.

4.5.8 Extended duration outages

Extended-duration outages take more than three hours to restore. Pleasingly, Electra's performance is better than our peer group and the industry (Figure 59). Other than FY2023, the trend in extended duration has been static. Extended-duration outages make the most significant contribution to third-party damage outages—where repair time influences the outage time—and this is most apparent on the underground network.[31]

Figure 59: Extended Duration Outage Benchmark

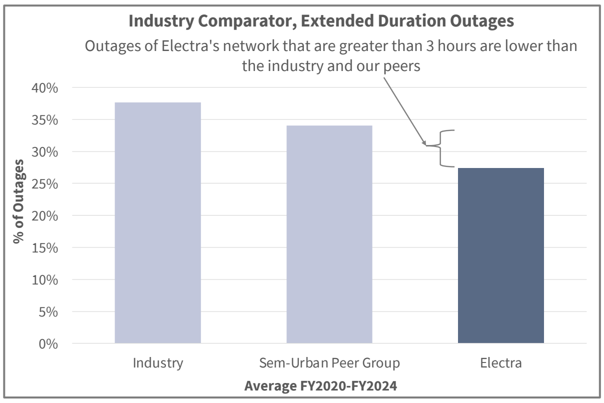
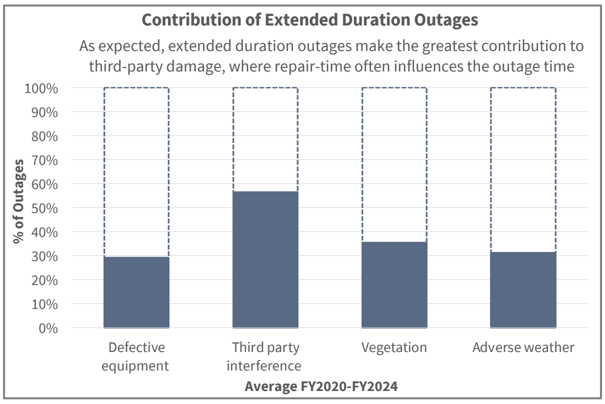


Figure 60: Extended Duration Outage Contribution to Top-4 Causes



4.5.9 Worst-performing feeders

The worst-performing feeder contribution to SAIDI has been reasonably static (Figure 61). There are no indicators that the performance in this area is declining or improving. The 90th percentile worst-performing generally only comprises four feeders and averages around 21% of unplanned SAIDI. Unfortunately, the same feeders consistently appear on the list—an area of focus for us.

Figure 61: Worst-Performing Feeders (90th Percentile)

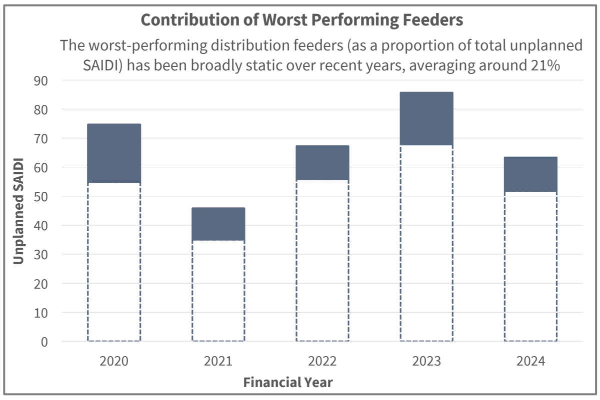


Table 5 identifies our top 10 worst-performing feeders by SAIDI (and these strongly overlap with the worst-performing by the number of outages). Half of the list is in Ōtaki—which reflects high customer numbers per feeder, lower security on some feeders, and exposure to vehicle damage. Improving the performance of these feeders is a focus of this AMP, and Table 5 provides a link to our improvement plans.

[30] The recent industry average is 9% and the semi-urban peer group is 11%.

[31] In FY2024, extended duration outages comprised 53% of faults on the underground network and 25% on the overhead network.

Table 5: Top-10 worst performing feeders FY22-24

Feeder	Substation	Average SAIDI FY22-24	Primary cause	Secondary cause	Plans to improve performance
L349*	Ōtaki	6.1	Lightning	Vegetation	• Security improvement (Section 11.10.3, Project 11) • Target for lightning arrestors (Section 11.10.4) • Target for switch automation (Section 11.10.4) • Target for trip saver protection (Section 11.12.3)
119*	Shannon	3.7	Adverse Weather	-	• Target for switch automation (Section 11.10.4) • Target for trip saver protection (Section 11.12.3) • Will be assessed for resilience improvements • Being assessed for targeted asset renewal
L350*	Ōtaki	2.9	Defective Equipment	-	• Security improvement (Section 11.10.3, Project 13) • Target for switch automation (Section 11.10.4) • Target for trip saver protection (Section 11.12.3) • Being assessed for targeted asset renewal
L352*	Ōtaki	2.1	Vegetation	Defective Equipment	• Included in the vegetation remediation plan • Target for switch automation (Section 11.10.4) • Target for trip saver protection (Section 11.12.3) • Being assessed for targeted asset renewal
G308	Levin East	1.6	Defective Equipment	-	• Security improvement (Section 11.10.3, Project 10) • Target for switch automation (Section 11.10.4) • Target for trip saver protection (Section 11.12.3) • Being assessed for targeted asset renewal
C4	Foxton	1.6	Third-party damage	Defective Equipment	• Will be assessed for resilience improvements • Being assessed for targeted asset renewal
L348*	Ōtaki	1.6	Third-party damage	Defective Equipment	• Security improvement (Section 11.10.3, Project 12) • Will be assessed for resilience improvements • Being assessed for targeted asset renewal
139	Shannon	1.2	Vegetation	Defective Equipment	• Included in the vegetation remediation plan • Being assessed for targeted asset renewal
L351	Ōtaki	0.9	Human Error	-	• Security improvement (Section 11.10.3, Project 12)
E153	Levin West	0.8	Adverse Weather	-	• Will be assessed for resilience improvements • Being assessed for targeted asset renewal
Total		**22.6**			

* Feeders at the 90th percentile or above in the past three years

4.6 Network efficiency

We have two broad measures for efficiency—opex and asset cost-to-serve. There are many efficiency measures—we use cost-to-serve measures as these give the best line of sight to (and significantly influence) affordability.[32] [33]

Increasing costs have had a declining trend in real opex cost-to-serve in recent years. This is an industry-wide trend driven by:

- Capability-building in response to increasing capital works programmes and increasing business complexity;

[32] Efficiency can be measured in many ways (per MW of demand, per kVA of installed capacity, per kWh of energy transported, per customer served). The other measures provide a technical view of efficiency, which may or may not impact customers.

[33] As opex and the return on assets and depreciation are the largest components of distribution prices.

- Many IT costs moving to software-as-a-service,[34] and,
- Some business-related costs are increasing faster than general inflation (e.g. insurance).

Our asset cost-to-serve has improved slightly in recent years. Our strong growth in customer connections has assisted. This is because the incremental asset cost to connect a new customer is below that required to serve existing customers. This is as expected as new customer utilise existing assets (as well as new assets) for their supply.

Figure 62: Opex Cost-to-Serve[35]

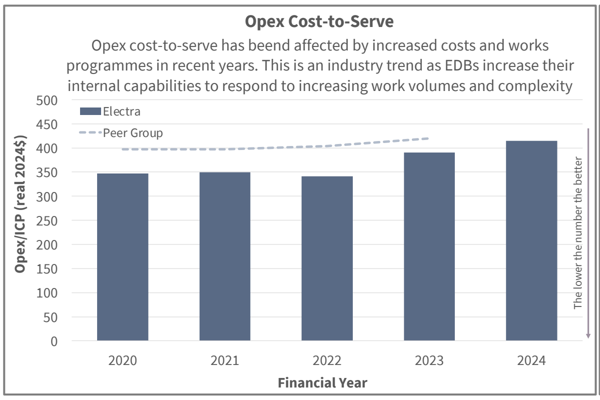
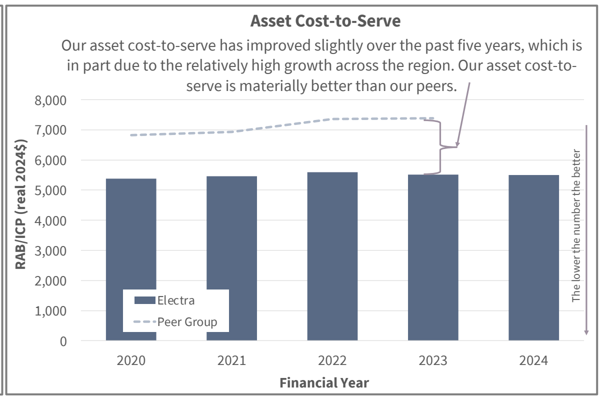


Figure 63: Asset Cost-to-Serve[35]



4.7 Work delivery performance

Delivering the capex works program relies on the work being designed, property rights procured, materials being supplied, and field resources being available. Figure 64 shows various external and internal factors that have impacted delivery in recent years. We have plans in place to address these.

The most significant delivery impacts have been in relation to system growth projects. Various external factors have impacted this work, including consultation on route selection, land acquisition and large project-based material requirements. The time taken to select new line and cable routes has been longer than anticipated, and the time taken to deliver materials has also increased. We are working on improving delivery, which is discussed later in Sections 9 and 13. The variance has been amplified by underspending on customer connection capex (outside of our control) and capitalising internal staff time (which is not a delivery issue *per se*).

Pleasingly, the delivery of asset replacement and renewal work over the last three years has been on plan (in total).

The opposite has occurred for the delivery of network opex, where we have consistently exceeded the budget (refer to Figure 65). Over the past three years, the main driver for this has been higher system interruption and emergency costs (e.g., fault response and restoration). We have increased the budget by 18% over that period, but the increase has not been sufficient to keep pace with increases in work costs. The number of faults (whilst volatile due to weather) was lower in 2022, 2023, and 2024 than in 2020; hence, the cost of undertaking the work has been the primary driver of the increase. This is due to various reasons,

34 That were previously capital licencing and development costs

35 We only benchmark versus our peers as they have similar network characteristic. Network characteristics can have a significant influence on business cost structure and the level of assets employed. Whilst the absolute difference is useful. It is the relative trend that is most important as this less influenced by network characteristics.

including materials, resources and traffic management costs. The rise in fault response costs is consistent with the industry, where system interruption and emergency were exceeded budgets by 15% from 2020 to 2023.

We experienced a resource constraint with our asset inspections, which led to some underspending in 2023 and 2024, and a timing issue with an external specialist due to their availability. This underspend partially offsets the higher system interruption and emergency costs.

Figure 64: Network Capex Works Delivery

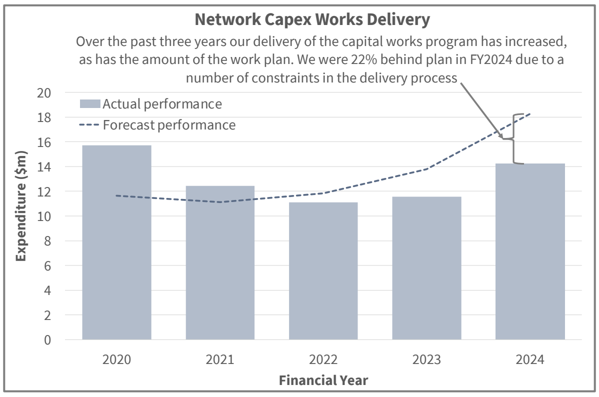


Figure 65: Network Opex Delivery

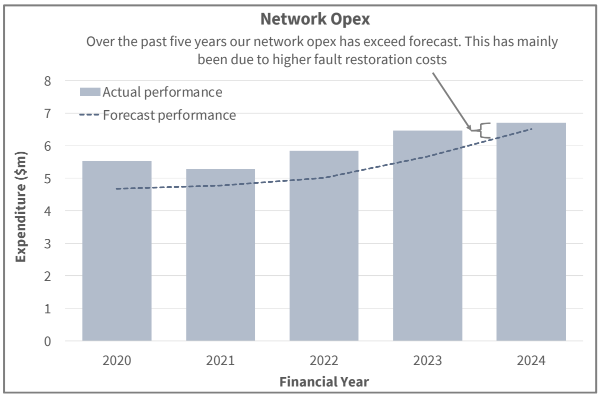


Table 6 summarises our planned inspection performance. Prior to 2023, we consistently completed our planned inspections. A resource constraint in our inspection team impacted distribution and LV asset inspections in 2023 and 2024. These constraints have now been resolved. We also deferred our 33kV thermography inspections in 2023 and 2024. The current backlog of inspections will be completed by early 2025.

Table 6: Completion of Planned Inspections

Assets	Target 2024[36]	Average 2020-2023	Actual 2024	Comments
Sub-transmission assets (visual and thermography)	>95%	73%	50%	Resource constraints delayed line inspections in 2023. No thermography inspections undertaken in 2023 and 2024
Zone substation assets	>95%	100%	100%	All inspection completed
Distribution lines and switchgear assets	>95%	97%	80%	Resource constraints delayed line inspections in 2023 and 2024. This issue has now been resolved.
LV pillar boxes	>95%	98%	30%	Resource constraints delayed line inspections in 2024. This issue has now been resolved.

4.8 Other aspects of performance

We monitor compliance with all our legislative and regulatory compliance using the ComplyWith system. As detailed in section 14.2.4, the most recent certification process covered 44 pieces of legislation, with 415 responses completed. There were no non-compliances identified.

[36] We are targeting to achieve practical completion of our inspection. Practical completion means the work is completed with the exception of minor omissions (of less than 5%), hence the target is >95%. We take a practical approach as some inspection require access to private property and can have weather restrictions.

5. The Key Issues Driving Investment and Performance

5.1 Introduction

This Section considers other key issues that are driving investment and performance. It builds on the preceding two sections. The key issues discussed in this Section shape our asset management policy and strategy. The key issues are:

- Demand growth due to regional population growth;
- Demand growth due to electrification to meet New Zealand's net zero 2050 goal;
- The aging of the network assets which will see the emergence of end-of-life drivers;
- The increasing risk that future reliability targets won't be met;
- Increasing our asset management maturity to meet future requirements;
- The need to balance competing limbs of the energy trilemma.

We discuss each of these issues in the following sections.

5.2 Demand growth due to regional population growth

Horowhenua region

Until around 2017, the Horowhenua district saw relatively low growth. Given the recent high growth[37], the Horowhenua District Council forecasts the population to grow to 62,000 by 2041. The District's population is projected to grow 1.8% annually over the next ten years[38].

The growth is partly driven by the Wellington Northern Motorway project, which improves access to the Wellington region.[39] The Northern Motorway to Ōtaki is complete, and the Ōtaki to Levin section is currently underway and is due for completion by 2029.[40]

Sense Partners note:

> *"it appears that domestic migration into Horowhenua has been higher than we or other experts, such as Statistics New Zealand, would have predicted three or four years ago. This is likely to be due to a combination of factors, including:*
>
> - *Improved accessibility from the expressways that have been built to the south of the District;*
> - *Increased costs of living, especially house price inflation, in most urban centres including Palmerston North and Wellington."*

Horowhenua District Council's current view is that the population will continue to grow at the 95th percentile (consistent with the past six years). The most recent census indicates the region's population growth was 2.0% from 2013 to 2023. We have adopted the 75th percentile over the long term as this reflects a continuation of the ten-year trend (rather than the shorter trend adopted by the Horowhenua District Council). However, we recognise some upside risk of higher growth (refer to Figure 66 and Figure 67). Our

37 The population growth has been 2.1% per year for the last six years.

38 Sense Partners, "Horowhenua Socio-Economic Projections Summary and Methods", May 2020

39 https://www.horowhenua.govt.nz/Growth-Projects/Growth. This is based on the 95th percentile growth rate from the May 2020 projections.

40 https://www.nzta.govt.nz/projects/wellington-northern-corridor/otaki-to-north-of-levin

current review implies a compounding annual growth rate of 2.1% over the AMP forecast period, up from the 1.4% used in our prior forecasts. This reflects a shift from the 50th percentile to the 75th percentile.

We expect population growth to drive an increase in residential, commercial, and small industrial customers. Plenty of flat land is available in the Horowhenua close to transport links. This land is cheaper than that available in Wellington and Palmerston North, which will likely fuel commercial and light industrial development in the region. Based on our projections, we are forecasting around 9,500 new connections by 2050 in the Horowhenua region.

The higher population growth is expected to see the base demand (before the impact of electrification) grow by 15% by 2035 and 39% by 2050. These are significantly greater than our forecasts in the 2023 AMP and indicate an additional 16 MW of demand before any impact from electrification.

Figure 66: Horowhenua Population Forecasts

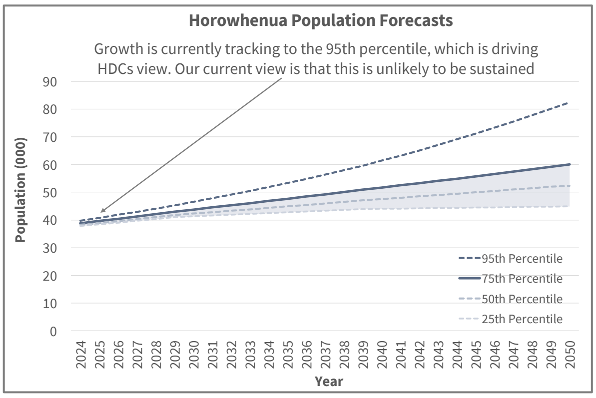
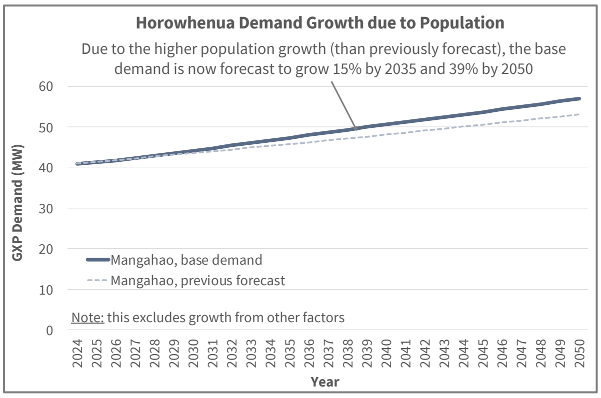


Figure 67: Horowhenua Demand Growth due to Population



Kāpiti Coast region

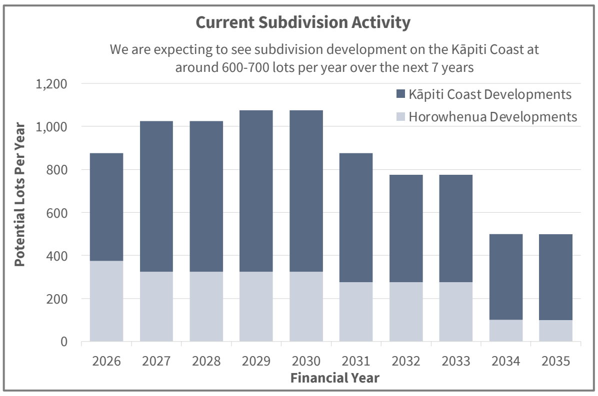
In 2021, Sense Partners forecast the Kāpiti Coast to grow by approximately 32,000 people to 90,000 by 2051, requiring close to 14,000 additional dwellings (based on the 50th percentile).[41] Recent growth (to 2023) has been below those prior forecasts, and the population growth forecasts have been reduced. The May 2023 update by the Kāpiti Coast District Council saw an easing of growth across the next 30 years, reflecting lower levels of migration into the region. The Council's view is that the population is now expected to grow to 78,000 by 2050, a growth rate of 1.2% p.a.[42]

We are seeing significantly more progress on land developments than suggested by the revised Kāpiti Coast District Council (refer to Figure 68). The current view suggests land development could be in the order of 600-700 sections per year, which equates to a growth rate of around 1.7%, which implies a population growth rate at the 75th percentile.

41 This was prepared for the Greater Wellington Regional Council and the Kāpiti Coast District Council.

42 https://www.kapiticoast.govt.nz/community/community-insights/population-and-demographics

Figure 68: Subdivision development



Given what we are seeing, we have adopted the 75th percentile for population growth in the Kāpiti Coast region. This is consistent with our previous forecasts (and the Council's prior forecasts). Based on our projections, we are forecasting around 14,000 new connections by 2050 in the Kāpiti Coast region.

Our view on population growth will see the base demand (before the impact of electrification) grow by 13% by 2035 and 40% by 2050. These are lower than our forecasts in the 2023 AMP (as recent growth and the ADMD[43] per customer have been below our prior forecast). However, they indicate an additional 26 MW of demand by 2050, before any impact from electrification.

Figure 69: Kapiti Coast Population Forecasts

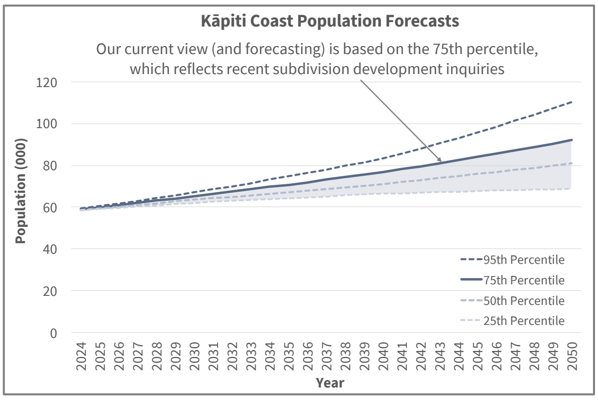
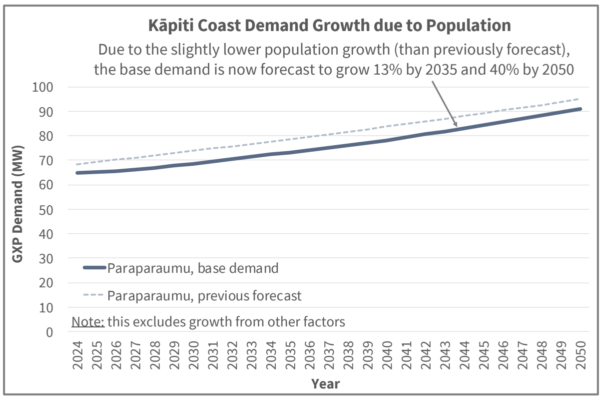


Figure 70: Kapiti Coast Demand Growth due to Population



5.3 Demand growth due to electrification to meet New Zealand's net zero 2050 goal

Reducing emissions through electrification and increasing renewable generation are critical for New Zealand's net-zero 2050 goal (refer to Figure 71). In particular, electrification of transport and heat (both process and general) is the central pillar to achieving decarbonisation. As a result of electrification, the industry forecasts consumption to increase by around 70% by 2050 (refer to Figure 72).

43 ADMD means the After Diversity Maximum Demand, which is a measure of the average peak demand per customer.

Figure 71: New Zealand's Net Zero Pathway

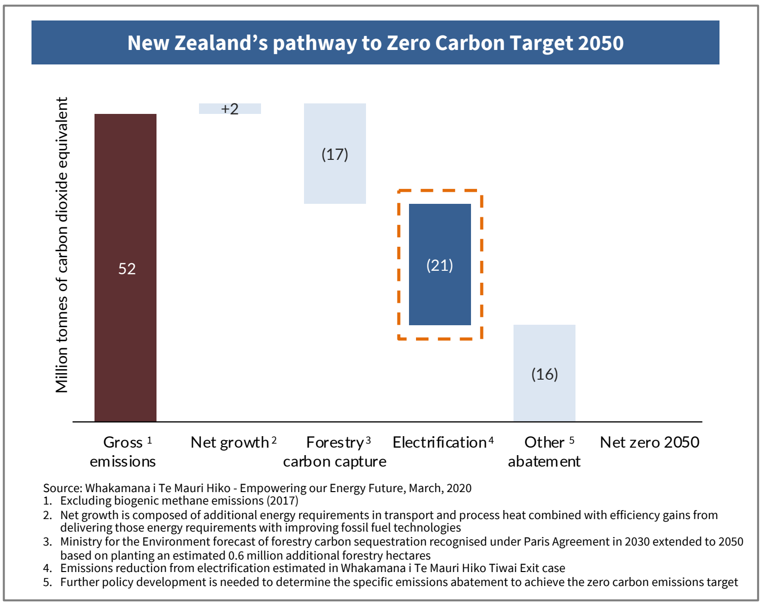
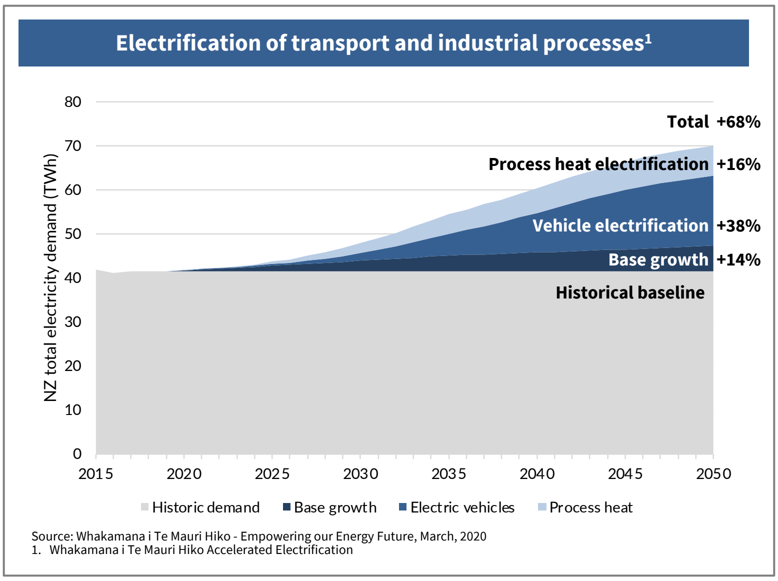


Figure 72: Industry Forecast of Consumption Growth Due to Electrification



We expect the pace of electrification to increase due to the improving economics of new technology and the increasing cost of carbon emissions. We expect to see an increase in electric vehicle (EV) charging, installing solar PV and batteries, and electrifying process and general heat. EVs (particularly secondhand EVs) have strong economics for commuting, and we expect to see strong uptake in the Kāpiti Coast and along the Wellington Northern motorway. Transpower's most recent energy transformation monitoring report notes, "*New Zealand continues to exhibit signs of a new period of electrification growth…indicators continue to point towards growth in electrification of transport and process heat.*"[44]

We revised our demand forecasts (included in Section 10.8), and they indicate material growth due to the impact of electrification (refer to Figure 73). There is significant uncertainty regarding the extent of demand growth, and material reductions are possible using flexibility from EV smart charging and other sources of demand response (refer to Figure 5).

[44] Transpower, Whakamana i Te Mauri Hiki, Monitoring Report, October 2023.

Figure 73: Demand Growth due to Electrification

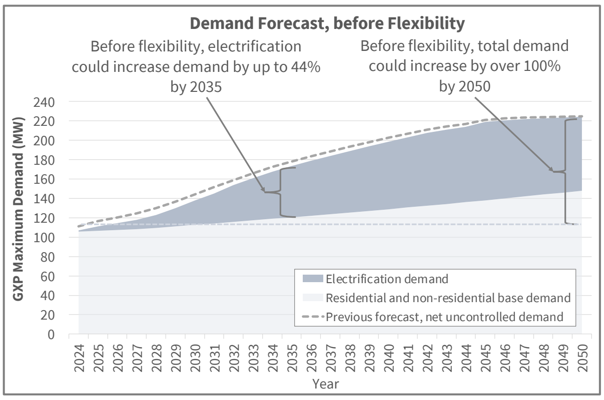
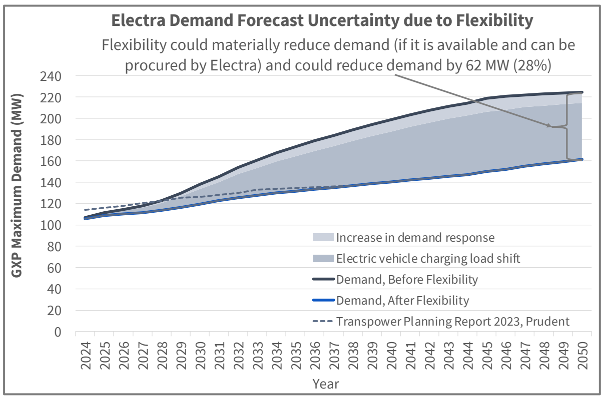


Figure 74: Uncertainty in Demand Growth



Combined with the impacts of population growth, we are forecasting that demand could increase between 25 and 66 MW by 2035 and between 55 and 115 MW by 2050. The range reflects the influence of flexibility in relation to EV charging load-shifting and additional demand response. These increases will have a material impact on the network.

Our forecast uncontrolled demand growth equates to a 110% increase in demand by 2050, before the contribution from flexibility. This demand growth is slightly higher than recent industry forecasts (before flexibility), which indicates that national peak demand could increase 93% by 2050.[45] The higher uncontrolled growth we are forecasting reflects higher connection growth present in our region. Our controlled demand growth forecasts (after flexibility) are slightly below that forecast by Transpower in their most recent planning report. Transpower's forecasts reflect electrification demand consistent with their Te Mauri Hiko report, which assumes that EV charging load-shifting and additional demand response will occur.[46]

5.4 The network assets are aging, and end-of-life drivers are emerging

Like most distribution businesses in New Zealand, many of our assets were installed in the 1950s, 1960s and 1970s, and many will reach end-of-life over the coming decades. Figure 75 through Figure 81 show the age profile of our primary asset categories and where we expect to see end-of-life drivers emerging. The actual driver for replacement (as set out in our fleet plans in Section 12) is based on a combination of asset health and criticality. However, these graphs indicate that we will see increased asset-related risks over the coming decade.

The end-of-life drivers for replacement could emerge in around 18% of the fleet over the next decade. How we manage asset-related risks will be a greater focus for the business, including ensuring that we understand the health of the assets and can reasonably forecast the required maintenance or renewal of the assets. This AMP includes fleet plans for our primary asset classes, which communicate the health, risk and expected asset renewals over the coming decade.

[45] BCG, "The Future is Electric", October 2022, Page 47.

[46] Transpower, "Transmission Planning Report, 2023", Page 202 and 265.

Figure 75: Concrete and Wood Pole

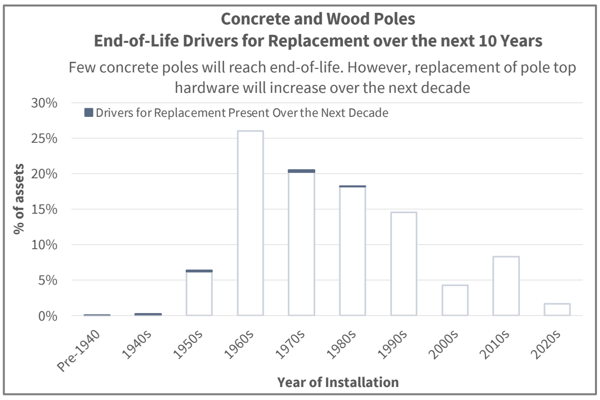


Figure 76: Conductor

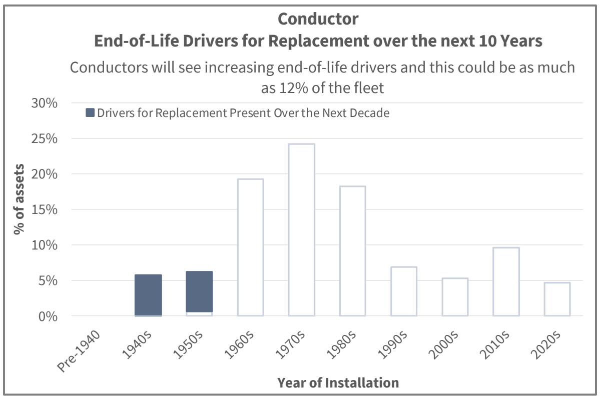


Figure 77: Cables

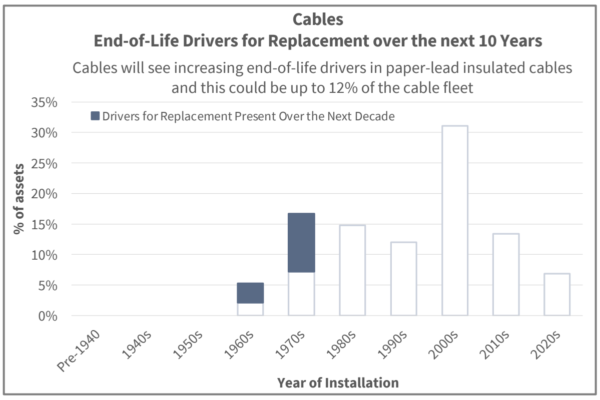


Figure 78: Zone Substation Switchgear

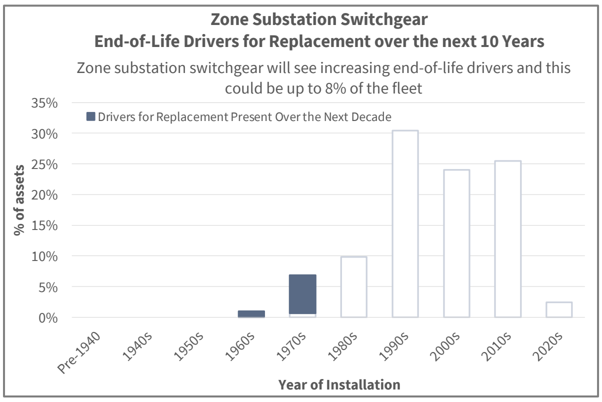


Figure 79: Zone Substation Transformers

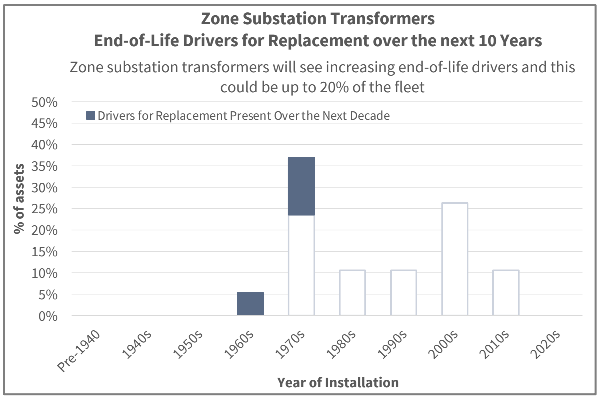


Figure 80: Distribution Switchgear

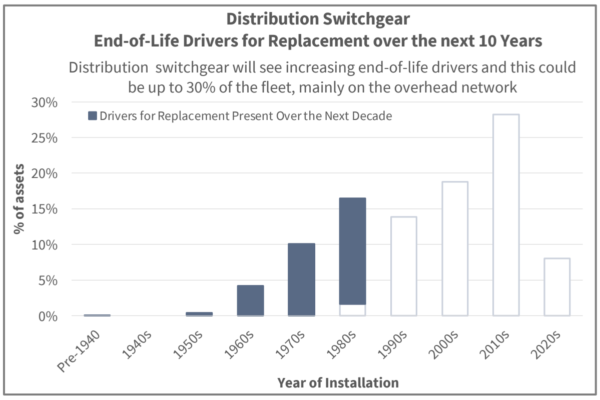
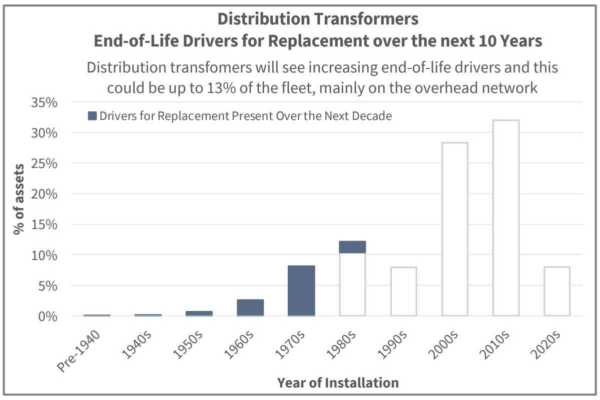


Figure 81: Distribution Transformers



5.5 There is an increasing risk that future reliability targets won't be met

Our planned and unplanned reliability performance has generally been good, but without changes to our expenditure levels, there is an increasing risk of deteriorating reliability performance (refer to Figure 82 and Figure 83). The risks to reliability performance arise from climate change, population growth, our aging asset fleet and the limited switching points on the underground network:

- We are seeing an increase in adverse weather events due to climate change. Increasing adverse weather events will increase the number of outages due to asset design limits being exceeded and increase the number of out-of-zone vegetation outages;
- Increasing population and economic activity increases vehicle-kms travelled and increases the risk of third-party damage to lines (from vehicles) and to cables (from contractors);
- Our assets are aging, and the risk of end-of-life drivers resulting in asset failures will increase;
- We are forecasting increasing maintenance and renewal work on the underground network, which will require very large outage areas due to the legacy network architecture which features a low number of switching points on the network.

Based on a continuation of historical performance, we have a 38% probability of achieving our unplanned reliability (SAIDI) target in any year. Given the risks mentioned above (if left unmitigated), this could deteriorate to less than a 10% probability of achieving the target by the end of the decade and we have plans in this AMP to address this issue.

Given the increase in planned work (and that the current configuration of the underground network is not meeting our planning standards), we won’t be able to achieve the current target, and our planned work on the underground network will severely impact customers due to the large outage areas required. We believe that this situation will be unacceptable to our urban customer base.

Managing reliability is increasingly important. Electrification will reduce energy diversity and increase New Zealand's dependence on a reliable electricity supply. Customers need confidence that electricity will be delivered where and when required, and maintaining the reliability of supply will provide this confidence.

Given the reliability risks, we must actively pursue projects to increase the network's security, reliability and resilience.

Figure 82: Risk to unplanned reliability performance

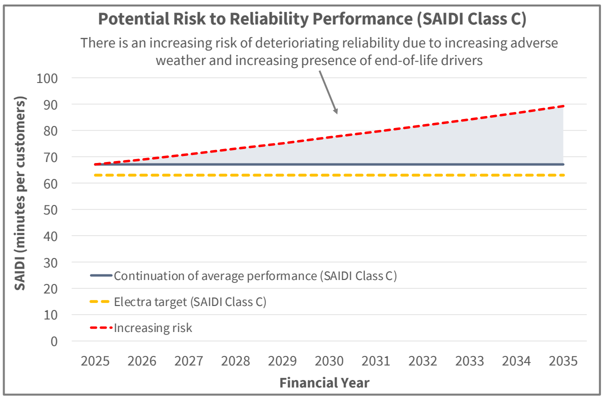
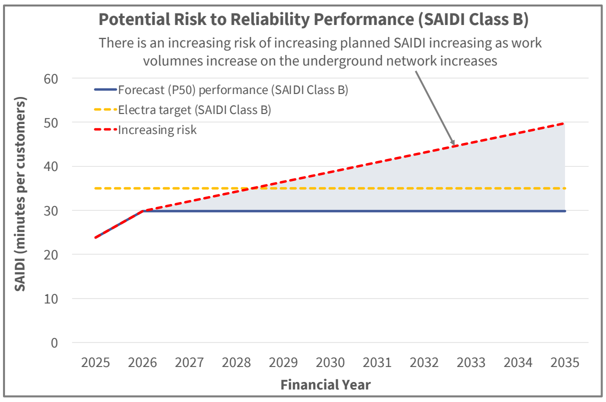


Figure 83: Risk to planned reliability performance



CASE STUDY ON INCREASING UNDERGROUND FAULT CONSEQUENCE

In June 2024, there was a cable failure during a planned job where the cable used to backfeed the customers during planned work failed. 3,358 customers affected and a SAIDI of 5.53.

In October 2024, there was a cable termination failure; 1,648 customers were affected and a SAIDI of 1.93. The limitation on network switching points increased the outage area and duration for many customers as staged restoration was impossible.

As of November 2024, unplanned SAIDI on the underground network is over 10 SAIDI, which is well above prior years.

5.6 Increasing our asset management maturity to meet future requirements

Figure 84 shows our current asset management maturity. Until now, our maturity has been a good fit for the needs of the network. Over the last decade, the network performance has generally been good, and our assets have been in good condition (commensurate with their age). While strong, growth has been manageable with the capacity and security limits of the network. However, as noted in the preceding sections, future growth will be greater, complexity will increase, asset end-of-life drivers will emerge, and network risks will increase.

We now need to improve our asset management maturity assessment tool (**AMMAT**) from Level 2.4 to 3.0. Level 3 means that all elements of our asset management system are in place and are being applied and integrated, with only minor inconsistencies.[47] Our current level of 2.4 means that in some areas, the system is fully developed, and in others, implementation is not yet fully completed and integrated.

The extent of the gaps in the AMMAT assessment indicates that a wide-ranging improvement programme is required. Our immediate focus will be on the following areas:

- Given the expected increase in demand, development planning (the early phase in an asset's lifecycle) needs to be more mature;
- The increasing use of DERs and the evolution of flexibility markets will increase the complexity of our business and will require new processes to dynamically manage demand and higher maturity in information management;

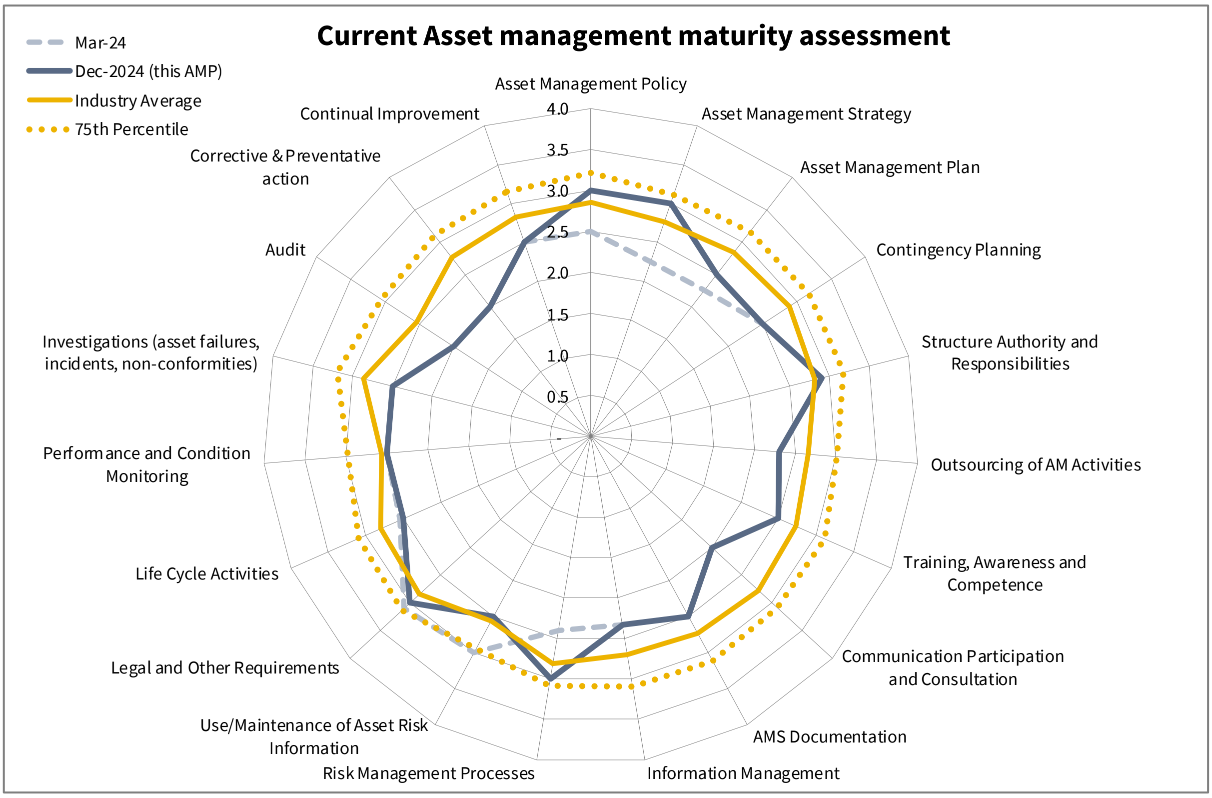
[47] EEA, Guide to Commerce Commission Asset Management Maturity Assessment Tool (AMMAT), May 2014.

- Given that asset end-of-life drivers are emerging, a higher maturity in life cycle activities, information management, performance and condition monitoring, and asset management strategy will be required;
- Asset condition assessment standards, condition data and age data have not kept pace with the evolution of the condition-based asset risk management model (CBARMM), which has impacted the quality of our forecasting for some asset classes;
- Much of the asset information (and associated processes) is stored in different systems and spreadsheets, which makes analysis and forecasting difficult, which makes optimising asset risks and renewal more difficult;
- Capex work has seen delivery delays due to the time taken to select new line and cable routes and the delivery of materials. Improvement in our front-end engineering design (FEED) and outsourcing processes is required.

Better information and process management will support many of these focus areas. This requires a step-up in our asset information systems.

Following the more immediate work, our focus will be on training, communication, documentation, audit, corrective actions, and continuous improvement.

Figure 84: Current Asset Management Maturity



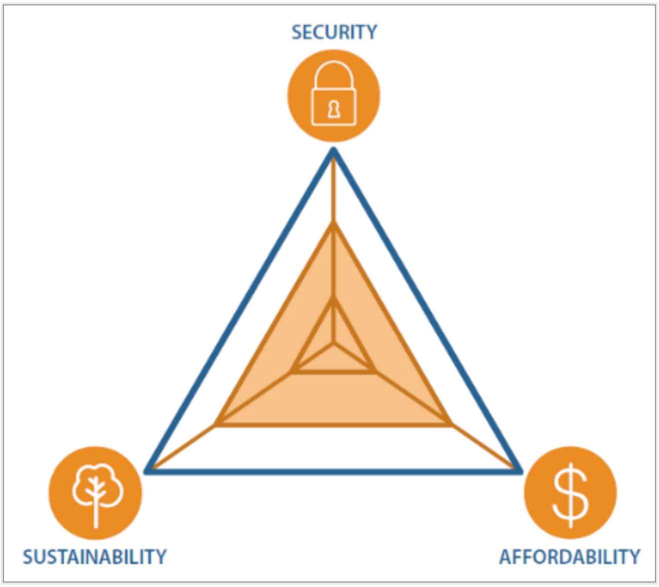
5.7 The need to balance competing limbs of the energy trilemma

The Energy Trilemma is a well-recognised framework (refer to Figure 85) for strategic optimisation in the energy sector. This framework has been adopted throughout the industry to communicate how these factors are balanced.

In the energy context, the three limbs of the trilemma refer to:

- **Sustainability:** means supporting New Zealand's energy transformation, minimising emissions, and adapting to climate change.
- **Security:** means meeting current and future energy demands reliably, as needed by our customers, and being resilient to external events.
- **Affordability:** means the cost of, and access to, energy (of which electricity is an increasingly important component).

Figure 85: The energy trilemma



The importance of this balance has increased for Electra due to:

- The need for higher opex and capex to respond to our aging asset fleet;
- The need for higher opex and capex to support New Zealand's sustainability and decarbonisation goals through supporting the electrification of transport and process heat;
- The need for higher opex and capex to maintain a secure, resilient and reliable network as energy diversity reduces (due to electrification) and risk increases (due to climate change);
- The need to maintain a strong emphasis on affordability given the concentration of older people and the generally low income of our customers (refer to Figure 18 and Figure 19 in Section 0).

The energy trilemma balance needs to be a key consideration for major projects. We also need to communicate how we are balancing factors as a business. We believe that it is important to communicate with stakeholders about our thinking about balancing the energy trilemma and what this could mean for our customers.

Part 2:

Our asset management strategy

6. Asset Management Policy and Strategy

6.1 Introduction

This Section presents the asset management policy and strategy. The policy and strategy define the principles and objectives to guide the more detailed plans contained later in the AMP.

6.2 Asset Management Policy

The Asset Management Policy establishes the principles that guide the direction and approach to managing the electricity network. The policy describes Electra's commitment to the responsible stewardship of the electricity network assets. It sits alongside our Health, Safety and Wellbeing Policy, Sustainability and Environmental Policy, Risk Management Policy, Procurement Policy and other key corporate policies.

Asset Management Policy

Electra is committed to responsible stewardship of the electricity network to meet the needs of our customers and stakeholders over the long term.

Effective asset management is the foundation for meeting this commitment. Asset management involves the entire organisation. We shall apply sound technical, social, and economic principles that consider customers' present and future needs and the services they require from the network assets.

We will:

- Maintain and manage the network assets to enable the safe, efficient and effective delivery of electricity to our customers
- Consider the economic, environmental and cultural impact of our business and find an appropriate balance between them
- Monitor service levels to ensure they support customers and our business goals and objectives
- Develop the network responsibly to meet current and future needs, and we will adopt new technology to ensure we keep pace with the requirements of customers and other stakeholder
- Establish asset operating, maintenance and replacement strategies to ensure our assets support the services required and minimise the total lifecycle costs, including through extending the useful life of assets
- Seek to provide stable long-term pricing to our customers and appropriate financial stewardship
- Implement good governance and management practices to ensure risk is appropriately managed, service levels are delivered, and actions are taken to improve performance when necessary
- Report to customers and other stakeholders on the status and performance of work related to implementing this asset management policy

6.3 Asset Management Strategy

Our asset management strategy

We have developed an asset management strategy to guide our asset management work over the next decade. We will review the strategy periodically to ensure it continues to respond to the needs of customers, stakeholders and the network.

Asset Management Strategy

Our asset management strategy comprises six initiatives:

1. Prepare the network (or non-network alternatives) to support the forecast future growth in our region.
2. Implement an energy transformation roadmap to further prepare for increased electrification.
3. Develop comprehensive fleet plans and renewal forecasts.
4. Continuously improve the security, reliability and resilience of the distribution network.
5. Improve asset management maturity to level 3.
6. Balance the energy trilemma in a manner that aligns with our customer, stakeholder and network needs.

Work programmes (discussed in the implementation section) are aligned under each initiative.

The strategy is aligned with the asset management policy and:

- Is aligned with Electra's business strategy and the needs of our stakeholders contained in Section 2.4;
- Is consistent with the context of our network and the types of customers we have, as discussed in Section 3;
- Responds to any material gaps in performance described in Section 4;
- Responds to the key issues driving investment and performance as described in Section 5;
- Supports the achievement of our performance targets contained in Section 7.

Table 7 provides further detail on each of the initiatives.

Table 7: Our asset management strategy

Initiative	Description
1. Prepare the network (or non-network alternatives) to support future growth in our region	We need to ensure we properly plan for future demand growth in a manner that has the least cost and risk for our customers. We will do this by: • Preparing development plans to cater for forecast growth at the GXPs, sub-transmission, distribution and low voltage networks; • Developing a long-term solution for providing capacity and security at Mangahao GXP; • Ensuring the plans provide a staged development pathway that can be adjusted for non-network alternatives (i.e. flexibility) and advanced or deferred if growth differs from that forecast.
2. Implement an energy transformation roadmap to further prepare for increased electrification	In addition to planning for network demand growth, we must ensure all aspects of our business are ready for the energy transformation to support New Zealand and our region's decarbonisation goals. We will do this by: • Preparing monitoring reports and adjusting the roadmap steps to align with technology change and the pace of the energy transformation; • Continue implementing the roadmap (a comprehensive energy transformation roadmap was developed in 2021); • Being ready to utilise flexibility where this provides viable non-network alternatives to manage demand and reduced the extent of network augmentation.
3. Implement comprehensive	As an increasing number of our assets approach end-of-life, we need to prepare comprehensive fleet plans. We will do this by:

Initiative	Description
fleet plans and renewal forecasts	• Ensuring condition assessment standards and data align with our health assessment and renewal forecasting methodology; • Defining asset fleet strategies that are aligned to the quality and availability of asset age, condition and risk data; • Preparing asset fleet plans and renewal forecasts for all material asset classes • Accelerating asset condition inspections where data gaps exist; • Targeting asset renewals where asset health is deteriorating, including prioritising pole-top hardware and the worst-performing feeders.
4. Continuously improve the security, reliability and resilience of the distribution network	Whilst our reliability is generally good, we need to continuously improve to ensure future reliability targets can be met. We will do this by: • Increasing the automation and protection of rural feeders, targeting the worst-performing feeders; • Increasing the number of ground-mounted switches, targeting areas where asset health is deteriorating and where there is heightened third-party damage risk; • Reviewing our overhead line designs and practices to ensure they meet site-specific wind speed requirements to improve resilience; • Prioritise our operational vegetation management plans to ensure the worst-performing feeders (for vegetation) are addressed; • Undertake further analysis of vehicle damage incidents and high-traffic areas to assess options to reduce vehicle damage risks.
5. Improve asset management maturity to level 3	We need to ensure our capabilities keep pace with the changing needs of the business. We will do this by: • Developing an asset management improvement plan that closes the key maturity gaps, which will involve: • Updating our policies and procedures across design, construction, commissioning, inspection and maintenance; • Revising and developing business processes (the focus areas are outlined in Section 5.6); • Consolidating asset information and key processes within an new asset management system (included in Electra's Digital System Strategic Plan); • Implementing an asset management committee (AMC) to oversee various asset management actions required to lift maturity and to support the Board's asset management and planning subcommittee; • Improving the maturity of the AMP content, particularly in the area of asset lifecycle.
6. Balance the energy trilemma in a manner that aligns with our customer, stakeholder and network needs	We must carefully balance the influence of our capex, opex and sustainability programmes on affordability. We will do this by: • Modelling the impact of our expenditure on affordability (an initial view is provided in this AMP) and adjusting programmes where appropriate; • Ensure that the timing for our various programmes is optimal so that expenditure keeps pace with demand but does not lead to asset stranding if demand changes; • Ensure that our support for decarbonisation is consistent with industry standards and timing, and that it serves the needs of our customers.

Alignment of asset management strategy to issues

Table 8 describes how the asset management strategy aligns and responds to various issues described in Sections 3 to 6. The asset management strategy does not address all of the issues identified, as some issues are addressed directly by a programme or project specified in the implementation sections of the AMP.

Table 8: Alignment of our asset management strategy to the key drivers

Initiative	In response to…
1. Prepare the network (or non-network alternatives) to support the forecast future growth in our region	• Demand growth due to regional population growth • Demand growth due to electrification to meet New Zealand's Net Zero 2025 • Changing customer behaviours, which will have an impact on our demand profile and the effectiveness of our hot water load control • The forecast breach of firm capacity at Mangahao GXP and the continued reliance on Mangahao Generation to manage peak demand
2. Implement an energy transformation roadmap to further prepare for increased electrification	
3. Develop comprehensive fleet plans and renewal forecasts	• Asset condition assessment standards, condition data and age data have not kept pace with the evolution of the CBARM model • The aging of the network assets which will see the emergence of end-of-life drivers • The concentration of defective equipment and adverse weather outages on our worst-performing (overhead) feeders
4. Continuously improve the security, reliability and resilience of the distribution network	• The increasing risk that future reliability targets won't be met • The very low number of switching points on the underground network which restricts the timely restoration of faults • The concentration of defective equipment and adverse weather outages on our worst-performing (overhead) feeders • The high incidence of vehicle damage outages, which could increase as population and economic activity increases • The high concentration of vegetation-related outages on a few feeders and the likely increase due to climate change
5. Improve asset management maturity to level 3	• The need to increase development planning maturity in response to the expected increase in demand • The need to develop new processes to dynamically manage demand and increase maturity in information management in response to the increasing business complexity due to DERs and flexibility markets • The need to increase the maturity of lifecycle activities, information management, performance and condition monitoring, and asset management strategy in response to the emergence of asset end-of-life drivers • Asset condition assessment standards, condition data and age data have not kept pace with the evolution of the condition-based asset risk management model (CBARMM), which has reduced the quality of our forecasting for some asset classes • Our asset information is stored in different systems and spreadsheets, which makes analysis and forecasting difficult, which makes optimising asset risks and renewal more difficult • Capex work has seen delivery delays due to the time taken to select new line and cable routes and the delivery of materials. Improvement in our front-end engineering design (FEED) and outsourcing processes is required. Note: We also address the field resources in relation to works delivery in Section 13. • The areas for improvement need to be supported by better information and process management. This requires a step-up in our asset information systems
6. Balance the energy trilemma in a manner that aligns with our customer, stakeholder and network needs	• The importance of affordability given the age and income demographics of our customers (and beneficiaries) • The need to support New Zealand's sustainability goals through supporting the electrification of transport and process heat • The need for higher opex and capex to maintain a secure, resilient and reliable network as energy diversity reduces (due to electrification) and risk increases (due to climate change)

6.4 Customer Service

6.4.1 Customer service strategy

Traditionally, the nature of our services meant that we engage with customers infrequently and reactively, for example, in the event of an unplanned outage or when things go wrong, when we need to do planned works and these impact them, or when they want to do something that affects us like a new connection or change in capacity.

To support the growth and electrification in our region, we are proactively engaging with commercial organisations and developers to understand where and when the expected growth in our network is required.

This engagement will take the form of direct and regular meetings with our large energy consumers, identifying and meeting our emerging energy users to understand timing and demand characteristics, and working with KCDC and HDC to build a pipeline of future works within the developer community. Input for these activities will influence future AMPs.

Internally, we will be building a set of service level targets for typical activities and dashboards to monitor progress on key performance indicators such as:

- Customer service (reliability) targets;
- Customer connections;
- Customer satisfaction targets.

Electra customers should expect quality service and support at all times. Customers are encouraged to advise us of problems or complaints, including land issues, so that we can fix them. Customers can access Electra via telephone or the Electra website.[48] All our staff are committed to treating complaints seriously and reaching resolutions as quickly and fairly as possible.

6.4.2 Customer communication

An increased level of communication with customers and the broader community is essential. Our approach is to:

- Build strong relationships with customers through proactive communication, particularly during power outages. Our goal is to have consistent and timely communication via multiple media channels;
- Engage with the community across multiple media channels on areas of interest such as planned network developments, outages, public safety, energy efficiency and pricing changes;
- Having a clear and easily accessible portal that provides information on areas such as staying safe around our network, how to get connected, and how to connect new devices like solar PV, batteries and EV chargers;
- Communicate our service standards and performance (through this AMP, the summary AMP, the SCI, our website, social media channels and at community engagement sessions);
- Provides a platform to connect industry partners and stakeholders.

Our primary customer communication channels are our website and outage application. The website contains the current status of the network, information about connecting to the network, safety

[48] https://electra.co.nz/contact-us/complaints-process/

information, the services we provide, network prices, general company information and our compliance process. We also use social media (Facebook and LinkedIn) to communicate with customers and stakeholders. We also operate a 24 x 7 call centre to report power outages.

6.4.3 Notice of planned and unplanned interruptions

Notices for planned outages are issued to customers by their energy retailers and are also displayed on the network status page on the website and the Electra outage application. Electra also does a card-drop for all planned outages. For major outages, we may also provide notices on social media.

For short-notice planned outages (which may be required for urgent work), the card-drop is provided (but there is no notification from retailers).

Notices for unplanned outages are displayed on the network status page on the website and the Electra outage application. For major outages, we may also provide notices on social media.

7. Performance Targets

7.1 Introduction

This Section describes our performance targets. The targets are consistent with our asset strategies, stakeholder interests and customer expectations. Section 7.8 explains how this asset management plan influences the energy trilemma—that is, how it balances affordability, security of supply and supports New Zealand's decarbonisation efforts. This is the first time we have sought to measure ourselves against the trilemma, so we expect this to evolve over the coming AMPs.

7.2 Safety and environmental targets

Table 9 shows our safety and environmental targets. These targets remain unchanged from prior AMPs and reflect our commitment to safety and environmental performance.

Electra is committed to ensuring the health and safety of its customers, employees, contractors, and the public. We have a comprehensive health and safety system aimed at achieving zero LTIs (concerning critical risks), summarised in Section 13.4. We predominantly measure safety performance using leading indicators—which is the best way to ensure that we have influencing safety outcomes. The integrity of our assets also impacts safety, and completing planned inspections (to understand risk) and remediating defects is important.

We have commented on our prior performance in Section 4.2. Our future targets are consistent with prior years, and we believe the targets are appropriate, consistent with stakeholder expectations, and achievable over the long term.

Table 9: Safety and Environmental Targets

Area	Indicator	Indicator type	Average of last 5 years	Target FY2025-30
Safety of staff, contractors, and the public	Staff Lost Time Injuries (LTIs)	Lagging	2.2	Zero LTIs (for critical risks)
	Number of incidents	Lagging	80	No target. Reporting of incidents is encouraged
	Public safety audits	Leading	45	60 per year
	Contractor safety audits	Leading	148	60 per year
	Contractor training seminars	Leading	>3	No target. Training is provided as required.
	Compliance with our public safety management system	Leading	Compliant	Compliant
Asset integrity	Completion of planned Inspections[49]	Leading	89%	>95%
	Remediation of defects in the required timeframe[50]	Leading	TBA	Future measurement following the implementation of the EAMS
Environmental responsibility	Number of environmental incidents	Lagging	0	Zero incidents

[49] This is a composite measure of the completion of planned inspections. Practical completion means the work is completed with the exception of minor omissions (of less than 5%), hence the target is >95%. We take a practical approach as some inspection require access to private property and can have weather restrictions.

[50] The target is det to achieve practical completion. That is, the work is completed with the exception of minor omissions (of less than 5%), hence the target is >95%. We take a practical approach as some as some defect repair work requires planed outages, access to private property and can have weather restrictions.

We are in the process of updating our Sustainability Policy and framework (refer to Section 14.4.4). We will be expanding our environmental responsibility measures in future AMPs.

7.3 Network reliability targets, customer perspective

The context for reliability targets

As mentioned in Section 4.3, our primary customer service measure is network reliability, which is measured using SAIDI (the average duration of outages) and SAIFI (the average number of times an outage occurs). Outages may be planned or unplanned; unplanned outages are particularly important because they inconvenience customers due to their unforeseen nature.

As mentioned in Section 4.4, customers are generally unwilling to accept a lower level of service and are satisfied with the current reliability. For these reasons, our unplanned reliability SAIDI targets remain unchanged, and our SAIFI target has improved slightly.

Our planned and unplanned reliability performance has generally been good, but there is an increasing risk of deteriorating reliability performance. The risks to reliability performance arise from climate change, population growth, our aging asset fleet, and the legacy network architecture of our underground distribution network which features a very low number of switching points, which restricts the timely restoration of faults (refer to Sections 0 and 5.5).

Managing reliability is increasingly important. Electrification will reduce energy diversity and increase New Zealand's dependence on a reliable electricity supply. Customers need confidence that electricity will be delivered where and when required.

Planned improvements to offset increasing risk to reliability performance

Given the increasing reliability risks and the importance of maintaining a reliable network, we are planning a range of improvement projects to increase the network's security, reliability and resilience. The impact these projects are forecast to have on reducing reliability risk is shown in Figure 86 and Figure 87. The initiatives will improve unplanned reliability performance over what we currently provide and enable us to achieve our recently revised planned reliability target.

The key initiatives are:

- Urban underground network security, automation and protection enhancements (Sections 11.10.3 and 11.10.4);
- Rural overhead network security, automation and protection enhancements (Section 11.10.3, 11.10.4 and 11.12.3);
- Improvements in asset health on the worst-performing feeders (Section 12.12 and 12.13);
- Improvement in vegetation management on the worst-performing feeders (Section 12.19.2);
- Improvements in resilience (Sections 14.5, 11.9.4 and 11.10.5[51]);

We have forecast our future reliability performance separately from our target. The future performance is based on a continuation of an "average" year (regarding the impact of weather, third-party damage, and other factors) and incorporates our planned improvements.

51 We have a reliability improvement target for our resilience initiative. However, we have not yet specified the resilience projects. We have only recently finalised our resilience strategy, and the projects are being considered over the coming year.

Figure 86: Unplanned reliability improvements to offset increasing risk

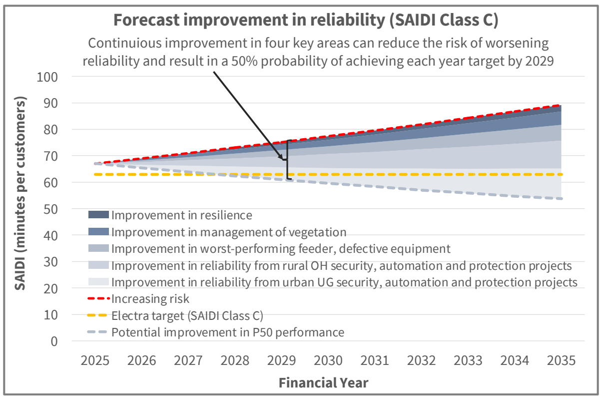


Figure 87: Unplanned reliability improvements to offset increasing risk

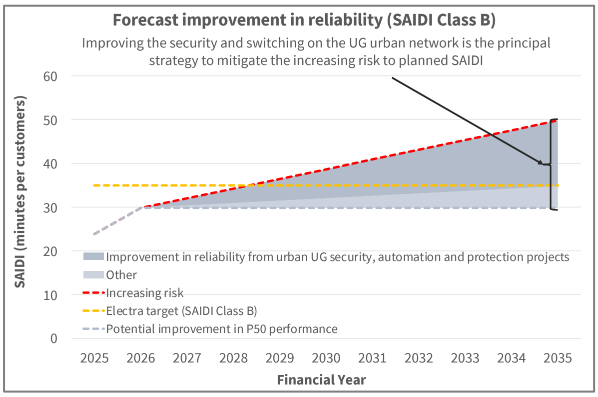


Figure 88 to Figure 91 show our reliability targets. Including the planned improvements, we expect a 50% probability of achieving the unplanned SAIDI target in FY2029. Having forecast performance to at least achieve P50, and we think it strikes the right balance between investing more in reliability and accepting that there will be some years (due to weather) that we will exceed the target.[52]

We are forecasting an increase in planned outages. This reflects the planned increase in work volume. Even with this increase, we will perform significantly better than our peers. The new target is a 90% increase of that included in the 2024 AMP; however, our prior targets have been insufficient and exceeded four out of the past five years. Planned outages are notified in advance and generally cause less inconvenience for customers.

Figure 88: Unplanned outage duration

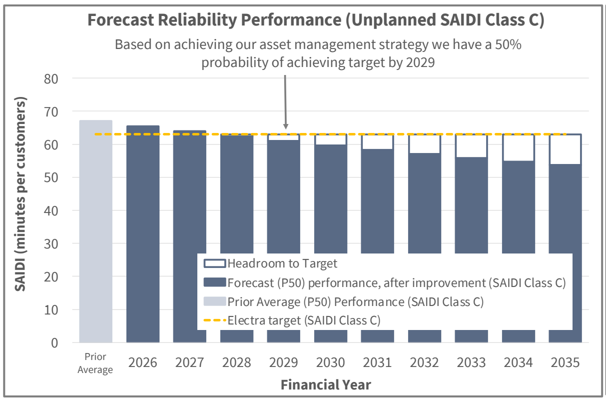
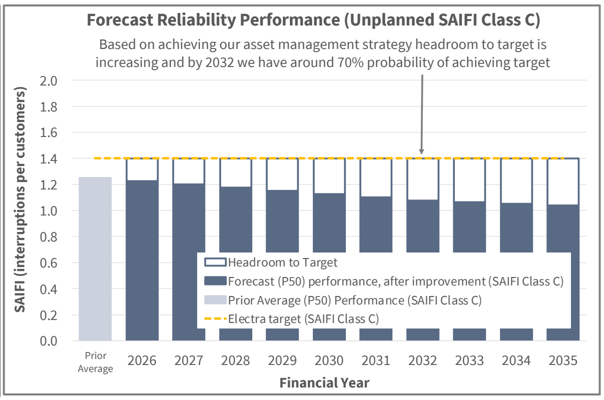


Figure 89: Unplanned outage frequency



52 Based on our historical performance, a worst-case (1 in 10 years) reliability outturn will be a SAIDI of 84 minutes. This is 33% above target, but will occur once in every 10 years. Electra's actual and target performance is based on RAW SAIDI and SAIFI. That is, there is no normalisation for major events. This differs from regulated EDBs, which normalise for major events.

Figure 90: Planned outage duration

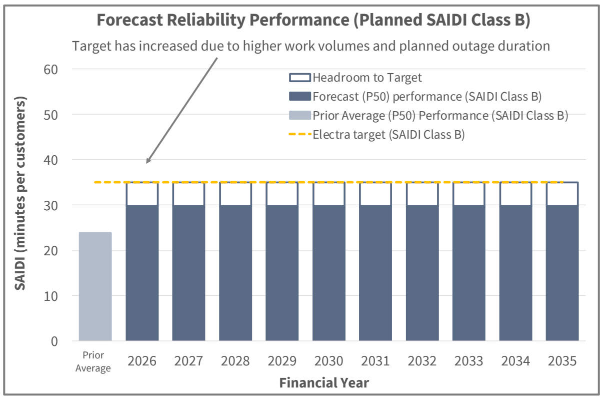
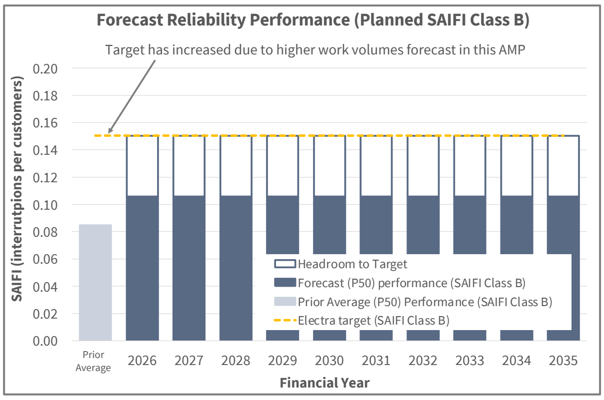


Figure 91: Planned outage frequency



7.4 Other customer service targets

During FY2026, we will adopt an industry-standard customer survey prepared by the Electricity Networks Aotearoa (**ENA**). This will give us a customer perspective on network reliability and fault services. Our target is to provide a reliable supply of electricity that meets customers' needs and, when faults occur, a fault service that also meets customers' needs. When we adopt the new survey tool, we will define measurable targets for customers' views on network reliability and fault service.

Ease of connection and timely planned outage notification are two measures that support customers. We are currently developing measures for new connection processing and planned outage notifications to ensure our service is appropriate in these areas.

7.5 Asset performance targets

Table 10 shows the asset performance targets. The table shows that our current average reliability performance is above target[53] and is forecast to deteriorate without intervention. We have set long-term targets for improving our asset performance (and unplanned SAIDI), consistent with the improvements outlined in Figure 86 and Figure 87. These targeted improvements offset the forecast deterioration and should see our average (P50) performance achieving target by FY2029. We have presented the expected (post-intervention) reliability outturn in FY2035 as a range as we are doing further work on the targeted performance over the coming 12 months.

Sections 7.3 and 4.5.9 presented the linkages to the various improvement initiatives. Improving performance through structural changes like security, automation, and protection takes time. Hence, we have sent our targeted improvement by the end of the current planning period. We expect to see improvement as we progress and will monitor and report on these trends.

[53] 63 SAIDI.

Table 10: Asset performance targets

Asset performance measure	Recent unplanned SAIDI performance (P50)	Forecast increase in unplanned SAIDI without intervention by FY2035	Target improvement in unplanned SAIDI by FY2035	P50 Unplanned SAIDI Performance by FY2035
Reliability performance on the distribution underground network	67.1	7.2	12.5[54]	In the range from 53.7 to 63.0
Reliability performance on the distribution overhead network		6.5	12.0[54]	
Defective equipment outages on the worst-performing distribution feeders		3.7	6.0	
Vegetation outages on worst-performing distribution feeders		3.1	5.0	
Subtransmission network		-	-	
Total	**67.1**	**22.1**	**35.5**	**53.7 to 63.0**

7.6 Network efficiency targets

We are presently updating our forecast modelling. Forecasts of opex and asset cost-to-serve will be included in the 2026 AMP.

7.7 Work delivery targets

Our work delivery targets have two components: expenditure and asset inspections. For both these programmes, we aim to achieve practical completion. Practical completion means the work is completed except for minor omissions (less than 5%); hence, the target is >95%. We take a practical approach, as various external factors can influence delivery (e.g., weather conditions, coordination with other utilities, customers, and landowners).

We have had some gaps in delivery in recent years. Much of this was related to front-end engineering design (**FEED**) issues or resourcing (refer to Section 4.7). We have improvement plans for both aspects—FEED improvements are addressed in Section 9.3, and resourcing is addressed in Section 13.

Table 11: Work Delivery Targets

Indicator	Average of last 5 years	Target FY2025-30
Network capex (actual vs. forecast)	98%	>95%
Network opex (actual vs. forecast)	112%	>95%
Inspection of sub-transmission assets (visual and thermography)	68%	>95%
Inspection of zone substation assets	100%	>95%
Inspection of distribution lines and switchgear assets	94%	>95%
Inspection of LV pillar boxes	85%	>95%

7.8 Energy trilemma balance

A key strategy for this AMP is to *balance the energy trilemma in a manner that aligns with our customer, stakeholder and network needs* (asset management strategy #6). The importance of this balance has

[54] Includes a share of resilience improvements

increased for Electra due to the forecast increase in opex and capex in response to demand growth, preparing for the energy transformation and our aging asset fleet.

Finding the right balance will allow us to support New Zealand's aim of decarbonising transport and process heat through electrification while still placing a strong emphasis on affordability.

The objective is to ensure that customers experience a lower overall energy cost (which will be achieved through lower cost electricity offsetting high cost fossil fuels).

Figure 92: Forecast changes in the Energy Trilemma[55]

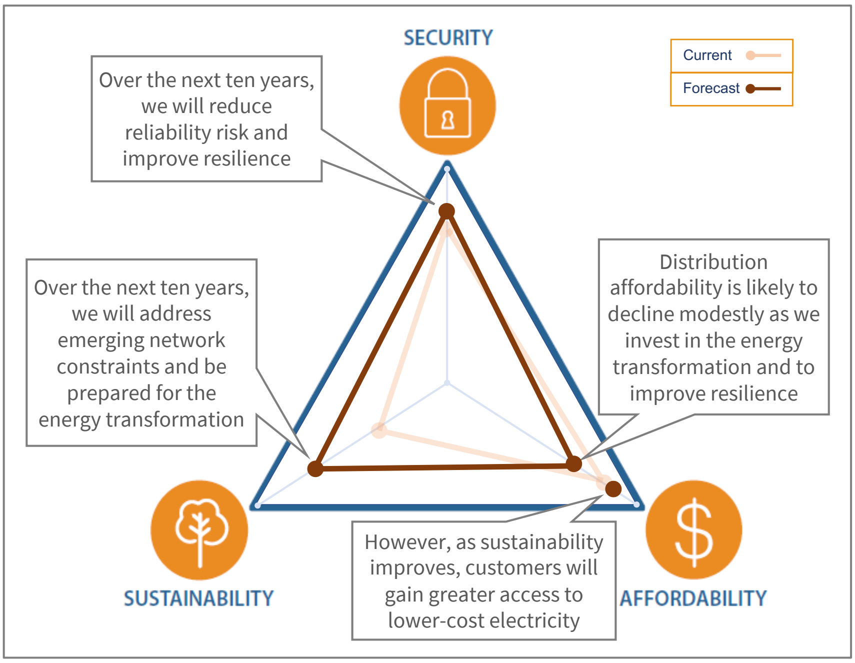


Figure 92 illustrates our assessment against the three limbs of the energy trilemma framework. This assessment indicates the direction of travel over the 10-year horizon of this AMP, which is:

- Sustainability is expected to improve as we *develop the network (or non-network alternatives) to support future growth in our region* (asset management strategy #1) and *implement an energy transformation roadmap to further prepare for increased electrification* (asset management strategy #2);
- Security and reliability are expected to improve as we *continuously improve the security, reliability and resilience of the distribution network* (asset management strategy #4) and implement comprehensive fleet plans (asset management strategy #3);
- Due to the increase in capital expenditure, electricity distribution will become less affordable. However, as sustainability improves, customers will gain greater access to lower-cost electricity (as a substitute for pricier fossil fuels), thereby enhancing their overall affordability.

Our focus on sustainability is vital to ensure that customers can transition away from higher-cost fossil fuels without restrictions.

[55] An explanation of the three limbs is given in Section 5.7.

Our focus on security and reliability is crucial, especially as customer dependence on electricity increases (reducing energy diversity). Therefore, we anticipate that our customers will demand a more secure, reliable, and resilient supply.

Our focus on affordability is also essential, given our region's concentration of older people and our customers' generally low incomes. Balancing sustainability and security against affordability is a critical challenge for the business. We must ensure the energy transition is fair for all customers. In this and future AMPs, we must remain focused on prudent long-term investment, maintenance, and operating needs for the network.

In the 2026 AMP, we will provide greater visibility of the metrics that support this trilemma balance.

8. Asset Management System

8.1 Introduction

This Section describes Electra's asset management framework and system, which guides the management of the network assets and the development of this AMP. We also describe our existing information and operational technology systems and data that support the asset management system. The improvements we intend to make to our asset management system are discussed in Section 9.

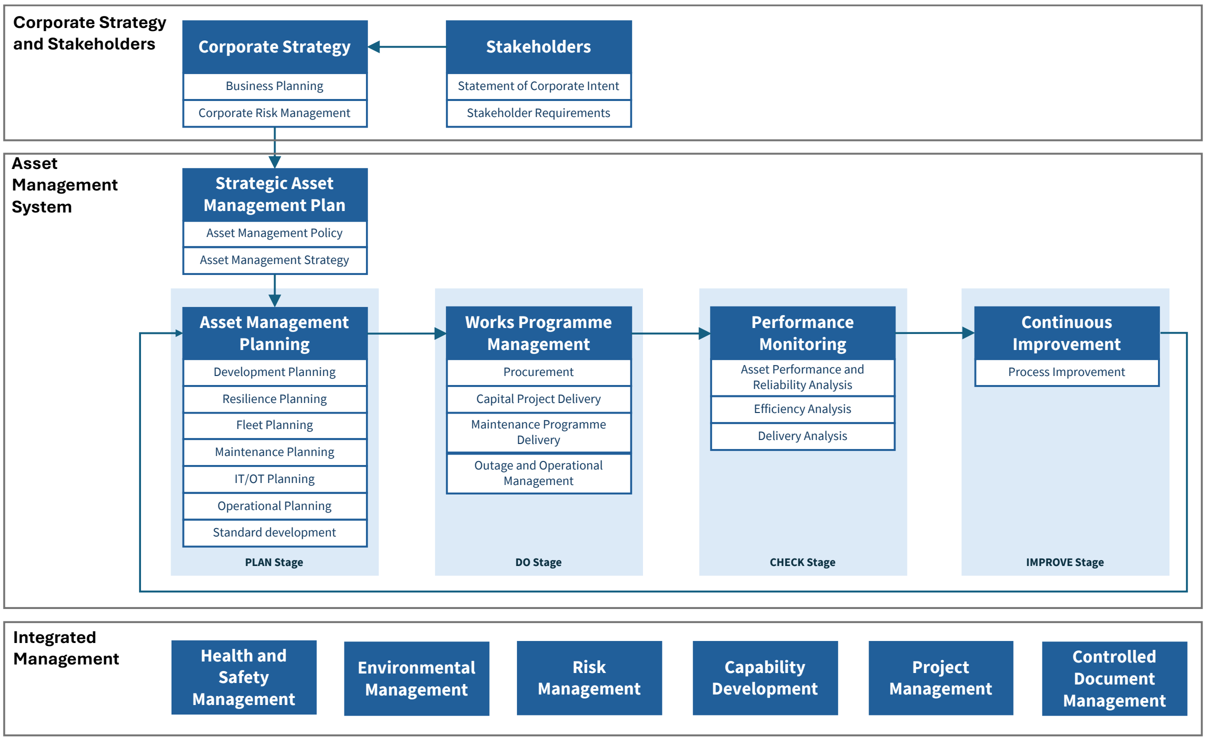
8.2 Asset management framework

We are implementing an asset management framework (refer to Figure 93) as part of the asset management improvement plan (Section 9). This framework guides our asset management activities and includes the key elements of ISO 55000[56]. The framework ensures that our asset management strategies, plans, and actions align with our vision, values, and corporate goals. It also ensures that services are delivered to meet the required standard and that high-impact, low-probability risks are appropriately considered and controlled.

The asset management system forms part of our integrated management framework to ensure risks are managed, capabilities are developed, and projects are delivered. It also ensures that we monitor performance and continually seek to improve performance.

Recent developments include establishing a Board Asset Management and Planning Committee (**AM&PC**), updating and communicating our asset management policy, developing our project governance processes, and resetting this AMP. The AM&PC comprises Directors, is supported by key management, and provides increased oversight and governance over important asset management decisions.

Figure 93: Asset Management Framework

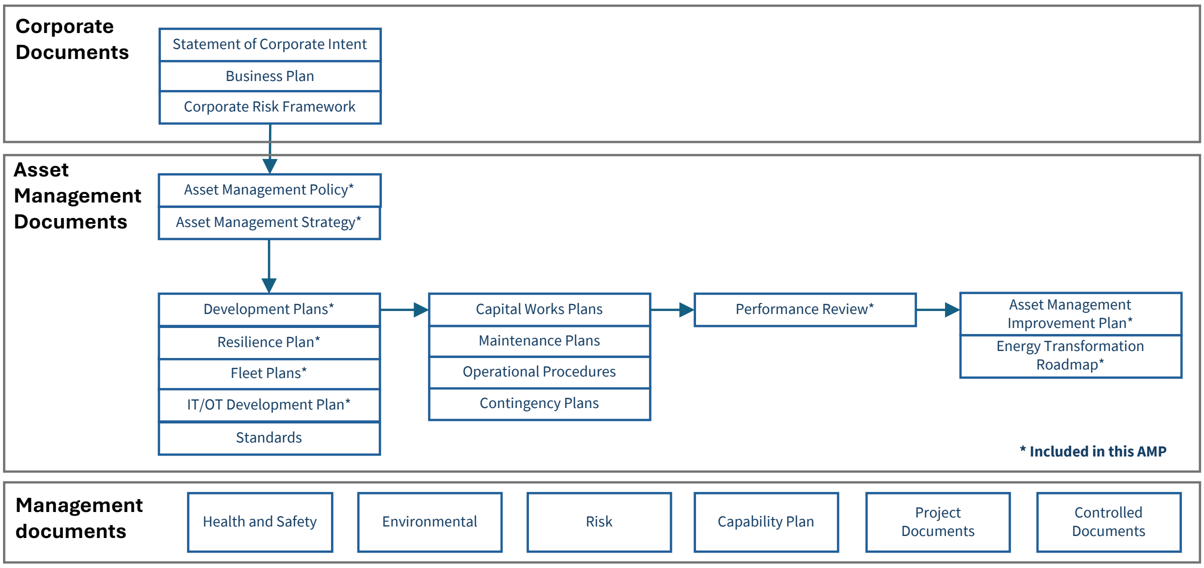


[56] The ISO 55000 suite of standards covers the asset management system's overview, definition and requirements.

8.3 Framework documents

Figure 94 depicts the relationship between Electra's key plans and documents. It shows the links between Electra's asset management documents.

Figure 94: Asset Management linkages



8.4 Asset management information technology and operational technology

By way of an introduction, operational technology (**OT**) systems control and monitor the physical equipment on the network. They focus on real-time management to ensure safe and efficient operations. Information technology (**IT**) systems collect, process, and store data, assisting in business decision-making and communication.

Electra's strategy is to implement *fit for purpose* systems (not a business-wide ERP) for its OT and IT systems and seeks to integrate these where practical. We will align our systems with good industry practices and systems where possible.

Electra has three core OT systems:

- System Control and Data Acquisition (**SCADA**);
- Advanced Distribution Management System (**ADMS**);
- IoT network status monitoring.

These integrated systems are the primary tools for monitoring and controlling access and switching operations on the network, managing the restoration of network outages and associated reporting. They enable monitoring IoT devices on network assets, power quality meters, and customer outage sensing devices.

Electra uses GE iFIX for general SCADA control and monitoring. This was installed in 2010. The master station has had progressive software and hardware upgrades and is located at Levin, Head Office, with a second instance on "hot" standby at Levin West Substation. This relays information via a point-to-point link to the network control centre at Electra's offices in Levin.

Electra's core IT systems comprise:

- Microsoft NAV/Business Central, which is Electra's financial system;
- Esri ArcGIS Enterprise Geographical Information System (**GIS**), which is the primary source of asset and geospatial information for all assets and currently includes tools for maintenance management;
- Condition-based asset risk management model (**CBARMM**), which is used to determine asset health, criticality and risk;
- DIgSILENT PowerFactory application is used for network load flow modelling, to determine network constraints and solutions;
- Vegetation management database, which is used for the management of vegetation around the network;
- Customer Relationship Management (**CRM**), which is used for customer relations and service delivery management;
- Damstra Technology Vault application is our risk and safety management software, which is used to manage risks, incidents, injury, illness and near misses, plus associated injury management and rehabilitation;
- Axos is our electricity billing system.

We operate various other systems to support document management, data storage, integration, and reporting. Some IT systems are integrated to share data where needed, particularly for asset information. The OT systems and the GIS are also integrated to provide asset information.

Recent improvements include implementing new load flow modelling software (DIgSILENT PowerFactory) and upgrading our core financial system from Microsoft NAV to Business Central, which is planned to go live around April 2025. We have also completed the rollout of other ADMS modules to support our operational processes.

8.5 Asset management data

Accurate asset data is critical for operating the business and accurately forecasting asset renewals. Improving asset data is an ongoing focus for Electra. The data was initially populated from the original construction records and GPS site inspections. For new assets, the data is obtained from construction drawings and documentation, and for name-plated assets, it is verified during field inspections.

Over the past two years, we have completed a significant programme to improve asset age and attribute data on overhead structures such as poles, crossarms, switches and pillars. These assets are not nameplated, so determining accurate ages requires a review of old construction drawings and a review of nameplated assets that were installed at the same time as the line.

We have defined objective data quality measures, as shown in Table 12. These grades map to the data accuracy scoring used for information disclosure purposes. We use this grading for asset attributes (ID Schedule 9a), asset age (ID Schedule 9b) and asset condition (which is used in combination with asset age to determine asset health in ID Schedule 12a).

Table 12: Data Quality Grades

Electra Data Quality Grade	Measurable definition	Comparable Commerce Commission grading
4 – Very good	• Data is available for all assets • Data accuracy is greater than 99% (error rate less than 1/100)	4 –means good quality data is available for all assets
3 – Good	• Uncounted assets less than 1% • Data accuracy is greater than 90% but less than 99% (error rate between 10/100 and 1/100)	3 –Data is available for all assets but includes a level of estimate where there is some poor data
2 – Average	• Uncounted assets between 1% and 10% • Data accuracy is greater than 50% but less than 90% (error rate between 50/100 and 10/100)	2 –Good quality data is available for some assets and includes estimates for uncounted assets
1 - Poor	• Uncounted assets greater than 10% • Data accuracy is less than 50%	1 –Good quality data is not available for any assets, and estimates are likely to contain significant errors

As shown in Table 13, we have very good or good-quality data for most asset fleets. Where there are gaps in data quality, we adjusted our asset renewal forecasting process as needed, which we discuss in Section 12.5.

Table 13: Quality of asset data

Asset fleet	Quality of attribute data	Quality of asset age data	Quality of asset condition data
Power transformers	Very good	Very good	Very good
Zone substation switchgear	Very good	Very good	Very good
Zone substation buildings and structures	Very good	Very good	Very good
Overhead structures (poles and crossarms)	Good	Good. Some gaps in pre-1995 data.	Good
Conductor	Very Good – subtransmission Average – distribution and LV	Very good – subtransmission Good – distribution and LV	Average
Cables	Very good – subtransmission Good – distribution and LV	Very good – subtransmission Good – distribution and LV	Good quality (where partial discharge data is available, which is currently only subtransmission)
GM distribution switchgear	Good	Good	Good
GM distribution transformers	Good	Good	Good
PM reclosers	Good	Good	Good
PM air-break switches	Good	Average	Average
PM drop-out fuses	Average	Average	Poor. No reliable condition data
PM distribution transformers	Good	Good	Good
LV pillar boxes	Good	Average	Good
Secondary systems	Very Good	Very good	Good

Our SCADA and ADMS have very good quality data on the HV networks, but there are some limitations on the LV network. Improvements to this data are planned (refer to Section 9.5).

We have a very good working loadflow model for the 33kV system and have loadflow models of key parts of the 11kV system. We are working to prepare a complete 11kV load flow model (refer to Section 9.5).

We have a comprehensive demand forecast model. This model is reviewed annually, and assumptions are refined to reflect the most current data.

8.6 Cyber Security

We are committed to ensuring we have robust cybersecurity. We have chosen to safeguard our digital assets by adopting the NIST Cybersecurity Framework. The National Institute of Standards and Technology (**NIST**) provides a comprehensive approach to managing and mitigating cybersecurity risks. This framework encompasses a set of industry standards and best practices to help organisations identify, protect, detect, respond to, and recover from cyber threats. By integrating the NIST framework, we ensure a robust and systematic approach to cybersecurity, enhancing our resilience against potential cyber incidents.

Figure 95: NIST Cyber security framework

Over the past few years, we have delivered a cybersecurity improvement programme to elevate cybersecurity maturity and implement various controls and measures. This programme covered a range of initiatives, including deploying advanced threat detection systems, enhanced access controls, regular vulnerability assessments, and continuous monitoring of network activities. Electra's commitment to cybersecurity is a continuous process involving all staff. Regular training sessions, awareness campaigns, and simulated phishing exercises are conducted to educate employees about the latest threats and the best practices to counter them.

We aim to maintain a secure digital environment by focusing on these areas, effectively mitigating risks and safeguarding critical information assets. This addresses current security needs and builds a foundation for long-term cybersecurity resilience.

8.7 Expenditure Forecasts

The expenditure associated with the asset management system and existing IT/OT systems are incorporated with the Business Support and System Operations and Network Support opex forecasts in Sections 9.7 to 9.9.

9. Asset Management Improvement Plan

9.1 Introduction

We are embarking on a process to improve our asset management maturity from Level 2.4 to 3.0.[57] Our maturity has been a reasonable fit for the network's needs. However, future needs are changing, and we need to lift our maturity to prepare for future changes.

In this Section, we describe our asset management improvement plan that will drive the improvement in asset management maturity. The improvement plan comprises three parts:

- Enhancing policies, processes and procedures;
- Enhancing IT/OT systems (Electra's digital system strategy);
- Enhancing asset management data.

Electra's Digital System Strategic Plan (**DSSP**), which we summarise in Section 9.4, drives the development of our IT/OT systems. Our internal people capabilities, discussed in Section 13, support these improvements.

The section includes details of the capex and opex required to support the improvement plan.

9.2 Asset management improvement—overall plan and target

9.2.1 Link to Asset Management Strategy

The improvement plan primarily supports asset management #5 *Improve asset management maturity to level 3* and #3 *developing comprehensive asset fleet plans*. The asset management strategies are outlined in Section 6.3.

Concerning asset management strategy #5, we need to ensure our capabilities keep pace with the changing needs of the business. We are developing an asset management improvement plan that will guide the:

- Updating our policies and procedures across design, construction, commissioning, inspection and maintenance;
- Revising and developing business processes, with a particular focus on our front-end engineering design (**FEED**), real-time information management and power flow management, performance and condition monitoring (refer to Section 5.6);
- Improving the maturity of the AMP content, particularly asset lifecycle management;
- Consolidating asset information and key processes within a new asset management system (included in Electra's DSSP);
- Implementing an asset management group (**AMG**) to oversee various asset management actions required to lift maturity and to support the Board's asset management and planning subcommittee.

Concerning asset management strategy #3, the improvement plan will ensure condition assessment standards and data align with our health assessment and renewal forecasting methodology.

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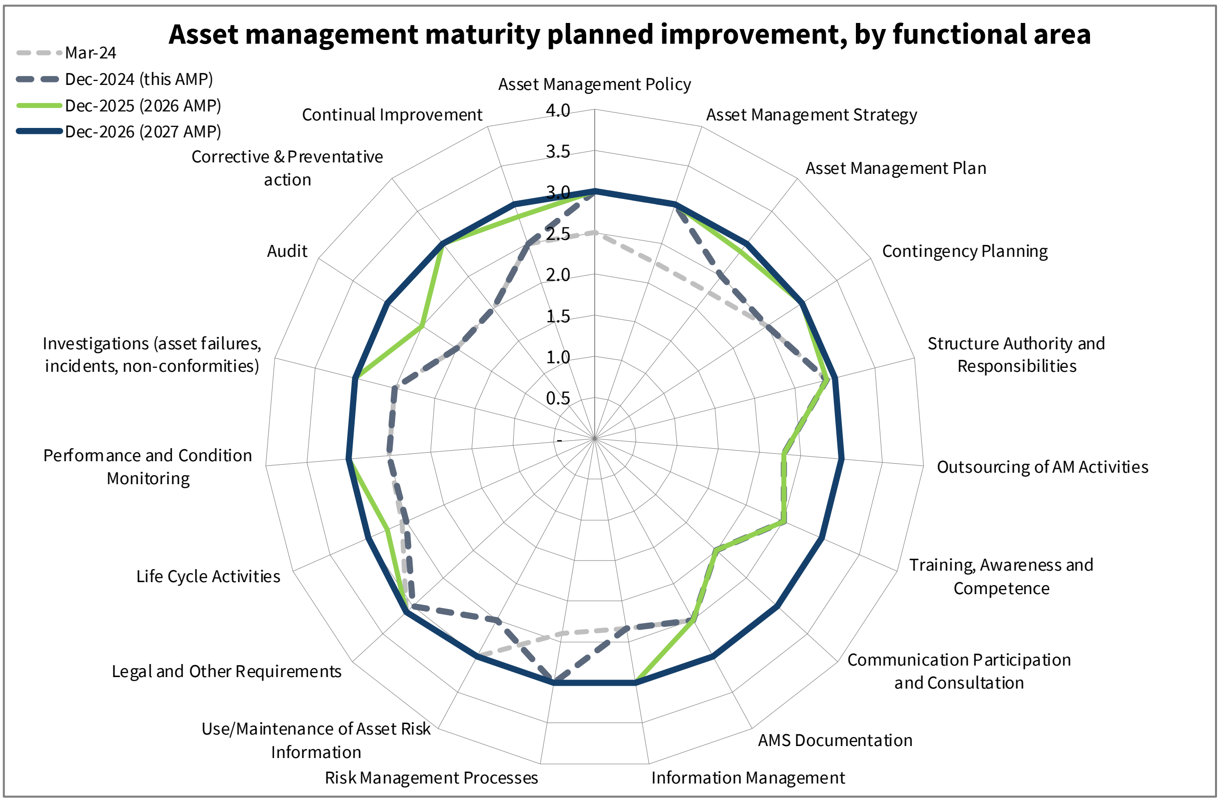
[57] Level 3 means that all elements of our asset management system are in place and are being applied and integrated, with only minor inconsistencies. EEA, Guide to Commerce Commission Asset Management Maturity Assessment Tool (AMMAT), May 2014.

9.2.2 Target improvement areas and timing

Since the 2024 AMP, we have improved our maturity (which is included in the AMMAT assessment accompanying this AMP). The improvements relate to our asset management policy, strategies, fleet plans and risk management.

As shown in Figure 96, we target significant improvement during CY2025 (for inclusion in the 2026 AMP). Further improvements will be made during CY2026 (for inclusion in the 2027 AMP). The programme IT/OT system and data improvements will continue beyond FY2028. However, the work completed by FY2027 should achieve an asset management maturity of 3.0 in the 2027 AMP.

Figure 96: Target improvements in asset management maturity



9.3 Improvements to policies, processes and procedures

We have developed a detailed plan to address gaps in our asset management maturity. The planned improvements are summarised in Table 14. Our immediate focus is on condition assessment standards, development planning, front-end engineering design (**FEED**) and contingency plans. We will also look to formally establish an asset management group (**AMG**) to oversee various asset management actions required to lift maturity and to support the Board's asset management and planning subcommittee. These near-term actions will support the more pressing needs of the business. We have employed a resource to progress these actions in the past year.

Following the more immediate work, our focus will be on training, communication, documentation, audit, corrective actions, and continuous improvement.

Table 14: Policies, Processes and Procedures Improvement Plan

Improvement Plan	FY2026	FY2027
Technical standards	• Preparation/updating of inspection, testing, maintenance standards, and management of change standards • Note: The inspection and testing standards need to be aligned with the requirements for CBARMM	• Updating design, construction, maintenance and commissioning standards
Align core asset management processes to the best-practice processes in an enterprise asset management system (EAMS)	• Review the asset defect process and align it to EAMS's processes • Align inspection and maintenance processes with best-practice processes within an EAMS	• Align works delivery processes with best-practice processes within EAMS • Align remaining processes with best-practice processes within EAMS
Contingency plans	• Update the emergency response plans • Determine and prepare contingency plans for all reasonable events	• Communicate plan requirements to the team • Test and improve plans
Outsourcing	• Audit compliance with the new procurement policy	• Review and refine outsourcing requirements • Audit compliance with outsourcing requirements;
Resourcing and competency	• Review competency requirements and delivery of training (via Our Hub) • Review external contractor competency requirements • Implement a common competency framework	• Review resourcing requirements given the future needs of the business and ETR.
Asset management framework (and associated documentation)	• Increasing the maturity of our development planning process • Improving our front-end engineering design (FEED)	• Review/prepare documentation supporting the asset management framework
Continuous improvement and corrective actions	• Review and implement improvements to the as-builts process • Improvement to business case processes	• Develop ICAM process for minor and major fault review • Implement a formal process to consider innovations • Oversight by AMG
Asset Management Group (AMG)	Implementing an AMG, with a focus on: • Communicate delivery requirements for AM • Communicate objectives and responsibilities for AM • Six-monthly network and delivery performance reviews	The focus for the AMG will be: • Managing cost-effectiveness and efficiency • Review of major outages and proposed solutions • Develop an internal audit plan and implementation process

The Energy Transformation Roadmap has identified a range of other process requirements. Refer to Section 10 for details.

9.4 Improvements to IT/OT Systems (Electra's DSSP)

We have identified a significant IT/OT system enhancement programme. The OT developments are focused on our core SCADA and ADMS operational systems. Our SCADA system is reaching end-of-life, and newer systems offer opportunities to increase resilience and cybersecurity. Our current SCADA and ADMS application layers are becoming outdated, with some areas of limited functionality, which we plan to upgrade or replace. These planned upgrades will ensure we keep pace with the evolving operating environment and prepare for the energy transformation.

We are progressing with significant IT upgrades to our financial system, GIS and developing an enterprise asset management system (**EAMS**). Consistent with our strategy of choosing right-sized and least customised technology products, and aligning to good industry practice, we are progressing with implementing separate financial and asset management systems. Modern EAMSs provide significant industry-standard processes to enhance maintenance and asset management delivery. We will also upgrade the GIS data model, as our current model was developed over a decade ago. This will align us with industry standards and facilitate better integration with an EAMS.

The following sections provide details on each of our primary systems, the data they hold, what the data is used for, and any planned improvements. The systems cover OT, IT, and cyber security, and the proposed system needs to support the Energy Transformation Roadmap.

9.4.1 Operational technology systems

Table 15: OT System improvements

<table>
<tr><th>System</th><th>Data held</th><th>What the data is used for</th><th>Extent of integration</th><th>Planned Improvements</th></tr>
<tr><td>System Control and Data Acquisition (SCADA)</td><td>System Control and Data Acquisition System is the primary tool for monitoring and controlling access and switching operations for Electra's network; asset operational information, including loadings, voltages, temperatures and switch positions</td><td>Measuring voltages, currents and device statuses on various parts of the network. This is used for assessing security, load forecasts and feeder configurations</td><td>Integrated with ADMS</td><td>• FY26: Upgrade the application layer to the latest version of iFix SCADA
• FY26-27: End-of-life hardware upgrades (serves and switches)
• FY28+, provision for further hardware upgrades</td></tr>
<tr><td>Advanced Distribution Management System (ADMS)</td><td>An integrated system containing geospatial information of assets, customers, and engineering models. ADMS takes input from SCADA and displays load flows.
The authoritative source for the network connectivity model.</td><td>Used by field, real-time operators, planning and project management staff to update customer outages, obtain asset information and carry out engineering studies</td><td>Integrated with GIS, SCADA, Field Service Management, IoT, customer outage mobile application, customer web outage viewer and business intelligence reporting and analytics</td><td rowspan="2">• FY26-29, minor capex associated with:
○ EAMS integration
○ Automated customer notifications (social media and app)
○ Serve to distributed workforce and remote offices
• Further upgrade of ADMS is under consideration in FY29-30 to provide LV monitoring and optimisation and flexibility management to meet energy transformation needs</td></tr>
<tr><td>ADMS (incident tracking)</td><td>System outages, location, duration, cause, number of consumers affected</td><td>Used to identify assets that are causing outages and to report on SAIFI/SAIDI and CAIDI</td><td>Integrated with other ADMS applications</td></tr>
<tr><td>IoT network status monitoring</td><td>The status information of specific network assets – RMU fault condition, DDO fuse status, voltage present indicators, power quality meters, client outage sensing devices, plus other non-critical data used for post-analysis</td><td>IoT communications can have significant latency and are not typically used for real-time decisions. The platform is primarily used to gather small amounts of data from multiple sites at low cost and to confirm or locate real-time events reported by SCADA or other systems</td><td>Integrated with ADMS and SCADA. IoT devices can report to the control room in the same way as SCADA/ADMS</td><td>• Increase the number of sensors on our network.
• Integrate the data into our SCADA and ADMS.
• Include data from 3rd party devices or services to increase sources of loss-of-power event reports</td></tr>
</table>

9.4.2 Information technology systems

Table 16: IT System improvements

System	Data held	What the data is used for	Extent of integration	Planned Improvements
Financial system	All company financial information, including the asset registers, P&L and balance sheet	Financial and management reporting and information disclosure reporting	The financial system will be integrated with the EAMS (when implemented)	• FY25, Upgrading of the financial system from Microsoft NAV to Business Central
Enterprise asset management system (**EAMS**)	A new system is being implemented. It will become the authoritative source of asset information (attributes, age, condition, health, risk)[58]	Primary asset management system and asset-related information disclosure reporting Used for all network inspection, maintenance and other asset management processes	The new system will integrate with the financial system, GIS and CBARMM	• FY26-27, EAMS, implementation, including work order management • See data improvements*
Geographical Information System (**GIS**)	The authoritative source for geospatial asset information (location and associated easements)	Used by field, real-time operators, planning and project management staff within the Network team to obtain information on asset location, attributes and connectivity	Requires at least some manual intervention to import or export data into recognised formats.	• FY26, Upgrade to the common information model, and the ESRI GIS utility networks model • See data improvements*
Condition-based Asset Risk Management Model (**CBARMM**)	Asset condition, health, criticality and risk	Used to determine the health and risk of assets to determine planned asset renewals	Integrates with GIS and EAMS	• See data improvements*
Network modelling, loadflow and contingency analysis system	Complete 33kV network model	Modelling the capacity and voltage of the network	Integrates with GIS	• FY26, migration of the ADMS 11kV network model*
Strategic Vegetation Management Database	Tree owners, requests, trimming works, proactive and reactive plans	Monitoring of requests, works, costs, proactive and reactive planning, reporting	The system is not currently integrated	• The intention is to integrate vegetation management into the EAMS/GIS. The project is not yet defined
Customer Relationship Management (**CRM**)	Customer Information, complaint information, 3rd party service requests and customer queries	Customer relations and service delivery management	Integrates with electricity registry, financial system and other office systems	• FY26-30, Increase adoption and functionality • A further upgrade is being considered for FY30 to provide connection and consumer data management to meet energy transformation needs
Website and customer apps	Corporate and outage information	Communicate with customers and stakeholders	Outage data integrated with ADMS	• FY26-35, Upgrade of corporate website and apps
Vault	Risk register (organization and H&S): incidents, injury, illness and near miss, plus	Used by H&S for managing risk register and incidents; used by employees to report H&S	Stand-alone system	• n/a

[58] This information is currently in GIS and will be transferred to the EAMS

System	Data held	What the data is used for	Extent of integration	Planned Improvements
	associated injury management and rehabilitation	and public safety incidents; used to report to senior leaders and Board; automatically notifies the above for critical events; audit and checks through mobile apps		
AXOS Billing System	ICP connection details, electricity consumption, price option, retailers	Used to determine electricity consumption, losses, ICPs by price option, retailer billing and sales discounts	No automated integration with other systems	• n/a
Reporting and analysis tools	Analytical tools that access data held in other systems	Various analytical tasks	Integrated with ADMS, IoT, SCADA business systems (Power BI)	• Ingest more information and commit resources to analyse and interpret data to identify additional value*

* No associated capex

We operate various other systems to support document management, data integration and reporting. These systems include Electra's electronic document management system (**EDMS**), safety management system (which is a library of safety documents held in the EDMS), information disclosure compilation tool, and Plexus gateway (legal document storage). These systems are in a steady-state or continuous improvement phase; no material capex is required.

9.4.3 Cyber security

We continue implementing cybersecurity controls to improve our maturity and cybersecurity posture. Central to this programme is the adoption of Secure Access Service Edge (SASE) and zero-trust architecture. Integrating SASE will streamline our network security into a single, cloud-delivered service model, enabling us to enforce comprehensive security policies seamlessly across all users and devices. The zero-trust model enhances our security posture and minimises the risk of unauthorised access to our networks and systems.

In addition to delivering SASE and zero-trust services, deploying a centralised vulnerability management system will identify, assess, and remediate vulnerabilities within our IT infrastructure. This system will maintain a comprehensive inventory of assets and ensure that all components are secure. By proactively managing vulnerabilities, we will mitigate potential threats before malicious actors can exploit them. Strong vulnerability management will be another control crucial in maintaining the integrity and security of our digital environment.

We will also further secure our OT and SCADA systems, which are integral to our operations and manage critical processes and infrastructure. Implementing robust cybersecurity controls for OT and SCADA ensures that these essential systems are protected from cyber threats that could disrupt operations or cause significant harm. Additionally, we will benchmark our efforts against the NIST cybersecurity framework to ensure we meet industry standards and identify opportunities for future improvement and investment.

9.4.4 Potential IT/OT systems required to support the Energy Transformation Roadmap

Section 10 discusses the Energy Transformation Roadmap (**ETR**). The ETR has identified a range of system enhancements that will allow Electra to effectively and efficiently fulfil its role in the energy supply chain and provide the tools to manage the complexity associated with the increasing use of DERs and the evolution of flexibility markets.

The potential system requirements to support the Energy Transformation Roadmap:

- Meter Data Management System: To manage meter data and make it available for ADMS. Whether this is required will depend on Electra's approach to meter data management (as there are likely to be different procurement and hosting models);
- ADMS Upgrade—LV Monitoring and Optimisation: Real-time modelling of LV voltage & capacity to optimise loading and hosting capacity;
- ADMS Upgrade—Flexibility Management: Issuing market signals to procure flexibility services;
- Connection and consumer Data Management: Management of consumer connection data, including flexibility information, hosting capacity, installation standards, and auditing.

9.5 Improvement to asset management data

The quantity and use of data is increasing across all areas of the business, and our need to maintain data quality is also growing. As a result, we have prepared a data transformation strategy. This strategy will guide the processes, policies, and technologies for data collection, storage, management, and analysis across the business.

Our data transformation roadmap will deliver significant benefits through the creation of advanced data products. Business benefits include:

- Network performance and capacity intelligence, ensuring our infrastructure operates at peak efficiency
- A focus on asset health and service delivery optimisation to enable proactive maintenance and superior customer service, reducing downtime and enhancing reliability
- The development of customer and community intelligence tools, which will provide deeper insights into behaviour and needs, allowing us to tailor our services more effectively; and
- Improved finance, pricing, and performance forecasting capabilities will enable us to make informed, strategic decisions to drive profitability and growth.

Notwithstanding our strategic work, we are progressing in a range of asset data improvements, as shown in Table 17. There are two key themes for our data improvements:

- Enhancing the network connectivity models to enable accurate load flow modelling and enable real-time monitoring of the LV network;
- Enhancing the asset data (attributes, operations, duty and loadings) to enable more accurate asset health and renewal forecasting.

During FY2026, we will prepare a data issues register to assess other information gaps and proposed solutions.

Table 17: Asset Data Improvement Plan

Improvement Plan	FY2026	FY2027	FY2028+
Data transformation strategy (digital roadmap)	• Implementation (work is yet to be defined) • Prepare data issues register		
High voltage connectivity (Loadflow, ADMS)	• Improve HV schematic accuracy	-	-

Improvement Plan	FY2026	FY2027	FY2028+
	• Migration of the 11kV model from ADMS for loadflow and contingency analysis		
Low voltage connectivity (ADMS)	-	• Improve LV schematic and loadflow model accuracy • Develop LV transformer schematic diagrams	• Undertake customer phase verification
Asset location (GIS)	• Implement processes to verify asset location • Capture the location of conductor joints • Capture the location of cable joints	-	-
Asset attributes (GIS, EAMS, Loadflow, CBARMM)	• Improve distribution and LV conductor attributes (size) • Improve distribution and LV cable attributes (size) • Improve distribution OH fuses and ABSs attributes (type)		-
Condition Data (GIS, EAMS, CBARMM)	• Condition data will be improved as condition assessment standards are revised		
Equipment operations (SCADA, EAMS, CBARMM)	-	• Capturing equipment operations and fault tripping and using it as input into CBARMM for health assessment	-
Equipment duty (SCADA, EAMS, CBARMM)	-	• Capturing equipment duty (i.e. loading) and using it as input into CBARMM for health assessment	-

9.6 Continuous improvement

Over the past decade, we have pursued continuous improvement, but this has mainly been ad hoc. Recent improvements include developing project governance processes and stakeholder consultation framework. We have also implemented weekly Kanban and monthly progress assessments to improve delivery performance.

As part of this improvement plan, we will enhance our approach and ensure appropriate oversight by the AMG. Work has begun on improving the distribution inspection process to enhance operational reporting, inspection quality and issuing inspector's manual. This work will be completed during FY26.

During FY26, we plan to improve the defect process, including identifying and recording defective assets using mobile devices. We will also improve the as-built process to ensure that as-built information is accurate and readily available to stakeholders.

9.7 Forecast expenditure on IT/OT systems

Table 18 and Table 19 summarise the developments of the proposed OT and IT systems. These projects and programmes were previously all capex. However, they are progressively moving to software as a service (**SaaS**), and the associated costs are moving from capex to opex. All projects and programmes align with the improvement work identified in the previous sections except for the ongoing IT infrastructure hardware renewal and upgrading. The GIS upgrade and the EAMS implementation include related data improvements.

Table 18: Proposed Major OT projects

Project	Driver	Cost/Year	Justification/options considered
SCADA hardware replacement	SCADA hardware has reached end-of-life and needs to be upgraded (FY26-27), then an ongoing programme of replacements, including the next end-of-life upgrade in FY34-35	$1.4m FY26-27 $2.8m FY28-35	• There are no SaaS alternatives, as hardware is required to interface to operational assets • The option of further delaying the FY26-27 expenditure was considered, but end-of-life replacement is required before support contracts expire • The ongoing replacement of hardware and the end-of-life upgrade at the end of the planning period aligns with good industry practice
SCADA GE iFix version upgrade	The SCADA has reached end-of-life and needs to be upgraded to the latest product	$102k FY26	• The current SCADA application layer is end-of-life, and support will cease at the end of FY26. There is no option to delay the upgrade

Note: This expenditure is asset replacement and renewal capex, as SCADA is defined as other network assets.

Table 19: Proposed Major IT projects and programmes

Project	Driver	Cost/Year	Justification/options considered
Upgrading the financial system from Microsoft NAV to Business Central	The current system has reached end-of-life and needs to be upgraded to the latest product suite	$482k FY25	• The project will be completed at the end of FY25
IT Infrastructure and hardware renewal programme	An ongoing programme to replace and upgrade hardware (servers, switches, laptops, tablets, phones, etc.) and meet organic growth requirements	$3.0m FY26-35	• The programme is optimised to maintain IT hardware within support contract requirements, consistent with application layer requirements, performance and cybersecurity standards • There is higher spending planned for FY28 for core infrastructure replacement
Implementation of EAMS. This is a two-year implementation that involves core asset management processes (phase 1) and works order management (phase 2)	Consistent with our strategy of choosing right-sized and least customised technology products, and aligning to good industry practice, we are progressing with the implementation an EAMS and adopting the best-practice processes embedded within the system	SaaS FY26-27	• We do not currently have an integrated asset management system. This is needed to support our process improvement and consolidation of business processes as outlined in Section 9.3. This system supports the processes required to improve asset management maturity
Upgrading the GIS to the common information model, and the ESRI GIS utility networks model	Align GIS asset data model with industry standards, facilitate the integration with EAMS and provide the foundation to adopt best-practice processes	SaaS FY26	• Electra's GIS data model is decades old and will not support the implementation of best-practice processes available in the new EAMS

Table 20: OT System Projects and Programmes (Real $000)

Projects and Programmes	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
SCADA hardware replacement	710	710	305	204	204	204	204	205	715	718	4,128
SCADA, iFix application upgrade	102	-	-	-	-	-	-	-	-	-	102
ADMS minor projects	41	51	51	-	-	-	-	-	-	-	142
IoT network status monitoring	Included with network asset capex										

Projects and Programmes	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Total	**852**	**761**	**357**	**204**	**204**	**204**	**204**	**205**	**715**	**718**	**4,372**

Note: ADMS is non-network capex. SCADA costs are asset replacement and renewal as SCADA is an other network asset.

Table 21: IT System Projects and Programmes (Real $000)

Projects and Programmes	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
IT Infrastructure and hardware	234	198	569	276	174	225	225	634	225	226	2,985
Upgrade financial system to Business Central	Go-live 01 April 2025										
EAMS	FY26-27 SaaS implementation, refer to SONS opex										
GIS Common Information and Utility Data Model	FY26 SaaS implementation, refer to SONS opex										
Customer related systems	FY26-37 SaaS, refer Business Support opex										
Major project provisions	-	-	-	-	204	204	204	205	204	205	1,228
Total	**233**	**198**	**569**	**276**	**378**	**429**	**430**	**840**	**429**	**431**	**4,213**

Note: IT infrastructure and hardware and major project provision is non-network capex.

Table 22 shows the range of possible future OT projects under consideration. We are considering upgrading Milsoft ADMS and have identified potential systems associated with the Energy Transformation Roadmap (refer to Section 10). A decision on the ADMS upgrade project should be included in the 2026 AMP. Decisions on the other systems will evolve over the next three to four years. The projects in Table 22 are not included in the expenditure forecasts.

Table 22: OT System improvements in the concept phase (Real $000)

Concepts	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
ADMS Upgrade, including LV monitoring and optimisation	-	-	-	Currently estimated as an FY29 SaaS implementation						
ADMS Upgrade, flexibility management	-	-	-	-	Currently estimated as an FY30 SaaS implementation					
Meter data management system	TBA. This will depend on the approach to customer meter data									
CRM, connection and consumer data management	-	-	-	-	Currently estimated as an FY30 SaaS implementation					

9.8 Business Support and associated expenditure forecasts

Business support covers all corporate activities, including governance, information technology, commercial, customer service, sustainability, people, safety, and culture (refer to the organisation structure in Section 2.7).

Business support costs have increased principally due to additional IT costs and changes to the business structure (refer to Table 23). The IT increase relates to higher SaaS (Software as a Service) costs associated with implementing Business Central, enhancements to backup services and a growing trend of adopting SaaS platforms (for example, our Human Resource Information System), which shifts our cost structure to operational expenditures rather than traditional capital expenditures. We are increasing our IT team's capacity to drive the data transformation roadmap forward (shown separately in Table 23). This programme will provide critical expertise across key areas such as data management, business analysis, project delivery, and IT and OT systems integration.

We have changed our business structure following the divestment of several Group companies. The structural changes include strengthening our communications function to support the delivery of our communications strategy. This will focus on community engagement, content creation, and social media, ensuring our stakeholders are well-informed and actively involved. Our commercial and risk functions have been enhanced.

We are also incurring additional project costs. These costs relate to support for our process improvement work.

These changes support our strategy to improve our asset management maturity. After completing the maturity work, our focus will turn to efficiency improvements.

Table 23: Business Support (Real $000)

Cost	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Historical business support[59]	6,819	6,819	6,819	6,819	6,819	6,819	6,819	6,819	6,819	6,819	68,186
Insurance[60]	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	11,769
Additional personal costs	2,537	2,597	2,597	2,597	2,597	2,597	2,597	2,597	2,597	2,597	25,911
Additional OT Costs	-	-	-	-	-	-	-	-	-	-	-
Additional IT costs	681	574	476	321	376	276	276	276	276	258	3,687
Additional project costs	50	250	-	50	50	50	50	50	50	50	650
Data Transformation Strategy[61]	297	649	594	299	299	299	299	299	299	299	3,633
Total	**11,561**	**12,065**	**11,663**	**11,263**	**11,318**	**11,218**	**11,218**	**11,218**	**11,218**	**11,199**	**113,836**

9.9 System Operations and Network Support and associated expenditure forecasts

System Operations and Network Support (**SONS**) covers the network team (refer to the organisation structure in Section 2.7) and associated network IT systems and OT systems. We have spent the past three years focused on building the capability and capacity of our engineering and network support teams. During this period, we have made strategic investments in talent and development.

SONS costs are increasing principally due to additional IT and OT costs and to support our asset management maturity.

The increase in network IT and OT costs relates to higher SaaS costs associated with implementing an EAMS and associated data improvements and system integrations.

The increase in personnel and project costs relates to external and staff costs to improve the technical standards and support our process improvement work. Our work volumes are increasing; hence, an additional project engineering role is needed. Our use of operational technology is increasing and will become increasingly important as we progress the energy transformation roadmap—a new role is planned in this area.

We have also allowed a provision to procure flexibility to support the maximum demand in the Northern region (ahead of the commissioning of the new Northern GXP).

59 Based on the FY25 forecast, excluding insurance.

60 This includes a 5% real increase in FY26.

61 This includes three roles for IT data roles, additional IT costs associated with data management, and external project support.

We are currently focused on improving maturity and preparing for the future. Over the coming years, we will focus on optimising and leveraging our workforce to drive efficiency.

Table 24: System Operations and Network Support (Real $000)

Cost	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Historical SONS[62]	5,868	5,868	5,868	5,868	5,868	5,868	5,868	5,868	5,868	5,868	58,684
Additional personal costs	-	87	87	87	87	87	87	87	87	87	783
Additional project costs	50	100	100	50	50	50	50	50	50	50	600
Additional OT Costs	444	1,006	1,024	994	994	994	994	994	994	994	6,258
Additional IT costs	725	513	316	286	286	286	286	286	286	286	3,556
Flexibility costs	-	50	50	50	50	50	-	-	-	-	250
Total	**7,087**	**7,625**	**7,445**	**7,335**	**7,335**	**7,335**	**7,285**	**7,285**	**7,285**	**7,285**	**70,131**

62 Based on the FY25 forecast, less one-off costs.

10. Energy Transformation Roadmap

10.1 Introduction

In this Section, we present our Energy Transformation Roadmap (**ETR**) and discuss the implications that the energy transformation could have on electricity demand on our network.

Reducing emissions through electrification and increasing renewable generation are critical to achieving net-zero 2050. In particular, the electrification of transport and heat (both process and general) and the use of distributed energy resources (**DERs**) are central to decarbonisation. This is the *energy transformation* from oil, coal and gas to renewable and low emissions electricity.

There is general recognition of the importance that EDBs play in the energy supply chain. Distributors form the critical link between customers and energy markets and can enable greater participation by customers in decarbonisation (or constrain involvement if they are ill-prepared).

Enabling decarbonisation through electrification requires that EDBs:

- Have the capability and network capacity to allow customers to increase their use of electricity to replace fossil fuels;
- Can connect and integrate DERs into the network and allow the owners of DERs to participate in energy markets.

We prepared the ETR in FY2022 and have been monitoring industry developments and progressing with the various actions on the roadmap since then. The ETR ensures we have a pathway to build the capability and capacity to support New Zealand's decarbonisation efforts. We are confident that by following the roadmap, we will be ready for the energy transformation.

10.2 Alignment to asset management strategy

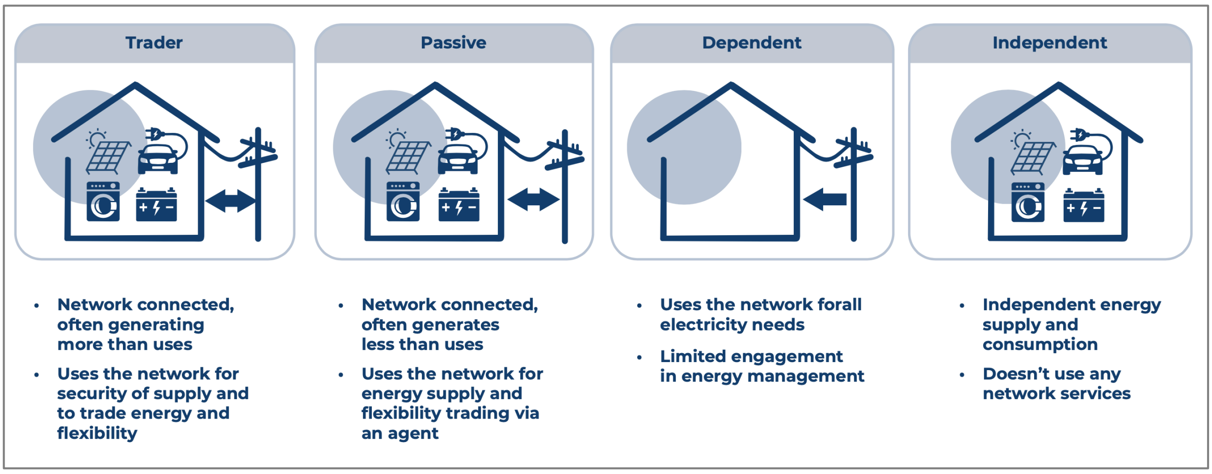
This section delivers on asset management strategy #2 to *implement an energy transformation roadmap to further prepare for increased electrification*. It sets out the plan and steps to achieve the activities under the strategy.

10.3 Evolution of customers and market structures to support the energy transformation

How customers will use the network

Customers are at the centre of the energy transformation. Much has been written about the evolution of energy customers. We have distilled this work into four types of customers (Figure 97). The difference between them relates to the adoption of technology and engagement with energy markets (except for independent customers who, as the name suggests, operate independently of the energy market). These definitions cover the range of customers from active to passive (the spectrum used by the ENA).

Figure 97: Customer types



Market structures

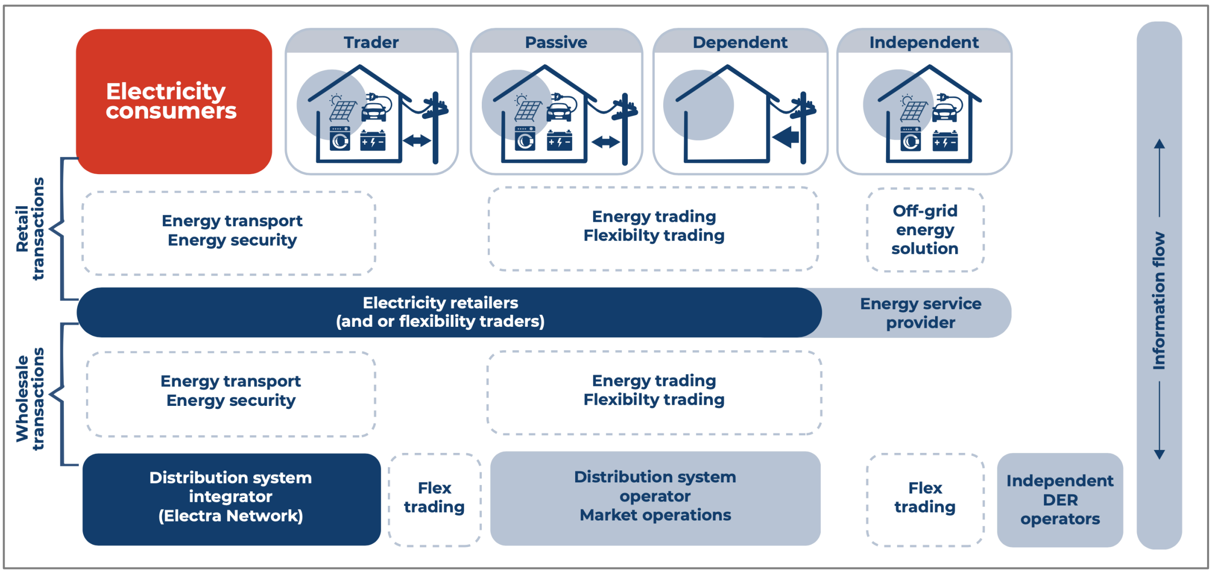
Understanding the industry operating model is essential to ensure Electra can fulfil its role in connecting and integrating DERs. Figure 98 illustrates the generally accepted industry view of the market model (consistent with the ENA view and the Electricity Authority's views in their recent regulatory settings paper). There is a reasonable consensus that distributors must evolve and the first stage of this we have termed being a distribution system integrator.

A distribution system integrator (**DSI**):

- Operates the distribution network to connect customers (with and without DERs) to energy and related markets;
- Develops the distribution network to integrate DERs and support bidirectional power flow;
- Invests in the systems required to support open access to the distribution network for a wide range of customers and DERs.

There is also the possibility that distributors could take on all or part of the role of a distribution system operator (**DSO**), where they monitor and control controllable DERs to maximise the value of the flexibility they offer. This is less clear and we continue to engage with regulators and industry as this structure, and the roles and functions develop.

Figure 98: Current view of the market operating model



Flexibility

Flexibility is where customers (or merchant providers) change their usage patterns by either switching on generators or reducing consumption in response to a signal (e.g., hot water load control). *Flexibility resources* are delivered through controllable DERs. Distributed solar without a battery is not a flexible resource because it is uncontrollable. Hot water load control, EV charging, and charging /discharging of batteries are flexible resources. *Flexibility markets* are the mechanisms for matching and rewarding traders of controllable DERs, including providing dispatch instruction in response to prices.

The purchases of flexibility could be:

- Energy retailers or generators who buy flexibility as an alternative to energy on the spot market;
- The System Operator who buys flexibility for energy reserves or ancillary services;
- Transpower who buys flexibility as an alternative to upgrading transmission assets;
- EDBs who buy flexibility as an alternative to upgrading distribution assets.

We are forecasting a material increase in the connection of controllable DERs. These are expected to reach over 11,000 by 2050.

10.4 The future is uncertain

It is unclear how the industry will deploy flexibility, as 66% of the benefits can be attributable to parties other than EDBs.[63] This creates significant uncertainty about how much EDBs can rely on demand response. Hence, how the transformation will unfold is not yet clear, and we developed the ETR anticipating two possible pathways—one where we can control demand effectively (using flexibility) and one where we are not able to control demand effectively (and therefore need to augment the network to support increasing demand and use of DERs).

It will take some time for clarity to emerge on how flexibility services will evolve. However, the likelihood of distributors continuing to enjoy the sole benefits of demand control (via the ripple control system) is remote.

[63] Sapere Research Group, "Cost-benefit analysis of distributed energy resources in New Zealand, Report for Electricity Authority", September 2021

The ETR is only the starting point for our transformation work. There will be further detailed network modelling and refinement of solutions over the next 12-24 months. We expect the roadmap to evolve (along the direction laid out) as technology evolves and customers and society adapt.

10.5 Development of the Energy Transformation Roadmap

The ETR (coupled with ongoing monitoring and adjustments) will guide us through this uncertainty. It does this by defining two pathways—one where we continue to enjoy the benefits of demand control and one where we need to augment the network without relying on demand control.

Figure 99: Controlled Pathway Roadmap

Figure 99 shows the controlled pathway. This outlines the steps we need to take to enjoy the benefits of a controlled demand outcome and enable customers to enjoy the benefits of their investment in DERs. The network augmentation pathway is similar; however, it focuses on optimising network augmentations to support electrification while still enabling customers to enjoy the benefits of their investment in DERs.

In the medium term, the roadmap defines low-regret investments that build our capabilities while keeping both pathways open. These include:

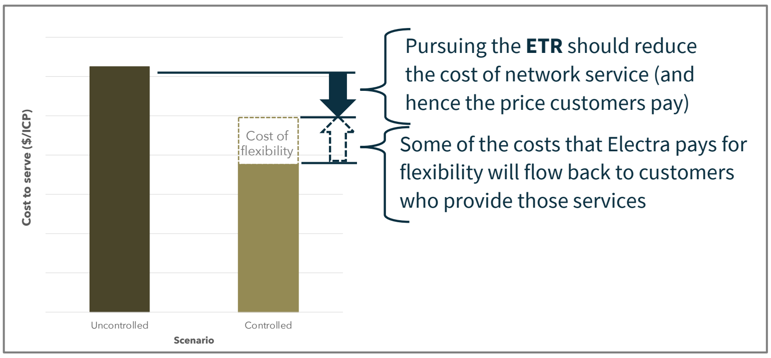
- Building people capabilities;
- Completing the constraint and solution modelling, including an assessment of available hosting capacity;
- Building LV monitoring capabilities;
- Preparing and implementing key system enhancements;
- Enhancing technical standards that reduce risks;
- Revising and progressing Electra's pricing strategy to better influence demand response;
- Monitoring the direction and pace of the transformation (and adjusting our plans accordingly).

10.6 Benefits of the ETR

Our modelling suggests there are three key benefits of pursuing the ETR to deliver the controlled demand outcome (Figure 6). These include:

- Lowering the cost of network services;
- Enabling customers to decarbonise through electrification;
- Lowering overall energy costs to customers through electrification and flexibility payments.

Figure 100: Benefits of the ETR



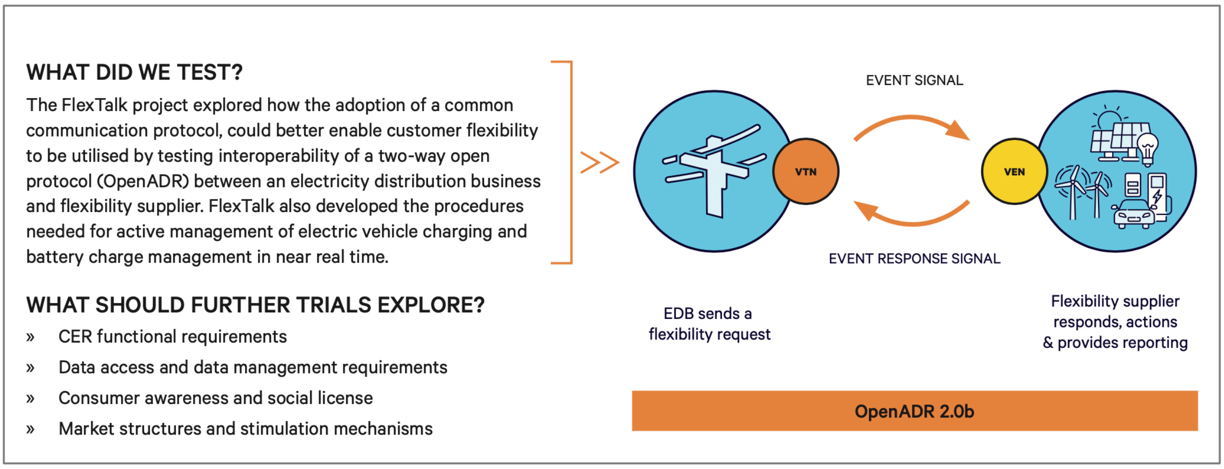
10.7 Collaborative approach

The energy transformation will only be efficient and effective if the industry standardises the market structure and communication protocols. Our approach is to support and adopt industry arrangements and protocols.

We are taking a collaborative approach to our energy transformation work. We are involved with the ENA Future Networks Forum. Electra is also part of the Northern Energy Group, a member of the Flex Forum, and participated in the EEA's Flex Talk project (Figure 101).

While we have shown our own ETR, this is consistent with the ENA's Network Transformation Roadmap (**NTR**). The NTR will be refreshed over the coming year, and we will adjust our plans to align with any changes.

Figure 101: Summary of FlexTalk



10.8 Demand forecasts

10.8.1 Methodology and demand drivers

We have developed two demand forecast scenarios in relation to the energy transformation:

- In the uncontrolled scenario, we have little influence and control over demand behaviour. This could be a result of weak incentives to shift demand, or that demand response has a higher value in other parts of the system, and it is uneconomic for us to procure it;
- In the controlled scenario, consumers respond to incentives, and we can shift consumption and cause the dispatch of DERs to control demand at an economic cost.

We assessed five demand drivers to determine our demand forecasts. These are explained in Table 25.

Table 25: Demand drivers

Demand driver	Assumptions for controlled demand	Assumptions for uncontrolled demand	Influence on demand
Population growth	• This drives residential and commercial connection growth • Based on Council population projections using the 75th percentile (which is consistent with historical trends) • Refer to Section 5.2	• The same as the controlled scenario	• High for controlled • High for uncontrolled
Future electricity intensity	• This factor accounts for future changes in the efficiency of electricity • Continued improvement in efficiency of 0.6% is assumed • Informed by Transpower's “accelerated electrification” scenario[64]	• The same as the controlled scenario	• Low for controlled • Low for uncontrolled
Uptake of electric vehicles	• 6 MW increase in demand by 2050 • Penetration of EVs is forecast to be 51% in the Northern region and 61% in the Southern region by 2050 • The impact on ADMD is 0.13 kW per ICP with an EV. This accounts for the diversity of controlled charging • Informed by Transpower's accelerated electrification scenario[64], but moderated by average income levels across our two regions • The forecasts have been reduced over the next ten years due to the recent changes in Government policy	• 58 MW increase in demand by 2050 • The same penetration rate as the controlled scenario • Impact on ADMD increases to 1.3 kW per ICP with an EV. This accounts for the diversity of uncontrolled charging	• Low for controlled • High for uncontrolled
Electrification of gas	• 17 MW increase in demand by 2050 • 5.6 MW relates to the electrification of boiler load[65] • ~22% of Electra's customers currently use natural gas or LPG, with an average annual consumption of 24 GJ for residential and 374 GJ for commercial customers • These customers are all assumed to use low and medium heat and switch to electricity by 2050, consistent with accelerated electrification[64]	• The same as the controlled scenario	• Medium for controlled • Medium for uncontrolled
Demand control	• Demand reduces by 0.4 MW by 2050 • Electra's current demand control amounts to 10 MW (refer to Section 3.4) • Existing ripple control is by-passed (as per the uncontrolled scenario); however, effective demand response is available through flexibility market	• Demand increases by 10 MW by 2050 • Existing ripple control is by-passed by new technology associated with the development of the flexibility market • The by-pass rate occurs at the rate that EV penetration increases. This assumes that future EV chargers integrate with the home demand control system	• Low for controlled • Medium for uncontrolled

[64] Transpower, “Whakamana i Te Mauri Hiko”, 2020

[65] Based on a report of potential low temperature heat conversion. The report was prepared by DETA in 2024.

Demand driver	Assumptions for controlled demand	Assumptions for uncontrolled demand	Influence on demand
	or other means, which increases the level of demand response		
Uptake of distributed energy resources	• Controllable DERs reduce demand by 11 MW by 2050 • DERs uptake based on accelerated electrification penetration rate for both controllable and non-controllable DERs[64], moderated for regional sunshine hours • External financing is assumed to overcome household income differences	• The same as the controlled scenario	• Medium for controlled • Medium for uncontrolled

10.8.2 Demand forecasts

Controlled demand forecast (used for planning purposes)

Figure 102 and Figure 103 show the controlled forecast to 2050. In this scenario:

- System electricity demand increases by 21% from 107 MW to 129 MW in FY2035 and by 49% to 160 MW in FY2050;
- Most of the demand growth is due to population growth. This adds 42 MW of demand growth by 2050. The next most significant driver is the electrification of gas;
- Due to the impact of flexibility and pricing incentives, only 17% of EV charging occurs during the morning and evening peak, which materially reduces peak demand over the uncontrolled scenario;
- Demand response via flexibility services more than offsets the loss of ripple control (with an additional 2 MW of demand being controlled).

We use the controlled demand forecasts for planning purposes in this AMP.

These demand forecasts are lower (in the near term) than our prior forecasts, as we have included a reduction in near-term EV uptake given the recent changes in Government policy.

Figure 102: Northern region demand forecast (controlled)

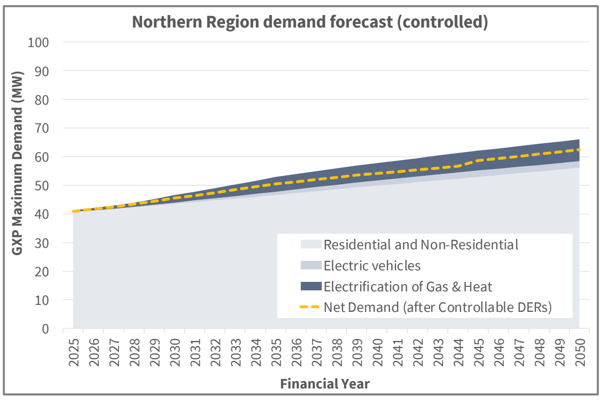
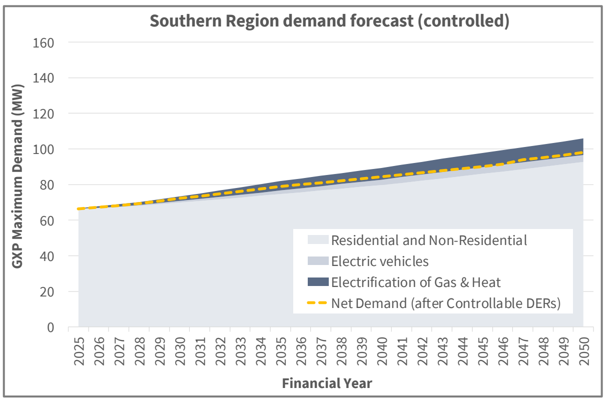


Figure 103: Southern Region demand forecast (controlled)



Uncontrolled scenario

Figure 104 and Figure 105 show the uncontrolled forecast to 2050. In this scenario:

- Electricity demand increases 103% from 107 MW to 223 MW;
- Just under 40% of this growth is due to population;

- 56% of EV charging occurs during the morning and evening peak, which accounts for 56 MW of demand growth by 2050;
- Around 10 MW of demand response is lost to other usages (or is unreliable to offset network augmentation).

Figure 104: Northern region demand forecast (uncontrolled)

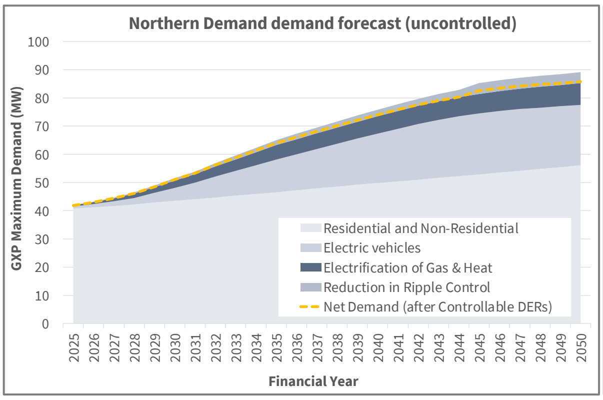
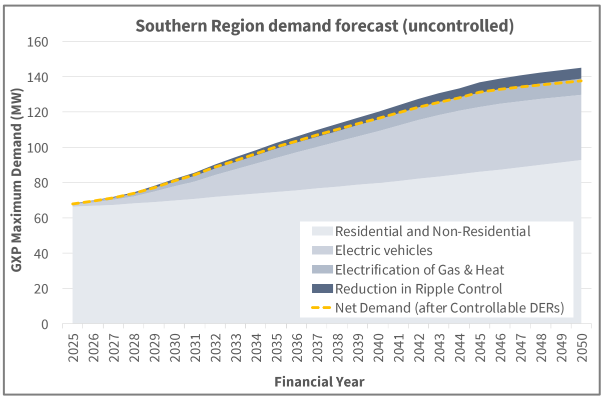


Figure 105: Southern Region demon forecast (uncontrolled)



<u>Zone substation and feeder demand forecasts</u>

We prepared zone substation and feeder demand forecasts using the same demand drivers. Demand drivers were assigned to each feeder (based on the feeder's customer mix). The feeder demand forecasts were then summed to provide zone substation forecasts (with appropriate adjustments for changes in demand diversity at the different network levels).

10.8.3 Managing the uncertainty

We have considered demand forecast uncertainty. This is discussed in each of the developments that follow.

10.9 Impact on energy trilemma

Pursuing the ETR will have a positive impact on the energy trilemma balance:

- Overall energy affordability will improve as customers convert their energy usage to lower-cost electricity (compared to fossil fuel alternatives)[66]. For those customers that have DERs, they will also benefit from lower cost (or income) from using them to provide flexibility;
- Sustainability will improve as customers reduce their carbon output by converting their energy usage to renewable (and low-carbon) electricity;
- Security will improve for customers with DERs (as some DERs can provide electricity during a power outage).

We are mindful of the potential equity issues that may arise. That is, not all customers may benefit from lower overall energy costs (i.e. some customers may be unable to make the investments needed to convert from fossil fuels to electricity), and some customers may not be able to invest in DERs. We intend to monitor the distribution of benefits over time and will consider how these might be addressed.

66 Sapere, "Total household energy costs NZ, report for the ENA", November 2022.

10.10 Low-voltage network monitoring

10.10.1 The importance of low voltage monitoring

Low voltage network monitoring is an essential step on our ETR. Visibility at the low voltage level will be important as electrification demand and DER uptake increases. These changes will likely result in complex multi-direction power flow on low-voltage networks.

To minimise the requirement to upgrade the network in the future, we will need to manage power flows on the low-voltage network to maintain power quality and thermal constraints (loading) in real time. This requires significant changes to the quality and granularity of our systems and data.

10.10.2 Current steps to improve the visibility of the LV network

We have a programme to install power quality monitoring on the LV network (refer to Section 11.11.4). This will provide real-time data on power flow and power quality and can be used by our ADMS for future load management decisions. We plan to install these on 20% of ground-mounted transformers and will evaluate the outcome of the data over the coming years, which will inform whether we continue the rollout.

We are also considering the use of real-time data from customer smart meters. This can assist in providing proactive and efficient customer service as we can be informed of power outages, power flows and power quality. However, not all customers have smart meters.[67] Customer meter data could allow us to identify emerging trends and localised issues with power quality, constraints or emerging faults and defects on the low-voltage network. This will allow us to make a targeted response to low-voltage demand constraints or power quality issues.

10.10.3 Using customer meter data

Current usages

During 2024, we embarked on a project to obtain and process half-hourly customer consumption data (not in real-time). The project aim was to leverage data collected from meters within our network to deliver improved outcomes across planning, asset management, and operations. We procured a single supply of three years of historic half-hourly consumption data to improve our load forecasting and pricing models. We obtained a high level of coverage on our network.[68]

The current usages of customer meter data include:

- Distribution transformer loadings: We have aggregated the consumption data for each distribution transformer (making assumptions to cover the data gaps) and compared the consumption profile against the transformer ratings. This has identified distribution transformers that have or may soon exceed their ratings;
- We have entered the half-hourly consumption data into our existing network modelling application to assess selected LV networks. This analysis has highlighted that the lack of customer phasing in our network model limits the analysis we can currently undertake. We will work on improving our network model with field verification as required.

[67] Around 89% of our customers have suitable smart meters.

[68] Our agreements with retailers and MEPs have enabled us to obtain data from approximately 70% of smart meters, representing 63% of total ICPs on our network.

Challenges with customer meter data

Working with our industry partners, we have addressed half-hourly consumption data's commercial and privacy issues. Overcoming some real and perceived risks relating to the data has been a time-consuming journey. This data has come at a cost, and we are still evaluating the value it provides. We have not sought to obtain the more granular real-time data known as NODS (network operational data services) as the costs are significantly higher than half-hourly consumption data.

The benefit of historical half-hourly consumption data is limited to planning and asset management functions. It is purely consumption data and does not give insight into power quality issues experienced by that customer.

The volume of data, even just half-hourly consumption data, is considerable, as are the costs associated with storage and initial data processing. We have looked to service providers to store the data and proprietary analysis applications that are available and emerging on the market. While many of these applications offer exciting potential, we have not yet been able to justify the costs based on our current network conditions.

We intend to continue testing the value proposition by obtaining further half-hourly consumption data, real-time data, and the proprietary offerings in the market to analyse this data.

10.10.4 Low voltage network modelling challenges

Analysis using our existing network modelling application has been affected by network and connection information, requiring us to make assumptions about connectivity that will require verification. It may be possible to provide this verification through data analysis, or it may require on-site investigation. Both options will come with associated costs and will need to make the economic trade-off between value and accuracy.

We plan to focus on improving our network connectivity model. This will enable us to use and analyse half-hourly consumption data more confidently.

10.10.5 Alternatives to meter data

We commenced a programme in FY2020 to identify distribution transformers and sections of the low voltage network where we believed we would benefit from high-quality real-time data that we could analyse in our network modelling systems. This programme has now installed over 200 low-voltage power quality monitors on ground and pole-mounted distribution transformers, which gives us granular real-time visibility of ~10% of our low-voltage network down to each phase of the feeders. This data provides accurate data on LV circuits and transformer loadings in real time.

11. Asset Lifecycle Management (Development Plans)

11.1 Introduction

In this section, we discuss the *development* and *design and construct* phase of our asset lifecycle management (refer to Figure 106). A description of the *operate and maintain* and *renew or retire* phase is provided in Section 12.3.

This section describes the material development plans for the network. These comprise:

- Our current thinking for the development of a new Northern GXP (which is not yet in the expenditure forecasts);
- The $20m subtransmission and zone substation development plan, which includes two new mini-zone substations and two subtransmission line upgrades that are required in response to growing demand;
- The $56m distribution development plan, which includes 13 new feeders in response to growing demand and significant programmes to improve network security and reduce reliability-related risks;
- The $5m distribution transformer and LV development plan, which includes upgrading distribution transformers due to growth, interconnection projects to improve LV security, and a continuation of our LV monitoring programme;
- The $8m zone substation communication and protection upgrade programme (which is addition to the end-of-life protection replacements included in the secondary system fleet plan in Section 12.11);
- Our current estimates for customer connections and asset relocations.

Our development plans typically include specific projects over the next three to five years and more general programmes to the end of the planning period (FY35).

In this Section, we cover:

- How this section aligns with policy and strategy;
- Our approach to asset lifecycle management, as it relates to network development;
- The planning criteria used to guide network development;
- Design standards and other policies;
- Our approach to innovation;
- Network constraints and our development plans in response to those constraints;
- Customer connection and asset relocations.

This section has changed materially from that presented in our last full AMP published in 2023. We have consolidated and expanded the disclosure of our planning criteria and restructured the development plans to follow the network hierarchy from GXPs to LV. This approach better aligns with how we disclose expenditures in the Information Disclosure schedules.

11.2 Alignment to our asset management policy and strategy

Our development plans support the asset management policy in the areas of:

- Developing the network responsibly to meet current and future needs, and we will adopt new technology to ensure we keep pace with the requirements of customers and other stakeholder

- Considering the economic, environmental and cultural impact of our business and finding an appropriate balance between them.

The asset management strategies in Section 6 include three initiatives concerning network development. These include:

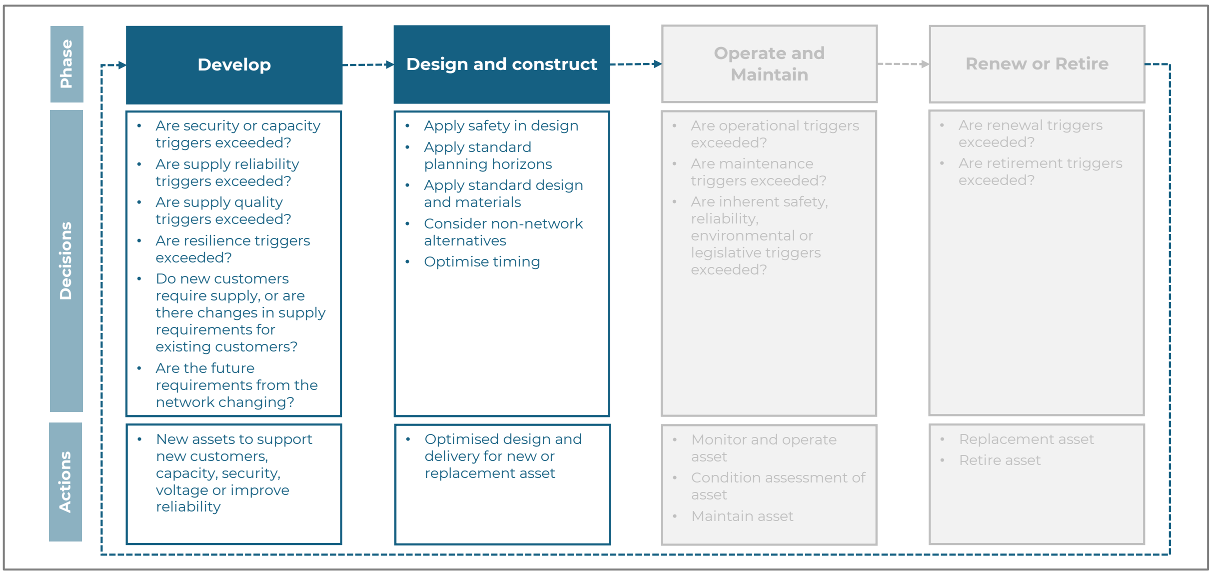
- **#1 Prepare the network (or non-network alternatives) to support future growth in our region:** The actions relate to preparing plans to cater for forecast growth, developing a long-term solution for Mangahao GXP, and ensuring our plans provide a staged development pathway that can be adjusted for non-network alternatives and changes in growth;
- **#2 Implement an energy transformation roadmap to further prepare for decarbonisation:** The implementation of this initiative is mostly addressed in Section 10. However, in this Section, the action is being ready to utilise flexibility where this provides viable non-network alternatives to manage demand and reduce the extent of network augmentation;
- **#4 Continuously improve the security, reliability and resilience of the distribution network:** The actions relate to increasing the automation and protection of our worst-performing rural feeders, increasing the number of ground-mounted switches, reviewing our overhead line designs to improve resilience, and reducing vehicle damage risks.

This Section gives effect to these policy aims, strategic initiatives and actions.

11.3 Asset lifecycle management (development)

We manage our assets throughout their lifecycle using the process shown in Figure 106. A description of the *development* and *design and construct* phase is provided below.

Figure 106: Asset Lifecycle



11.3.1 Development

The *development* phase involves creating an asset. It includes identifying the need, evaluating options, undertaking conceptual design work, and preparing the preliminary business case (if the project's scale warrants it). The purpose of this phase is to ensure the network is developed economically in response to customers' needs.

Typically, new assets are developed or acquired in response to one or more triggers (referred to as planning criteria):

- To support growth (security, capacity and customer numbers;
- New customer connections, changes in demand from existing customers and relocations of existing assets;
- Supply reliability;
- Supply quality;
- Resilience;
- Future network needs.

A network constraint occurs when a planning criteria is breached or forecast to be breached. When a constraint occurs or is forecast to occur, the planning team assesses possible solutions. This assessment may result in operational changes (e.g., reconfiguration of the network or implementation of an operational contingency), a network development project, or a non-network solution.

11.3.2 Design and Construction

The *design and construction* phase covers detailed design, procurement, business case and approval, project management, construction, and commissioning of the asset. This phase occurs in response to development or renewal needs. The design phase has taken on increasing importance as material risks in relation to safety, reliability, resilience, and serviceability can be removed through good design and selection of materials.

The outcome of this phase is the creation of an asset that is economically efficient (over its lifecycle), has appropriate inherent risks, and meets the business and customer needs.

11.4 Planning criteria used for network development

11.4.1 Planning criteria

Planning criteria define the standard across various network attributes that drive performance and enable the network to meet customers' current and future needs. The network is assessed against these standards to determine gaps (or constraints). Solutions are then developed to resolve the constraints, which includes considering network upgrades, operational changes and non-network alternatives.

11.4.2 Network security, capacity and customer numbers

We assess the need to upgrade the network due to growth across three domains: security, capacity and customer numbers.

Electra's security of supply standards are shown in Table 26. For GXPs and zone substations, our security standards are above the traditional N-1 standard. The higher security standards support the network if a second fault occurs. Security for second faults is provided by:

- The additional security for GXPs is provided through the subtransmission network. However, the second fault standard cannot be met for all fault types and network loads;
- The additional security for zone substations is provided through alternative sub-transmission assets or back-feeding on the 11kV network. However, the second fault standard cannot be met for all fault types and network loads;

- For large 11kV feeders, the additional security is provided by back-feeding through adjacent 11kV feeders.

We plan to review the second fault criteria over the next 12 months to ensure that the second fault criteria are appropriate and economically achievable.

Table 26: Network security criteria

Network level	Load type	Security level	First fault	Second fault
GXP	Greater than 12 MVA or 6,000 consumers	N-1^{+}	No loss of supply	50% of load restored in 15 minutes, 100% of load restored in 2 hours
Zone substation	Between 4 and 12 MVA or 2,000 to 6,000 consumers	N-1	No loss of supply	All load restored within 60 minutes
	Less than 4 MVA	N-1 switched	Loss of supply, 100 % load restored within 30 minutes from adjacent substations	Fault repair time
Distribution feeder	Urban and large rural feeders typically between 2.0 and 4.0 MVA	N-1 switched	Loss of supply, supply restored within 30 minutes from adjacent feeders	Loss of supply, supply restored within 4 hours from adjacent feeders
	Rural feeders between 0.5 and 2.0 MVA	N-1 switched	Loss of supply, supply restored within 30 minutes from adjacent feeders where available.	Fault repair time
	Feeder segment between switching point	Less than 0.5 MVA transformer capacity between switching points with backfeed capability	Fault repair time	Fault repair time
	Feeder spur	No more than 0.5 MVA transformer capacity on spur	Fault repair time	Fault repair time
Distribution transformer	Less than 1.0 MVA	N	Fault repair time	Fault repair time
LV circuit, commercial	Commercial circuits may supply between 1 and 20 customers	N+ switched	Loss of supply, supply restored to customers outside of faulted areas within 90 minutes	Fault repair time
LV circuit, residential	Residential circuits typically supply 30 to 40 customers	N	Fault repair time	Fault repair time

In addition to our security criteria, we have asset capacity planning criteria, as shown in Table 27. The security and capacity standards are related. The capacity standards provide a second layer of support to our security of supply standards.

Table 27: Network capacity criteria

Asset	Capacity criteria
Sub-transmission lines and cables	Conductor current should not exceed 66% of the thermal rating for more than 240 half-hours per year during normal operation[69]
	Conductor current should not exceed 100% of the thermal rating for more than 10 consecutive half-hours per year
Power transformers, zone substation switchgear and associated busbars conductor and cables	Maximum demand during normal operation should not exceed 50% of the full[70] nameplate rating (except for zone substations less than 4 MW and feeder circuit breakers)
	Load exceeds guidelines in IEC 354
Distribution lines and cables	Conductor and cable current should not exceed 70% of the thermal rating for more than 240 half-hours per year during normal operation
	Conductor and cable current should not exceed 100% of the thermal rating for more than 10 consecutive half-hours per year at any time
	HV and or LV fusing routinely exceeds ratings
	HV and or LV fuse operates
Distribution substations	Where fitted with a maximum demand indicator the reading should not exceed 100% of the nameplate rating. Where fitted with a power quality monitor demand should not exceed 100% of the name plate rating for more than 240 half-hours per year during normal operation[71]
	HV and/or LV fuse operates repeatedly
	Short-term loading exceeds guidelines in IEC 354
LV lines and cables	Conductor current should not exceed 100% of the thermal rating for more than 10 consecutive half-hours per year. However, as limited on-line measurement is currently in place, this is criteria is monitored during GM transformer inspections. There is no active monitoring of overhead circuit demand.

The third area we assess to determine if the network needs to be upgraded is the customer number per feeder. The maximum customer number per feeder is shown in Table 1. In many cases, operational changes to the network (e.g., rebalancing customer numbers across adjacent feeders) can resolve most identified constraints.

Table 28: Network customer number criteria

Network level	Customer number criteria
GXP	Not applicable
Zone substation	Not applicable
Distribution feeder	Maximum of 1,500 urban domestic consumer connections per feeder
	Maximum of 200 urban commercial consumer connections per feeder
	Urban light industrial consumer connections based on loading
Distribution substation and LV	No defined limits

11.4.3 New customer connections, changes in demand from existing customers and relocations of existing assets

The growth-related criteria in Section 11.4.2 define our response to organic growth. We also assess the network where a localised step-change in demand is foreseen. This assessment occurs when a new industrial or large commercial customer applies for a connection or an existing industrial or large commercial customer advises of a load upgrade. It also happens when a new subdivision development is

[69] Excluding contingency operation.
[70] Full means at ADAF or AFAF ratings
[71] Excluding contingency operation.

planned. The criteria in Section 11.4.2 are applied to the localised change in demand and customer numbers to assess if a constraint will emerge; a solution is then developed accordingly.

There are no specific standards for asset relocations. They are initiated upon the request of NZ Transport Agency Waka Kotahi, Local Councils, or customers.

Our current connection standards are on our website[72] and in our network extension policy[73]. The network extension policy describes the responsibilities of Electra and developers when connecting new subdivisions and other large developments.

11.4.4 Supply reliability

We evaluate the need for an upgrade to the network should reliability be below the standards in Table 29. Reliability issues often indicate the presence of end-of-life drivers. The asset fleet plans included in Section 12 address the response to end-of-life drivers. However, in some situations, reliability issues are resolved through changes in protection settings, network configurations, or the addition of sectionalisers and reclosers. The development plan deals with reliability improvements using network protection, changes in network configuration, or changes in asset type (e.g. undergrounding).

Table 29: Network reliability standards

Network level	Reliability criteria
GXP	Achieve a fault rate better (i.e. lower) than industry average
Sub-transmission feeder	Achieve a fault rate better than industry average. For sub-transmission feeders, all faults are assessed for the route cause to determine whether improvements are required.
Zone substation	Achieve a fault rate better than industry average. For zone substations, all faults are assessed for the route cause to determine whether improvements are required.
Distribution feeder	Achieve a fault rate better than industry average Intervention will also be evaluated for all worst-performing feeder[74].
Distribution substation	Not applicable. A fault on a distribution substation typically occurs at end-of-life
Low voltage system	Intervention will also be evaluated where there are multiple faults within 12 months on an LV circuit

11.4.5 Supply quality (voltage)

Voltage is the primary supply quality parameter we assess. The standards in relation to network voltage are shown in Table 30.

Table 30: Network voltage standards

Network level	Voltage criteria
GXP	The grid voltage at the GXPs is to be maintained to at above 198kV (on the 220 kV system) and 99kV (on the 110kV system). Maintaining GXP supply voltage is the responsibility of Transpower in their role as System Operator.
Sub-transmission feeders	33kV voltage below 31.5kV (0.95 pu) at the zone substation being supplied
Zone substations	Voltage drops below the level at which online tap changers can automatically raise taps
Distribution feeders	Voltage at HV terminals of transformer consistently drops below 10.5kV (0.95 pu) and cannot be compensated by local tap setting
Distribution substations	Voltage at LV terminals consistently drops below 100% of the nominal value

[72] https://electra.co.nz/getting-connected/

[73] https://electra.co.nz/our-company/disclosures/

[74] **Worst-performing feeder** means the feeder lines on an **EDB's network** that, in respect of the most recent **disclosure year**, are in the 90th percentile or higher for one or both of the following: (a) **feeder SAIDI**; and (b) **feeder SAIFI.**

Network level	Voltage criteria
400V lines and cables	Voltage below 94% of nominal voltage at the customer's point of supply Voltage above 106% of nominal voltage at the customer's point of supply

We also assess voltage and current harmonics when an issue is identified through our power quality monitors installed across 33kV, 11kV and LV in addition to any issues identified by customers.

11.4.6 Resilience

We are developing a resilience standard to define the network's capabilities to respond to natural hazards and other threats. Table 31 is the current draft standard. This will be refined over the next 12 months. We take a pragmatic approach to applying this standard to existing structures as site restrictions can impact remediation work—in which case we seek the highest practical performance or alternative supply arrangements in the event of a natural disaster.

Table 31: Draft resilience standard

Hazard	Draft Standard
Seismic	• All new zone substations, 11kV switching stations, control room and 11kV structures supplying critical infrastructure shall meet Importance Level 4 (**IL4**) defined in the National Building Standard. IL4 requires buildings to remain operational after a natural disaster (concerning earthquake, wind and snow structural loading). • All existing zone substations, 11kV switching stations, control room and 11kV structures supplying critical infrastructure shall meet IL4 where it practical and economic to do so; • 11kV buildings and fixings for ground mounted assets shall meet IL3. These buildings have increased performance requirements as they fulfil a role of increased importance to the local community.
Wind, snow and ice	• All new zone substations, 11kV switching stations, control room and 11kV structures supplying critical infrastructure shall meet IL4; • All existing zone substations, 11kV switching stations, control room and 11kV structures supplying critical infrastructure shall meet IL4 where it practical and economic to do so; • 11kV buildings and fixings for ground mounted assets shall meet IL3; • All new overhead lines shall meet security level 3 (under AS/NZS7000). Level 3 applies to lines where failure would cause increased risk to life or economic lost or where post disaster function is required.
Flooding and coastal inundation	• We have reviewed the network based on Council data. This data is based on a 1% annual exceedance probability (**AEP**) with significant climate change impacts[75] (which is a 1:100 year return period). • This return period (or AEP) is below that applied for other hazards. We are aware that some other distribution businesses apply 1:350 (0.35% AEP) or 1:500 (0.2% AEP). We are current reviewing what standard is appropriate for Electra.
Landslips and subsidence	• This is yet to be defined. We currently assess this during site selection.
Vehicle damage to the overhead network and ground-mounted assets	• This is yet to be defined. However, we review all vehicle damage incidents and will assess whether there is an ongoing vulnerability. • We have commenced work with a roading consultancy to provide us with guidance regarding asset locations.
Third-party contractor damage to the underground network	• This is yet to be defined. However, we review all third-party contractor damage incidents and will assess whether there is an ongoing vulnerability.

This standard excludes cyber security, which is discussed in Sections 8.6, 9.4.3 and 14.4.6.

[75] The climate change impacts are based on RCP 8.5 as defined by NIWA. This applies a range of mean annual temperature increases of 0.9–1.1 degrees Celsius by 2031–2050 and 2.8–3.1 degrees Celsius by 2081–2100.

11.4.7 Environmental

Electra's policy is to prevent pollution, comply with all applicable environmental regulatory requirements and continually improve our environmental performance. Table 32 summarises our current environmental standard.

Table 32: Environmental standard

Environmental hazard	Standard
Oil contained in transformers	• Maintain bunding equivalent to 110% of the oil contained in power transformers. Incorporate oil/water separation units on power transformer bunding. • Respond rapidly to any identified oil leaks in distribution transformers and switchgear. All soils contaminated with oil shall be removed and disposed appropriately.
SF_6	• Regular monitoring of all switchgear containing SF_6. • Respond rapidly to any identified leaks and follow industry guidelines for repairs, removal and disposal.
Site waste	• Our Sustainability and Environmental Policy details Electra's overall priorities to reduce, reuse and recycle where possible. We use the Resource Management Act to guide our waste disposal activities. • Detailed environmental standard being created next year.

11.4.8 Distributed generation

Electra's policies for embedded generation are on its website.[76] Key features of those policies include the following requirements:

- Compliance with the requirements of Part 6 of the Electricity Industry Participation Code 2010;
- Identification of the requirement for exported electricity to be sold to a retailer;
- Setting out the application process for both PV and batteries;
- Setting out the safety, technical, operational, commercial and regulatory requirements;
- A list of approved inverters.

11.4.9 Project evaluation and selection

We have recently updated our project governance process and have introduced a series of stage gates. The process covers:

- Project Justification Phase: Where we identify the issue (e.g. the breach of planning criteria or requirement from a new development or major customer), undertake optioneering, and create a project brief;
- Stage Gate 1: The project is escalated based on the delegated authorities. Gate 1 decides if a project goes from concept to live project;
- Front End Engineering Design: Preparation of concept design and high-level costings are created;
- Stage Gate 2: Design and costing review to determine if the project will progress to the detailed design;
- Detailed Design Phase: Preparation of the detailed design (using internal service delivery or contractors). This phase includes the detailed design, bill of materials, construction methodology, and detailed project costs.
- Stage Gate 3: Detailed design review and approval to proceed to construction.

Following Stage Gate 3, the project proceeds to procurement, construction and commissioning. Once complete, there is a final inspection, defect remediation (if needed) and as-builting. The as-builts are used to update the GIS and asset records.

[76] https://electra.co.nz/services/distributed-generation/

The project may be presented to the Board for approval, if required by the delegated authorities, at Stage Gates 2 and 3. Presenting at Stage Gate 2 provides the Board with oversight of the options considered, as well as the recommended option. Stage Gate 3 presents the accurate costings available at this time to the Board.

11.5 Design standards and other policies

11.5.1 Introduction

We have a range of other standards and policies that influence the design of any new project. These policies and standards drive safety, efficiency (via standardisation and modular concepts), and the amount of future capacity built into the design.

11.5.2 Safety in design

Safety in Design (SID) integrates hazard identification and risk assessment methods early in the design process. The project team participates in SID risk reviews to ensure a safe and smooth project delivery. SID development and assurance stages occur throughout the project delivery lifecycle. Safety is Electra's paramount consideration, and SID workshops provide traceability of its application of best-practice safety standards.

11.5.3 Standardisation

In September 2022, we created the Standards Review Forum, a cross-functional group that meets frequently to govern the approval and performance review of engineering standards, equipment approvals, and procedures. Using a RACI matrix, the group seeks to build consensus around standards and equipment approvals. This includes reviewing systemic issues identified through audit, observation, and event investigations and incorporating these into amended standards or procedures.

Electra uses NZ and international standards, codes, and guidelines to standardise design and materials. The areas where we have adopted a high level of standardisation (with minor site-specific alterations) are:

- Zone substation design and configuration, including conductor and cable types, switchgear, power transformers and protection systems;
- Distribution design and configuration, including conductor and cable types, ground-mounted distribution switchgear and transformers;
- LV design and configuration, including conductor and cable types, LV pillar and link boxes.

Our design and materials evolve as new standards offer improvements in safety, performance, inventory, or costs. Table 33 describes how standardisation across our supply chain supports asset management.

Table 33: Benefits of standardisation

Types of standardisation	Support construction and operational safety	Support asset performance	Minimise inventory costs	Minimise operating costs	Minimise design and construction costs
Standard design concepts				•	•
Technical design standards	•	•		•	
Standard asset capacity and configuration			•	•	•
Preferred purchasing arrangements	•	•	•		•

Types of standardisation	Support construction and operational safety	Support asset performance	Minimise inventory costs	Minimise operating costs	Minimise design and construction costs
In-house field staff	•	•			•

11.5.4 Standard asset capacities and planning horizon

We have defined planning horizons so that upgrading the network takes a suitably long view of future demand to maximise fixed construction costs (e.g., trenching or building work) and avoid the need for uneconomic near-term reinforcements. Electricity is an essential service, and reliance on electricity will increase as electrification increases. For this reason, we see the risk of under-investment that compromises security and capacity (and limits decarbonisation) as higher than the risk of short-term over-investment.

We have defined standard capacities for network elements to guide material and equipment selection and to achieve standardisation, purchasing, and construction efficiencies. The standard capacities and planning horizons outlined in Table 34 reflect the standard cable, conductor, switchgear, and transformers typically available.

Table 34: Asset Capacity and Planning Horizon

Network level	Standard Capacity	Planning Horizon	Description
GXP	n/a	30+ years[1]	We apply a long planning horizon as development can take up to ten years, and the incremental cost of higher capacity at the time of construction is generally low. There is no standard capacity; however, capacity typically follows Transpower's standard transformer sizes.
Sub-transmission feeders	To support the required contingent capacity	20-30 years	We apply a long planning horizon due to the time and complexity of route selection and procurement of property rights.
Zone substations	Typical nominal rating is 23 MVA (N-1) for urban substations	20 years	We apply a long planning horizon due to the time required to consent and develop a zone substation. The standard substation capacity reflects Electra's historical practices.
Distribution feeders	4/6 MVA for urban feeders 3/4 MVA for rural feeders	Ten years	We apply a medium planning horizon, and distribution work can typically be completed in 1-2 years. The standard feeder capacity relates to normal/backfeeding and reflects Electra's historical practices.
Distribution substation, industrial	Customer-specific	Ten years	A ten-year view of capacity is generally appropriate for industrial customers. Distribution transformers can be incrementally upgraded in most cases.
Distribution substation, commercial	500-1,000 kVA	Ten years	A ten-year view of capacity is generally appropriate for commercial areas—the selected capacity needs to have suitable spare capacity for back-feeding adjacent loads.
Distribution substation, urban	200-300 kVA	n/a	Distribution transformer capacity is sized based on the standard residential customer number (3.5 kVA ADMD) and the expected number of connections.
Low voltage	Standard cable and conductor sizing	n/a	Capacity is based on standard cable and conductor size. LV runs are limited to maintaining voltage and capacity compliance based on the standard residential customer number (3.5 kVA ADMD) and the expected number of connections
Residential customer demand	3.5 kVA ADMD (distribution TX level)	n/a	This is the maximum demand of a residential customer used for planning purposes. The diversity is measured at the urban

Network level	Standard Capacity	Planning Horizon	Description
			distribution transformer. We are reviewing the ADMD we use for planning as part of our energy transformation work.

11.5.5 Energy efficiency

We seek to minimise network losses where it is economic to do so. We recognise that total network losses are significant (about 8% of energy entering the network); hence, the following approaches are used to minimise losses:

- Upgrading of overloaded conductors to reduce the I^2R losses;
- Consideration of losses when purchasing equipment;
- Identify and improve poor power factor installations to a minimum of 0.95;
- Optimisation of open points to ensure the load is balanced across feeders and LV circuits.

11.6 Innovation practices

At Electra, we do not directly innovate new products, materials, or systems. Instead, our strategy involves being a fast follower in adopting new products, systems, or processes. We aim to be an early adopter of new technology that has reached the commercialisation stage (by others) when significant benefits are available. The one exception to this approach has been our involvement in Flex Talk (refer to Section 10.7), which involved pre-commercialisation work (that was led by others).

Proposed innovations require a business case that considers the benefits of change, including safety, maintainability, longevity, customer service, and the impact on capex and opex. Innovations could involve changes to processes, systems, designs, or materials.

Due to our relatively small scale, we generally operate a conservative approach to design innovation—that is, when balancing standardisation vs. innovation, we place reasonable weight on standardisation, ensuring we can maintain competency (in operating and maintaining) assets. However, we will innovate on design with material performance or lifecycle cost advantages (the new modular outdoor zone substation circuit breakers are a good example). New products that can reduce future maintenance costs and perform well in coastal conditions are areas where we actively seek innovation.

Proposed innovations that could impact design or materials standards are reviewed by the Standards Review Forum (refer to Section 11.5.3). The forum ensures that there is a cross-business view on the impacts on safety, maintainability and longevity (in particular).

Recent innovations include our involvement in Flex Talk (refer to Section 10.7), the modular 33kV switchgear (Section 11.9.4), trip saver (Section 11.12.3), and the power transformer moisture probes (Section 12.8.4).

11.7 Demand forecasts for planning purposes

Our demand forecasts in Section 10.8 forecast demand at the GXP, substation, and feeder levels. They use two scenarios: one in which we have access to flexibility, which results in controlled demand forecasts, and one in which we do not have reliable access to flexibility, which results in *uncontrolled* demand forecasts.

The development plans have been prepared using the **controlled demand** forecasts, but we discuss our approach to managing demand uncertainty where necessary.

Figure 107: Mangahao GXP demand forecast

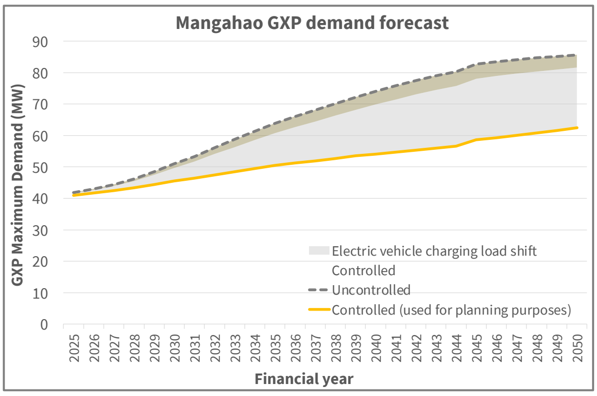
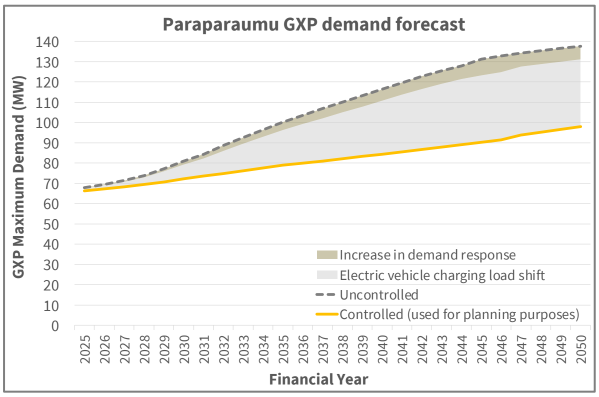


Figure 108: Paraparaumu GXP demand forecast



11.8 Development plan—grid exit points

11.8.1 GXP developments to meet security and capacity requirements

Background

Electra's network consists of two regions:

- The northern network, which is supplied from the 110 kV Mangahao GXP and Mangahao generation and supplies Levin East and West, Foxton and Shannon substations in a ring configuration;
- The southern network, which is supplied from the 220 kV Valley Road Paraparaumu GXP and supplies Paekākāriki, Paraparaumu East and West, Raumati, Waikanae and Ōtaki substations in a double spur configuration;

There is significant capacity available at GXP supplying the southern network. However, the capacity of the Mangahao GXP (at 44 MVA N-1-g firm, including the generation) is close to the current demand of 42 MVA in the northern region. The 38 MW Mangahao hydro station is an essential generator for Electra. The output from this station currently supports the security of supply from the Mangahao GXP during peak demand, typically operating at ~26 MW.

The Mangahao GXP transformers (owned and operated by Transpower) are reaching end-of-life. It is an ideal time to consider options for a long-term solution for the northern region.

Planning standards drivers

Four relevant planning standards are guiding the development of options:

- Security of supply;
- Consideration and use of non-network alternatives;
- Planning horizon;
- Resilience.

Table 35 shows Electra's current security standards (as they relate to GXPs). The first fault requirement reflects a typical N-1 standard, and the second fault requirement requires a higher level of redundancy or alternatives. The network doesn't meet the second fault requirement in most situations; hence, it is under review. Hence, our principal focus is presently on the first fault requirement.

Table 35: Network security criteria

Network level	Load type	Security level	First fault	Second fault
GXP	Greater than 12MVA or 6,000 consumers	N-1+	No loss of supply	50% of load restored in 15 minutes, 100% of load restored in 2 hours

For all significant network development projects, non-network alternatives are considered when it is practical to do so. In the case of the Mangahao, given the GXP transformers are at end-of-life, non-network options are being considered to provide additional capacity or security support, as the transformers need to be replaced or a new GXP developed.

GXP developments are amongst the largest projects undertaken to support electricity supply in a region. GXP developments can take up to ten years, and the incremental cost of higher capacity at the time of construction is generally low. For this reason, a 30+ year planning horizon is adopted.

We are yet to define our resilience standard. This will be completed for the 2026 AMP.

Equipment standardisation, safety in design, and energy efficiency will be considered further along the development process.

Policy and strategy drivers

There are two asset management policy items relevant to the upgrade/replacement of Mangahao GXP:

- Developing the network responsibly to meet current and future needs, and we will adopt new technology to ensure we keep pace with the requirements of customers and other stakeholders;
- Considering the economic, environmental and cultural impact of our business and finding an appropriate balance between them.

The upgrade/replacement of Mangahao GXP will be a significant project that will alter the energy trilemma balance. Our preliminary view is that the project will enhance security/reliability and sustainability at the expense of affordability. Given the long planning horizon associated with GXPs, the project will provide significant capacity for the future. Our choice of solutions will seek to minimise the impact on affordability in the near term but also recognising the creation of a long-life intergenerational asset which supports the future growth, development, electrification and resilience in the region.

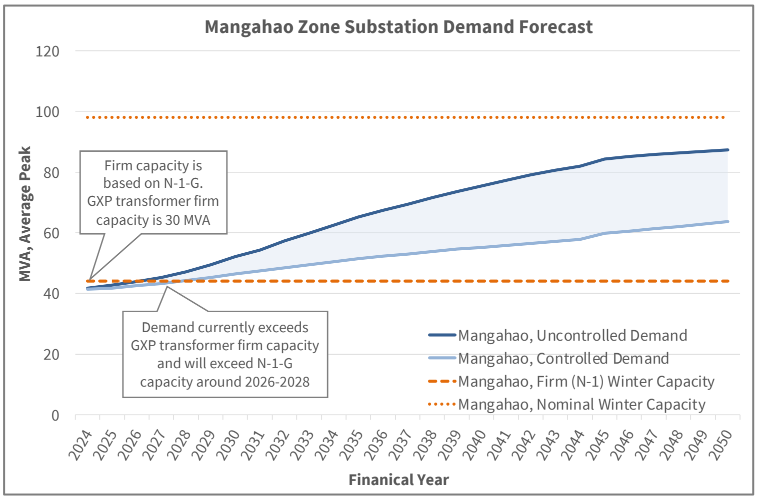
Lastly, the Mangahao GXP is owned and operated by Transpower for the benefit of Electra. Electra could own a new GXP; however, we do not consider this feasible given the significant capital costs, the complexity with property rights and the connection of generation (if this is needed), and the introduction of 110 kV or 220 kV assets, which we currently do not have expertise in.

Current constraints

Demand forecasts indicate a shortfall in capacity and a breach of GXP firm capacity in 2026-2028 (Figure 109). We have assessed GXP firm capacity including Mangahao, based on the N-1-G industry standard (where G is the largest turbine at Mangahao).

Demand is currently exceeding the GXP transformer firm capacity but is supported by Mangahao generation at peak times.

Figure 109: Mangahao GXP Demand Forecast



Our approach is to plan for controlled demand, but to have contingencies or an upgrade path to cater for uncontrolled demand, should this occur.

Mangahao GXP currently has a peaky demand profile. This increases the potential for optimisation using non-network alternatives to manage constraints in the short term.

Network solution, preferred option

We have undertaken extensive studies into the options for the GXP supply to the northern region. Our preferred network solution is a new Levin Southwest 220/33kV GXP located south of Lake Horowhenua (Figure 110). This option satisfies the planning horizon requirements.

There is a significant advantage in the resilience of the Levin Southwest GXP relative to the other options due to shorter interconnecting lines (reducing the exposure to environmental factors), reduced exposure to potential flooding and greater distance from known earthquake fault lines. This option also presents the lowest construction risk due to generally lower property rights requirements.

It is our preference that Transpower would own and operate the new GXP. The new GXP will be a transmission connection asset.

A new Shannon switching station is necessary to enable Mangahao GXP to be decommissioned. The switching station interconnects the circuits presently interconnected at the Mangahao GXP.

Figure 110: Northern GXP, preferred network solution (proposed)

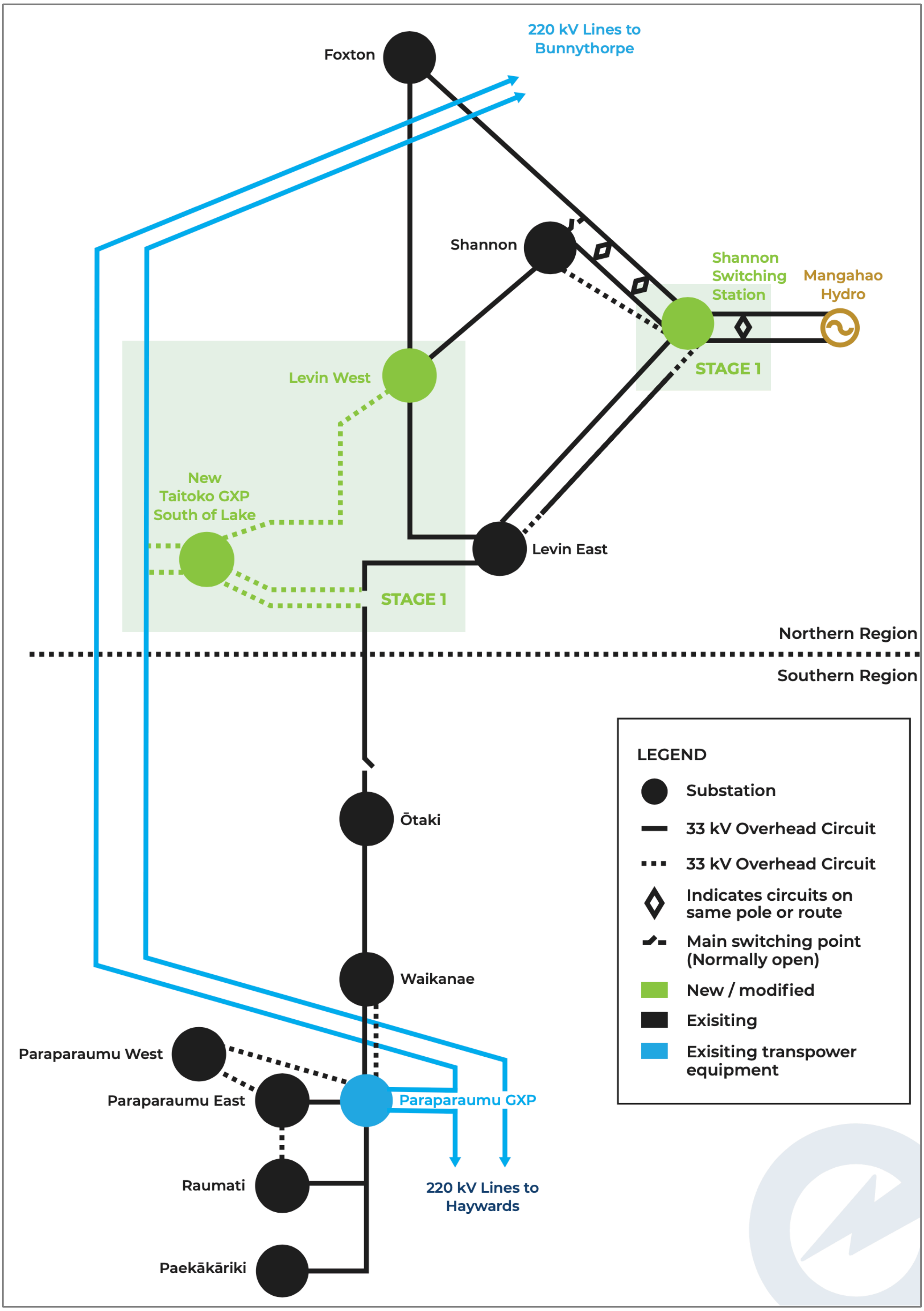


Table 36: Projects under consideration (not current in the expenditure forecasts)

Solution under consideration	Driver	Estimate/Year	Options considered
1. A new Levin Southwest 220/33 kV GXP (South of Lake)	To deliver the required firm capacity for the Northern region	Transpower costs, subject to negotiation FY32-33	• A new Mangahao 220/33 kV GXP; • A new Levin Southeast 220/33 kV GXP; • An expanded Paraparaumu 220/33 kV GXP as a single point of supply to feed both Northern and Southern networks; • A new shared Electra/Genesis 220/33 kV GXP/GIP connecting both Electra and a proposed Genesis 200 MW solar farm northeast of Foxton. • A new Levin Northwest 220/33 kV GXP (North of Lake)
2. 33kV subtransmission cabling to connect new GXP to the existing subtransmission network (Stage 1) • 33kV Cable from GXP to existing Levin East to Ōtaki circuit. ~4.8 km 1000mm2 ALXLPE • 33kV Cable from GXP to existing Levin West to Levin East circuit ~4.8 km 630mm2 ALXLPE • 33kV Cable from GXP to existing Levin West 9.1 km 630mm2 ALXLPE, including load sharing reactors	To deliver the required firm capacity for the Northern region	$12.7m FY32-33	
3. New Shannon switching station (Stage 1)	To deliver the required firm capacity for the Northern region	$4.5m FY32-33	
4. 33kV subtransmission cabling to connect new GXP to the existing subtransmission network (Stage 2)	To deliver the required firm capacity for the Northern region	$4.1 m FY43	• This is currently beyond the AMP planning horizon
Total (not in expenditure forecasts)		**$17.2m**	• **FY32-33, System growth capex**

Due to the forecast capacity constraints and the Mangahao GXP transformer's end-of-life, there is no realistic do-nothing option. Upgrading the existing Mangahao 110/33kV GXP/GIP was discounted due to site constraints, resiliency issues, and capacity limitations on the 110kV lines, making an upgrade significantly more expensive than other options.

11.8.2 GXP developments to meet other drivers

No GXP developments are required to meet other drivers. We have yet to complete work on defining our resilience standard. This is a potential area for future work, and we expect to include resilience analysis in the 2026 AMP.

11.8.3 Managing demand growth uncertainty

The GXP development plan has been prepared based on achieving controlled demand growth. Due to the low incremental cost of providing GXP capacity, the network solution has been sized to cater for uncontrolled demand should this arise.

11.8.4 Consideration of non-network alternatives

Under our energy transformation roadmap, we will develop a non-network procurement policy, standards, and evaluation criteria. These will define performance standards for non-network alternatives. Where non-network alternatives are deployed or procured, we need to develop processes for monitoring their performance to ensure the benefits procured are delivered. Work on these policies and standards has not yet commenced.

Non-network alternatives cannot fully substitute a new or replacement GXP as a new grid connection or upgrade to the existing GXP is required (given the end-of-life of the existing GXP transformers). However, non-network alternatives may reduce the capacity needed at the GXP and downstream network augmentation (e.g. the number and capacity of circuits and the requirement for capacitor support). Given the peakiness of the Mangahao GXP demand profile, there could be options for merchant/market flexibility to soften the peak demand. Non-network alternatives will be considered in the detailed study of the shortlist option.

11.8.5 How we are thinking about the energy trilemma balance

The proposed GXP development could have a ~5% impact on line charges (when commissioning the initial works), which is a material increase. Greater GXP capacity is required to meet the northern region's future population and electrification needs—meeting this need is essential for the region. Greater GXP capacity is necessary to maintain GXP security as demand grows (at N-1, which is the standard currently afforded the region)—maintaining security is essential to meeting our ongoing reliability performance targets.

We are mindful of the affordability impacts. Our approach to managing affordability is:

- To stage the development to the maximum extent possible, commensurate with the risk (which is discussed below);
- To provide capacity to service the controlled maximum demand (at the planning horizon) and have an upgrade path to service the uncontrolled demand (should this be necessary);
- Utilise non-network alternatives (if viable) to minimise the initial development's capacity requirements or delay planned upgrades.

Proceeding with the preferred option will increase security and sustainability at the expense of affordability. However, our approach will minimise upfront costs and the initial pricing impacts. It will also minimise or defer the pricing impact of any future upgrades.

11.8.6 Managing demand while a new GXP is developed

Until a new GXP is commissioned, we are managing the risk of the maximum demand exceeding firm capacity and the end-of-life failure of one of the Mangahao GXP transformers. Our demand forecasts indicate that peak demand could exceed firm capacity at the Mangahao GXP between 2026 and 2028. Given the peakiness of the seasonal demand profile, any exceeding of the peak will be for a small number of half-hour periods (for around the next 5-8 years). We have options available to manage peak demand through the existing Mangahao generator, more aggressive load control, seeking flexibility options from the market, or utilising the two-hour overload rating of the transformer (this is least preferred due to the age of the transformers).

Concerning the end-of-life failure risk of the Mangahao transformers, Transpower forecasts the replacement for 2026-2028. A new GXP could be commissioned around 3-5 years after 2028. Transpower has not escalated any concerns regarding transformer health and is managing the transformers appropriately. We will seek additional condition monitoring of the units and explore contingency arrangements with Transpower before we operate beyond 2028.

11.8.7 Summary of justification for the GXP development projects

The capacity-driven projects in this section are required to meet demand from new customers and support future demand growth from existing customers. This is an essential requirement for Electra.

11.8.8 Expenditure forecasts

The development of a Northern region GXP is in the concept phase. Hence, the expenditure forecasts do not include $17.2m project costs. Over the next 12 months, we will be firming up the potential network and non-network alternatives.

11.9 Development plan—subtransmission and zone substation

11.9.1 Overview

During the planning period (to the end of FY35), subtransmission and zone substation developments are required to meet demand growth. The forecast demand growth is driving:

- Subtransmission constraints during contingency (N-1) operations on the Northern network;
- Voltage support for the Ōtaki substation;
- The development of new zone substations to support demand growth on the 11kV system that cannot be met through the augmentation of the 11kV system.

The developments are primarily needed to maintain firm capacity as demand grows. Electra operates a very secure and reliable subtransmission system, and maintaining security is crucial to operating a reliable network. The subtransmission developments in this section are consistent with the commissioning of a new GXP in the Northern region, as discussed in Section 11.8.

The subtransmission and zone substation developments are forecast to cost $18.6m. The significant projects are two mini-zone substations (at Manakau and Peka Peka) and the upgrading of two subtransmission circuits in the Northern region. Development at several zone substations is also required to meet resilience and environmental needs. This is a continuation of existing programmes.

11.9.2 Zone substation demand growth

The demand growth drivers identified in Section 10.8 have been applied to each feeder based on customer mix to determine the zone substation demand (Table 37). Zone substation demand is forecast to grow significantly by 2050, with Northern region substations' demand growth between 55% and 67%. Zone substation demand growth in the Southern region is lower, at between 13% and 53%. Growth in Paekākāriki and Raumati is constrained due to land availability constraints.

Despite the strong demand growth, zone substation capacity is suitable to meet the controlled demand growth at all zone substations, except Shannon and Waikanae, to 2050. Constraints will occur at seven of the ten zone substations by 2050 if uncontrolled demand growth occurs.

Table 37: Zone substation customer type and demand growth

Zone substation	Current security level	Customer type	Controlled Peak Demand 2025 (MVA)	Controlled Peak Demand 2030 (MVA)	Controlled Peak Demand 2035 (MVA)	Controlled Peak Demand 2050 (MVA)	Total Controlled growth to 2050
Shannon	N-1	Mix of urban load in Shannon and rural load toward Tokomaru and Opiki	4.7	5.1	5.4	6.7	57%
Foxton	N-1	Predominantly urban load in Foxton with some rural load in all directions	7.2	8.1	9.1	11.4	63%
Levin West	N-1	Predominantly the rural areas to the north and west of Levin, Waitārere	14.7	14.9	16.9	21.4	67%

Zone substation	Current security level	Customer type	Controlled Peak Demand 2025 (MVA)	Controlled Peak Demand 2030 (MVA)	Controlled Peak Demand 2035 (MVA)	Controlled Peak Demand 2050 (MVA)	Total Controlled growth to 2050
		Beach, and some urban load in the western parts of Levin					
Levin East	N-1	Predominantly urban, although with some rural load to the south and east of Levin	13.1	16.3	18.2	22.4	55%
Ōtaki	N-1	Predominantly urban load in Ōtaki with some rural load in Ōtaki Gorge, Manakau, Te Horo and Waikawa Beach	12.5	13.1	13.7	15.9	29%
Waikanae	N-1	Dense urban load in and around Waikanae, some rural load to the north in Peka Peka and the east in Reikorangi	15.3	16.7	18.3	24.0	53%
Paraparaumu East[77]	N-1	Dense urban load in the eastern and central parts of Paraparaumu, some rural load on the immediate outskirts of Paraparaumu	13.0	14.4	15.9	19.2	52%
Paraparaumu West	N-1	Dense urban load in central and western parts of Paraparaumu	12.0	13.2	14.6	18.8	51%
Raumati	N-1	Dense urban load in and around Raumati	9.6	10.5	11.5	15.1	39%
Paekākāriki	N-1 switched	Mix of light urban and semi-rural load around Paekākāriki.	3.2	3.6	4.1	4.8	13%

11.9.3 Subtransmission and zone substation developments to meet security and capacity requirements

We have undertaken extensive studies into the options for the subtransmission and zone substation development to meet controlled and uncontrolled demand growth. The constraints and proposed solutions presented meet the requirements for controlled demand growth. We discuss the impact of uncontrolled demand growth later in this section.

Constraints—on the subtransmission system and at zone substations

Besides firm transformer capacity at Shannon and voltage constraints limiting available capacity at Ōtaki (when supplied from the North during contingency situations), the zone substations have sufficient firm (i.e. post contingency) capacity to supply the controlled demand for the next ten years (Table 38). Within the planning period, all substations other than Shannon and Waikanae can support uncontrolled demand growth.

Table 38: Zone substation capacity constraint

Existing Zone Substations	Current security level	Current Firm Capacity (MVA)	Current spare capacity (MVA)	FY30 spare spare Controlled (MVA)	FY35 spare spare Controlled (MVA)	FY35 spare spare Uncontrolled (MVA)	Forecast constraint
Shannon	N-1	5.0	0.3	(0.1)	(0.4)	(1.7)	Power transformer security/capacity constraint from FY30
Foxton	N-1	23.0	15.8	14.9	13.9	11.4	No constraint

77 Paraparaumu renamed Paraparaumu East.

Existing Zone Substations	Current security level	Current Firm Capacity (MVA)	Current spare capacity (MVA)	FY30 spare spare Controlled (MVA)	FY35 spare spare Controlled (MVA)	FY35 spare spare Uncontrolled (MVA)	Forecast constraint
Levin West	N-1	23.0	8.3	6.7	4.8	0.2	No constraint
Levin East	N-1	23.0	9.9	8.1	6.1	1.2	No constraint
Ōtaki	N-1	23.0	0.0	(0.6)	(1.2)	(3.4)	No constraint when supplied from the South. There is a voltage constraint from FY26 when fed from the North
Waikanae	N-1	23.0	7.7	6.3	4.7	(1.1)	No constraint
Paraparaumu East	N-1	23.0	10.0	8.6	7.1	3.4	No constraint
Paraparaumu West	N-1	23.0	11.0	9.8	8.4	4.1	No constraint
Raumati	N-1	23.0	13.4	12.5	11.5	7.8	No constraint
Paekākāriki	N-1 switched	5.0	1.8	1.4	0.9	0.0	No constraint

The voltage at Ōtaki will drop below 0.95 (33kV) when supplied from the North from FY26 and below 0.90 pu around FY35. The current breach in voltage (compared to our planning standard) is presently minor and can be supported by more aggressive load control for the next few years. However, voltage support is required within 3-5 years. Longer term, voltage support is required at Ōtaki to maintain voltage at Manakau, Ōtaki, and Peka Peka zone substations in the event of a 33 kV outage from either the new northern GXP or from Waikanae in the south.

There are multiple drivers for upgrading sections of low-capacity conductors on the Foxton to Levin West 33kV line and the Levin West to Levin East 33kV line. Capacity on these lines is presently restricted to around 20 MVA, below our standard of 30 MVA. The sections of smaller conductors are of lower health than the rest of the line, and risk-based renewal is expected within the planning period. Operating these lines at 30 MVA capacity will be required to export generation from the planned solar farm at Foxton during contingency operations (in the current network configuration and when the new Northern GXP is developed). Our current expectation is for the commissioning of the Foxton solar farm in FY26.

Table 39: Subtransmission and zone substation constraints

Constraints	Proposed network solutions
Demand at Shannon substation exceed power transformers firm capacity around FY30	Project 1: Transfer demand to Levin West and Foxton using the 11kV network
Foxton to Levin West 33kV line is below standard capacity and the low-capacity sections are of low health. Full capacity from this line will be required within the planning period	Project 2: Capacity upgrade on the last remaining section of Foxton to Levin West 33kV line
Foxton to Levin West 33kV line is below standard capacity and the low-capacity sections are of low health. Full capacity from this line will be required within the planning period	Project 3: Capacity upgrade on the last remaining section of Levin West to Levin East 33kV line
Low 33kV voltage occurs at Ōtaki when supplied from Levin from FY26	Project 4: O2NL 33kV ducting in anticipation of future circuit capacity upgrades between Levin East and Ōtaki Project 10: Voltage compensation at Ōtaki substation using 3 x 5 MVAe static synchronous compensators

Constraints—on the distribution system that require subtransmission or zone substation solutions

There are three areas where localised demand growth cannot be serviced through augmentation of the 11kV network. These are:

Figure 111: Taraika proposed development

- The Taraika residential and commercial development. Taraika is a 420ha block of land to the east of Levin. It is privately owned by several parties and has been identified as a key growth area for the Horowhenua District. The development will comprise approximately 2,500 houses (at a range of different section sizes), a small commercial area, new parks and reserves, and education opportunities. Development of the site is expected to commence in 2025 and be completed by around 2032.
- The O2NL highway development will significantly reduce travel times to Wellington, and land usage near the highway is expected to change. We have recently received significant connection inquiries and applications in the Manakau, Kuku and Ōhau areas. These comprise commercial developments and two residential developments comprising over 300 lots. The extent of these inquiries and applications indicates that the load growth in the area will exceed the 11kV network capacity. We are expecting constraints to emerge around FY30 (depending on the actual pace of development);
- We continue to see extensive growth in the Peka Peka area and have received significant connection inquiries and applications for the area. Over the next three years, around 400 residential lots will be developed, and a further 1,200 over the long term. The extent of these inquiries and applications indicates that the load growth in the area will exceed the 11kV network capacity. We are expecting constraints to emerge around FY27.

Table 40: Subtransmission and zone substation constraints

Constraints	Proposed network solutions
New >2,500 Taraika residential and commercial development. The development is expected to commence in 2025, with civil work already underway for stormwater ponds and roading.	Project 5: Installation of ducting during site development And Project 6: Taraika development new mini-zone substation
The existing 11kV network is forecast to become constrained in Manakau, Kuku and Ōhau around FY30 due to developments following the opening of the O2NL highway.	Project 7: Manakau new mini-zone substation
The existing 11kV network supplying Peka Peka is forecast to become constrained by around FY27 due to continued residential growth in the area.	Project 8: Peka Peka new mini-zone substation
The existing 11kV network around Waikanae is forecast to become constrained by FY28 due to continuing residential growth in the region. The 11kV constraints are further discussed in Section 11.10.2.	Project 9: New feeders from Waikanae zone substation (see Section 11.10.3)

Proposed network solutions

Figure 112 and Table 41 shows our proposed network solution. We considered a range of development options, and the suite of proposed projects has a low cost to achieve controlled demand growth, and the lowest incremental costs should demand increase above this level (compared to other options). Given the uncertainty associated with future demand, having a low incremental cost to account for demand growth is important.

Figure 112: Subtransmission and zone substation proposed projects

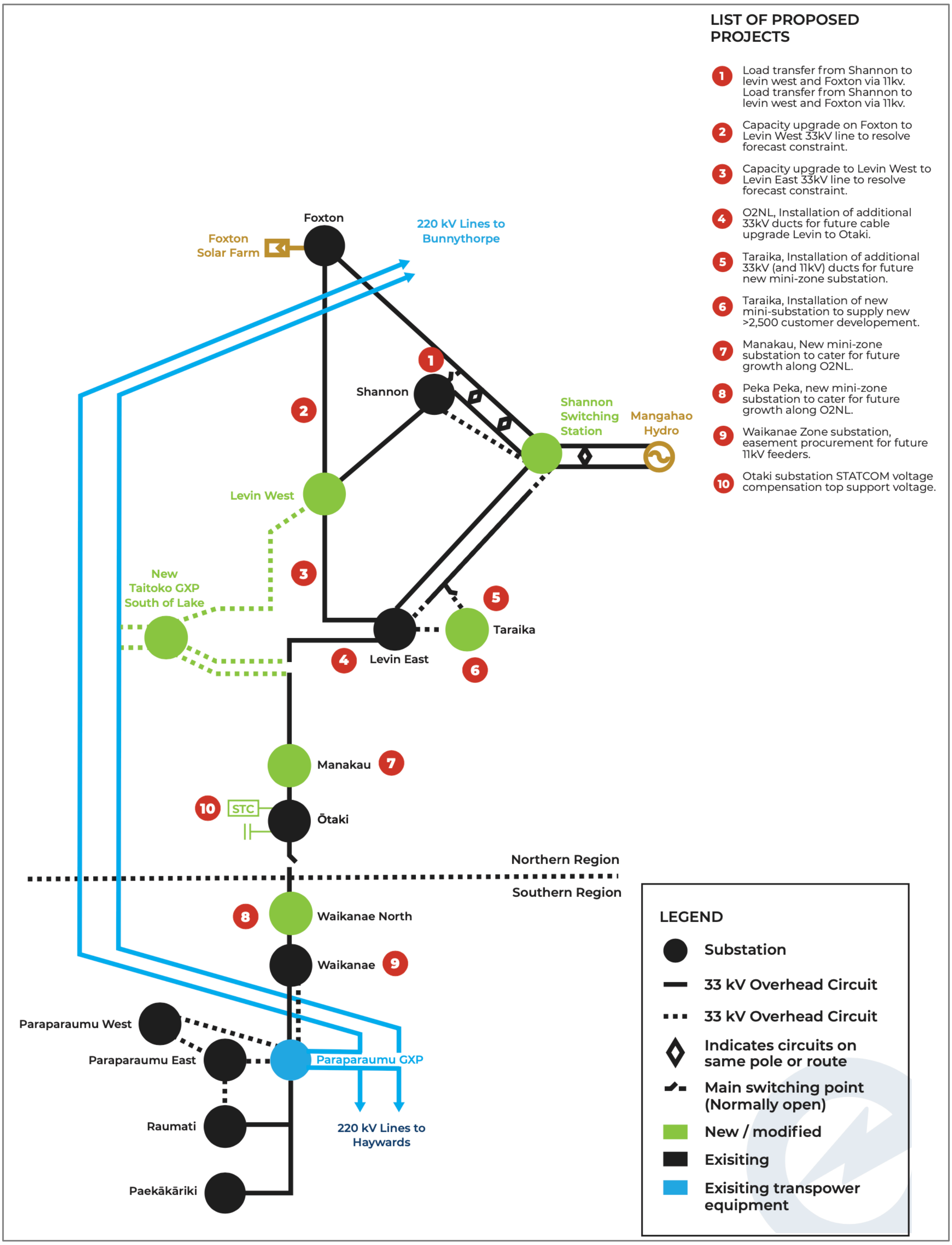


Table 41: Proposed Projects

Project	Driver	Cost/Year	Justification and options considered
1. Transfer demand to Levin West and Foxton using the 11kV network	Capacity	Nil	• Constraint resolved through changes to network configuration. This is the least cost option.

Project	Driver	Cost/Year	Justification and options considered
2. Foxton to Levin West 33kV line • Upgrade 11km of line to butterfly conductor to achieve full line capacity	Capacity	$3.8m FY31-34	• A section of the existing line has not been upgraded to butterfly conductor. Completing the conductor upgrade is the least cost option to achieve full line capacity, which will be required during the planning period • The timing of the capacity upgrade balances the need for the additional capacity and when the sections of conductor will fall due for risk-based replacement.[78]
3. Levin West to Levin East 33kV line • Upgrade 3.2km of line to butterfly conductor to achieve full line capacity	Capacity	$2.2m FY30-33	• As above
4. Taraika development 33kV (and 11kV) ducting for mini-zone substation • Installation of spare ducting in anticipation of future capacity required at Taraika	Capacity	$250k FY26-28	• This project is making future provisions for 33kV and 11kV cable installation. Ducting installation during site construction is ~50% cheaper than installation when the development is completed
6. Taraika development new mini-zone substation • New 11.5/23 MVA N switched substation	Capacity	$4.6m[79] FY26-28	• This project will provide new capacity to new customers (>2,500). The current network has insufficient capacity, and a new zone substation is required • To optimise the development, an 11.5/23 MVA ONAN/OFAF transformer will be installed that can later be upgraded to N-1 with the addition of a second transformer and HV bus. Contingent support will use the 11kV network • Different configurations of substation were considered, and an N-1 switched (single transformer) substation is proposed to minimise overall cost
7. Manakau new mini-zone substation • Stage 1: Land procurement	Capacity	$810k FY27	• Supply using the 11kV network. The 11kV network will not be able to supply the required load over the long term cost-effectively
8. Peka Peka new mini-zone substation • New 11.5/23 MVA N switched substation	Capacity	$4.1m[80] FY26-27	• Supply using the 11kV network. The 11kV network will not be able to supply the required load over the long term cost-effectively • To optimise the development, an 11.5/23 MVA ONAN/OFAF transformer will be installed that can later be upgraded to N-1 with the addition of a second transformer and HV bus. Contingent support will use the 11kV network • Different configurations of substation were considered, and an N-1 switched (single transformer) substation is proposed to minimise overall cost
9. Waikanae zone substation • Easement procurement for future new feeders	Capacity	$150k FY26	• New 11kV feeders are required. Refer to the distribution development Section 11.10.2
10.Voltage compensation at Ōtaki substation: • 3 x 5 MVAe static synchronous compensators (STATCOM) and switchgear	To provide voltage support at Ōtaki during contingency situations	$2.2m FY28	The proposed solution has a lower lifecycle cost than the other options considered: • Using 33 kV voltage regulators

[78] We have defined these projects and system growth, rather than renewal, as the need for standardisation and additional capacity is likely to be in advance of their risk-based renewal.

[79] The project commenced in FY25. Total project costs are forecast at $5.3m.

[80] The project commenced in FY25. Total project costs are forecast at $4.9m.

Project	Driver	Cost/Year	Justification and options considered
• Enhancing the special protection scheme[81]			• Construction of a second 33 kV line in parallel to the existing Levin – Manakau – Ōtaki – Waikanae North – Waikanae line
Total		**$18.1m**	• **FY26-35, System growth capex**

Table 42: Projects under consideration

Project	Driver	Cost/Year	Justification and options considered
4. O2NL 33kV ducting for future use • Installation of spare ducting in anticipation of future capacity and protection upgrades between Levin East and Ōtaki	Capacity	$510k FY26	• Ducting installation during site construction is ~50% cheaper than installation when the highway is completed • Low 33kV voltage occurs at Ōtaki when supplied from Levin (the primary solution is project 10). This project is making future provision for 33kV cable installation to increase capacity to Ōtaki (which) will be utilised beyond the planning period), provision for new 11kV feeders (also beyond this planning period), and provision for fibre installation for protection (see Section 11.12.3). • This project remains under consideration awaiting agreement with NZTA
Total		**$510k**	• **FY26-35, System growth capex**

We have also identified the need to upgrade the old copper conductor on the Mangahao to Shannon Line ($5.9m). This project is being considered for FY27-30; however, it will only proceed if the new Northern GXP does not proceed. The new Northern GXP is our preferred solution; hence, this line upgrade project is not included in the expenditure forecasts.

11.9.4 Developments to improve resilience

Electra's resilience standard requires all zone substations to meet importance level 4 (**IL4**) under the NZ building code where it practical and economic to do so. IL4 requires buildings to remain operational after a natural disaster (concerning earthquake, wind and snow structural loading). All zone substations have been assessed against the IL4 standards for seismic, wind and snow. Any site below IL4 has been scheduled for strengthening or demolition. Of the ten zone substations, six have been strengthened to IL4. These are Ōtaki, Paraparaumu West, Raumati, Shannon, Waikanae, and Levin East.

In respect to the four remaining substations:

- Paekākāriki substation is due for completion in early FY26;
- Foxton substation is due for completion by the end of FY26;
- Paraparaumu East is in the design phase and work is schedule for FY27;
- Remediation plans for Levin West have yet to be defined. The draft design has proved to be impractical and uneconomic. We are currently reviewing our options which could include strengthening or establishing a new structure.

We are moving to modular outdoor switchgear at substations with space for outdoor switchgear (see case study below). The modular outdoor switchgear increases the separation between the two bus sections and enables one bus section to be replaced within approximately one week in the event of a failure. This

81 Extending the existing Special Protection Scheme (SPS) at Ōtaki, used to automatically changeover supply between North and South, to cover automatic changeover for Manakau, Ōtaki, and Peka Peka.

approach has been adopted following a circuit breaker failure at Shannon substation, which necessitated the replacement of one bus section and breaker, taking several months. To achieve a one-week repair time, a spare circuit breaker module is needed.

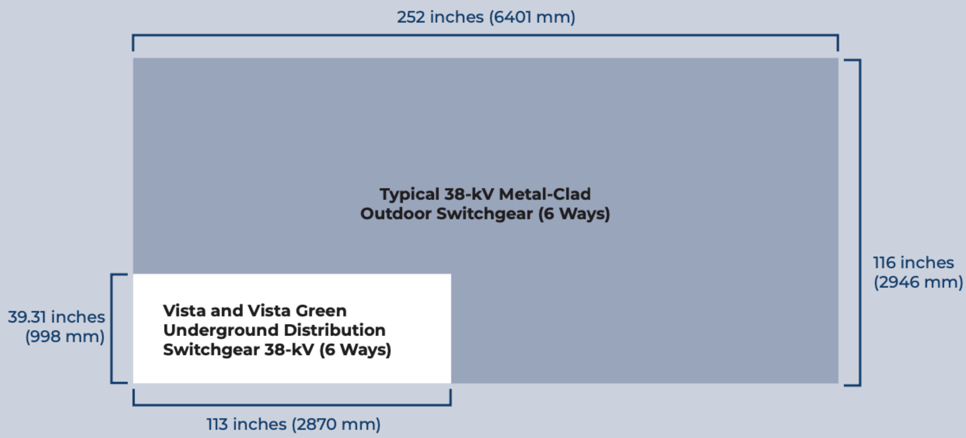
Table 43: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
1. Seismic strengthening of Paekākāriki, Foxton and Paraparaumu East zone substation buildings to IL4	Resilience	$978k FY26-27	• Strengthening was the least cost option. A complete rebuild was not a viable option.
2. Critical spares. Purchase of 1 x 5 way S&C Vista 33kV circuit breaker to support the outdoor modular switchgear approach	Resilience	$456k FY27	• The purchase of the critical spare supports the move to modular 33kV switchgear at zone substations.
Total		**$1,434k**	• **FY26-27, Other reliability, safety, environmental capex**

CASE STUDY ON VISTA SWITCH GEAR

Vista Underground Distribution Switchgear is designed to operating safely while minimizing the 33kV switchgear footprint. The Vista ratings chosen by Electra are 38 kV with 25 kA symmetrical short-circuit. It utilises elbow connectors and the bus is enclosed in a submersible, welded stainless steel tank. Electra has opted for all ways on the Vista to be installed with fault interrupters to ensure future flexibility and for the pad mounted SF6 option. This substantially reduces the 33kV bus from a full HV switchyard to a footprint more comparable with that of an 11kV ring main unit for each bus (see Figure 3).

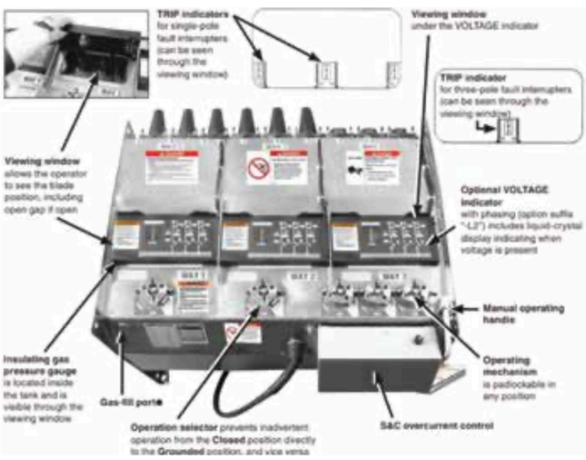
Vista Underground Distribution Switchgear versus typical metal-clad outdoor switchgear line up size comparison.



(Reproduced with permission of S&C: www.sandc.com/en/products--services/products/vista-and-vista-sd-underground-distribution-switchgear-utilities 15th November 2024)

From historic fault experience Electra has found that a fault within a 33kV bus contaminates the entire bus leaving the network vulnerable for up to 18 months. By adopting the Vista, Electra is moving towards a modular solution for our 33kV bus by using monolithic switchgear (see Figure 4) that can be removed and replaced within a week at most, significantly reducing the time our network is vulnerable.

Vista Underground Distribution Switchgear stainless steel tank and external enclosure.



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11.9.5 Developments to meet other drivers

Electra's environmental policy and requirements necessitate that all zone substations be bunded to capture transformer oil in the event of a leak and that the bunding be fitted with oil/water separators. Oil bunding has been installed around all power transformers in service for some time—however, a programme to install oil/water separation units is ongoing. Two of our zone substation bunds use a replaceable oil barrier arrangement. Oil separation units provide a more robust environmental long-term solution and we will replace oil barriers with oil separator units to ensure compliance with our environmental policy.

Table 44: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
3. Foxton substation, oil/water separation unit	Environmental	$120k FY26	• The project is required to meet environmental requirements. There were no viable alternatives.
4. Shannon substation, upgrade oil bunding for existing critical spare transformer	Environmental	$160k FY27	• The project is required to meet environmental requirements. There were no viable alternatives.
Total		**$280k**	• **FY26-27, Other reliability, safety, environmental capex**

11.9.6 Impact of distributed generation

Two large distributed generators are connected to the network—Mangahao hydro generation (37MW) and at a customer site in Paraparaumu (0.96MW x 2). We have been approached by several large solar and wind farm projects (over 1MW) for potential embedded connections. We encourage these start-ups, aiding them with planning, equipment requirements, load flow studies, congestion determination, and alternative solutions. The proximity of the proposed connections to our subtransmission and zone substation assets has been advantageous in keeping connection costs down and reducing congestion of embedded generation on the distribution network. We have also reviewed our connection and pricing policies and formalised the treatment of transmission rebates for large generators fairly and equitably.

11.9.7 Managing demand growth uncertainty

The subtransmission and zone substation development plan has been prepared based on meeting controlled demand growth. The development plan can be adjusted to accommodate uncontrolled demand growth, should this occur—which requires bringing forward developments from the FY35-FY50 period to this current planning period. Should uncontrolled demand occur, an additional $11.5m of capex will be required around FY33. This work is primarily on the southern subtransmission network. Further work would also be necessary for the FY23-FY50 period, but importantly, our current development plan can efficiently cater for high growth, should this occur. Conversely, we can defer development should demand growth fall below the controlled demand forecasts.

11.9.8 Consideration of non-network alternatives

As noted, this development plan was prepared based on controlled demand growth. It incorporates the use of flexibility to shift the charging of EVs, shift the heating of hot water cylinders, and utilise DERs to support peak demand. We have a programme (the ETR) to build capabilities to access the flexibility market.

We have considered the use of merchant flexibility (e.g., larger-scale network batteries or other forms of flexibility) to remediate the constraints identified. At this stage, there are no viable alternatives to the subtransmission solutions proposed for projects 1 to 4 due to the timing and nature of those constraints.

Projects 5 to 9 all relate to supply to new developments requiring servicing from the network; hence, there are no viable non-network alternatives.

11.9.9 How we are thinking about the energy trilemma balance

Proceeding with projects 1 to 4 will increase security and sustainability and have a minor impact on affordability. Although the impacts are minor, we have staged the work to the maximum extent possible to minimise the impacts.

Proceeding with projects 5 to 9 will not impact affordability over the long term, as their incremental cost (per connection) is below the average cost of supplying customers.

11.9.10 Summary of justification for the subtransmission development projects

The capacity-driven projects in this section are required to meet demand from new customers and support future demand growth from existing customers. This is an essential requirement for Electra.

The resilience and environmental-driven projects in this section are required to ensure that the network meets the relevant standards. Again, this is an essential requirement for Electra.

11.10 Development plan—Distribution

11.10.1 Overview

During the planning period (until the end of FY35), distribution developments are required to meet demand growth and support continuous reliability improvement through security of supply enhancements, automation, and protection. These programmes strongly link to our asset management strategies (noted in Section 11.2).

This is the most significant development area, costing $55.7m[82] over the planning period.

Over half of the development work is related to capacity augmentation to meet growth, which reflects the continuation of strong connections and inquiries, much of which is now moving into the Northern region as the O2NL expressway development progresses. The plan includes the development of 13 new distribution feeders.

The remaining work relates to security, reliability, automation, and protection enhancements. Much of this work is “catching up” on interconnections and switch installations, which was not undertaken when the original 11kV underground network was developed in the Southern region. The plan includes adding or automating over 250 switches on the underground network and 60 on the overhead network. This is a significant undertaking, and we expect to see improvements in unplanned and planned reliability due to these projects.

11.10.2 Developments to meet capacity and customer requirements

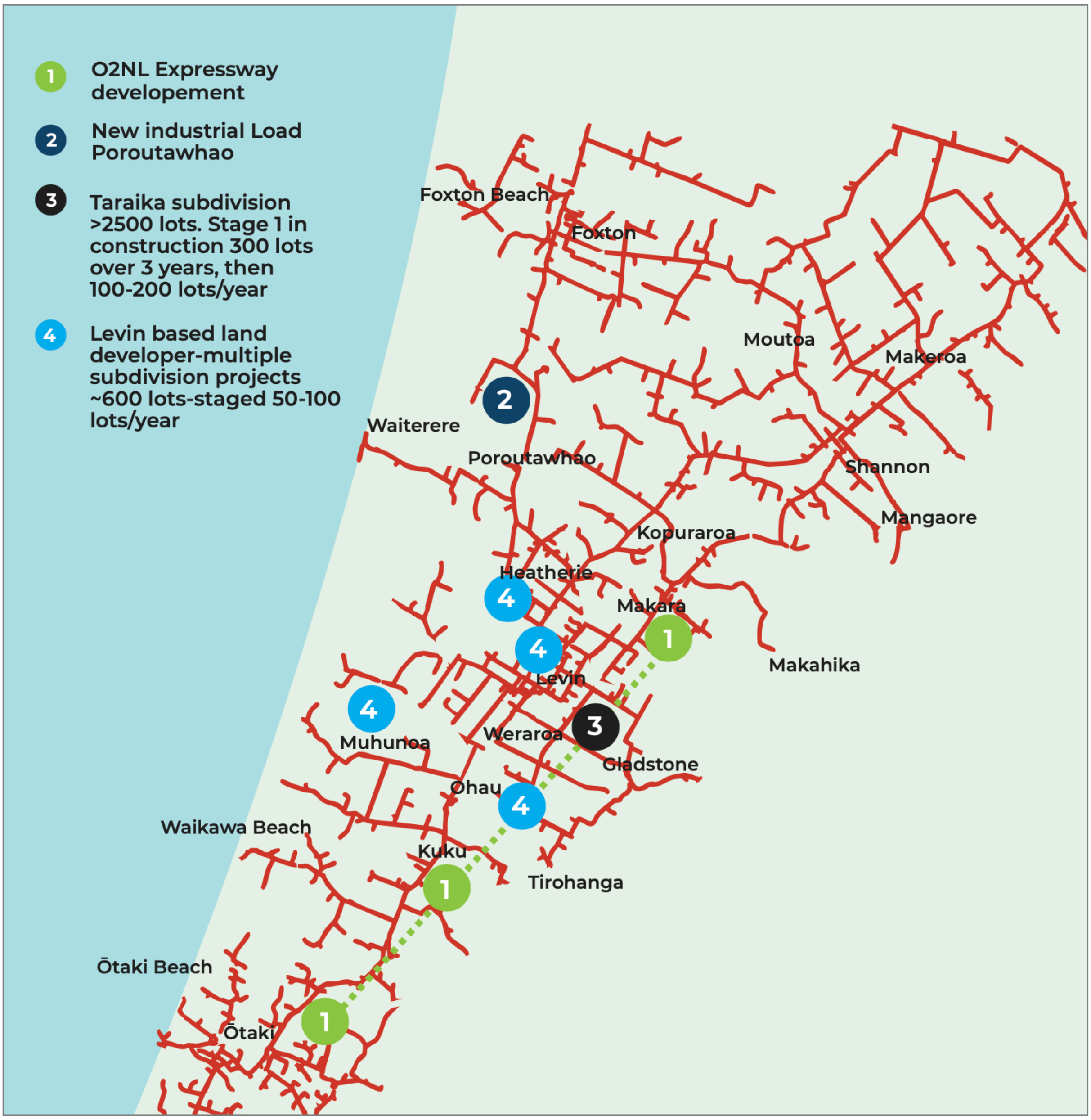
Distribution demand growth and forecast feeder constraints

Significant residential, commercial and industrial developments are occurring across the region. We are also seeing increased connection requests and early-stage inquiries for large developments. Figure 113 and

[82] Before deducting capital contributions. This includes System Growth, Quality of Supply, and Other Reliability, Safety and Environmental capex.

Figure 114 illustrates the areas of known growth. We are seeing very strong residential development in the Southern region. The increase in residential development has begun in Ōtaki and is now commencing in Manakau, Ōhau and Levin. The increase in residential developments in the Northern region aligns with the progression of the O2NL expressway development[83]. We are also seeing an increase in industrial development in the Northern region, which again is aligned with the O2NL development. This demand growth is consistent with the regional and zone substation demand forecasts in Section 11.7 and Section 11.9.2.

Figure 113: Areas forecast for significant development and load growth, Northern region



83 https://www.nzta.govt.nz/projects/wellington-northern-corridor/o2nl-proposed-new-expressway/

Figure 114: Areas forecast for significant development and load growth, Southern region

Table 45 summarises current and forecast feeder constraints given the known growth areas. We have identified various projects to resolve these constraints.

The demand forecast model indicates that constraints will occur on six feeders between FY26 and FY30 and seven between FY30 and FY35. More than 13 feeders are mentioned in Table 1 as they identify the areas impacted by growth, but not all these feeders will become constrained. Projects are linked to areas where specific constraints have been identified.

Our modelling indicates that the demand growth at Taraika, Manakau/Kuku/Ōhau, and Peka Peka/Waikanae North exceeds the firm 11kV network capacity in the area (that is, we do not have sufficient capacity in the network to meet our 11kV security requirements). The sub-transmission and substation development section includes projects catering to this growth (Section 11.9.3).

Table 45: Forecast feeders constraints

Zone substation	Feeder	Constraint	Solution
Levin West	E148	Capacity constraints could emerge due to large industrial load growth at Poroutawhao, South of Levin. Timing is customer dependent.	No specific project as a constraint not yet certain
Levin East	G309, G313	Capacity constraints are forecast due to the Taraika development. This is expected to add 2,500 residential and commercial connections and around 8-10 MVA over 10 years from FY26	Refer to Section 11.9.3
Levin East	G311	Capacity constraint is forecast due to the Tararua Industrial Development Zone. This could add around 4-5MVA over a 3-5 year period from FY27	Project 1
Levin East Ōtaki	G313, G308 L349	Capacity constraints are forecast due to the growth in Manakau, Kuku, and Ōhau. This includes around 600 residential sections in Manakau and Ōhau and the proposed Muhunoa East golf course	Refer to Section 11.9.3
Ōtaki	L351	Capacity constraints are forecast due to Ōtaki-Māori racecourse development. The development is expected to add 700+ residential connections and around 2 MVA	Project 3
Ōtaki	L350	Growth is strong in Ōtaki. Feeder L350 has significant customer connections and is forecast to reach planning limits in the next few years. L348 will also likely reach planning limits at the end of the planning period. Demand on both feeders is likely to reach planning limits by the end of the planning period	Project 4
Waikanae	622, 632	This is an area for significant future growth. Capacity constraints are forecast due to the following: • 600+ residential development in Peka Peka • 400+ development in Waikanae North • 400+ development at Manu Park These developments could add 5 MVA of demand.	Refer to Section 11.9.3
Waikanae	672, 682	There are current constraints in Waikanae North and Waikanae Beach areas and additional developments in the area will increase demand further (in particular, the supply to the 200-300 lot Harakeke development). Feeder 672 already exceeds firm capacity limits.	Project 5
Paraparaumu West	405	A section of lower capacity cable (70mm^2) between transformer W97 and W98 is limiting capacity. KCDC is adding a pumping station on the feeder that will increase demand above firm capacity.	Project 6
Paraparaumu East Waikanae	V311, V318 662	Capacity constraints are forecast towards the end of the planning period due to the 2,000+ lot residential development (Tini farm) at Otaihanga to North Paraparaumu. This could add 8-10 MVA	No specific project as constraints are beyond FY30. Refer Project 9.
Paraparaumu East Paraparaumu West	V311 403	Capacity constraints are forecast to emerge at the end of the planning period. They are driven by a 400+ lot residential development in the area	No specific project as constraints are beyond FY30. Refer Project 9.
Paraparaumu West	405	The 405 feeder supplies a large portion of Paraparaumu Beach. This feeder has a mix of residential and commercial customers, including medium-density apartments. It has 1990 ICPs (above the planning criteria), and demand is above firm capacity.	Project 7
Raumati	Z209	The demand on Z209 is above firm capacity, and customer numbers are above the customer number limits.	Project 8

New feeders, feeder augmentations and interconnections to meet capacity requirements

Table 46 describes the distribution developments required to meet capacity requirements. These projects address the constraints identified in the preceding section. These projects comprise six new feeders, one under-rated cable upgrade and ducting installation in anticipation of growth. Based on our demand forecasts, we expect additional feeders will be required over the six specified, and an allowance has been included for this future work. We will identify these additional feeder developments in subsequent AMPs.

Table 46: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
1. New Levin East Feeder G314 to supply Tararua Industrial Development Zone	Capacity	$1.1m FY27-28	• Existing Levin East feeders G309 and G313 will not have the capacity to cater for the forecast growth from the industrial development zone • G309 and G313 are rated at our standard feeder capacity and cannot be practically upgraded to the extent required. There are no viable alternatives to supply the industrial development zone
2. O2NL 11kV ducting for future use • Installation of spare ducting in anticipation of future capacity south of Levin East substation	Capacity	$304k FY26-27	• Ducting installation during site construction is around 50% cheaper than installation when the expressway is completed • Significant demand growth is forecast to the south of Levin (Ōhau, Kuku. Manakau), and this project makes a low-cost provision for future growth
3. Additional feeder to offload Ōtaki L351 feeder to enable the supply to the Ōtaki racecourse development	Capacity	$2.1m FY30-31	• L351 will be used to supply the Ōtaki-Māori racecourse development, which will increase demand above its firm capacity. L351 is rated at our standard feeder capacity and cannot be practically upgraded to the extent required • There are no viable alternatives to supply the Ōtaki racecourse development; hence, demand needs to be transferred to make way for supply to the racecourse • The Ōtaki-Māori project is consented; hence, options to delay the new feeder construction are unlikely to be viable.
4. Additional feeder to offload Ōtaki feeders L348 and L350 (some of the route will be shared with Project 3 to reduce costs)	Capacity	$1.0m FY31-32	• Demand forecasts indicate constraints occurring on both L348 and L350. Given the high growth forecasts in the region (to 2050), a new feeder is required to maintain L348 and L350 within firm capacity and customer connection limits. • The project is forecast beyond the next five years; there may be an opportunity to delay this feeder construction by 1-2 years if growth is slower than anticipated.
5. New 11kV Waikanae Beach feeder to supply the Harakeke Heights development and to balance load on adjacent feeders	Capacity	$5.5m FY28-29	• Feeder 672 is already above firm capacity, and an additional feeder is required to enable the supply to the Harakeke Heights development • Options to rebalance demand across adjacent feeders are not available, and options to delay the construction of the new feeder further are not possible • <u>Note:</u> A customer contribution is being proposed for this project, which will materially reduce the cost to Electra.
6. Cable replacement between W97 & W98 on Paraparaumu West feeder 405	Capacity	$355k FY28	• There is an increase in load due to a new pump station. There are no viable alternatives to upgrading the cable to ensure firm capacity is maintained.
7. New 11kV 401 feeder to supply central Paraparaumu to offload feeder 405, which has demand above current capacity	Capacity	$2.1m FY26	• Due to the strong growth across the region, there are no options to transfer load to other feeders • Feeder 405 is currently above firm capacity and customer number limits; hence, there are no options to defer the project.
8. New 11kV feeder to offload Raumati feeder Z210. Z210 will then be used to offload feeder Z209	Capacity	$850k FY27	• We have modelled a range of solutions, and the least cost option was to transfer the load from Z210 to a new feeder and then transfer the load from Z209 to Z210. Building a new feeder to directly support Z209 was more expensive.

Project	Driver	Cost/Year	Justification and options considered
9. Augmentation of an additional seven feeders, FY30-FY35	Capacity	$17.0m FY30-35	• Our demand forecast indicated constraints will occur on 13 feeders over the planning period. Specific projects exist for six feeders (above). We have included an estimate for augmenting a further seven feeders over FY30-35. The cost is based on the average feeder cost in this table.
Total		**$30.4m**	• **FY26-35, System growth capex**

Note: The total is $26m after deducting the forecast capital contributions associated with the relevant customer-initiated projects.

11.10.3 Developments to meet security requirements

Distribution feeder security and reliability constraints

We have been analysing the network to determine areas where it does not meet our security and reliability standards (i.e. where a constraint exists). The areas where we currently (or are forecast to) breach our planning criteria are shown in Table 47. These mainly relate to:

- Breaches of the maximum transformer capacity (of 0.5 MVA) between switching points or on feeder spurs;
- Feeders with poor reliability that can be improved through interconnections to adjacent feeders.

By way of background, in the early stages of the residential developments in the Southern region, 11kV switches and interconnections were only installed in key locations. At the time, demand for the feeders was low, so the absence of switches and interconnection points was not a material breach of the planning standards. As demand and customer numbers have grown, the load between switching points has increased, and a program of interconnections and switch installations is now required.

Table 47: Forecast feeder constraints

Zone substation	Feeder	Constraint	Solution
Levin East	G308 G313	Feeder G308 supplies the Hokio area and ranks in the top 10 worst-performing feeders. Feeder G313 supplies the adjacent Kimberly areas and ranks just outside the top 10 worst-performing.	Project 10
Ōtaki	L349	Feeder L349 supplies the Manakau area and ranks as the worst performing feeder. There is a single supply into Manakau village with >0.5 MVA of transformers	Project 11
Ōtaki	L348 L351	L351 is the 9th and L348 is the 7th ranked worst performing feeder. The Mill Rd area includes OH & UG network that are below security requirements (>0.5 MVA of transformer capacity on a spur line)	Project 12
Ōtaki	L350	Feeder L350 is the 3rd worst performing feeder. Te Rauparaha St includes network that are below security requirements (>0.5 MVA of transformer between switching points and spur line)	Project 13
Paraparaumu East	V317	There is a residential spur (Milne Rd) on the feeder that is below security requirements (>0.5 MVA of transformer capacity on a spur line)	Project 14
Paraparaumu West	404	There are two residential spurs (Regent Drive) on the feeder that are below security requirements (>0.5 MVA of transformer capacity on a spur line)	Project 15
Raumati	Z211	The area around QE Park (Jeep Rd) includes OH and UG network that is below security requirements (>0.5 MVA of transformer and 340+ customers on spur line)	Project 16
Paekākāriki Paraparaumu East	Z167 V313	The Waterfall Rd to Valley Rd area includes OH & UG network that falls below security requirements (with 472 customers and 3.6MVA of transformer capacity, well above the 0.5 MVA limit).	Project 17

Zone substation	Feeder	Constraint	Solution
Levin West	E150	Security of supply to Waitārere Beach is below network requirements. This spur has >1.5MVA of demand and 1074 ICPs, which is well in excess of the security limit	Project 19

Interconnections to meet the security of supply requirements

The projects in Table 48 resolve the constraints mentioned in Table 47. Projects 10-12 will improve reliability on several feeders in the Levin and Ōtaki areas that are currently performing poorly. Projects 13-22 will enhance the security of supply of the distribution network, which is necessary to operate the network reliability, over the long term.

Table 48: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
10. Levin East: install an interconnection between feeders G308 and E153 to improve reliability	Reliability	$435k FY26-27	• An interconnection between these feeders will enhance security and provide additional backfeeding options to assist in fault restoration. The gap between the feeders is ~200m • G308 and E153 are poor performing feeders and improvement is required. This project offers a low-cost security improvement. There are no alternative projects that can improve security (and reliability) at lower cost.
11. Ōtaki feeder L349: improve security into Manakau Village 11kV	Reliability	$610k FY28	• Improve the security to Manakau village by creating an OH ring (L470-L332) on feeder L349. The NZTA expressway will require some reconfiguration at the south-east of the village and enable interconnection via underground cable to Manakau Heights Drive (which reduces the overall cost of this project) • L339 is a poor performing feeder and improving security is necessary to enhance reliability. There are no other viable options available to improve security to the 120 customers in the village.
12. Ōtaki: installation of additional circuits to connect feeders L351 and L348	Security	$341k FY32	• The project requires two connections between Anzac Road to Carkeek Drive and Haruātai Park to Millhaven Place • Both L351 and L348 are poor performing feeders and improvement is required. This project offers a low-cost security improvement. There are no alternative projects that can improve security (and reliability) at lower cost.
13. Ōtaki, feeder L350: installation of switchgear and an interconnection to feeder L348	Security	$482k FY33	• This project involves installation of switchgear at M139, M143, M194, M149 and to reconfigure the open points to feeder L348 to improve security • L350 is a poor performing feeder and improving security is necessary to enhance reliability. There are no other options available to improve security.
14. New interconnection between Raumati feeder Z209 and Paraparaumu West feeder V317 to improve security on Milne Rd spur and increase interconnection between Raumati and Paraparaumu	Security	$610k FY26[84]	• The project involves cable connection and switchgear between transformers W468 and Z50. • The proposed interconnection is the least cost option to resolve security issues on feeder V317.
15. Paraparaumu West feeder 404 interconnection – improve security of supply.	Security	$355k FY26	• This project involves installation of 200m cable and switchgear between transformer W494 and W502 to enhance security (and remove the two spurs).

[84] Project is underway. Total project cost is $1.1m.

Project	Driver	Cost/Year	Justification and options considered
			• The proposed interconnection is the least cost option to resolve security issues on feeder 404.
16. QE park interconnect project: Jeep Rd to transformer Z9, Raumati South 11kV underground ring	Security	$556k FY27	• Project to interconnect Raumati South feeder Z211. GWRC have request us to move our lines in the park so the timing of this project will depend/align with negotiations and requirements of GWRC • The proposed interconnection is the least cost option to resolve security issue to >340 customers.
17. Interconnection between feeder Z167 and V313 to connect spurs between Waterfall Rd to Valley Rd	Security	$354k FY27	• There are 3 sections of 11kV line required to interconnect feeder Z167 (Paekākāriki) and V313 (Raumati South) to resolve security issues • The proposed interconnection is the least cost option to resolve security issue to >470 customers
18. Unspecified interconnections to support the security of supply	Security	$1.2m FY29-35	• Funding for a continuation of the programme to improve interconnections between feeders to meet security of supply requirements in future years.
Total		**$5.0m**	• **FY26-35, Quality of supply capex**

The constraint concerning Waitārere Beach is a complex issue that needs to be resolved. We are currently considering four options:

- A connection to the existing Foxton C1 feeder to provide an alternative supply;
- Increasing the resilience of the existing line, which has sections built close to the road carriageway;
- Installing diesel generation;
- Non-network solutions.

A new feeder connection is the higher cost option, has some property rights issues to resolve, but fully resolves the security issues. The resilience option has a lower cost and will materially reduce vehicle damage risk however it does not resolve the security issues. The diesel generator can meet the security requirements but has a range of operating costs, noise and potential consenting issues. Non-network solutions are yet to be fully assessed. We expect to select a solution for the 2026 AMP.

Table 49: Projects under consideration (these projects are not currently in the expenditure forecasts)

Project	Driver	Cost/Year	Justification and options considered
19. Construction of an 11kV link to Waitārere Beach from Foxton C1 feeder and new cable from Waitārere Rise Avenue to Truebridge Drive	Security	$2.5m FY33	• The project involves an extension to Foxton C1 ($1.0m) and a new cable ($1.5m) • Alternative 1: is to improve the resilience of the existing line by installing a cable circuit to bypass a section of the line along Waitārere Rise Avenue to Park Avenue. The current circuit is built on the roadside and is exposed to vehicle damage (and there has been a significant outage on this circuit) • Alternative 2: is to install generators • Alternative 3: is to assess non-network solutions
Total		**$2.5m**	**FY33, Quality of supply capex (not yet in forecasts)**

New ground-mounted switches to meet the security of supply requirements

Currently, the distribution network has one of the lowest ground-mounted switch densities in New Zealand (refer to Section 0). The current situation reflects how the original network was rolled out in the Southern region. Consequently, the network does not meet our security of supply standard (having no more than 0.5 MVA of distribution transformer capacity between switching points) in many areas. While faults on the underground network are rare, when they do occur, having sufficient switching points allows for quicker network restoration and avoids lengthy repair-time outages. As the network ages (refer to Section 5.4), the risk of cable faults increases. Hence, it is now timely to undertake a switching point installation programme on the underground network. Table 50 outlines the two programmes that address the issue.

The installation of switches will also significantly benefit our planned work programme and mitigate the expected increase in planned outages to undertake inspection, maintenance and renewal work on the underground network as our underground fleet ages.

Table 50: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
20. RMU installation to split daisy-chain transformers between switching points	Security	$2.8m FY26-35	• This programme splits the daisy-chained transformers between switching points. Priority is given to older network areas with three or more transformers between switching points • 36 priority switches have been identified for the first six years. After that, two switches will be installed per year • The current network configuration breaches the planning criteria. • There are no alternatives to switch installation to improve security
21. RMU installation during GM transformer renewals	Security	$8.4m FY26-35	• This programme is used to install RMU when ground-mounted transformers are renewed. The programme equates to 13 new RMUs each year • The current network configuration breaches the planning criteria. • There are no alternatives to switch installation to improve security
Total		**$11.2m**	• **FY26-35, Quality of supply capex**

11.10.4 Developments to improve reliability

As mentioned in the introduction (Section 11.1), we have a strategy to continuously improve the reliability of the distribution network. In this section, we outline our programmes to:

- Increase the automation of rural feeders;
- Increase the automation on urban feeders;
- Improve lightning protection on the overhead network.

Network automation and sectionalisation enhancements

As feeder customer density increases, the number of customers at risk of interruption from any single fault increases. To mitigate this risk, we plan to:

- Reduce the number of customers exposed to any single fault (by increasing the use of feeder sectionalisation)
- Increase interconnection points between feeders to enable greater restoration by switching (and few customers on the faulted section of line).

Projects 22 and 23 relate to the automation of overhead feeders, focusing initially on the worst-performing feeders mentioned in Section 4.5.9 and also on feeders that exceed our planning criteria (either >1,500 domestic customers or 5 MVA of commercial load). This is a continuation of a longstanding programme to automate the network.

Our initial focus is on the worst-performing feeders, as the SAIDI contribution from the top 10 feeders[85] is 23 minutes, 70% of which occurred on rural overhead feeders. Half of the top 10 worst-performing feeders (by SAIDI) are supplied from the Ōtaki zone substation, and others are spread across the Northern zone substations. Our approach is to identify suitable locations for installing additional switches that will both reduce the customers at risk and allow for greater interconnection with another feeder; thus providing a dual benefit of reducing the number of customers affected by a fault and reducing restoration times.

These projects will improve reliability by reducing restoration times and the number of customers impacted by an unplanned outage. They will also improve efficiency by avoiding labour and travel time to switch the network. The projects aim to improve unplanned reliability by 0.75 SAIDI annually (7.5 SAIDI by the end of FY35). To achieve this, we target around a 10% improvement in feeder restoration time, where 4-5 automation points are added[86].

Projects 24 and 25 relate to the automation of the underground network. The programme to automate the urban underground network has been progressing for several years. These projects will improve reliability by reducing restoration times and the number of customers impacted by planned and unplanned outages. They will also improve efficiency by avoiding labour and travel time to switch the network. In combination with the security and switch installations, we are targeting 25 SAIDI improvement in planned and unplanned outages.[87] The projects are being targeted in areas that will provide the most significant benefit in reducing outage times. Installing automated switches on new sites will progress over six years (28 sites), and the automation of existing sites over 20 years (65 sites). We have a longer timeframe for existing sites as we have yet to work through the economic benefits for all sites.

Table 51: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
22. Overhead network switch automation (existing sites)	Reliability	$1.6m FY26-35	• This programme consists of two new enclosed and automated switches to replace existing air-break switches per year. The sites selected are principally based on the worst-performing feeder but also consider the expected number of operations and travel times
23. Overhead network automation (new sites)	Reliability	$3.1m FY26-34	• This programme consists of four new enclosed and automated switches in new locations per year. The sites selected are principally based on the worst-performing feeder but also consider the expected number of operations and travel times
Total		**$4.7m**	**FY26-35, Quality of supply capex**

Table 52: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
24. Underground network ground-mounted switch automation (existing sites)	Reliability	$1.9m FY26-35	• 65 existing sites have been identified where automation can materially reduce outage times and reduce operating costs • This programme consists of the automation of three existing sites annually
25. Underground network automation (new sites)	Reliability	$1.8m FY26-31	• 28 new sites have been identified where automation can materially reduce outage times and reduce operating costs

85 Average of the past three years.

86 The reduction in restoration time will be proportional to the level of automation applied to the feeder. We expect a 10% reduction in restoration time by adding 4-5 automated switching points on a feeder. We expect a 30% reduction in restoration time by adding 12-15 automated switching points on a feeder.

87 This is 5 SAIDI (unplanned) and 20 SAIDI (planned) at the end of the 10-year programme.

Project	Driver	Cost/Year	Justification and options considered
			• This programme involves installing new automated RMU at five sites annually between FY26 and FY30 and three sites in FY31.
Total		**$3.7m**	**FY26-35, Quality of supply capex**

Network protection enhancements

Electra's network is exposed to lightning, averaging greater than 5 SAIDI minutes over the past five years. We had a significant lightning event in FY23 and incurred 20 SAIDI minutes due to lightning that year. The damage to overhead transformers in FY23 was also substantial, significantly impacting customer restoration times. The lightning arrestor installation programme (in Table 53) is expected to deliver a 0.5 SAIDI minute improvement in unplanned outages and deliver cost savings in the form of avoidance of replacing lightning damaged transformers.

Table 53: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
26. Installation of lightning arresters on existing PM transformers	Reliability	$1.4m FY26-29	• To mitigate the impact of lightning events. The programme is being targeted in areas with known lightning risk.
Total		**$1.4m**	• **FY26-29, Quality of supply capex**

11.10.5 Developments to meet resilience requirements

Work on our resilience strategy has only recently been completed. We have not defined any resilience-related projects on the distribution network in this AMP. Further work is being undertaken over the next year, including additional analysis of vehicle damage incidents and high-traffic areas to assess options to reduce vehicle damage risks. We are expecting an increase in resilience-related projects in future AMPs.

11.10.6 Justification for the development projects

Capacity projects

The capacity development projects[88] amount to $30.4m. This is a significant programme due to the extent of the demand growth we are seeing on the network. The capacity-driven projects are required to meet demand from new customers and support future demand growth from existing customers. This is an essential requirement for Electra, for which no feasible alternatives exist.

Rural overhead security, reliability and automation projects

The total overhead network security and reliability development projects cost $6.4m.[89] Based on our economic analysis, the automation projects provide a net benefit to customers due to the reduction in the economic cost of unplanned outages[90]. That is, the economic benefit from the reduction in unplanned SAIDI that the projects provide is greater than the cost to customers (due to higher prices associated with the project costs)[91].

The security improvement projects in Ōtaki and Levin are intended to deliver a 1.5 SAIDI minutes improvement in unplanned outages. For these projects, the reduction in the economic cost of outages is greater than the cost to customers (due to higher prices associated with the project costs).

88 Projects 1 to 9.

89 Projects 10-12, 22, 23 and 26.

90 There is also a small reduction in operation costs, which will have a small impact on lines changes over time.

91 The annualised reduction in the economic cost of outages (based on Electra's VOLL of $40,000 per SAIDI minute) less the annualised cost of operating the assets is $11k p.a. Providing a net benefit to customers.

The lightning arrestor programme is minor and intended to reduce outages and equipment damage. We expect the programme to deliver a 0.5 SAIDI minute benefit at the end of the planning period. This economic cost of the reliability improvement (and the savings in the economic cost of outages) is greater than the impact of the project on future prices.

These benefits are consistent with the forecast improvement in reliability shown in Section 7.3.

Urban underground security, switching and automation projects

The total cost of the underground network security, switching, and automation development projects will be $19m over the planning period.[92] These projects provide the foundation for the reliable operation of the underground urban network. By the end of the planning period, we expect the projects to deliver around a 10 SAIDI minutes improvement in unplanned outages and a 15 SAIDI minutes improvement in planned outages. The economic benefit of a 25 SAIDI minutes reduction in planned and unplanned outages will be greater than the increase in line charges resulting from the $19m investment.[93] There will also be a modest reduction in operation costs as switching times will be reduced.

Most of the benefit arises through a reduction in planned outages where isolation areas can be materially reduced due to greater network segregation. This will offset the expected increase in planned outages as maintenance and renewal work increases as the assets age.

Presently, the performance of the underground network is good (around 7 SAIDI minutes for defective equipment and third-party damage). However, we expect this to deteriorate as mentioned in Section 5.5. We also expect unplanned outages to increase on the underground network as the asset ages and planned renewal work increases. The improvements in security and switching will offset these increases. However, this does not provide a complete view of the benefits—outages on the underground network are infrequent; however, they can have significant repair times—hence, a key benefit of these programmes is minimising the impact through enabling timely fault isolation and restoration of supply. Avoiding these high-consequence events is a significant benefit.

These benefits are consistent with the forecast improvement in reliability shown in Section 7.3.

11.10.7 Managing demand growth uncertainty

The distribution development plan has been prepared based on meeting controlled demand growth. Distribution developments have a relatively short planning horizon and are generally easier to plan and execute. Hence, the need to accommodate uncontrolled demand growth is not required. Should the uncontrolled demand occur, additional capacity-related distribution development projects will be required.

11.10.8 Consideration of non-network alternatives

As noted, this development plan was prepared based on controlled demand growth. It incorporates the use of flexibility to shift the charging of EVs, shift the heating of hot water cylinders, and utilise DERs to support peak demand. Given the pressing requirement to meet new demand and improve security, we are not proposing using merchant flexibility as a non-network alternatives for the projects proposed for FY26 and

92 Projects 13-18, 20, 21, 24 and 25.

93 Based on Electra's VOLL of $40,000 per SAIDI minute.

FY27 as the market is not yet sufficiently mature, and our ability to call on this flexibility is not sufficiently mature. However, using merchant flexibility will be explored for projects beyond FY27 in subsequent AMPs.

11.10.9 How we are thinking about the energy trilemma balance

Overall, we are not expecting the distribution development projects to impact affordability. The capacity-related project will generally enhance affordability as the incremental cost to service the new customer demand is lower than the current average cost to service existing customers. The improvement will be offset by the security and reliability-related projects; however, security will be enhanced.

11.11 Distribution transformer and LV developments

11.11.1 Overview

This section describes the distribution transformer and LV development plan. The development plan is consistent with prior years and includes programmes to:

- Upgrade distribution transformers capacity due to growth;
- Install links, interconnections and extensions on the LV cable to resolve capacity, voltage and security issues;
- Install LV monitoring at our distribution transformers to better understand current quality and the impact that the energy transformation is having on the LV network.

11.11.2 Distribution transformer developments to meet capacity and customer requirements

We have an ongoing programme to upgrade distribution transformer capacity in response to localised growth. We monitor the demand on our ground-mounted distribution transformers using the MDIs installed in the LV cabinet or our online power quality monitors (see 11.11.4). Where we identify that demand is reaching the name-plate capacity, we will schedule an upgrade of the transformer.

The programme is based on the historical upgrade rate. In 2021, we undertook some initial studies on the performance of distribution transformers in response to the energy transformation (for both controlled and uncontrolled demand growth). For either scenario, we are unlikely to see any wholesale need to upgrade our distribution transformer fleet because the transformers are sized based on an ADMD of 3.5 kVA (well above our current ADMD). Hence, future upgrades will continue to be in response to localised issues.

Table 54: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
Ground-mounted transformer upgrades due to growth	Capacity	$1.6m FY26-35	• This programme allows the upgrade of three ground-mounted distribution transformers annually.
Total		**$1.6m**	• **FY26-35, System growth capex**

11.11.3 LV developments to meet capacity, security and voltage requirements

We have ongoing programmes to install new LV links and extend or modify the low-voltage cable network. We have identified a programme to add LV links to enable load transfers to meet voltage, capacity or fault restoration needs. We also have a reactive programme to extend or modify the LV cable network in response to voltage or capacity issues or where security could be enhanced through interconnections to other LV circuits.

These programmes are based on historical upgrades; however, we may see the number of LV cable extensions or modifications increase towards the back end of the planning period. In 2021, we undertook some initial studies on the performance of the LV network in response to the energy transformation (for both controlled and uncontrolled demand growth). If uncontrolled demand growth is observed, we could see constraints on 30-40% of our LV circuits at the end of the planning period. If controlled demand growth occurs (which is our current planning case), these constraints will likely emerge from around FY39, beyond the end of the current planning period.

Table 55: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
Installation of LV links to connect LV cable circuits	Security Voltage Capacity	$1.2m FY26-35	• This is a planned programme to add LV links to better load transfers to meet voltage, capacity or fault restoration needs
Extensions or modifications of the LV cable network	Voltage Capacity Security	$1.2m FY26-35	• This is a reactive programme to extend or modify the LV cable network to address voltage, capacity or reliability needs
Total		**$2.4m**	• **FY26-35, Quality of supply capex**

11.11.4 Developments to meet future network needs

As discussed in Section 10, understanding demand and power quality on the LV network is increasingly important. We have an ongoing programme to install power quality meters on 20% of our distribution transformer fleet. The data from the meters will provide a baseline of existing power quality, validate our ADMD assumptions and allow us to assess the impact of demand drivers on the LV networks (e.g. DERs and EVs). The ADMS can also use the data to inform LV outages. We will evaluate the outcome of the data over the coming years, which will inform whether we continue the rollout.

Table 56: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
Installation of online power quality monitors on the LV network	Future	$1.1m FY26-29	• This programme targets to have power quality meters on 20% of our distribution transformer fleet by the end of FY29.
Total		**$1.1m**	• **FY26-29, Quality of supply capex**

11.11.5 Justification for the development projects

Most of the distribution and LV capex are driven by capacity or voltage constraints. Electra must provide suitable network capacity and maintain voltage within regulatory limits.

The online LV monitoring programme is being pursued as an alternative to using smart meter data. Our current assessment (discussed in Section [10]) is that LV monitoring will provide more appropriate information than purchasing smart meter data.

11.11.6 Managing demand growth uncertainty

The distribution transformer and LV development plan have been prepared to meet controlled demand growth. Distribution transformer and LV developments have a short planning horizon and are generally easier to plan and execute. Hence, the need to accommodate uncontrolled demand growth is not required. Should the uncontrolled demand occur, additional capacity-related distribution development projects will be required.

11.11.7 Consideration of non-network alternatives

As noted, this development plan was prepared based on controlled demand growth. It incorporates the use of flexibility to shift the charging of EVs, shift the heating of hot water cylinders, and utilise DERs to support peak demand. We have a programme (the ETR) to build capabilities to access the flexibility market.

At this stage, we have not considered merchant flexibility (e.g., larger-scale network batteries or other forms of flexibility) to offset the augmentation of distribution transformers or LV capacity. However, this will be explored further in subsequent AMPs.

11.11.8 How we are thinking about the energy trilemma balance

Refer to Section 7.8.

11.12 Other network assets

11.12.1 Overview

Other network assets include protection, communication, ripple control plants and SCADA. This section deals with the first three. SCADA is covered in operational technology in Sections 8 and 9.

11.12.2 Recent technical review of protection

In 2021, we undertook a comprehensive study of our subtransmission protection system. The study followed several spurious protection trippings caused by mutual coupling. Mutual coupling occurs when two or more power lines are close together and can affect the power system's reliability and safety. The issues exist where we have 33kV and 11kV circuits on the same poles, which often occurs around zone substations. The report indicated that the potential risks to the network are high, including the possibility of widespread network loss of supply. While many risks have a lower probability of occurring, in some cases, the outcomes should such risks occur can be severe. For example, a network fault that isn’t cleared has obvious safety risks due to a permanently energised primary equipment fault but may also result in severe and widespread equipment damage, such as damage to long lengths of overhead lines.

The report also noted that the existing 33 kV line protection schemes have become increasingly unfit for purpose as Electra has interconnected the network. In addition to having significant known protection performance limitations, the existing schemes limit the network's operational capabilities. Upgrading the protection system is considered a high priority.

The report proposed a roadmap to improve the primary and backup protection schemes for various asset classes based on cost, risk and performance. Electra agreed with the recommendation and is proceeding with the roadmap.

11.12.3 Developments to improve reliability

Table 57 shows the project associated with the protection roadmap (projects 1 to 6). The upgrading of the relays themselves is covered in the *balance of plant* fleet plan as the relays assets are also at end-of-life. The protection roadmap involves:

- Line protection replacement on all Electra 33 kV lines;
- Upgrading of communication links between substations to allow line differential functions and associated advanced protection strategies to be implemented;

- Adding 33 kV busbar protection.

The communication link upgrades increase the resilience of our SCADA communication network as these new routes provide an alternative path for SCADA communication.

CASE STUDY ON TRIP SAVERS

The protection programme also includes the installation of Tripsavers on spur lines with repetitive nuisance faults. Three units have been installed at sites that had issues with nuisance faults in 2022. The three sites averaged 16 outages a year together; since the installation of Tripsavers, the number of faults has dropped to three in FY23.

Tripsaver in closed and open position

The majority of overhead faults are transient from either storms, vegetation or wildlife. Older protection schemes used traditional fuses with the resulting time to restoration for crews attending site and replacing the fuse. Tripsavers have the operational characteristic of a fuse but reclose up to 3 times before dropping open. Using this we can restore remote spurs faster reducing outage times for customers.

Table 57: Proposed projects

Project	Driver	Cost/Year	Justification and options considered
1. Fibre installation between Waikanae ZS to Paraparaumu East	Reliability	$680k FY26-27	• See Section 11.10.6
2. Fibre installation between Waikanae and Waikanae North	Reliability	$914k FY27-28	• See Section 11.10.6
3. Fibre installation between Waikanae North and Ōtaki	Reliability	$643k FY28-29	• See Section 11.10.6
4. Fibre installation between Ōtaki and Levin East	Reliability	$2.1m FY29-32	• See Section 11.10.6
5. Levin West substation protection upgrade	Reliability	$1.1m FY29-30	• See Section 11.10.6
6. Levin East substation bus-zone and circuit breaker failure protection	Reliability	$716k FY28-29	• See Section 11.10.6

Project	Driver	Cost/Year	Justification and options considered
7. Bus zone projection optimisation at Paraparaumu East and Raumati	Reliability	$35k FY26	• See Section 11.10.6
8. Install trip-saver on the worst-performing feeders	Reliability	$1.8m FY26-35	• This project is part of our integrated approach to addressing the performance of our worst-performing feeders
Total		**$8.0m**	• **FY26-35, Quality of supply capex**

11.12.4 Developments to meet growth requirements

The existing ripple injection plants cannot cover the entire network should there be a plant failure. Installing a third in the centre of the existing network will allow for continued ripple control during faults. Being able to control demand is necessary as this is the basis for our demand forecasts used throughout this development. However, alternatives to traditional ripple control are evolving in the market. Market flexibility solutions will likely become available to supersede traditional load control. For this reason, we have not yet committed to this project. It will remain in the concept phase until we can be more confident that the plants will not be stranded by other technology or that other technology will become viable.

Table 58: Projects under consideration

Project	Driver	Cost/Year	Justification and options considered
Additional ripple control plant	Security	$550k FY29	• Alternatives to traditional ripple control are evolving in the market. Market flexibility solutions will likely become available that will mitigate the need for an additional ripple plant
Total		**$0.55m**	• **FY29, System growth (not yet in forecasts)**

11.12.5 Justification for the protection projects

The 33kV protection programme is being undertaken to mitigate High Impact Low Probability (**HILP**) events associated with a material protection failure. A failure of the 33kV protection system could have material safety and reliability consequences that must be mitigated. Due to the low probability of these failures, we have not evaluated the programme from an economic standpoint (as the economic cost of low-probability events is low when considered on an annualised basis). The annualised cost of the programme is $370k, which is low compared to the economic cost of a significant subtransmission outage, which could quickly run into the millions.

The trip-saver programme is expected to save 2.5 SAIDI annually by the end of the planning period. The economic benefit of saving in outages[94] is greater than the increase in line changes (resulting from the project capex).

11.12.6 How we are thinking about the energy trilemma balance

Refer to Section 7.8.

[94] Based on Electra's VOLL of $40,000 per SAIDI minute.

11.13 Customer connections

11.13.1 New connections forecasts

We connect around 400 new residential, commercial, and industrial electricity customers annually to our network. We are forecasting the number of new connections will increase over the coming decade, which aligns with the Council's population growth predictions (see Figure 115 below and Figure 66 and Figure 69 in Section 5.2).

We are also expecting to see an increase in the connection of DERs (Figure 116), where an increasing number of these will contain batteries and hence be able to offer flexibility services. The proportion of DERs with batteries is expected to grow from 25% (in FY24) to nearly 60% in FY35. Many of these DERs are being connected to existing customers.

Figure 115: Forecast new connections

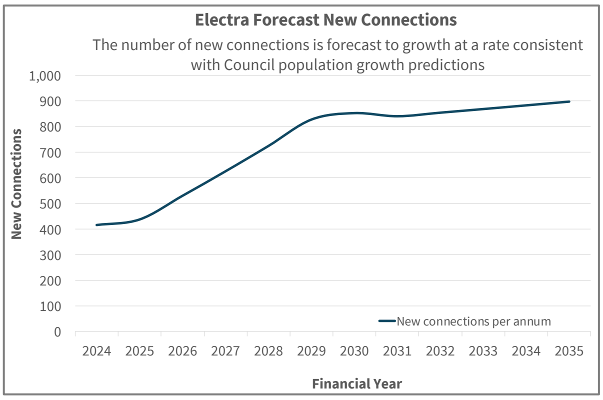
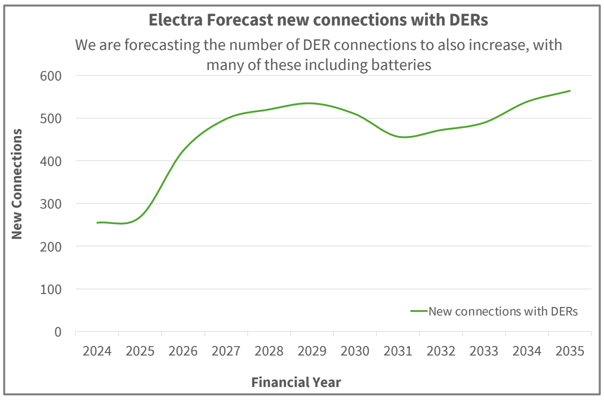


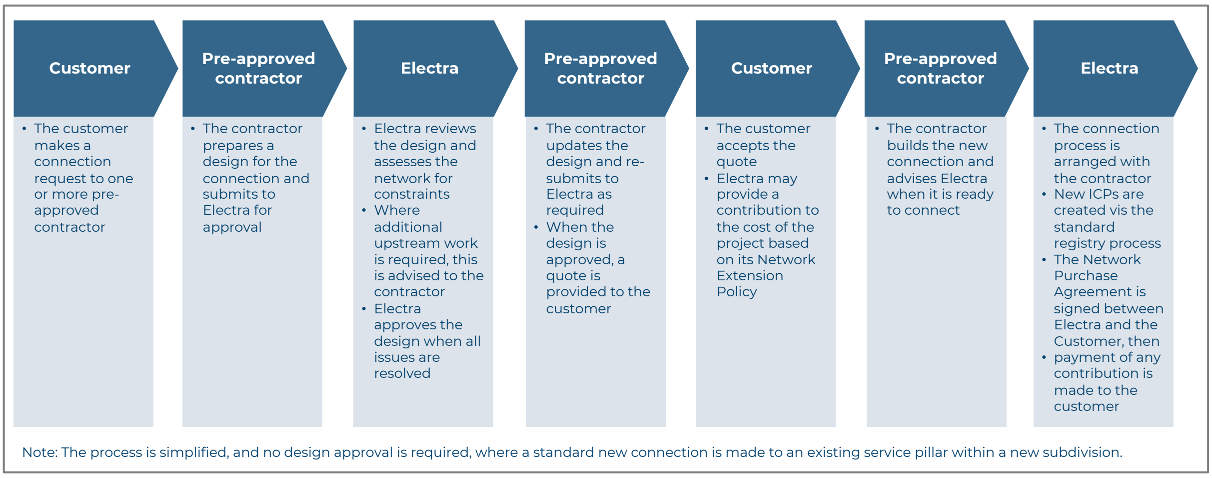
Figure 116: Forecast new connections with DERs



11.13.2 Connection process

Electra's connection process is shown in Figure 117 and is contained on our website.[95] The connection process is arranged between the customer and various approved contractors and applies to new connections, alternations and distributed generation.[96]

Figure 117: Electra's new connection process



[95] https://electra.co.nz/getting-connected/

[96] Electra has three primary approved contractors (Electra service delivery, Conectics, Scanpower) for large-scale connection work. There are another two approved contractor who undertake small standard connections to existing LV assets (where no changes to the network are required.

For residential and commercial customers, the connection is arranged via an approved contractor, and any associated connection costs are payable by the customer (hence, we have no forecast customer connection capex).

For connection of new subdivision developments, network upgrades to connect large customers, or line extensions required to connect rural properties, these are undertaken by an approved contractor. The customer pays the entire cost of the developments, upgrades, and extensions, and then Electra acquires the network asset portion. The payments made to customers are known as vested assets. We have an internal contribution model that is used to determine the payments made to customers for new connection assets. This calculates the net present value of the new connection (of the new revenue and new costs, including the return on, and of capital). We have determined standard payments for subdivisions based on the number of new lots being developed.

Electra's payments to customers are recognised as vested assets. We anticipate that they will increase in line with the growth in new connections. This process is outlined in the Electra Network Extension Policy.[97]

During the design approval process, we evaluate the network for constraints and inform the contractor of any additional upstream work needed. The contractor will then update the customer about the constraints and required upstream work. Depending on the scale of the new connection, we may conduct load flow studies to examine constraints and possible solutions. Our target turnaround for design approval is ten working days. For larger and more complex connections where network constraints are present, this process may take longer as we discuss the constraints and potential solutions with the contractor.

We do not actively publish details about load or injection constraints on the network (at sub-transmission, distribution, or LV). This information is provided to contractors (who then pass it on to customers) as needed. For large and complex connections, we usually meet with both the customer and contractor to discuss the constraints and potential solutions.

This connection process is also applied to distributed generation. However, there are some other connection requirements and the connection costs are applied consistent with the Electricity Code requirements.[98] The additional requirements for distributed generation is provided on our website.[99] Also, refer to Section 11.4.8.

We operate a competitive process for new connections. This ensures that customers pay the efficient cost of connecting to the network (less the payment made by Electra, which is calculated based on the net benefit to us).

We presently assess the impact of new demand, generation, or storage capacity on a case-by-case basis using load flow modelling. In our energy transformation roadmap, we have a work activity to better understand network constraints and hosting capacity (refer to Section 10.5).

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97 https://electra.co.nz/our-company/disclosures/

98 Part 6 of the Electricity Industry Participation Code 2010.

99 https://electra.co.nz/services/distributed-generation/

11.13.3 Expenditure forecasts

Table 59: Vested assets (Real $000)

Cost	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Customer connections	-	-	-	-	-	-	-	-	-	-	-
Vested assets	399	418	438	461	487	511	537	564	594	622	5,686
Total	**399**	**418**	**438**	**461**	**487**	**511**	**537**	**564**	**594**	**622**	**5,686**

11.14 Asset relocations

Electricity network assets often require relocation due to the impact of land or other infrastructure development. We fund the relocation work and generally receive a capital contribution equal to the cost of the work. We often use this opportunity to augment the network or install a spare duct, which we pay for (this explains the difference between the capex and capital contributions in Figure 116).

We typically are only aware of asset relocations a year or two in advance. The known projects are:

- Asset relocations associated with the O2NL expressway project. There is currently a pipeline of 20 areas where our assets will be impacted (some of which have yet to be fully scoped and included in the forecasts below);
- GWRC requested relocation of 11kV overhead lines through QE park;
- Asset relocations related to a subdivision in Waikanae North.

Table 60: Asset relocations (Real $000)

Cost	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Asset relocation capex	51	710	2,540	-	-	-	-	-	-	-	3,330
Less: capital contributions	-	500	2,500	-	-	-	-	-	-	-	3,000
Total	**51**	**210**	**40**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**300**

12. Asset Lifecycle Management (Fleet Plans)

12.1 Introduction

This Section describes our asset lifecycle management. It deals with the asset lifecycle beyond its development (which is described in Section 11).

Fleet plans describe the steps within an asset's lifespan to ensure that the asset delivers the required performance at the lowest overall lifecycle cost.

An increasing number of our assets are approaching end-of-life, so we have increased our focus on asset lifecycle management and made a number of improvements in line with our asset management strategy.

In this Section, we cover:

- How this section aligns to policy and strategy;
- Our approach to asset lifecycle management, as it relates to fleet plans;
- Planning approach and standards used for fleet planning;
- The approach to assessing asset health;
- Detailed fleet plans for our material asset classes;
- High-level fleet plans for other asset classes;
- Our vegetation management plan.

The comprehensive fleet plans are the key improvement visible in this Section. We have also continued to improve our asset data and condition data, accelerate inspections where needed, and better target renewals. These improvements are the main drivers for the changes in our renewal forecasts.

12.2 Alignment to our asset management policy and strategy

Our fleet plans support the asset management policy in the areas of:

- Maintaining and managing our network assets at defined levels to enable the safe, efficient and effective delivery of electricity to our customers
- Establishing asset operating, maintenance and replacement strategies to ensure our assets support the services required and minimise the total lifecycle costs, including through extending the useful life of assets
- Considering the economic, environmental and cultural impact of our business and finding an appropriate balance between them.

The asset management strategies in Section 6 include two initiatives concerning our asset lifecycle plans. This included:

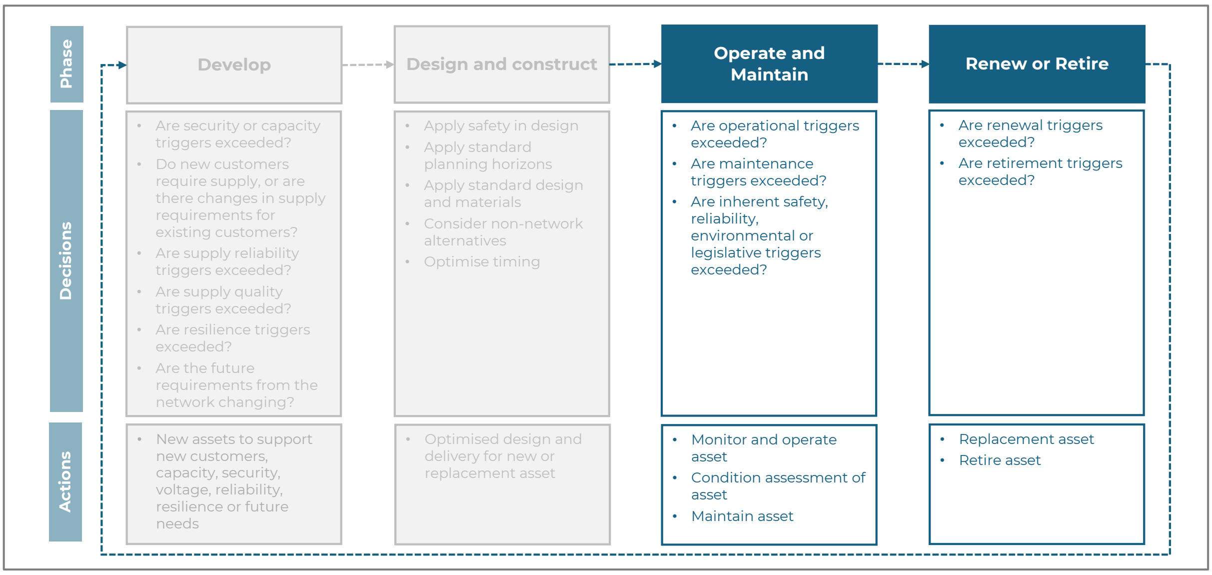
- **#3 Develop comprehensive fleet plans and renewal forecasts:** The actions relate to defining fleet plans and strategies, condition assessments, health and renewal forecasting, and targeting renewals in areas where health is deteriorating. We have incorporated the actions from this initiative within the fleet plans;
- **#4 Continuously improve the security, reliability and resilience of the distribution network:** The actions relate to better targeting our vegetation management activities. The other actions from this initiative are covered in Section 11.

This Section gives effect to these policy aims, strategic initiatives and actions.

12.3 Asset lifecycle management (fleet management)

We manage our assets throughout their lifecycle using the process shown in Figure 106. In this section, we discuss the *operate and maintain* and *renew or retire* phase. A description of the *development* and *design and construct* phase is provided in Section 11.3.

Figure 118: Asset Lifecycle



12.3.1 Operate and maintain

The *operate and maintain* phase covers the operation of the assets, ongoing condition assessment, corrective and preventative maintenance, and any emergency response in relation to the assets. The purpose of this phase is to ensure the safe and reliable performance of an asset over its expected life.

12.3.2 Renew or Retire

The *renew or retire* phase covers deciding when to renew or retire assets. Typically, the decision to renew an asset is made in response to:

- Increasing asset risk (which is a combination of asset health and criticality). The actual replacement of the assets is subject to a detailed assessment of the asset condition and criticality;
- Deteriorating reliability performance;
- Safety and integrity concerns;
- Technical or operational obsolescence;
- The economics of ongoing maintenance (compared to replacing with a modern equivalent asset).

Disposal of the asset occurs when the asset is removed from service and cannot be redeployed or reused.

12.4 Planning approach and standards used for fleet planning

12.4.1 Condition-based asset risk management modelling

We have developed a Condition-Based Asset Risk Management Model (CBARMM) to forecast asset risk and renewals. The model is based on the DNO Methodology.[100] CBARMM models have been developed for all network assets. These models apply a risk-based, information-driven approach to asset renewal forecasting.

The DNO Methodology provides industry-specific guidance for quantifying individual asset risk by evaluating an asset's health and criticality. An asset's health is calculated as its probability of failure, and its criticality is calculated as its consequence of failure. Thus, asset risk is calculated as the product of probability and consequence of failure.

Whilst the principles and the key calculations of the DNO Methodology were adopted in developing CBARMM, the inputs and calibration parameters were customised to align with our environmental and operating conditions.

The CBARMM models provide a systematic, data-driven methodology to identify asset renewal needs and enable us to evaluate overall asset fleet risks based on different renewal, refurbishment or maintenance scenarios.

An overview of the CBARMM process is shown in Figure 119. It consists of three main elements:

- **Health assessment:** This process involves determining the health of an asset based on various inputs. Under the DNO Methodology, asset health is defined using a health index and health index bands (HIB1 to HIB5). The probability of failure (**PoF**) is determined for the individual assets based on the individual health indices and the performance of the asset class. The PoF calculation forms an important relationship in the methodology between the health indices of individual assets and the performance of the asset class. This relationship between an asset's health and PoF is shown in Figure 120. The CBARMM model allows the future health of an asset to be calculated, given the aging of the asset.
- **Criticality assessment:** This involves assessing the consequences of failure (**CoF**) for each asset class across four categories: safety, network performance, financial, and environmental. Each of these is quantified in monetary terms on an asset class basis and then specified for each asset by considering the importance of the asset in its location. CoF remains static over time.
- **Risk assessment:** The probability and consequences of failure of an individual asset are combined to quantify risk. This is the product of the asset's PoF and CoF.

The health assessment inputs include nominal expected life, location, duty, asset age, operations, reliability, and condition inputs. Location factors are principally used to assess the impact of the coastal environment on an asset's expected life. Duty factors are used where equipment loading can impact an asset's expected life. The number of operations (typically under fault conditions) is used where this has an impact on the condition of the assets over time.

[100] Ofgem, "DNO Common Network Asset Indices Methodology—Version 2.1", April 2021.
This is a common framework of definitions, principles and calculation methodologies published by Ofgem and adopted by all GB Distribution Network Operators for the assessment, forecasting and regulatory reporting of asset risk.

The reliability factor is applied to an asset class based on the asset's performance history and experience in managing and operating the asset. It is used to identify if there are any generic issues that affect health associated with the make and type or construction of the asset.

Condition inputs include those that are observed (through inspections) and those that are measured (through standardised testing). The health score is modified depending on the condition based on the approach defined in the DNO Methodology. In Table 64, we have provided our view on how reliable the condition data is in determining the health of an asset.

Figure 119: CBARMM[101]

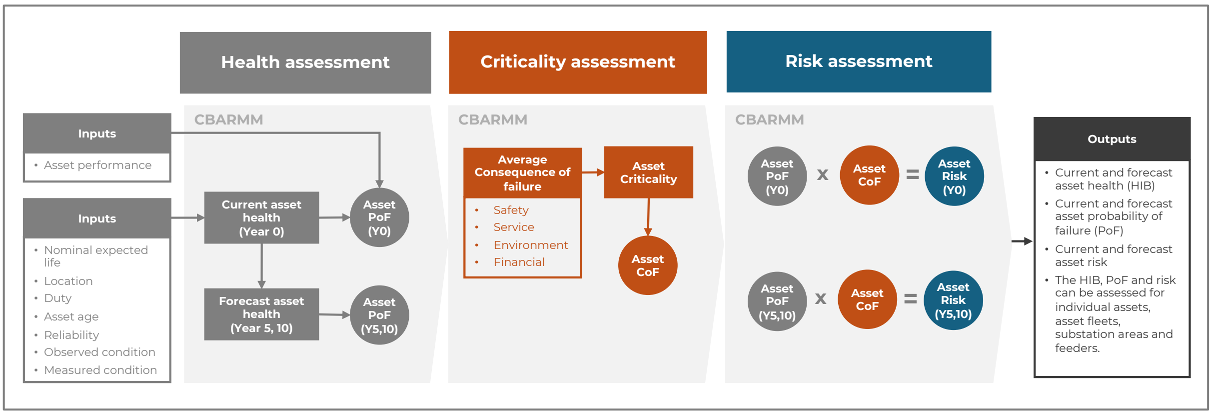
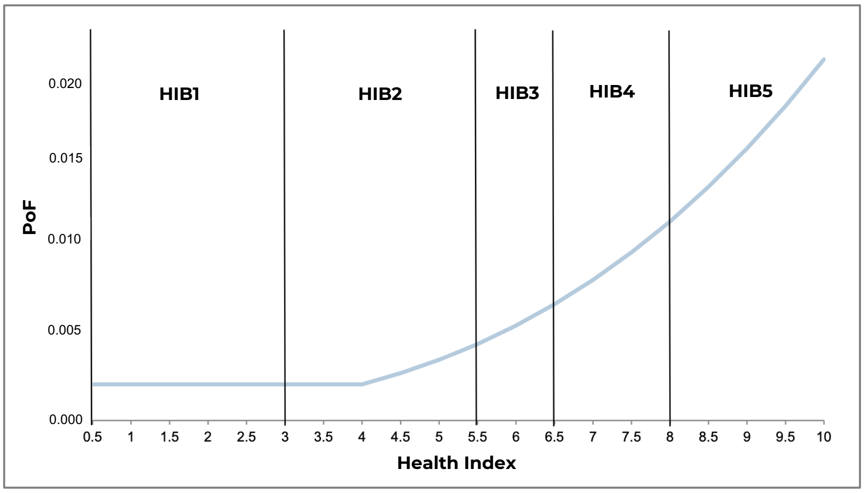


Figure 120: Relationship between asset health and PoF[102]



12.4.2 Asset health standards

CBARMM uses a combination of a nominal (or average) expected life and operational factors to determine the expected life for the asset. The relationship between the asset's age and the expected life determines the initial health index, which is then modified using the asset condition inputs.

An asset's age forms the underlying basis for determining its health (which is modified based on its condition); hence, ensuring quality asset age data is important and has been a key focus for the business.

[101] This is a simplified version of various figures included in the DNO Common Network Asset Indices Methodology.

[102] Ofgem, "DNO Common Network Asset Indices Methodology—Version 2.1", April 2021. Figure 3.

In this AMP, we describe asset health using the CBARMM health index bands, which are mapped to the EEA and Information Disclosure asset health scores (refer to Table 61).

Table 61: CBARMM Asset Health Index Bands to EEA and Information Disclosure Asset Health Scores

CBARMM health Index band	CBARMM health index	Description	EEA and ID health score
HIB1	≥0.5 to <4.0	**As new condition:** no drivers for replacement	H5
HIB2	≥4 to <5.5	**Serviceable condition:** no drivers for replacement, normal in-service deterioration	H4
HIB3	≥5.5 to <6.5	**Emerging health risks:** End-of-life drivers for replacement emerging, asset-related risks are increasing above serviceable condition	H3
HIB4	≥6.5 to <8	**Increasing health risks:** End-of-life drivers for replacement present – high asset-related risk	H2
HIB5	≥8	**End of life:** End-of-life is imminent, replacement recommended	H1

12.4.3 Asset criticality standards

In this AMP, we describe asset criticality using the CBARMM criticality index bands (which are the same as the DNO Methodology), which can be mapped to the EEA criticality scores (refer to Table 62).

CBARMM uses a combination of nominal (or average) expected life and operational factors to determine the asset's expected life. The relationship between the asset's age and expected life determines the initial health index, which is then modified using the asset condition inputs. An asset's age forms the underlying basis for determining its health (which is modified based on its condition); hence, ensuring quality asset age data is important and has been a key focus for the business.

Table 62: CBARMM Asset Criticality Bands to EEA Asset Criticality Scores

CBARMM criticality index band	Description	EEA criticality scores
C1	**Low criticality:** Credible consequences of failure are broadly tolerable, and run to failure may be a valid strategy	C4
C2	**Average criticality:** Asset failure would cause some disruption and inconvenience, but systems are already in place to anticipate and manage the outcomes	C3
C3	**High criticality:** Asset failure would cause significant harm to people, assets, the business or the environment. The consequences are tolerable but should be avoided or mitigated if it is practicable to do so	C2
C4	**Very high criticality:** The credible consequences of failure would generally be unacceptable	C1

12.4.4 Asset risk standards

Risk gradings are not explicitly defined in the DNO methodology. We have also adopted the risk grading and definitions from the EEA (refer to Figure 121 and Table 63). The EEA grades reflect how we manage asset risk. The risk grades include a tolerable risk rating where run-to-fail may be acceptable (which is common practice for small distribution transformers and fuses where asset health is difficult to determine).

Figure 121: Asset risk matrix

	HIB1	HIB2	HIB3	HIB4	HIB5
C4	RG3	RG3	RG5	RG5	RG5
C3	RG2	RG2	RG4	RG4	RG5
C2	RG2	RG2	RG2	RG4	RG5
C1	RG1	RG1	RG1	RG1	RG1

Table 63: CBARMM Asset Risk Ratings

CBARMM risk grades	Description	EEA risk grades
RG1	**Acceptable risk:** Low consequences of failure and increased failure rates or running assets to failure are tolerable, depending on the asset class. Proactive interventions are based on efficiency considerations.	RG5
RG2	**Low risk:** Typical asset in the useful life phase. Asset to be monitored and maintained	RG4
RG3	**Medium risk:** Healthy but very high critical assets. Appropriate monitoring of the assets is required, and interventions are required to minimise health deterioration.	RG3
RG4	**High risk:** A combination of criticality and health indicates elevated risk. Appropriate intervention is required within a reasonable timeframe, provided current risks can be prudently managed in the interim.	RG2
RG5	**Intolerable risk**. Deteriorating asset health. Immediate intervention is required.	RG1

12.4.5 Operational, maintenance, inherent safety, reliability and environmental legislative triggers

Operational, maintenance, inherent safety, reliability, environmental, and legislative triggers are defined for each asset class within the fleet plans. Safety, reliability, environmental, and legislative triggers relate to issues inherent in the asset class, not network related issues. Network related issues are discussed in the development section (refer to Section 11).

12.4.6 Renewal and refurbishment triggers

Specific renewal and refurbishment triggers are discussed in each fleet plan.

In general terms, Electra classifies work as renewal if there is no change (usually an increase) in functionality (i.e., the output of any asset does not change). The key criteria for triggering a renewal or refurbishment are:

- Asset health and asset risk;
- Technological obsolescence;
- When its capitalised operating and maintenance costs exceed the renewal cost.

Safety, reliability, environmental, and legislative triggers may also result in renewal.

12.4.7 Retirement triggers

The general criteria for retiring an asset include:

- Its physical presence is no longer required usually because a consumer has ceased demand;
- It creates unacceptable risk exposure, either because its inherent risks have increased over time or because safe exposure levels have reduced. Assets retired for safety reasons are not re-deployed or sold for re-use;

- Where better options exist to deliver similar outcomes, and there are no suitable opportunities for re-deployment;
- Where an asset has been upsized, and no suitable opportunities exist for re-deployment;

Safety, reliability, environmental, and legislative triggers may also result in retirement.

Our group policy on "Asset Lifecycle and Waste Disposal" identifies the following principles when disposing of waste materials and end-of-life assets:

- Consider the all-of-life impact in the design, procurement and implementation of the asset:
- Support central, regional and local government environmental commitments;
- Encourage suppliers to minimise waste and take responsibility for the waste that is generated;
- Protect the company and employees from accusations or acts of fraudulent behaviour associated with disposal;
- Seek to maximise the useable life of asset and encourage re-purposing before disposal by re-cycling, with treatment as waste as a last resort.

12.4.8 Planned improvements

We have recently undertaken a significant program of work to improve asset attributes and age data. These are key inputs in determining the initial health score for the asset.

We are currently undertaking a program to review our condition assessment standards to ensure that we capture the necessary observed and measured condition inputs to enable an accurate asset health assessment (this is an action under asset management strategy #3). This work is included in the asset management improvement roadmap (refer to Section 9.3).

We are progressively improving the data inputs used in CBARMM. Our future work includes:

- Using duty (e.g. loading) as input for power transformer and circuit breaker health assessment;
- Using joint data as input for conductor and cable health assessment;
- Using the number of fault operations as input for ABSs, reclosers and circuit breaker health assessment;
- Using observed condition as input for recloser health assessment.

We are also constantly reviewing survival statistics to ensure that the nominal expected life for the assets is consistent with the materials and equipment used by Electra and its operating and environmental conditions.

12.5 Summary of our approach to determining asset health, renewal forecasts and renewal projects

Table 64 summarises how we determine asset health and asset renewals and define specific renewal projects. Additional details are included in the fleet plans. Our approach to assessing health and forecasting renewals varies based on the quality of our data and the ability to obtain reliable condition data that can be used to predict asset health. Presently, for some assets, it is difficult to obtain condition data (e.g. for buried assets, where significant outages are required to inspect the equipment or where material samples need to be removed) or where condition data can only provide a broad indicator of asset health.

Table 64: How we are determining asset health, asset renewals and specific renewal projects

Asset fleet	Quality[103] of asset age data	Quality of asset condition data and reliability[104] to predict health	How we determine asset health	How we forecast asset renewals	How we determine renewal projects
Power transformers	Very good	Very good quality and a reliable health predictor	CBARMM, using age, location, duty and operations	CBARMM risk grade	Projects are defined following detailed assessment (initiated based on risk grade)
Zone substation switchgear	Very good	Very good quality and a reliable health predictor	CBARMM, using age, location, duty and operations	CBARMM risk grade	Projects are defined following detailed assessment (initiated based on risk grade)
Zone substation buildings and structures	Very good	Very good quality and a reliable health predictor	Interpretation of building assessment report and structure condition data	Projects identified in building assessment report and structure condition data	Projects identified in building assessment report and structure condition data
Secondary systems	Very good	Good quality and an indicative health predictor	We apply a nominal expected life to avoid technological obsolescence.	CBARMM risk grade	Health (technological obsolescence)
Overhead structures (poles and crossarms)	Good. Some gaps in pre-1995 data. Projects have been completed to improve data.	Good quality and a reasonable health predictor	CBARMM, using age, location, condition and reliability data	CBARMM risk grade, adjusted for the most recent condition assessments	Most recent condition data and risk grade
Conductor	Very good for subtransmission and good for distribution and LV	Average quality and an indicative health predictor	CBARMM, based on age, location and reliability Condition and joints are not current used	CBARMM risk grade, adjusted for recent asset reliability	Subtransmission conductor projects are based on health and risk assessment. Distribution conductor projects are based on reliability or defects
Cables	Good	Partial discharge condition data is only available for subtransmission. Other condition data relates to terminations, which is not a reliable indicator of asset health	CBARMM, based on age and reliability Condition and joints are not current used	CBARMM risk grade, adjusted for known asset reliability issues	For subtransmission we initiate projects based on asset condition For distribution and LV cables we initiate projects based on reliability or defects
GM distribution switchgear	Good	Good quality and a reasonable health predictor (where partial discharge and SG6	CBARMM, based on age, location, reliability and condition	CBARMM risk grade	Projects are defined based on asset condition and risk grade

103 Data quality grading is consistent with the data accuracy definitions included in Section 8.5. These are: **Very good**, which means a data accuracy score of 4; **Good**, means a score of 3; **Average**, means a score of 2; **Poor**, means a score of 1.

104 We have applied a grading in respect of how reliable condition data is at predicting asset health. This assessment is based on the condition assessments applied at Electra. These are: **Reliable**, which means that there is a strong body of evidence to support the relationship between asset condition and health; **Reasonable,** which means there is reasonable evidence to support the relationship between asset condition and health; **Indicative**, which means the relationship between asset condition is either difficult to assess (using the standards currently applied by Electra), or only provides a broad indicator of health

Asset fleet	Quality[103] of asset age data	Quality of asset condition data and reliability[104] to predict health	How we determine asset health	How we forecast asset renewals	How we determine renewal projects
		leak tests are available)			
GM distribution transformers	Good	Good quality and a reasonable health predictor	CBARMM, based on age, location, reliability, condition	CBARMM risk grade	Projects are defined based on asset condition and risk grade
PM reclosers	Good	Good quality and a reasonable health predictor (where partial discharge is available)	CBARMM, based on age, location, reliability Operations and condition are not currently used	Current renewal forecasts are based on recent inspection and operational data. This approach is being reviewed	The replacement programme is being revised
PM air-break switches	Good	Average quality and an indictive health predictor	CBARMM, based on age, location, condition and reliability Operations is not currently used	CBARMM risk grade	Current project are based on asset-type issues and asset condition
PM drop-out fuses and links	Average	No reliable condition data. The current line inspections drive the defect process	CBARMM, based on age and location	Based on historical replacement rates	No specific projects identified. Renewal coordinated with other projects or initiated from defects or fault
PM distribution transformers	Good	Good quality and a reasonable health predictor	CBARMM, based on age, location, reliability and condition	CBARMM risk grade	For large PM transformers projects are defined based on asset condition and risk grade No specific projects identified for small PM transformers where renewal coordinated with other projects or initiated from defects of fault
Underground connections (LV pillar and link boxes)	Good	Good quality and an indicative health predictor	CBARMM, based on age, location and condition	CBARMM risk grade, adjusted for known condition	Specific projects are defined from the most recent inspections. Assets in high risk areas are prioritised.
Overhead connections	Data is no maintained for these assets. No renewal forecasts or projects are prepared. These assets are replaced in conjunction with other projects or on failure				

12.6 Summary of risk and renewal plan for our asset fleets

12.6.1 Zone substation asset fleets

Due to their generally higher criticality, the zone substation asset fleets are managed more conservatively than distribution assets (that is, we have a lower risk tolerance for these assets). For zone substation assets, we generally plan to replace or refurbish the assets before the risk increases above medium (above risk grade 3). As shown in Table 65, we are replacing more assets than indicated by CBARMM. This reflects some replacement drivers that are not fully recognised in CBARMM (i.e. some safety-related factors, building resilience issues and protection scheme vulnerabilities).

Table 65: Zone substation fleet risk and renewal summary

Asset fleet plans	10 Year forecast assets with high risk and above[105]	10 Year forecast renewals and refurbishment	10-year forecast capex	Comments
Power transformers	7	7	$13.8m	Forecast renewals will maintain the fleet at medium or lower risk
Zone substation 33kV circuit breakers	3	16	$7.3m	The drivers for the additional renewals are to address safety risks
Zone substation 11kV circuit breakers	Nil	18	$2.1m	These renewals are driven by factors not included in CBARMM (building seismic issues and obsolescence issues restricting board extension to cater for growth)
Zone substation secondary systems	90	94	$9.1m	Forecast renewals are higher than forecast risk for protection relays as some relays are being replaced to remove known protection vulnerabilities.

12.6.2 Other subtransmission, distribution and LV asset fleets

For non-zone substation assets, we generally plan to replace the assets when they reach risk grade 4 (where the risks can be managed) and before they transition to risk grade 5. However, our view on risk tolerance and the drivers for renewals varies for each asset fleet and asset type.

The material renewal programmes are the replacement of poles and crossarms ($58.9m), conductors ($32.2m), and pillar boxes ($16.1m). These programmes address high-risk assets: older concrete and wood poles, overhead copper conductors, and steel pillar boxes.

Table 66: Material fleet plans

Asset fleet plans	5 Year forecast assets with high risk and above[106]	5 Year forecast renewals and refurbishment	10-year forecast capex	Reason for differences
Overhead structures (poles and crossarms)	Concrete 4.8% Wood 9.7% Crossarms 5.0%	6.3% 9.7% 16%	$58.9m	Renewal are greater than forecast risk for concrete poles and crossarms due to additional replacements during the reconductoring programme
Conductor	33kV 11.9% 11kV 1.5% LV 49.5%	0.2% 6.5% 14.6%	$32.2m	The forecast risk for 33kV overhead conductors relates to two circuits from Mangahao where the future use of the is unclear, hence renewal is not yet forecast. The 11kV conductor renewals are higher than forecast risk due to the copper conductor renewal programme, which is health (rather than risk based). Forecast renewals for LV overhead conductors are below forecast health and risk—the current forecast addresses assets with observed condition issues.
Cable	33kV 0.0% 11kV 13.1%	2.2% 0.2%	$0.3m (renewal)	There are no planned cable renewals (other than some 33kV cables relocations associated with O2NL). Most expenditure relates to shows the

[105] Before renewal or refurbishment intervention

[106] Before renewal or refurbishment intervention

Asset fleet plans	5 Year forecast assets with high risk and above[106]	5 Year forecast renewals and refurbishment	10-year forecast capex	Reason for differences
	LV 20.6%	0.1%	$2.3m (safety)	safety-related replacement of pitch-filled potheads and in-line joints on poles
Distribution switchgear	PM Reclosers 40% PM Switches varies RMUs 3.2%	6.3% 7.1% 4.5%	$4.7m	Forecast renewals for pole-mounted reclosers is an estimate only and is being validated. Forecast renewals for pole-mounted switches relates to our ABS replacement programme. There is not a renewal programme for dropout fuses and links. These assets are replaced as part of other programmed work or when defects are identified. Forecast RMU replacements are higher than forecast risk due to the replacement of ABB Safelink 1 RMUs that have a known type issue.
Distribution transformers	PM 30.7% GM 18.5%	3.0% 6.6%	$5.4m	Due to the lower consequence of failure associated with distribution transformers, we are forecasting replacing assets that transition to RG5. The forecast renewals are above forecast RG5 assets.
LV connections and pillar boxes	23.1%	11.7%	$15.1m (renewal) $1.0m (safety)	The forecast renewal is for the replacement of all steel pillars by FY35 and all steel link pillars by FY30. Plastic boxes are performing better than the risk-based forecasting suggests and their replacement is an estimate based on prior inspection-driven replacement rates.
Other networks assets	Varies	Varies	$102k	Refurbishment of the ripple injection plant at Shannon

12.6.3 Movement in Schedule 12a asset condition

There has been movement in the asset condition scores in Schedule 12a. This reflects a change from disclosing asset health using the EEA methodology (age-based) to the CBARMM HIB1 to HIB5 health scores (which incorporates conditions inputs) for some assets. There is also movement due to the natural aging of the assets and changes in condition inputs as new inspection data comes to hand.

12.7 Asset fleet plans included in this AMP

Table 67 shows the material asset classes for Electra. This AMP includes detailed fleet plans for our zone substation assets. Summary fleet plans are included for other assets. Detailed fleet plans for these assets will be included in the 2026 AMP.

Table 67: Material fleet plans

Asset fleet plans	Asset classes (Commerce Commission)	Status
Power transformers	Zone substation transformers	Comprehensive ten-year fleet plan included in this AMP
Zone Substations 33kV Circuit Breakers	22/33kV CB (Indoor)	As above
	22/33kV CB (Outdoor)	
Zone Substation 11kV Circuit Breakers	3.3/6.6/11/22kV CB (ground mounted)	As above
Zone Substation Secondary Systems	Protection relays (electromechanical, solid state and numeric)	As above
	Note: SCADA is discussed in Sections 8 and 9.	
	Concrete poles / steel structure	

Asset fleet plans	Asset classes (Commerce Commission)	Status
Overhead structures (poles and crossarms)	Wood poles	Five-year fleet plan included in this AMP. Ten-year fleet plan to be included in the 2026 AMP
	Crossarms[107]	
Conductor	Subtransmission OH up to 66kV conductor	As above
	Distribution OH Open Wire Conductor	
	LV OH Conductor	
Cable	Subtransmission UG up to 66kV (XLPE)	As above
	Distribution UG XLPE or PVC	
	Distribution UG PILC	
	LV UG Cable	
Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	As above
	3.3/6.6/11/22kV Switches and fuses (pole mounted)	
	3.3/6.6/11/22kV RMU	
Distribution transformers	Ground Mounted Transformer	As above
	Pole Mounted Transformer	
LV connections and pillar boxes	OH/UG consumer service connections	As above

We provide a high-level view of other (less material) assets in Section 12.18.

12.8 Power Transformer Fleet Plan

12.8.1 Fleet Overview

Electra has 19 power transformers located across ten zone substations. Power transformers convert energy from the 33kV sub-transmission network to the 11kV distribution network. Except for the Paekākāriki substation (where 11kV backup is available), all substations have N-1 security available for these assets.

The power transformer fleet makes up approximately 3% of the overall assets by value. Individually, these are the most valuable assets. Power transformers have a high initial investment and operational costs. Therefore, the total lifecycle costs are assessed before purchasing new transformers.

There are two major components to a power transformer—the transformer (consisting of the tank, windings and cooling system) and the tap-changer (which allows the output voltage to be changed while the transformer is carrying load).

Power transformers are very critical assets, and a failure can result in loss of supply or reduced supply security, depending on the network security level of the zone substation. For this reason, we take a more conservative approach to their management than we do for distribution assets.

[107] These are an identified asset class for asset management purposes, but are not a Commerce Commission asset class

Figure 122: Power Transformers

Power Transformers T1 and T2, Waikanae Zone Substation

12.8.2 Fleet Management Strategy

The 10-year power transformer fleet strategy is as follows:
Power transformers are very high criticality assets that can take significant time to replace should they fail. Hence, the fleet strategy requires them to be operated, monitored, maintained, and renewed to ensure fleet risk remains at medium (RG3) or below. This requires: • Operating the assets within the required security levels (for foreseeable normal loading conditions); • Upgrading all assets structure to achieve Importance Level 4[108] by the end of FY2028[109]; • Taking a conservative position on asset health and risk where assets are refurbished or replaced *before* health risks emerge (HIB3) and *before* risks increase above medium (RG3 and below); • Monitoring the condition of the asset fleet to ensure asset health can be reliably predicted; • Maintaining the assets consistent with the manufacturer's guidelines and Electra's standards to ensure assets are kept in serviceable condition (HIB2 and below).

12.8.3 What is driving our fleet strategy

Current fleet performance

The power transformer fleet is performing well, but some issues are emerging on some older assets. The issues are consistent with the fleet's age.

A recent tap-changer fault at Paekākāriki substation resulted in the transformer being replaced with our critical spare. The faulty tap-changer was manufactured in 1960, so it had reached its normal expected life of 60 years. Our critical spare is the only remaining transformer with a tap-changer of this type and vintage

[108] Importance Level 4 is defined as a structure that is essential to post-disaster recover. They require higher resilience to seismic, wind, snow and flooding hazards.

[109] This currently relates to seismic, wind and snow loadings. The resilience strategy includes a plan to assess flood resilience to an equivalent IL4 standard. The target date is indicative as site geotechnical and flooding assessment is ongoing.

(manufactured by AEI). This critical spare was installed and commissioned into service at Paekākāriki T1 in early 2024.

Dissolved gas analysis (DGA) results show signs of some internal arcing in the transformer tank at T1 Levin East and T1 Paraparaumu East. This is likely due to heightened moisture within the transformer oil, which has been noted using online monitoring. T1 Paraparaumu is 55 years old, and end-of-life drivers can be expected. T1 Levin East is only 46 years old, so the presence of end-of-life drivers is earlier than expected.

Specific fleet risks and failure modes

Table 68 shows the top risks and failure modes for the power transformers. Condition monitoring and maintenance (as shown in Table 70 and Table 71) identify and reduce failure risks.

Table 68: Specific risks

Asset	Risk/failure modes	Current controls or treatments
Power transformer	Coastal exposure resulting in tank corrosion that can reduce asset life	• Regular visual condition monitoring of the tank and remediation of corrosion as required • A location factor is incorporated in CBARMM as coastal exposure (within 3.6km of the coast) can reduce the nominal expected life of an asset.
	Overloading of the transformer can damage the winding insulation, reducing asset life and causing asset failure	• SCADA monitoring transformer loading. The load can be transferred to other zone substations if required. • Condition assessment (dissolved gas analysis) of the transformer oil.
	Moisture ingress and contamination of transformer oil can damage the winding insulation, reducing asset life and causing asset failure	• Regular (or online) oil moisture testing. • The transformer oil may be changed or filtered as required.
	Failure of a bushing or connection	• Inspection of bushing and thermal imaging of connection points with follow-up maintenance as required
	Mechanical failure of the tap-changer	• Regular maintenance of the tap-changer

As no known type issues are associated with the fleet and the current performance issues are not systemic, the reliability factor within CBARMM is set at 1.0, meaning the asset fleet has high reliability.

Fleet population and age

Table 69 shows the power transformer population and age. There are two transformers within five years of nominal expected life (**NEL**), which are T1 and T2 Paraparaumu East. Two more transformers will reach NEL over the next ten years (T2 Levin East and T2 Shannon). The two transformers at Ōtaki will reach NEL in 11 years.

Table 69: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[110] (years)	Population within 5 years of NEL
Power transformer	3 Phase Transformer (including tap-changer)	19	36	60	2

[110] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Fleet health, criticality and risk

Asset health is determined using CBARMM. For power transformers, we calculated asset health using a combination of asset age, location, duty, reliability and condition. We have *very good* quality asset age and condition data that can reliably determine asset health.

As shown in Figure 123, most assets are in serviceable condition. We have two assets with a health and risk profile requiring intervention due to asset condition (this is a recent change, as discussed in the performance section). However, as shown in Figure 124, over the next ten years, we expect the health of seven assets to deteriorate (before any interventions). As noted in the fleet strategy, intervention is required before the risk increases due to the very high criticality and the long lead time to replace power transformers. The following implementation section includes the proposed interventions to mitigate the current and future fleet risk.

Figure 123: Current Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5
C4	13	4	1	1	-
C3	-	-	-	-	-
C2	-	-	-	-	-
C1	-	-	-	-	-

Figure 124: 10-Year Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5
C4	9	3	1	5	1
C3	-	-	-	-	-
C2	-	-	-	-	-
C1	-	-	-	-	-

12.8.4 How the asset fleet is operated, monitored and maintained

Operating the assets

Power transformers are one of the primary assets within a zone substation (which also includes switchgear, secondary assets, and measurement equipment). The tap-changer is used to regulate the voltage output depending on the load it is supplying. As the only moving part within a transformer, the tap-changer is more susceptible to faults than other components. Faults for power transformers are identified through SCADA monitoring of the protection devices. This usually includes Buchholz relays, pressure relief valves, and tap-changer overload relays. Faults on transformers can vary in criticality, and technicians are dispatched to the site to investigate the cause of a fault should monitoring equipment be unable to provide adequate information.

Condition assessment

Table 70 summarises the power transformer fleet's current inspection and testing regime. The inspection and testing cover the transformer and tap-changer. Observed condition data is captured through regular inspections of the zone substation, and measured condition data (such as DGAs) is captured annually or bi-annually. Appropriately qualified technicians perform visual inspections, and external contractors perform the tests and measurements.

Our current condition assessment program is suitable for an aging asset fleet. However, the testing frequency may be shortened if we detect any deterioration. We are enhancing our condition assessments by installing online moisture analysis for each transformer. Four of the fleet of 19 power transformers currently have online monitoring, and the remainder will have online monitoring installed by the end of FY2030.

CASE STUDY ON POWER TRANSFORMER MOISTURE PROBE

We have commenced the installation of online oil monitoring probes into our zone transformers. These devices and the data they provide enables us to shift towards a predictive strategic approach with visibility into the health of the oil and condition of our power transformers. Such information enables us to make data-driven decisions regarding their replacement and maintenance through a condition-based monitoring approach and proactive recommendations.

Moisture Probe Installed on a Power Transformer

Moisture Probe Installed on a Power Transformer

Table 70: Condition assessments

Asset	Type	Scope of assessment	Trigger
Power transformer	Observed	Routine inspection checks for oil leaks, corrosion, oil levels and tap-changer operation. This is completed as part of the zone substation inspection programme.	Time-based, timing varies between bi-monthly and annual, depending on health
	Observed	Thermal imaging of connection points and checking for hot spots	Time-based, annually
	Measured	DGA and Furan analysis	Time-based, annually
	Measured	Online moisture via Autra-probes (partial fleet coverage)	Continuous
	Measured	Duty of the transformer and operation of the tap-changer	SCADA measurement
	Measured	Insulation resistance and winding resistance	Time-based, 5-yearly, in conjunction with maintenance

Maintaining the asset

Power transformer maintenance typically consists of work associated with the tap-changer. Planned maintenance is based on the manufacturer's recommendations and good industry practice.

Table 71: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Power transformer	Corrective	Defects (on subcomponents of the assets) are repaired following identification during inspection, maintenance or fault. The technician and the substation engineer assess the defect repair.	• Oil test results exceeding manufacturers' recommendations • Poor results for tests such as partial discharge, Furan analysis, paper sampling • Integrity of gaskets and flexible seals on tank and fittings;

Asset	Type	Scope of maintenance	Trigger
			• Oil leaks or staining suggests ongoing leakage • Corrosion
	Preventive	**Tap-changer:** Oil replacement, cleaning of components, removal of arcing products, contact alignment and tap resistance	Time-based, 5-yearly
	Preventive	**Transformer:** Detailed inspection of components, checking operation of secondary equipment, insulation resistance, winding resistance, etc... Repairs and maintenance as required	Time-based, at commissioning, then 5-yearly, in conjunction with the tap-changer maintenance

12.8.5 How renewal decisions are made on the fleet

Table 72 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects.

Table 72: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Power transformer	Renewal forecasts	CBARMM is used to forecast asset renewals. Due to the critical nature of the fleet, we forecast renewals for all assets where the risk increases above medium (above RG3). Asset health is determined using a combination of asset age, location, duty, reliability and condition. The condition inputs include the observed condition assessment and the measured condition concerning oil moisture, oil dissolved gases and furan tests shown in Table 70. These measurements are generally applicable to both the transformer and the tap-changer.
	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on our engineering assessment of the presence of end-of-life drivers, including: • Oil impurity, acidity, gas content and moisture content indicate deterioration of the insulation; • Poor results for tests such as partial discharge, furan analysis, insulation resistance, winding resistance and paper sampling; • Issues identified with the transformer or tap-changer, oil leaks or staining on the tank suggesting that the material, structural integrity or performance issues; • Deterioration (i.e. corrosion) of the tanks or cooling fins. Refurbishment of power transformers may be feasible and provide an economic life extension (instead of renewal). Refurbishment will consider the capacity available to support future load growth, the transformer age, the specific drivers for the deteriorating health (and whether refurbishment will mitigate these drivers), and the overall lifecycle cost implications of refurbishment vs. renewal. A mid-life refurbishment assessment is carried out at 30 years of age. Project timing considers the ability to manage the risks associated with the emergence of end-of-life drivers. This includes the redundancy available at the substation, critical spares, and the availability of spares.
	Corrective renewal of refurbishment	Not applicable to power transformers.

12.8.6 Asset renewal and refurbishment forecasts

Table 73 shows the forecast power transformer asset risk and renewals over the next ten years. Four of the seven transformers forecast for renewal are due in the next five years. As shown in Figure 125, the forecast renewals will maintain the fleet at medium or lower risk.

Table 73: Current and forecast asset risk and renewals

Asset	Type	Population	Current assets with high risk and above	10 Year forecast assets with high risk and above[111]	10 Year forecast renewals and refurbishment
Power transformer	3 Phase Transformer (including tap-changer)	19	2	7	7

Figure 125: 10 Year Asset Health Risk Assessment, after Renewals

	HIB1	HIB2	HIB3	HIB4	HIB5
C4	16	3	-	-	-
C3	-	-	-	-	-
C2	-	-	-	-	-
C1	-	-	-	-	-

12.8.7 Asset renewal and refurbishment projects and provisions

Table 74 shows the specific projects proposed. These projects cover the assets identified for renewal in Table 73. Given their value, specific business cases will be prepared, and approval will be sought. The business case considers the drivers, scope, costs, and alternatives, which may alter the timing and scope of the projects listed in Table 74.

Our current forecast assumes that all transformers undergo one mid-life refurbishment (to achieve NEL) and then replacement at the end-of-life. However, given the high refurbishment costs and low expected life extension for transformers at (or approaching) NEL, end-of-life refurbishments are unlikely to be viable. The decision to renew or refurbish is considered during business case development.

Table 74: Specific renewal and refurbishment projects (Real$)

Project	Driver	Cost/Year	Options considered/comments
T1 Levin East, replacement with new 11.5/23 MVA unit	Replacement is required due to asset risk which is driven by the current condition and very high criticality. The DGA results show internal arcing and gassing in the transformer tank, which indicates end-of-life.	$1,524k FY28	The options considered were: • Delay replacement and manage risk: Internal arcing is an irreversible end-of-life condition that will worsen over time and presents unacceptable risk • Refurbishment: The refurbishment costs will be uneconomic due to the likely damage to the windings. Parts for older Tyree transformers are difficult to procure, which will be exacerbated if refurbished • Major maintenance: There are no maintenance solutions available to resolve internal arcing
T1 Paraparaumu East, replacement with new 11.5/23 MVA unit	Replacement is required due to asset risk which is driven by asset age, current condition and very high criticality. The DGA results show internal arcing and gassing in the transformer tank, which is an end-of-life condition. The transformer is 56 years old, which is close to end-of-life.	$1,520k FY26	The options considered were: • Delay replacement and manage risk: Internal arcing is an irreversible end-of-life condition that will worsen over time and presents unacceptable risk • Refurbishment: The transformer is end-of-life. Refurbishment is no longer viable for a transformer of this vintage and winding damage

[111] Before renewal or refurbishment intervention

Project	Driver	Cost/Year	Options considered/comments
			• Major maintenance: There are no maintenance solutions available to resolve internal arcing
T2 Levin East, replacement with new 11.5/23 MVA unit	Replacement is forecast due to asset risk which is driven by asset age, expected condition the very high criticality. The transformer will be 55 years old at the time of replacement.	$1,388k FY28	We are forecasting health deterioration similar to T1 Levin East. The transformer health is being closely monitored. The options will be considered during business case development.
T2 Paraparaumu East, replacement with new 11.5/23 MVA unit	Replacement currently forecast based on increasing asset risk. The transformer will be around 60 years old when replaced.	$1,385k FY30	The options will be considered during business case development.
T2 Ōtaki, replacement with new 11.5/23 MVA unit	As above	$1,304k FY33	As above
T1 Ōtaki, replacement with new 11.5/23 MVA unit	As above	$1,041k FY34	As above
T2 Shannon Substation replacement	As above	$1,307k FY34	As above
T1 Shannon Substation replacement	As above	Commencing FY35 ($53k)	As above
T1 & T2 Waikanae midlife refurbishment	Midlife refurbishment to extend life to achieve full NEL	$1,431k FY27-35	As above
T1 & T2 Foxton midlife refurbishment	As above	$1,022k FY33-34	As above
T2 Levin West midlife refurbishment	As above	$204k FY32	As above
T1 & T2 Paraparaumu West midlife refurbishment	As above	$1,022k FY31-32	As above
Cooling fin replacement at Foxton Zone substation	Replace due to asset health (corrosion)	$163k FY26	Maintenance solution is not possible due to the location of the corrosion. Replacement of the radiator is required.
Programme to install moisture sensors on all power transformers	Moisture monitoring is appropriate as it is an end-of-life driver for transformer winding insulation	$447k FY26-30	This is a continuation of an existing programme
Total	**Asset replacement and renewal capex**	**$13.8m**	

Forecasts for zone substation fault repair, inspection and maintenance are included within the network opex forecasts contained later in Section 12.

Table 75: Asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Zone substation transformers	290	1,875	2,950	125	1,274	716	768	1,829	3,103	828	13,759

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.9 Zone Substation 33kV Circuit Breaker Fleet Plan

12.9.1 Fleet Overview

Electra has 35 indoor and 22 outdoor 33kV circuit breakers (**CBs**) across ten zone substations. These CBs switch and protect the 33kV bus, power transformers and sub-transmission feeders. This fleet consists of indoor and outdoor CBs from various manufacturers.

We are moving to modular 33kV outdoor switchgear to enhance network resilience and reliability (refer to Section 11.9.4). New and replacement 33kV switchgear will be modular where it can be accommodated on the existing sites.

33kV CBs are critical assets, and a failure can result in a loss of supply or reduced supply security, depending on the network security level of the zone substation. For this reason, we take a more conservative approach to managing them than we do for distribution assets.

Figure 126: 33kV Circuit Breakers

33kV indoor circuit breakers Merlin Gerin F400

33kV outdoor circuit breakers Nulec

12.9.2 Fleet Management Strategy

The 10-year fleet strategy is as follows:

Circuit breakers are critical assets and can disrupt supply should they fail. The fleet strategy requires them to be tested, maintained, monitored, and renewed to ensure fleet risk remains at medium (RG3) or below. This requires:

- Minimising switching operations and limiting testing to the 5 yearly maintenance programme;
- Tested in accordance with manufacturer's guidelines, good industry practice and network standards. Annual non-intrusive testing to assess condition shall be implemented whenever possible ;
- Taking a conservative position on asset health and risk where assets are refurbished or replaced *before* health risks emerge (HIB3) and *before* risks increase above medium (RG3 and below);
- Monitoring the condition of the asset fleet to ensure asset health can be reliably predicted.

12.9.3 What is driving our fleet strategy

Current fleet performance

The current fleet is performing well. All switchgear is well within the age-based (60 years) and operating (10,000 operations and 180 fault trips) end-of-life limits.

Specific fleet risks and failure modes

Table 76 shows the principal risks and failure modes for 33kV CBs. The key risks relate to historical design issues (indoor CB connectors and outdoor operational clearances to live 33kV), coastal conditions and obsolescence.

Table 76: Specific risks

Asset	Risk/failure mode	Current controls or treatments
33kV indoor CB	Where the indoor CB has flexible connections between the racking CB and the panel, the umbilical cord connections can deteriorate	• Minimising CB operation • Annual partial discharge (PD) and acoustic monitoring • 5 yearly testing of contact integrity • We hold spares of these cords and terminal plugs
	Some substations have sub-optimal working clearances to live 33kV, which presents safety and operational risks. These were compliant when designed but do not meet newer standards for working clearances	A programme is in place to replace CBs with low working clearances where the site is considered to be high-risk
33 kV Outdoor CB	Bushing failure	• Annual acoustic surveys • 5 yearly maintenance cleaning
	Exposure to coastal conditions causing corrosion and early failure	• Corrosion detection as part of routine inspection, with remediation as required. • Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate
All CBs	Obsolescence due to unavailability of spare parts	Electra has two models that no longer have manufacturer's support: • Two GEC OX36 outdoor (38 and 36 years old); • Three MERLIN GERIN SF1 outdoor. These are all set for replacement

Fleet population and age

Table 77 shows the population and age of the 33kV CB fleet. There are no CBs within five years of NEL. One CB is approaching 48 years, and two are at 35 and 36 years. Due to other drivers, these older CBs are scheduled for replacement within the next ten years.

Table 77: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[112] (years)	Population within 5 years of NEL
33kV Outdoor CB	MERLIN GERIN SF1	3	30	50	Nil
	GEC- OX36	2	36	50	Nil
	Schneider Nulec N36-ACR-SF6-38-12	3	21	50	Nil

[112] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Asset	Type	Population	Average Age (years)	NEL[112] (years)	Population within 5 years of NEL
	Schneider Nulec-N36-ACR-SF6-38-16	1	17	50	Nil
	Schneider Nulec-N38-ACR-SF6-38-16-170	6	15	50	Nil
	Schneider NULEC-N38S-ACR-SF6-38-16-170	7	17	50	Nil
33kV Indoor CB	MERLIN GERIN SF1	10	25	55	Nil
	MERLIN GERIN F400	10	10	55	Nil
	MERLIN GERIN FG 4	6	28	55	Nil
	Schneider NULEC N38	1	17	50	Nil
	Schneider F400 AD6	8	9	50	Nil

Fleet health, criticality and risk

Asset health and risk are determined using CBARMM. For indoor and outdoor 33kV CBs, we calculated asset health using a combination of asset age, location, duty, and operations. We have very good quality data that can reliably determine asset health. We intend to improve the range of inputs used to determine asset health, including condition and test results, obsolescence risk, industry performance reports, and type issues.

As shown in Figure 127 and Figure 128, assets are in good condition, with only three CBs with forecast risk above RG3. We do not have any assets with a health and risk profile requiring immediate intervention. However, the risk profiles exclude:

- The outdoor OX-36 CB & Merlin Gerin F1 CBs are obsolete;
- The safety risks associated with switchgear clearances to live 33kV.

These items will be included in CBARMM in future revisions of the AMP.

Figure 127: Current Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	18	1	-	-	-	19
C2	18	-	-	2	-	20
C1	18	-	-	-	-	18
Total	54	1	-	2	-	57

Figure 128: 10-Year Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	18	-	1	-	-	19
C2	18	-	-	-	2	20
C1	18	-	-	-	-	18
Total	54	-	1	-	2	57

12.9.4 How the asset fleet is operated, monitored and maintained

Operating the assets

33kV CBs operate to break load during routine network reconfiguration and by the protection relays to interrupt fault current. The number of routine and fault operations are end-of-life drivers, so these are minimised whenever possible. Faults are identified through SCADA monitoring of the protection relays. Faults on 33kV CBs can vary in criticality, and technicians are dispatched to the site to investigate the cause of a fault in all circumstances.

Condition assessment

Table 78 summarises the 33kV CB fleet's current inspection and testing regime. Under normal conditions, the zone substations are inspected every two months; this is a visual, non-intrusive inspection of the external condition of the SWGR and captures the number of operations. Annual non-intrusive testing is also undertaken.

Table 78: Condition assessments

Asset	Type	Scope of assessment	Trigger
33kV CB	Observed	External condition – cabinet assessment	Routine, time-based, bi-monthly
		Internal condition - cabinet assessment	
		Number of operations	
	Measured	Partial discharge assessment for electrical discharge that could indicate insulation breakdown or other condition issues	Routine, time-based, annually
		Acoustic assessment for noise that could indicate conditions issues	
		Infra-red assessment for hotspots	

Maintaining the asset

Table 79 summarises the CB maintenance and operational testing. Follow-up corrective maintenance may occur to address any adverse test results.

Table 79: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
33kV CB, all types	Operational testing and Preventive maintenance	• Comprehensive operational testing using the Omicron CIBANO 500 test set, which includes contact resistance, dynamic contact resistance, various timing tests, motor current, under-voltage release, overcurrent release, insulation resistance, demagnetisation • PD testing before and after cleaning • For indoor CBs, The CB is racked out, and the bushing and framework are cleaned and maintained as per the manufacturer's recommendation • Outdoor CBs are mainly self-contained, and maintenance is limited to lubrication and cleaning of the exposed bushings and terminations	Routine, time-based, 5 yearly
	Corrective	Follow-up corrective maintenance occurs as required	Inspection and test results

12.9.5 How renewal decisions are made on the fleet

CBARMM is used to forecast asset renewals based on risk. Table 80 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast).

Table 80: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
33kV CB types	Renewal forecasts	Includes all assets that are forecast to reach Risk Grades 4 and 5.
	Planned renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers; these include observed or measured conditions outside of acceptable parameters, obsolescence, exceeding design fault operations, exceeding design mechanical operations, age-based end-of-life criteria
	Corrective renewal of refurbishment	Replacement or refurbishment of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 24 months.

12.9.6 Asset renewal and refurbishment forecasts

Table 81 shows the 33kV circuit breaker forecast asset risk and renewals over the next ten years.

We are forecasting the renewal of 16 outdoor 33kV CBs, which is materially higher than that forecast by CBARMM. The drivers for the additional renewals are to address safety risks through the removal of CBs with clearance to live 33kV below modern standards (at Foxton, Levin East and Levin West).

Table 81: Current and forecast asset risk and renewals

Asset	Type	Population	Current assets with high risk and above[113]	10 Year forecast assets with high risk and above[114]	10 Year forecast renewals and refurbishment
22/33kV CB	Indoor	35	Nil	Nil	Nil
	Outdoor	22	2	3	16

12.9.7 Asset renewal and refurbishment provisions and projects

Table 82 shows the specific projects proposed. These projects cover the assets identified in Table 81. Specific business cases have not yet been prepared for the two projects commencing after FY29. Hence, the scope and costs may alter for those projects.

Table 82: Specific renewal and refurbishment projects (real$)

Project	Driver	Cost/Year	Options considered/comments
Replacement of 33kV bus and CBs (with modular type), Foxton	Risk-based replacement (working clearances to live 33kV does not meet the current standard) and protection does not meet current standard (missing line differential protection, which requires additional CT cores in CB) Customer works within the region also require an extension to the bus.	$2.0m FY26-FY27	Option 1: Refurbish the outdoor bus and install external CTs, which will address the protection risk but not the customer issues and operational safety risk Option 2: Refurbish the existing bus and replace the CBs with those of sufficient CT cores, which will address protection and customer issues but not the operational safety risk Option 3: Doing nothing is not considered viable, given the importance of the three drivers
Replacement of 33kV CBs (with modular type), Levin East Note: scope may be adjusted	Risk-based replacement (working clearances to live 33kV does not meet current standard) and protection does not meet current standard (missing line differential protection, which requires additional CT cores in CB)	$1.1m FY26-FY28	Option 1: Replace the entire outdoor bus and CBs was considered, but the cost was above the recommended solution. However, this may change due to issues with the 33kV cables on the site. The scope of the project is under review. Option 2: Doing nothing is not considered viable, given the importance of the operational risk and protection drivers
Replacement of 33kV CBs (with modular type), Levin West	Risk-based replacement (working clearances to live 33kV do not meet the current standard)	$2.0m FY30-FY32	Still under consideration. The project scope depends on the outcome of the building's seismic reinforcement design.

[113] HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

[114] Before renewal or refurbishment intervention

Project	Driver	Cost/Year	Options considered/comments
Replacement of 33kV CBs, Raumati	Risk-based replacement of CBs (assets approaching aged-based end-of-life)	$2.1m FY32-FY35	The business case has not yet been prepared. Timing will be adjusted based on maintenance results and site conditions
Total	**Asset replacement and renewal capex**	**$7.3m**	**FY26 to FY35**

Table 83: Forecast asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
33kV CB renewal	1,830	1,176	152	-	184	204	1,686	51	1,500	513	7,297

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.10 Zone Substation 11kV Circuit Breaker Fleet Plan

12.10.1 Fleet Overview

Electra has 79 indoor 11kV circuit breakers (**CBs**) across ten zone substations. These CBs connect and disconnect the power transformers and 11kV feeders and sectionalise the 11kV bus.

Eight South Wales CBs will be replaced by 31 March 2025, after which the fleet will consist of RPS switchgear manufactured in New Zealand (formerly Reyrolle Pacific). The assets include a fixed panel and bus with CBs that rack into the panel. The standardisation of switchgear aids maintenance and operations.

As the switchgear is manufactured in Wellington, we have direct factory support, increasing resilience and reliability with spare parts readily available when required.

11kV CBs are critical assets, and a failure can result in loss of supply or reduced supply security, depending on the network security level of the zone substation. For this reason, we take a more conservative approach to their management than we do for distribution assets.

Figure 129: 11kV Indoor Circuit Breakers

11kV Circuit Breakers, Paekākāriki Zone Substation

12.10.2 Fleet Management Strategy

The 10-year fleet strategy is as follows:
Circuit breakers are seen as critical assets and can disrupt supply should they fail. The fleet strategy requires them to be tested, maintained, monitored, and renewed to ensure fleet risk remains at medium (RG3) or below. This requires: • Minimising switching operations and limiting testing to the 5 yearly maintenance programme; • Tested in accordance with manufacturer's guidelines, good industry practice and network standards. Annual non-intrusive testing to assess condition shall be implemented whenever possible; • Taking a conservative position on asset health and risk where assets are refurbished or replaced *before* health risks emerge (HIB3) and *before* risks increase above medium (RG3 and below); • Monitoring the condition of the asset fleet to ensure asset health can be reliably predicted.

12.10.3 What is driving our fleet strategy

Current fleet performance

The current fleet is performing well. All switchgear is within the age-based (60 years) and operating (10,000 operations and 180 fault trips) end-of-life limits.

Specific fleet risks and failure modes

Table 84 shows the principal risks and failure modes related to 11kV indoor CBs. The key risks relate to historical design issues (indoor CB connectors) and building structural risks.

Table 84: Specific risks

Asset	Risk/failure mode	Current controls or treatments
11kV indoor CB	Where the indoor CB does have flexible connections between the racking CB and the panel, the umbilical cord connections can deteriorate	• Minimising CB operation • Annual partial discharge (PD) and acoustic monitoring • 5 yearly testing of contact integrity • We hold spares of these cords and terminal plugs
	Switchgear is located in a building with structural or other defect	Construction of new building and switchgear
	Cracking insulators	• Annual partial discharge (PD) and acoustic monitoring • 5 yearly maintenance and replacement as required
	Obsolescence due to unavailability of spare parts	The South Wales switchgear is obsolete and unsupported. It is scheduled for replacement.
	Arc flash containment risk	Exclusion areas marked. Full PPE required on entry. Remaining board identified and scheduled for renewal.

Fleet population and age

Table 85 shows the population and age of the 11kV indoor CB fleet. There are no CBs within five years of NEL. The average age of the fleet is 20. The oldest eight CBs are 35 years old, and these will be replaced in 2025.

Table 85: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[115] (years)	Population within 5 years of NEL
11kV indoor CB	South Wales HG12/2006	6	35	50	Nil
	South Wales HG12/2012	2	35	50	Nil
	RPS LM23VP/QMRO	4	1	55	Nil
	RPS LMVP RPM1 / QMRO	11	8	55	Nil
	RPS LMVP RPM3 / QMRO	8	11	55	Nil
	RPS LMVP/X11/QMRO	1	17	55	Nil
	RPS LMVP/X4/QMRO	5	29	55	Nil
	RPS LMVP/X4B/QMRO	18	23	55	Nil
	RPS LMVP/X5B/QMRO	24	23	55	Nil

Fleet health, criticality and risk

Asset health is determined using CBARMM. For 11kV indoor CB, we calculated asset health using a combination of asset age, asset location, duty and operations. We have very good quality data that can reliably determine asset health. We intend to improve the range of inputs to determine asset health, including condition and test results, obsolesce risk, industry performance reports and type issues.

As shown in Figure 123 and Figure 124, assets are in good condition. Six CBs will transition to high-risk within the next ten years. These are scheduled for replacement in FY25.

Figure 130: Current Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	12	-	-	-	-	12
C2	38	6	-	-	-	44
C1	23	-	-	-	-	23
Total	73	6	-	-	-	79

Figure 131: 10-Year Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	10	2	-	-	-	12
C2	38	-	-	6	-	44
C1	23	-	-	-	-	23
Total	71	2	-	6	-	79

12.10.4 How the asset fleet is operated, monitored and maintained

Operating the assets

11kV CBs operate to break load during routine network reconfiguration and by the protection relays to interrupt fault current. The number of routine and fault operations are end-of-life drivers, so these are minimised whenever possible. Faults are identified through SCADA monitoring of the protection relays. Faults on 11kV CBs can vary in criticality, and technicians are dispatched to the site to investigate the cause of a fault in all circumstances.

Condition assessment

Table 86 summarises the 11kV CB fleet's current inspection and testing regime. Under normal conditions, the zone substations are inspected every two months; this is a visual, non-intrusive inspection of the external condition of the SWGR and captures the number of operations. Annual non-intrusive testing is also undertaken.

Table 86: Condition assessments

Asset	Type	Scope of assessment	Trigger
11kV indoor CB	Observed	External condition – cabinet assessment	Routine, time-based, bi-monthly

[115] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Asset	Type	Scope of assessment	Trigger
		Internal condition - cabinet assessment	
		Number of operations	
	Measured	Partial discharge assessment for electrical discharge that could indicate insulation breakdown or other condition issues	Routine, time-based, annually
		Acoustic assessment for noise that could indicate conditions issues	
		Infra-red assessment for hotspots	

Maintaining the asset

Table 87 summarises the CB maintenance and operational testing. Follow-up corrective maintenance may occur to address any adverse test results.

Table 87: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
11kV Indoor CB	Operational testing Preventive maintenance	• Comprehensive operational testing using the Omicron CIBANO 500 test set, which includes contact resistance, dynamic contact resistance, various timing tests, motor current, under-voltage release, overcurrent release, insulation resistance and demagnetisation • PD testing before and after cleaning • For indoor CBs, The CB is racked out, and the bushing and framework are cleaned and maintained as per the manufacturer's recommendation • Outdoor CBs are mainly self-contained, and maintenance is limited to lubrication and cleaning of the exposed bushings and terminations	Routine, time-based, 5 yearly
	Corrective	Follow-up corrective maintenance occurs as required	Inspection and test results

12.10.5 How renewal decisions are made on the fleet

CBARMM is used to forecast asset renewals based on risk. Table 88 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast).

Table 88: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
11kV CB types	Renewal forecasts	Includes all assets that are forecast to reach Risk Grades 4 and 5.
	Planned renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers; these include observed or measured conditions outside of acceptable parameters, obsolescence, exceeding design fault operations, exceeding design mechanical operations, age-based end-of-life criteria
	Corrective renewal of refurbishment	Replacement or refurbishment of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 24 months.

12.10.6 Asset renewal and refurbishment forecasts

Table 89 shows the forecast 11kV CB risk and renewals over the next ten years. 18 CBs are due for renewal in the next five years. These renewals are driven by factors not included in CBARMM. It is not currently considered economic to bring the building that contains the switchgear at Levin West up to seismic requirement of IL4. As such, Electra is considering options, which include constructing a new building and installing new switchgear. The other CB replacements are due to obsolescence and load growth.

Table 89: Current and forecast asset risk and renewals

Asset	Type	Population	Current assets with high risk and above	10 Year forecast assets with high risk and above[116]	10 Year forecast renewals and refurbishment
3.3/6.6/11/22kV CB (ground mounted)	All types	79	Nil	Nil	18

12.10.7 Asset renewal and refurbishment provisions and projects

Table 90 shows the specific projects that are proposed. These projects cover the assets identified in Table 89. Specific business cases have not yet been prepared for the Levin West project. Hence, the scope and costs may change.

Table 90: Specific renewal and refurbishment projects

Project	Driver	Cost/Year	Options considered/comments
11kV switchboard replacement, Levin East	Risk-based replacement of CBs due to: • The South Wales switchgear is obsolete and unsupported; • Residual safety risk from arc flash; • Load growth necessitates the extension of the bus, which cannot be achieved with this switchgear	$600k FY26 (total spend is $1.2m)	This project is in progress and will be completed in FY26
11kV Switchboard replacement, Levin West	Risk-based replacement of CBs is due to the substation building being less than IL4[117].	$1.5m FY29-FY31	The business case has not yet been prepared. Timing will be adjusted based on maintenance results and site conditions
Total	**Asset replacement and renewal capex**	**$2.1m**	**FY26 to FY35**

Table 91: Asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
11kV CB renewal	610	-	-	205	205	1,124	-	-	-	-	2,144

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

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116 Before renewal or refurbishment intervention

117 Zone substation buildings should meet IL4 under the national building standard. IL4 means that post-disaster function can be maintained.

12.11 Secondary Systems Fleet Plan

12.11.1 Fleet Overview

Electra's current secondary systems fleet comprises 177 protection relays, and other power quality meters, SCADA remote terminal units, communication gateways, and DC systems. Secondary systems predominantly consist of Intelligent Electronic Devices (IEDs) deployed for network protection, monitoring, control, and data acquisition. These systems are essential for ensuring the safe and efficient delivery of electricity, providing alarms, monitoring equipment status, and measuring and recording relevant electrical parameters of the sub-transmission and distribution network.

Electra replaced almost all electromechanical relays (commencing in the late 1990s) with first-generation numerical relays. These first general numerical relays offered better reliability, less maintenance, and improved protection functionality. Modern-generation numerical relays, which have been available since the mid-2010s, provide material improvements in protection functionality. They allow more types of faults to be detected and more advanced protection schemes to be implemented cost-effectively.

Seven electromechanical relays are being used for transformer protection with zone substations. These are due for replacement.

Electra is currently working on installing power quality meters (PQMs) on the network. When commissioned, these devices will be added to the secondary systems fleet plan and CBARMM model.

Figure 132: Protection Relays

1st Generation Numerical Protection Relay SEL 351S

Current Generation Numerical Protection Relay SEL 751

Note: The SCADA system is discussed in Sections 8 and 9 and the communication system is discussed in Section 12.18.5.

12.11.2 Fleet Management Strategy

The 10-year secondary systems fleet strategy is as follows:
Secondary systems devices are considered as important as the assets they protect/monitor. To keep the fleet relevant and effective, the assets are maintained and replaced based on the following requirements:

- To implement a reliable, selective, sensitive, and stable protection scheme for subtransmission, zone substation and distribution network (which is available with modern generation numerical protection relays);
- Taking a conservative position on asset health and risk where assets are refurbished or replaced *before* risks increase above medium (RG3 and below);
- Adopting a NEL of 20 years to avoid the risk of obsolescence;
- Replacing assets with known type issues;
- Maintained 5 yearly except when governed by external factors (AUFLS)

12.11.3 What is driving our fleet strategy

Current fleet performance

Protection systems are complex, and failures of the protection systems are rare. We have a range of legacy protection schemes (which were appropriate when implemented); however, some recent failures have highlighted vulnerabilities within these schemes, including:

- Slow backup protection response during the 33kV bus fault at Shannon substation. The bus fault indicated that a layered approach using bus-zone protection (using differential relays) would improve the speed and effectiveness of the protection;
- Cascade outages on the subtransmission system due to mutual coupling[118] and reliance on over-current and earth-fault protection. These faults indicate that differential protection schemes are appropriate;
- Reliance on over-current and earth-fault protection can result in some faults not being correctly detected and isolated. Advanced protection schemes improve selectivity through additional fault pick-ups using Sensitive Earth Fault (SEF), High Impedance Fault (HIF) and Intermittent Earth Fault (IntEF) functionality.

Modern-generation numerical protection relays and high-speed communication between substations enable more advanced protection schemes to be implemented.

Specific fleet risks and failure modes

Table 92 shows secondary systems assets' top risks and failure modes. The key risks are technical obsolescence and protection scheme vulnerabilities.

Table 92: Specific risks

Asset	Risk/failure mode	Current controls or treatments
IEDs	Technical obsolescence (where parts and/or support become unavailable)	• We have adopted a NEL of 20 years to ensure that protection schemes remain relevant, current and effective.
	Scheme vulnerabilities	• There is a current project underway to implement standardised, comprehensive protection schemes within Electra's network
	Type issues	• Assess type issues and possible solutions like firmware upgrades. Schedule replacement work if no mitigation is found to resolve the type issue.
	Exposure to the external environment	• Outdoor cabinets are inspected during routine inspections, and any corrosion or other issues that could result in moisture ingress are identified and resolved.

[118] This is the phenomenon where electromagnetic fields generated by one power line induce currents in a nearby parallel line.

Fleet population and age

Table 93 shows the population and age of the secondary systems. We have adopted a 20-year NEL for protection relays to mitigate obsolescence risk. As a result, we have 50 relays exceeding and a further 28 relays within five years of NEL.

Table 93: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[119] (years)	Population within 5 years of NEL
Protection relays	Numerical first- and modern-generation	170	14	20	71
	Electromechanical/Static	7	36	20	7
Power quality meters	To be included in the 2026 AMP				

Fleet health, criticality and risk

The health of protection relays is determined using CBARMM. We calculated asset health using a combination of asset age, asset location and reliability. We have very good quality asset age data that can provide a reliable indicator of asset health (primarily as obsolescence is the key driver).

As shown in Figure 133 and Figure 134, assets are generally in good condition. Asset health and risk drivers are predominantly asset age (concerning the older electromechanical and static relays and the older first-generation numerical relays).

Figure 133: Current Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	13	-	2	-	7	22
C2	77	20	27	-	9	133
C1	12	1	9	-	-	22
Total	102	21	38	-	16	177

Figure 134: 10-Year Asset Health Risk Assessment

	HIB1	HIB2	HIB3	HIB4	HIB5	Total
C4	-	-	-	-	-	-
C3	5	5	-	2	10	22
C2	29	24	2	18	60	133
C1	2	4	3	2	11	22
Total	36	33	5	22	81	177

The health of our other secondary systems is not presently included in CBARMM. For these assets, asset renewals are undertaken based on time (in the case of DC system chargers and batteries) or when defects occur. The SCADA system is discussed in Sections 8 and 9.

12.11.4 How the asset fleet is monitored and maintained

Condition assessment

Table 94 summarises the fleet's current inspection and testing regime.

Table 94: Condition assessments

Asset	Type	Scope of assessment	Trigger
Relays	Observed	Observed during routine substation inspections	Routine substation inspections
	Measured	Primary and Secondary injection tests	Suspect operation or malfunction
DC systems	Observed	Observed during routine substation inspections	Routine substation inspections

[119] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Maintaining the asset

Maintenance on protection relays is undertaken on a 5-yearly schedule, excluding devices configured for AUFLS. Devices set up to comply with the Automatic Under Frequency Load Shedding scheme will be tested on a 4-yearly basis as required by Transpower.

Table 95: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Relays	Corrective	Defects	• Suspect operation or malfunction
	Preventive	Primary and Secondary injection tests	• Routine time-based, 4 or 5-yearly
DC systems	Preventive	Replacement of batteries and charger	• Routine time-based, 10-yearly

Power quality meters have only been recently installed on the network. Inspection and maintenance plans for these assets are being considered (based on the manufacturers' recommendation) and will be included in future AMPs.

12.11.5 How renewal decisions are made on the fleet

Table 96 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast) for secondary systems.

Table 96: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Relays	Renewal forecasts	Includes all assets that are forecast to reach Risk Grades 4 and 5, where the assets are forecast to reach NEL, or where specific protection scheme vulnerabilities need to be remediated.
	Renewal and refurbishment Projects	All assets identified in the renewal forecasts will be included as specific renewal projects.
	Corrective renewal of refurbishment	Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 24 months.
DC systems	Renewal and refurbishment Projects	Routine 10 yearly replacement programme

12.11.6 Asset renewal and refurbishment forecasts

Table 97 shows the protection relay forecast asset risk and renewals over the next ten years. Of the 99 relays forecast for renewal, 64 are due in the next five years. The forecast renewals will maintain the fleet at an acceptable risk level as relays exceeding their NEL (i.e. at end-of-life) have been prioritised for replacement. The replacement projects will address any vulnerabilities that will result in an overall increase in the asset register.

Forecast renewals are higher than forecast risk for protection relays as some relays are being replaced to remove known protection vulnerabilities.

Table 97: Current and forecast asset risk and renewals

Asset	Type	Population	Current assets with high risk and above	10 Year forecast assets with high risk and above[120]	10 Year forecast renewals and refurbishment
Relays	Numerical, Static and Electromechanical	177	16	90	94

12.11.7 Asset renewal and refurbishment provisions and projects

Table 98 shows the specific projects or provisions that are proposed. These projects cover the relays and gateways identified as relays in Table 97. The programme to replace the DC system is also included. This programme involves designing a new standardised system to install at each substation progressively.

Table 98: Specific renewal and refurbishment projects

Project	Driver	Cost/Year	Options considered/comments
Replacement of the DC system	Programme to replace the DC system with a modern and standardised system at all zone substations	$1.3m FY26-35	DC systems are replaced on a 10-yearly basis in line with manufacturer recommendations. A business case is being prepared that may alter the timing and costs.
Waikanae transformer protection replacement	Electromechanical relays have reached end-of-life (being 40 years old). The protection scheme is being upgraded. (4 relays)	$578k FY26-27	Risk-based replacement. Given the importance of these assets, replacement is appropriate to remove obsolescence risk and vulnerabilities associated with the legacy protection schemes
Foxton Line differential protection replacement	Protection is reaching end-of-life. The scheme also has vulnerabilities due to mutual coupling. The project will also improve the protection scheme and implement unit protection (2 relays)	$320k FY26	As above
Levin East line differential protection upgrade	The current protection has vulnerabilities due to mutual coupling. The project will also improve the protection scheme and implement unit protection (4 relays)	$454k FY26-27	As above
Ōtaki line differential and bus zone upgrade	Protection is reaching end-of-life. The scheme also has vulnerabilities due to mutual coupling. The project will also improve the protection scheme and implement unit protection and bus zone protection (4 relays)	$345k FY26-27	As above
Foxton protection replacement	Protection is reaching end-of-life. The project will also improve the protection scheme and implement bus zone protection (6 relays)	$648k FY27-28	As above
Paraparaumu West 11kV protection replacement	Protection is reaching end-of-life. The project will also improve the protection scheme and remove any current vulnerabilities	$1.23m FY27-28	As above

[120] Before renewal or refurbishment intervention

Project	Driver	Cost/Year	Options considered/comments
	(8 relays)		
Shannon protection upgrade	Protection is reaching end-of-life. The project will also improve the protection scheme and remove any current vulnerabilities (20 relays)	$964k FY28-29	As above
Raumati protection upgrade	Protection is reaching end-of-life. The project will also improve the protection scheme and remove any current vulnerabilities (13 relays)	$1.0m FY29-30	As above
Raumati sub-transmission protection upgrade	Protection is reaching end-of-life. (2 relays)	$317k FY29-30	As above
Paraparaumu East protection upgrade	Protection is reaching end-of-life. The project will also improve the protection scheme and remove any current vulnerabilities (25 relays)	$1m FY33-34	As above
Waikanae sub-transmission protection upgrade	Sub-transmissions are reaching end-of-life. (6 relays)	$462k FY34-35	As above
Paraparaumu West sub-transmission protection upgrade	Sub-transmissions are reaching end-of-life. (5 relays)	$462k FY35	As above
Total	**Asset replacement and renewal capex**	**$9.1m**	**FY26-35**

Table 99: Asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Secondary systems	2,077	1,481	1,129	1,391	492	123	123	941	685	687	9,127

Protection upgrades are also required at Levin West and Levin East. These will be scoped and added to the programme for the 2026 AMP.

We also have a programme to improve the reliability and performance of the communication system by installing fibre links between some substations (refer to Section 11.12.3). The differential/unit protection schemes will rely on these links.

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.12 Overhead Structures Fleet Plan

12.12.1 Fleet Overview and Strategy

Our overhead structure fleet consists of concrete and steel poles, wood poles and crossarms. These assets form the backbone of the network and support the sub-transmission, distribution and LV conductors.

Electra has 20,447 concrete poles (over 95%), 25 steel and 953 wood poles.[121] These range in age from new to 84 years and have been sourced from various suppliers, including the Horowhenua Electric Power Board's pole factory. Each pole has at least one crossarm, but there can be multiple crossarms where the pole is carrying multiple lines, which may be at different voltages.

The concrete poles are predominately mass-reinforced (86% of the fleet), with the remainder being of pre-stressed construction. Wood poles are a mix of hardwood and softwood.

Electra utilises traditional hardwood crossarms. Hardwood crossarms expected life is around half that of a pre-stressed concrete pole; hence, mid-life crossarm replacements are required. This is driving the higher crossarm replacement rate (c.f. poles).

Figure 135: Example of Pole Structures

New 11kV and LV Pre-Stressed Concrete Pole

Existing 33kV Two-Pole Structure

There is a high number of assets in this fleet, and failures can occur that interrupt supply. However, the sub-transmission and distribution network has inherent security, meaning supply can generally be restored to the un-faulted line sections through alternative lines. Overall, the fleet is performing as expected, but some issues are emerging from aging assets and harsh environmental conditions in coastal areas. This is consistent with the age and location of the fleets.

The 10-year fleet strategy is as follows:
Our strategy for the fleet is to: • Replace all assets commensurate with their risk—that is, to replace assets before failure (under normal loading), which is at Risk Grade 4 and 5; • Continually enhance our asset age and condition data to improve the reliability of the asset health forecasting (including reducing the number of assets with default ages); • Prioritise the renewal of wood poles due to their short life expectancy and complexity in accurately determining asset health.

[121] As at 31 March 2024.

12.12.2 What is driving our fleet strategy

Current fleet performance

Over the past five years, the overhead line fault rate (from all causes, including overhead structures and conductors) was 13.5 faults/100km for distribution lines and 1.4 faults/100km for sub-transmission. This is comparable to our peers for distribution lines (13.7 faults/100km) and substantially better for sub-transmission (3.4 faults/100km).[122] The very good subtransmission performance reflects the higher level of condition monitoring (and associated follow-up) for these assets.

Defective equipment fault rates are recorded at 0.02 faults per 1,000 units per year for poles and 0.2 per 1,000 units per year for crossarms. Most overhead structure defective equipment faults relate to insulators and jumpers (averaging around seven per year).[123] Given the very few defective equipment failures and no observable deteriorating trend, we consider the overhead structure fleet is operating reliably.

Overhead hardware is exposed to the elements impacted by the sea spray in coastal environments and higher winds. As with most assets in New Zealand, the sun also plays a large part in aging assets faster due to UV exposure. Accelerated corrosion occurs in some insulator types and older kidney strain insulators.

We have been experiencing some corrosion of the internal structural rebar of concrete poles, resulting in spalling and cracking of the pole. We only install concrete poles for new installations as they are known to last longer and perform better over their life.

We have observed that more heavily loaded concrete poles are deteriorating faster.

Also, issues stem from brittle insulators, again arising from corrosion, which is prominent on our DDOs and kidney strain insulators.

Specific fleet risks and failure modes

Table 100 shows the top risks and failure modes for overhead structures. Condition monitoring and maintenance (as shown in Table 102 and Table 103) identify and reduce failure risks.

Table 100: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Softwood poles	Rot and checking of wood	All wood pole types are assigned an appropriate NEL within CBARMM. Where end-of-life condition drivers are identified from routine inspection, an increased deterioration rate is applied with CBARMM. Assets are scheduled for replacement within one year when significant end-of-life drivers are found (which raises the risk to RG5).
Concrete Poles	Spalling and cracking exposing rebar	Where end-of-life condition drivers are identified from routine inspection, an increased deterioration rate is applied with CBARMM. Assets are scheduled for replacement within one year when significant end-of-life drivers are found (which raises the risk to RG5).
Concrete Poles	Leaning poles due to deteriorating blocking	Routine inspection and replacement of blocking and straightening of poles

[122] Median, FY20-FY24.

[123] Defective equipment faults for FY20 to FY24. Benchmark data is not readily available. We don't have reliable quantity data for insulators and jumpers, so per unit fault rates are not available.

Asset	Risk/failure mode	Current controls or treatments
Steel poles	Corrosion	Where end-of-life condition drivers are identified from routine inspection, an increased deterioration rate is applied with CBARMM. Assets are scheduled for replacement within one year when significant end-of-life drivers are found (which raises the risk to RG5).
All poles	Loading exceeding design limits due to external factors (e.g. storm windspeed or tree fall)	Poles designed to NZS 4676:2000. Implement the vegetation management plan to reduce the risk of vegetation damage (refer to Section 12.19.2).
	Vehicle damage	Additional physical protection or pole relocation in areas of know vehicle damage risks
Crossarms	Rot and checking of wood and king bolt/nut failure	Asset replacement is scheduled where end-of-life condition drivers are identified from routine inspection.
Kidney strain insulators	Fracturing of brittle insulators due to tension	Asset replacement is scheduled where end-of-life condition drivers are identified from routine inspection. Proactive replacement of where this can be achieved in conjunction with other scheduled work.

Fleet population and age

Table 101 shows the population and age of the overhead structure fleet. We have few wood poles reaching NEL presently; however, this is expected to increase over the coming decade.

Table 101: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[124] (years)	Population within 5 years of NEL
Poles	Softwood	709	35	45	90
Poles	Hardwood	244	59	50	12
Poles	Concrete poles	20,447	32	65	2,291
Poles	Steel structure	25	30	65	2
Crossarms	Distribution Crossarms	26,600[125]	-	40	-

Fleet health and risk

Asset health is determined using CBARMM. For overhead structures, we calculated asset health using a combination of asset age, asset location, asset type reliability, asset material, and inspected condition. We have good quality asset age and condition data that is a reasonable health predictor. There are still outlying data issues within the distribution fleet (relating to pre-1995 assets), and we plan to increase data quality and remedy known issues further.

Concrete poles are in good condition; however, due to the criticality of some poles, around 4% of the assets will be at risk grade 4 or 5 within five years (refer to Figure 136). Wood poles show more significant health deterioration indicators due to their shorter NEL. However, many wood poles are located in areas with low criticality. Hence, fewer high-risk poles need replacement (refer to Figure 137). As new condition information is captured during routine inspections, we expect to see movement in the health and risk assessments in future AMPs.

[124] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

[125] The crossarm count is understated and data is be validated.

For crossarms, 5% will be at risk grade 4 or 5 within five years (refer to Figure 138). We are undertaking further analysis and verification of crossarm data over the next year; hence our view on risk may change in future AMPs.

Figure 136: Asset Health and Risk, Concrete and Steel Poles

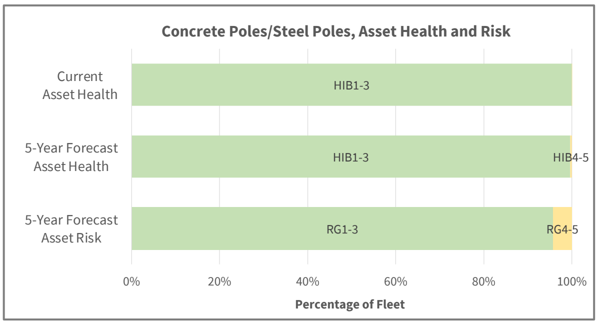


Figure 137: Asset Health and Risk, Wood Poles

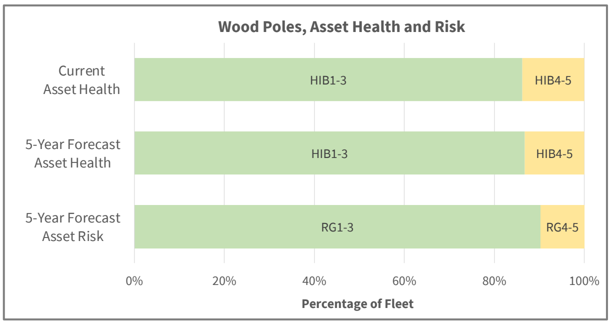
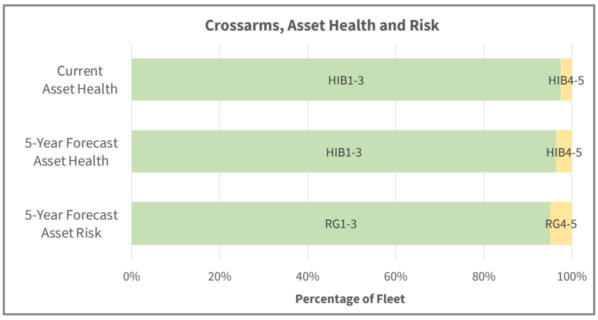


Figure 138: Asset Health and Risk, Crossarms



12.12.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Table 102 summarises the distribution fleet's current inspection and testing regime. Electra makes use of full-time network inspectors to assess the distribution network. These inspections happen routinely, and the entire distribution fleet is inspected at least once every 5 years. Sub-transmission assets are inspected annually.

Table 102: Condition assessments

Asset	Type	Scope of assessment	Trigger
Concrete/Steel poles	Observed	Routine inspection of visual condition including the integrity of concrete and reinforcing, corrosion (of steel poles), pole lean, line clearances, foundation slumping or subsidence	11kV and LV time-based, 5 yearly 33kV time-based, annual
Softwood/Hardwood poles	Observed	Routine inspection of visual condition, including rot, fungus, splitting of timber becomes greater than finger-width, warping or twisting of timber strains, heart timber becomes exposed, deterioration of timber more than surface deep (especially at ground level), pole lean, line clearances, foundation slumping or subsidence	11kV and LV time-based, 5 yearly 33kV time-based, annual
Crossarms	Observed	Routine inspection for rot, fungus, lichen/moss, burning or scorching possibly from tracking, rust on galvanised steel arms more than surface deep, corrosion of stays significant enough to reduce physical strength, loose or fallen stays, corrosion of bolts, missing nuts, plate washers or spring washers, chipped or cracked insulators, broken binders	11kV and LV time-based, 5 yearly 33kV time-based, annual

Maintaining the asset

Where necessary, corrective maintenance occurs following routine inspection results and fault responses. Maintenance is undertaken to minimise the risk of faults due to asset condition or where further asset deterioration could increase safety risk. Maintenance occurs where this is more economic than asset replacement (from a total lifecycle perspective).

Table 103: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Poles	Corrective	Straightening or reblocking of poles	• Routine inspections or defect order: where the lean is greater than 7°
Poles, concrete	Corrective	Repair of hairline cracks in concrete using commercially proven grout and treatments	• Routine inspections or defect order: concrete cracking detected
crossarms	Corrective	Replace insulators	• Routine inspections or defect order: Cracked/broken/leaning insulators

12.12.4 How renewal decisions are made on the fleet

CBARMM is used to forecast asset renewals. Table 104 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast). When projects are being selected, priority is given to the worst performing feeders (refer to Section 4.5.9).

Table 104: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
All pole types and crossarms	Renewal forecasts	Includes all assets where the risk increases above RG4
	Corrective renewal of refurbishment	Replacement or refurbishment of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 3 months
Wood poles	Renewal and refurbishment projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including checking, rotting at ground level, damage to wood around fittings (such as crossarm kingbolt)
Concrete poles	Renewal and refurbishment projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including cracking or missing concrete, exposed rebar, bending, leaning over acceptable limits
Steel Poles	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including bending, leaning over acceptable limits, rust/corrosion
Crossarms	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including rot, checking, cracking

12.12.5 Asset renewal and refurbishment forecasts

Table 105 shows the forecast overhead structure asset health, risk and renewals over the next five years. Forecast renewals address all high-risk assets. We have allowed for a higher replacement rate for concrete poles and crossarms to account for additional replacements during the reconductoring programme (a proportion of poles and crossarms are replaced during reconductoring due to health or strength assessments).

As mentioned in Section 12.12.2, condition data and health assessment is constantly evolving; hence, we expect to see movement in forecast renewals in future AMPs.

Table 105: Current and forecast asset risk and renewals

Asset	Type	Population[126]	5 Year forecast of assets with low health grade[127]	5 Year forecast of assets with high risk and above[128]	5 Year forecast renewals and refurbishment
Poles	Concrete and Steel	20,472	0.2%	4.8%	6.3%
	Wood	953	13.2%	9.7%	9.7%
Crossarms	All types	26,605	3.5%	5.0%	16%[129]

12.12.6 Asset renewal and refurbishment programmes

Table 106 shows the planned pole and crossarm renewal programmes. These projects/provisions cover the assets identified in Table 105. Most of the pole and crossarm replacements occur during reconductoring.

Table 106: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY26-30	FY31-FY25	Total
Poles				
33kV pole replacements, risk and inspection driven	Approximately 60 poles p.a.	1,684	1,691	3,375
11kV pole replacements, risk and inspection driven	Approximately 11 poles in FY26, and 22 p.a. from FY27	829	984	1,813
11kV pole replacements during reconductoring	Some poles need to be replaced during reconductoring to meet existing network standards or due to condition or strength. Approximately 32 poles in FY26 and 62 poles p.a. from FY27	2,422	2,695	5,117
LV pole replacements, risk and inspection-driven	Approximately 16 poles in FY26, then 17 p.a. from FY27	517	573	1,090
LV pole replacements during reconductoring	Some poles need to be replaced during reconductoring to meet existing network standards or due to condition or strength. Approximately 102 poles in FY26 and 131 poles p.a. from FY27	4,136	4,355	8,491
Crossarms				
33kV crossarm replacements, risk and inspection driven	Approximately 62 crossarms in FY26 and 80 p.a. from FY27	2,268	2,279	4,548
11kV crossarm replacements, risk and inspection driven	Approximately 78 crossarms in FY26 and 150 p.a. from FY27 Note: This includes the programme prioritising kidney strain insulator replacements, which will be factored into the prioritisation for renewals	2,656	2,957	5,613
11kV crossarm replacements during reconductoring	Some crossarms need to be replaced during reconductor to meet existing network standards or due to condition or strength. Approximately 46 crossarms in FY26 and 184 p.a. from FY27	3,089	3,647	6,735
LV crossarm replacements, risk and inspection-driven	Approximately 82 crossarms p.a.	1,615	1,623	3,238

126 As at 31 March 2024.

127 HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

128 Risk Grade 4 and 5. Before renewal or refurbishment intervention.

129 4,260 crossarms are forecast for replacement. The crossarm count is understated (and data is be validated), which has overstated the percentage of the fleet being renewed.

Project/Programme	Description	FY26-30	FY31-FY25	Total
LV crossarm replacements, during reconductoring	Some crossarms need to be replaced during reconductor to meet existing network standards or due to condition or strength. Approximately 260 crossarms in FY26 and 437 p.a. from FY27	7,766	8,493	16,259
Unplanned replacement of crossarms (all voltages)	Fault and urgent defect replacement of crossarms	153	153	306
Unplanned replacement of poles (all voltages)	Fault/urgent defect pole replacement includes car vs. poles and normal-year weather events Note: No allowance is included for major storm replacements.	1,156	1,193	2,349
Total	**Asset replacement and renewal capex**	**28,295**	**30,644**	**58,939**

Table 107: Asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Overhead structures (poles and crossarms)	3,873	6,071	6,087	6,128	6,136	6,125	6,123	6,127	6,123	6,146	58,938

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.13 Overhead Conductor Fleet Plan

12.13.1 Fleet Overview and Strategy

Electra has 186km of 33kV overhead conductor, 849km of 11kV overhead conductor and 523km of LV overhead conductor.[130] Most overhead conductors were installed between 1960 and 1990, when the network grew significantly. 7% of the 11kV and 55% of LV overhead conductors are copper—much of this was installed before 1960 and is falling due for replacement. The remaining overhead conductor is mostly aluminium or aluminium overhead conductor steel reinforced (**ACSR**). ACSR combines highly conductive aluminium with a steel core for good conductivity and strength. It is used extensively on the 11kV network.

All LV copper overhead conductors are bare, and 151km of the aluminium LV overhead conductor is also bare. All new LV overhead conductors are covered (i.e. insulated), which improves safety.

Like overhead structures, there is a high number of assets in this fleet, and failures can occur that interrupt supply. However, the sub-transmission and distribution network has inherent security, meaning supply can generally be restored to the un-faulted line sections through alternative lines.

The 10-year fleet strategy is as follows:
Our strategy for the fleet is to: • Replace all assets commensurate with their risk—that is, to replace assets before failure (under normal loading), which is at Risk Grade 4 and 5; • Prioritise the renewal of old copper overhead conductors that are reaching end-of-life;

[130] As at 31 March 2024.

- Assess and adopt industry standard condition assessment techniques to improve condition data and the reliability of the asset health forecasting;
- Build data on joints and develop a strategy for health assessment and proactive joint replacements.

12.13.2 What is driving our fleet strategy

Current fleet performance

Overhead conductors have generally been operated reliably, with very low defective equipment fault rates. Defective equipment fault rates are recorded at 1.1 faults per 100km/year. Many of these faults relate to conductor connectors and clamps (rather than the conductor).[131] There is no observable deteriorating trend.

End-of-life drivers for replacement are appearing on copper overhead conductors. This is driven by corrosion due to exposure to coastal conditions. Failures are highest where assets are exposed to coastal conditions.

We are also experiencing increased joint failures due to expansion/contraction due to the thermal effects of load changes. This can lead to water ingress and dissipation of the jointing paste, galvanic corrosion and eventual failure.

Our overhead line fault rate (including structures and overhead conductors) is comparable to the industry for distribution lines and favourable for subtransmission lines (refer to Section 12.12.2). The very good subtransmission performance reflects the higher level of condition monitoring (and associated follow-up) for these assets.

Specific fleet risks and failure modes

Table 108 shows the top risks and failure modes overhead conductors. Condition monitoring and maintenance (as shown in Table 110 and Table 111) identify and reduce failure risks.

Table 108: Specific risks

Asset	Risk/failure mode	Current controls or treatments
All overhead conductors	Joints failure	Where end-of-life condition drivers are identified from routine inspection, an increased deterioration rate is applied with CBARMM. Assets are scheduled for replacement within one year when significant end-of-life drivers are found (which raises the risk to RG5).
Bare overhead conductor	Corrosion and failure of overhead conductor strands	
Copper overhead conductor	Embrittlement of overhead conductor strains due to vibration	
All overhead conductors	Loading exceeding design limits due to external factors (e.g. storm windspeed or tree fall)	Overhead conductor tension designed to AS/NZS7000:2016. Implement the vegetation management plan to reduce the risk of vegetation damage (refer to Section 12.19.2).
All overhead conductor	Overhead conductor sagging which breaches minimum line clearances to the ground and buildings	Line clearances are assessed during routine inspections and any issues are resolved

[131] Defective equipment faults for FY20 to FY24. Benchmark data is not readily available.

Fleet population and age

Table 109 shows the population and age of the overhead conductors. 14% of the 33kV overhead conductor is above NEL. 24% of 11kV and 60% of LV overhead conductors are also within five years of NEL.

Table 109: Asset fleet quantity and age

Asset	Type	Population	Average Age (years)	NEL[132] (years)	Population within 5 years of NEL
33kV overhead conductor	Aluminium	128.6 km	39	65	Nil
	Copper	57.3 km	38	65	25.1 km
11kV overhead conductor	Aluminium	789.1 km	38	65	144.5 km
	Copper	59.8 km	66	60	56.5 km
LV overhead conductor	Bare Aluminium	155.6 km	42	65	35.9 km
	Covered Aluminium	83.2 km	21	65	5.7 km
	Bare copper	214.8 km	62	60	208.7 km
	Covered copper	73.3 km	62	60	65.2 km

Electra also has 64km of streetlighting overhead conductors. These are managed in conjunction with the associated LV overhead conductors.

Fleet health and risk

Asset health is determined using CBARMM. For overhead conductors, we calculated asset health using a combination of asset age, asset location, asset type reliability and asset material. Asset age data is very good for subtransmission and good for distribution and LV overhead conductors. Due to the complexity of assessing overhead conductor condition, our modelling only provides an indicative view of asset health.

For the 33kV overhead conductor, the lower health assets are predominantly driven by older copper overhead conductors on the Mangahao to Levin East circuit. Most segments on these circuits have high criticality. Hence, the forecast risk largely follows the health forecast (refer to Figure 139).

For the 11kV overhead conductor, the lower health assets are driven by older copper overhead conductors; however, due to lower criticality, none of these overhead conductors are forecast to transition to high risk (refer to Figure 140).

For the LV overhead conductor, a high proportion of older copper and aluminium overhead conductors are driving asset risk. The high-risk assets represent around 50% of the fleet (refer to Figure 141).

Due to these issues, the length of 11kV and LV overhead conductor replacement over the next ten years has doubled from the previous AMP.

[132] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Figure 139: Asset Health and Risk, 33kV Overhead Conductor

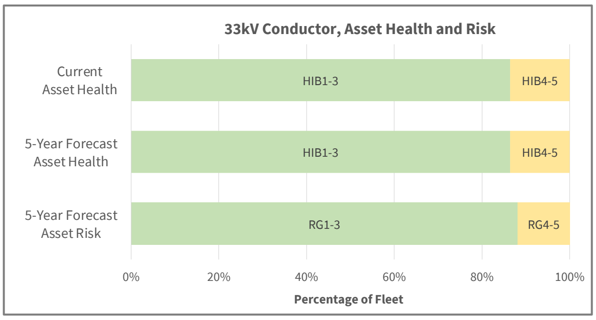


Figure 140: Asset Health and Risk, 11kV Overhead Conductor

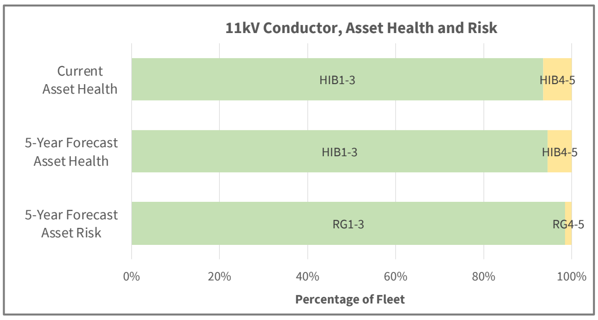
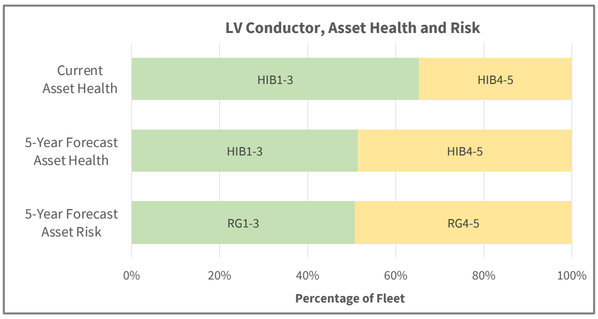


Figure 141: Asset Health and Risk, LV Overhead Conductor



12.13.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Currently, our routine inspections do not deliver reliable data to drive overhead conductor asset health in CBARMM. We are keeping abreast of industry developments for overhead conductor condition assessment (as aging overhead conductor fleets is an industry-wide issue). We plan to adopt better assessment techniques when these become available. Table 110 summarises the distribution fleet's current inspection and testing regime—this data is used to identify defects and define specific renewal projects.

11kV and LV assets are inspected at least once every 5 years. Sub-transmission assets are inspected annually.

Electra intends to complete the physical strength and remaining life tests on 33kV overhead conductors removed from service. These test results are a critical part of condition assessment and will be used to assist the development of the replacement programme for 33kV and 11kV circuits

Table 110: Condition assessments

Asset	Type	Scope of assessment	Trigger
Overhead conductors, all	Observed	Routine inspection for stretching, elongation or necking consistent with annealing, bird-caging of complete overhead conductor, clearance of live overhead conductors from ground, trees, other parties' wires and surrounding structures, excessive surface corrosion, overall integrity of complete overhead conductor	11kV and LV, time-based, 5 yearly 33kV, time-based, annually
Overhead conductors, 33kV	Measured	Thermography survey for heating of joints and terminations (including on overhead switchgear)	Time-based, 5 yearly

Maintaining the asset

Overhead conductor maintenance is limited to re-tensioning and joint/termination replacements (refer to Table 111).

Table 111: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Overhead conductors, all	Corrective	Re-tensioning of lines that do not meet NZECP 34	• Routine 5 yearly inspections where the distance between the ground/structure and the overhead conductor
	Corrective	Joint or termination replacements	• Routine 5 yearly inspections where corrosion on joints and terminations is observed

12.13.4 How renewal decisions are made on the fleet

Table 112 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast). CBARMM is used to forecast asset renewals. For overhead conductors, this is aged-based for 33kV and 11kV and observed-condition-based for LV.

When projects are being selected, priority is given to the worst performing feeders (refer to Section 4.5.9).

Table 112: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Overhead conductors, all	Renewal forecasts	Age-based health and risk forecasting. All assets where the age is above NEL are defined as HIB4 or HIB5. The risks associated with many of the HIB4 assets are manageable. For LV overhead conductors, the forecast renewals reflect known condition issues (which are lower than the forecast age-based health/risk forecasts).
	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the age of the asset and the presence of end-of-life drivers, including spragging, powdering, bird-caging, inline joints, EPOs

12.13.5 Asset renewal and refurbishment forecasts

Table 113 shows the forecast for overhead conductor asset health, risk, and renewals over the next five years.

33kV overhead conductor renewals are being considered for the Mangahao to Shannon line (but are dependent on the new Northern GXP not proceeding) and sections of the Levin West to Levin East and Foxton to Levin West lines (which will occur from FY30). These projects have dual renewal and development drivers and have been included in the development section (refer to Section 11.9.3). These projects amount to the renewal of 12.7% of the 33kV overhead conductor.

The 11kV conductor renewals are higher than forecast risk due to the copper conductor renewal programme, which is addressing all low health copper conductors.

The current forecast renewals for LV overhead conductors are below forecast health and risk—the current forecast addresses assets with observed condition issues (around 50% of assets at Risk Grade 5). As noted in Table 112, the current renewal forecasts are age-based. We are not seeing any material deterioration in LV performance or outages that would indicate a higher renewal rate is required.

As mentioned in the fleet strategy, we are looking at ways to enhance condition data to improve asset health and risk forecasts. Over time, this will improve asset health and risk forecasting. If a new Northern

GXP is commissioned, the future use (and criticality) of 33kV lines (with old copper overhead conductors) may change, altering the view of asset risk in future AMPs.

Table 113: Current and forecast asset risk and renewals

Asset	Type	Population[133]	5 Year forecast of assets with low health grade[134]	5 Year forecast of assets with high risk and above[135]	5 Year forecast renewals and refurbishment
Overhead conductor	33kV overhead conductor	186 km	13.6%	11.9%	0.2%
	11kV overhead conductor	849 km	5.4%	1.5%	6.5%
	LV overhead conductor	523 km	48.6%	49.3%	14.6%

12.13.6 Asset renewal and refurbishment programmes

Table 114 shows the planned overhead conductor programmes.

Table 114: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY26-30	FY31-FY25	Total
33kV overhead conductor upgrades	Upgrade of sections of the Levin West to Levin East and Foxton to Levin West lines (refer to Section 11.9.3)	-	-	-
11kV reconductoring	Replacement of all old copper overhead conductors over the next ten years 12.4km overhead reconductoring p.a.	10,842	11,517	22,359
LV reconductoring	Replacement of all old copper overhead conductors over the next ten years 16.2km overhead reconductoring p.a.	4,551	5,137	9,687
Unplanned replacement of overhead conductor (all voltages)	Fault/urgent defect overhead conductor replacement (includes normal-year weather events only)	76	77	153
Total	**Asset replacement and renewal capex**	**15,469**	**16,730**	**32,198**

Table 115: Asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Conductor	2,133	3,315	3,323	3,346	3,350	3,344	3,343	3,345	3,343	3,355	32,198

Note: the LV reconductoring project includes the replacement of any associated street lighting overhead conductor.

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

133 As at 31 March 2024.

134 HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

135 Risk Grade 4 and 5. Before renewal or refurbishment intervention.

12.14 Cable Fleet Plan

12.14.1 Fleet Overview and Strategy

Electra has 31km of 33kV cable, 268km of 11kV cable and 535km of LV cable.[136] The 33kV cables are modern cross-linked polyethene insulated with steel wire armour (**XLPE**) installed progressively since the 1990s. The 11kV cables consist of XLPE-insulated and older paper-insulated lead-sheathed (PILC). There are no first-generation XLPE cables that were prone to water-treeing and insulation breakdown. The PILC cables were mainly installed between 1960 and 1990. LV cables are predominantly modern PVC-insulated (87%) and XLPE-insulated (12%), with a very small amount of old PILC-insulated (0.2%).

Figure 142: Cable Types

There is a high number of assets in this fleet, and failures can interrupt supply; however, these are rare as cables are generally not exposed to environmental factors. The sub-transmission and distribution network has inherent security, meaning supply can usually be restored to the un-faulted line sections through alternative lines.

We have an aging fleet of 11kV and LV cables, and reliability- and defect-driven replacements will likely increase for this fleet in future AMPs. We also have some old pitch-filled pothead and in-line cable joints on poles that present public safety risks that need to be addressed.

The 10-year fleet strategy is as follows:
Our strategy for the fleet is to: • For 33kV cables (where health can be reliably determined), replace assets commensurate with their risk—that is, to replace all assets forecast at Risk Grade 4 and 5; • For 11kV and LV cables (where health cannot be reliably determined), replace assets where performance issues are detected; • Investigate any reliability issues to determine if any associated asset health issues need to be addressed; • Identify and replace all in-line cable joints on poles and all older pothead terminations; • Assess and adopt industry standard condition assessment techniques to improve condition data and the reliability of the asset health forecasting for 11kV and LV cables.

[136] As at 31 March 2024.

12.14.2 What is driving our fleet strategy

Current fleet performance

Over the past five years, the underground cable fault rate (all causes) was 5.2 faults/100km for distribution cables and 0.0 faults/100km for sub-transmission. This is comparable to our peers for distribution cables (5.8 faults/100km) and sub-transmission (0.0 faults/100km).[137] When we consider defective equipment faults only, most of these are related to the failure of cable terminations (nine in the past five years). By comparison, there were only two faults caused by cable joints.

End-of-life drivers for replacement are beginning to appear on older PILC cables and some older-style joints and terminations. These are rare; however, we expect failures to increase with the aging fleet. Repairing underground cables, joints, and terminations can be time-consuming, leading to extended outages for customers supplied from the faulted assets.

Specific fleet risks and failure modes

Table 116 shows the top risks and failure modes of cables. These include failure modes from normal deterioration and type issues relating to pitch-filled potheads and in-line joints on poles.

Pitchfilled potheads have failure modes related to the trifurcation within the bitumen insulation that could result in leaks, fires, and explosions. There was a short historic practice of installing 11kV in-line cable joints on poles, which poses a safety risk to the public should the joint fail. All the in-line cable joints were fitted with pole covers which partially mitigates the risk.

Table 116: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Cables (all)	Insulation deterioration due to the natural aging process	Partial discharge condition data is only available for subtransmission, which can reliably determine asset health in CBARMM. Assets are scheduled for replacement within one year when significant end-of-life drivers are found. For 11kV and LV, health and risk cannot be reliably forecast, so it is assessed based on reliability. Assets are scheduled for replacement within one year when reliability issuers are identified.
	Failure due to in-line joints	
Cables (LV)	Failure due to in-line joints Deterioration of internal connections resulting in livening of pillar lid	
11kV riser pole Inline cable joints	Failure of the cable joint that could result in leaks, fires, explosions	These are currently ducted to contain arc flash. However, a proactive replacement program is planned
Pitchfilled pothead OH/UG cable trifurcation	Failure of trifurcation within bitumen that could result in leaks, fires, explosions	Implementation of the replacement programme for all potheads over the next ten years
Cables (all)	Damage from third-party	Implementation of the public safety management system, including the dial-before-you dig process.

Fleet population and age

Table 117 shows the population and age of the cables. LV cables are the only asset with material quantities within five years of NEL (58%).

[137] All fault cases. Median, FY20-FY24.

Table 117: Asset fleet quantity and age

Asset	Type	Population[138]	Average Age (years)	NEL[139] (years)	Population within 5 years of NEL
33kV cable	XLPE-insulated	31 km	27	45	Nil
11kV cable	XLPE-insulated	147 km	19	45	2.0 km
	PILC-insulated	121 km	39	60	2.3 km
LV Cable	All types	535 km	37	45-60	308 km

Fleet health and risk

Asset health is determined using CBARMM. For cables, we calculated asset health using a combination of asset age, asset location, asset type reliability and asset material. Asset age data is good for all cables. Due to the complexity of assessing cable condition, our modelling only provides an indicative view of asset health.

There are no current or forecast health or asset risks for 33kV cables (refer to Figure 143).

Asset health and risk are forecast to deteriorate for 11kV and LV cables. This relates to the aging of the 11kV PILC cables and older PVC (and a very small quantity of PILC) LV cables (refer to Figure 144 and Figure 145). The risks associated with pitch-filled potheads and in-line cable joints relate to subcomponents of cables and are not included in the health and risk assessments below.

Figure 143: Asset Health and Risk, 33kV Cable

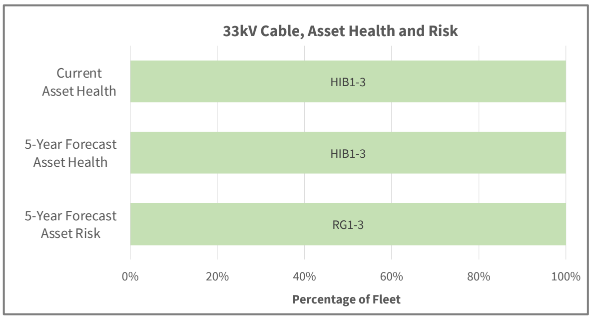


Figure 144: Asset Health and Risk, 11kV Cable

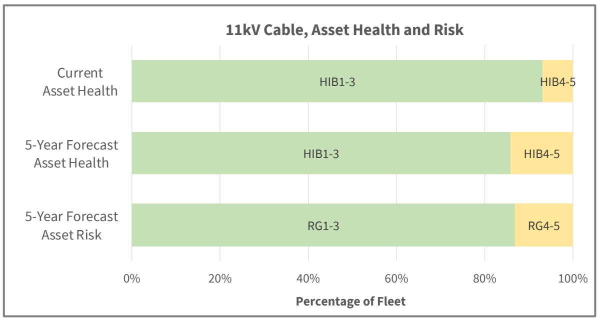
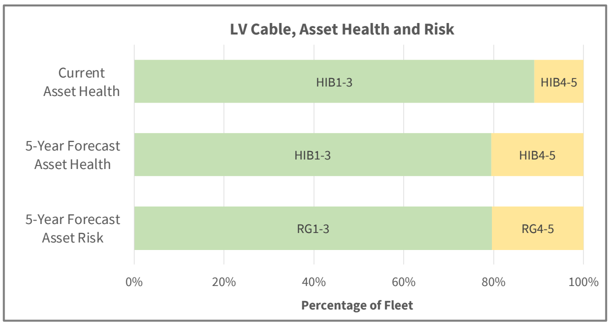


Figure 145: Asset Health and Risk, LV Cable



[138] As at 31 March 2024

[139] Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

12.14.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Our 11kV and LV routine inspections do not deliver reliable data to drive cable asset health in CBARMM. We are keeping abreast of industry developments for cable condition assessment (as aging cable fleets is an industry-wide issue). We plan to adopt better assessment techniques when these become available. Table 118 summarises the distribution fleet's current inspection and testing regime—this data is used to identify defects and define specific renewal projects.

Table 118: Condition assessments

Asset	Type	Scope of assessment	Trigger
Cables, 33kV	Observed	Inspection of route and terminations, including visible deterioration of potheads or composite terminations, visible deterioration of cable sheathing, visible shifting of the cable within the mountings or ground that may be straining internal components	Time-based, annually
Cables, 33kV	Measured	Partial discharge testing of single core XLPE insulated cables to assess deterioration of cable insulation (on some cables where the cable screens have been extended)	As required
Cables, 33kV	Measured	Tan Delta testing (also called Loss Angle or Dissipation Factor testing) to assess the quality of the cable insulation	Time-based, 3 yearly
		Thermography of cable terminations reveals excessive temperatures	
Cables, 11kV and LV	Observed	Underground cables are generally not inspected except at terminations in zone substations, ground-based transformers or switchgear. Observations are as per 33kV cables.	Time-based (in conjunction with zone substation and switchgear inspections)

Maintaining the asset

Cable maintenance is limited to minor work on terminations and associated fixings.

We have a programme to extend the 33kV cable screens in our other zone substations (as part of the 5-year maintenance programme). This will enable testing for transient earth voltage (TEV) to detect partial discharge (a measure to detect changes in cable insulation condition).

12.14.4 How renewal decisions are made on the fleet

Table 119 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast). CBARMM is used to forecast asset renewals. For cables, this is aged-based for 33kV and 11kV and observed-condition-based for LV.

Table 119: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Cables (all)	Renewal forecasts	CBARMM risk grade, adjusted for known asset reliability issues. There are no known reliability issues (other than the pothead and in-line joint type-issues).
	Renewal and refurbishment Projects	For sub-transmission, we initiate projects based on asset condition. For distribution and LV cables, we initiate projects based on reliability or defects.

12.14.5 Asset renewal and refurbishment forecasts

Table 120 shows the forecast for cable asset health, risk, and renewals over the next five years. We are not forecasting any 33kV cable health or risk issues. The 33kV cable renewals relate to cable replacements associated with the O2NL project.

We forecast health and risk issues in between 13% and 30% of the fleets—these are aged-based forecasts. Presently, renewal forecasts are based on known reliability or defect issues (which are none, save for the pothead and in-line joint type issue). The small amount of forecast renewal relates to our unplanned replacement provision.

As mentioned in Section 5.4, our assets are aging, and the risk of end-of-life drivers resulting in asset failures will increase—we expect this to be the case for 11kV and LV cables. Based on our reliability and defect driven renewal forecasting, we expect forecast renewals to increase in future AMPs.

Table 120: Current and forecast asset risk and renewals

Asset	Type	Population[140]	5 Year forecast of assets with low health grade[141]	5 Year forecast of assets with high risk and above[142]	5 Year forecast renewals and refurbishment
Cable	33kV cable	31 km	0.0%	0.0%	2.2%
	11kV cable	268 km	14.1%	13.1%	0.2%
	LV cable	535 km	20.6%	20.3%	0.1%

12.14.6 Asset renewal and refurbishment programmes

As shown in Table 121, asset renewals currently consist of an unplanned provision for unforeseen cable replacement (which is based on historical quantities). There are no planned cable renewal programmes. Table 122 shows the safety-related replacement of pitch-filled potheads and in-line joints on poles.

Table 121: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY26-30	FY31-FY25	Total
33kV cable	Some 33kV cables will be replaced in conjunction with the O2NL project (refer to Section 11.14)	-	-	-
Unplanned replacement of cable (all voltages)	Fault/urgent defect cable replacement (includes normal-year weather events only)	139	140	279
Total	**Asset replacement and renewal capex**	**139**	**140**	**279**

Table 122: Other reliability, safety and environmental programmes (Real $000)

Project/Programme	Description	FY26-30	FY31-FY25	Total
Pitch-filled pothead replacement	Replacement of all pitch-filled potheads with composite termination. The programme is targeting the replacement of all potheads by FY35.	713	716	1,429
In-line cable joint replacement	543 possible sites for in-line joints on poles have been identified. Many of the in-line joins were installed around head-height, and if there is a fault there is a potential safety issue. Further work to determine extent of the conversion programme.	896	-	896

[140] As at 31 March 2024.
[141] HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.
[142] Risk Grade 4 and 5. Before renewal or refurbishment intervention.

Project/Programme	Description	FY26-30	FY31-FY25	Total
	The programme is targeting the replacement of all in-line joints by FY30.			
Total	**Other reliability, safety and environmental capex**	**1,609**	**716**	**2,325**

Table 123: Asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Cables	28	28	28	28	28	28	28	28	28	28	279

Table 124: Other reliability, safety and environmental capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Cable pothead and joint replacements	321	320	321	323	324	143	143	143	143	144	2,325

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.15 Distribution Switchgear Fleet Plan

12.15.1 Fleet Overview and Strategy

Electra has 73 distribution pole-mounted reclosers and sectionalisers, over 3,000 11kV pole-mounted drop-out fuses and switches (including 336 air break switches) and 184 ground-mounted ring-main units (**RMUs**).[143] These assets are integral to the operation of the network during planned and unplanned outages. The switches allow the network to be reconfigured to restore supply when a section of the network is de-energised due to a fault or planned work. Pole-mounted fuses and reclosers are essential components of the electrical protection system and can reduce outage areas when faults occur.

Figure 146: Ground-Mounted Ring Main Unit

Ring Main Unit

143 As at 31 March 2024.

Figure 147: Pole-Mounted Switches

Air Break Switch | Recloser

The use of reclosers expanded in the 2000s, so a large proportion of this fleet is relatively new.

We have good data on our fleet of air-break switches (**ABSs**) and have identified various issues with these assets that require accelerated replacement and a change in maintenance practice. We do not currently have good data on drop-out fuses and links; hence, our renewal forecast for these assets is an estimate and reflects their replacement in conjunction with other renewal programmes. We are also replacing some ABSs (in key locations) with automated enclosed switches to improve network reliability. This programme is covered in Section 11.10.4.

Our fleet of RMUs is relatively new; however, some of these assets are located in coastal locations, reducing their expected life and driving renewal earlier than expected under normal conditions. There are also 11 units with a type issue that requires replacement. Our fleet of RMUs is also expanding as more switches on the underground network are required to meet our planned criteria. This programme is covered in Section 11.10.3.

The 10-year fleet strategy is as follows:

Our strategy for the fleet is to:

- Replace all assets commensurate with their risk—at Risk Grade 4 and 5;
- Prioritise the renewal of assets with type issues, including Mahanga ABSs and ABB Safelink 1 RMUs;
- Implement operational testing and maintenance of our ABS fleet;
- Review the health and risk for reclosers and develop an appropriate replacement programme;
- Improve the data quality of drop-out fuses and links;
- Ensure that public safety risks are managed as required under our Public Safety Management System.

12.15.2 What is driving our fleet strategy

Current fleet performance

The switchgear fleet has generally operated reliably, although there have been higher defective equipment fault rates for ABSs and reclosers than other distribution switchgear. Defective equipment fault rates are recorded at 5.5 faults per 1,000 units per year for reclosers, 7.4 per 1,000 units per year for ABSs, 1.4 per 1,000 units per year for fuses and links, and 1.1 per 1,000 units per year for RMUs.[144] Given the very few defective equipment failures, there is no observable deteriorating trend.

We are experiencing some operating restrictions and ABS failures due to a manufacturing defect.

Specific fleet risks and failure modes

Table 125 shows the top risks and failure modes for distribution switchgear. The key risks relate to type issues, corrosion and public access.

Table 125: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Air-break switches	We have type issues with Mahanga ABSs manufactured between 1995 and 2015. When mounted vertically, water ingress between the external insulation and internal pin causes corrosion, resulting in non-operating or failure during operation	The ABS fleet has been inspected, and all type issues have been identified. A replacement programme has been implemented for the 69 units identified. Operational restrictions are placed on ABSs as required.
	The prior management practices has led to the seizing of blades and switching mechanisms, misalignment of arc chutes and failure during operation	We are changing this approach by operating the entire ABS fleet to identify ABS with operational issues. These will be scheduled for maintenance to replacement ABS operational checks and maintenance are now being implemented A replacement program for non-operation switches has also been implemented. Operational restrictions are placed on ABSs, which include additional visual inspections before operation. Operational staff also wear appropriate PPE.
	Exposure to coastal conditions causing corrosion and early failure	Corrosion detection as part of routine inspection, with remediation as required. Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate
	Public access to ABS switch handles	Implementation of our Public Safety Management System.
Drop-out fuses and links	Fracturing of brittle insulators on some types of drop-out fuses	Replacement of asset types with known issues occurring during other scheduled work
RMUs	Exposure to coastal conditions causing corrosion and early failure	Corrosion detection as part of routine inspection, with remediation as required Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate
	Cable box or bus chamber partial discharge	Partial discharge testing is initiated when this is suspected.
	ABB Safelink 1 RMUs have a type issue causing overtravel during operation. These assets are not considered high risk in their current state, but replacement is seen as prudent	Replacement of the 11 units with known risks by FY36.
	loss/leakage of insulating medium (SF6 mainly)	Routine SF6 monitoring and remediation.

[144] For FY20 to FY24. Benchmark data is not readily available.

Asset	Risk/failure mode	Current controls or treatments
	Public access to equipment and exposure to live parts	Implementation of our Public Safety Management System, which includes various public safety checks

Fleet population and age

Table 126 shows the population and age of distribution switchgear. 27% of reclosers, 30% of ABSs and 3% of RMUs are within five years of NEL. We are undertaking further work on the drop-out fuse and link data and will clarify the aging of that fleet in future AMPs.

Table 126: Asset fleet quantity and age

Asset	Type	Population[145]	Average Age (years)[145]	NEL[146] (years)	Population within 5 years of NEL
Reclosers and Sectionalisers	All types	73	33	30	20
Pole-mounted switches and fuses	ABSs	336	24	45	100
	Drop-out fuses and links	2,678	-	15	-
RMUs	All types	184	10	45	5

Fleet health and risk

Asset health and risk are determined using CBARMM (refer to Figure 148, Figure 149 and Figure 150). For distribution switchgear, we calculated asset health using a combination of asset age, asset location, asset type reliability, asset material, and inspected condition. We have good data on reclosers and RMUs and have provided forecasts of the health and risk of those assets. We have good data on ABSs but less reliable data on drop-out fuses and links, so we have not provided forecasts of health and risk for those assets. This is a work-on for future AMPs.

Figure 148: Asset Health and Risk, Reclosers and Sectionalisers

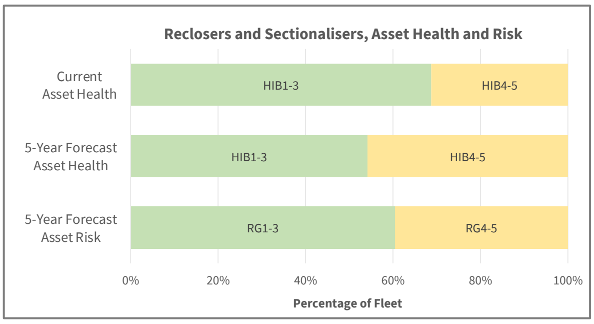
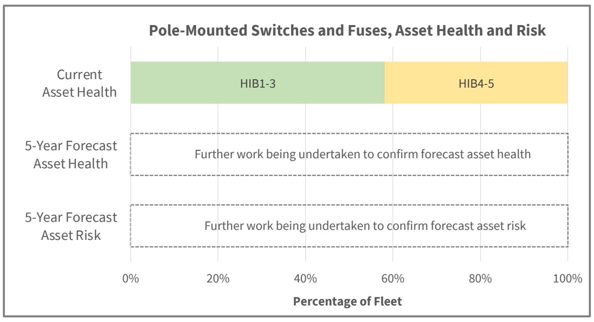


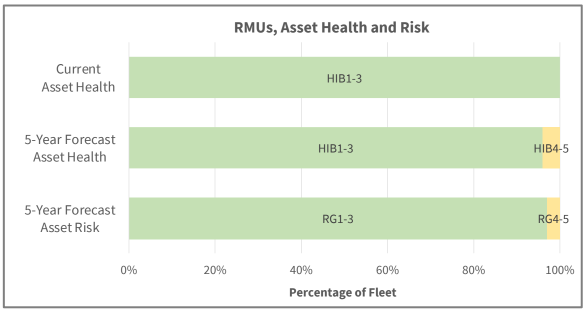
Figure 149: Asset Health and Risk, Pole-Mounted Switches and Fuses



145 As at 31 March 2024.

146 Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Figure 150: Asset Health and Risk, RMUs



12.15.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Table 127 summarises the distribution fleet's current inspection and testing regime—this data is used to identify defects and define specific renewal projects.

Table 127: Condition assessments

Asset	Type	Scope of assessment	Trigger
Reclosers	Observed	Routine visual inspection, including for corrosion and cracked insulators, checking of oil or SF6 levels	Time-based, 5 yearly
ABSs	Observed	Routine inspection, including for corrosion, cracked insulators, misaligned blades or flickers	Time-based, 5 yearly
DDOs	Observed	Routine inspection, including for corrosion and cracked insulators	Time-based, 5 yearly
Ring main Units	Observed	Routine inspection for corrosion, damage to lock, missing hold-down bolts, and checking of SF6 gauges	Time-based, 2 yearly
	Observed	Partial discharge testing of Cable box or bus chamber	Suspected during inspection
	Measured	Earth impedance readings	Time-based, 2 yearly

Maintaining the asset

A summary of the typical distribution switchgear maintenance is shown in Table 128.

Table 128: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Reclosers	Preventive	Manufacturers recommend maintenance depending on type and make, in line with manufacturer recommendations Operational testing, including contact separation timing. Maintenance may vary based on the number of operations, oil levels, SF6 pressure and results of operational testing	• Routine 5 yearly inspections and maintenance.
ABSs	Preventive	Maintenance of mechanisms, arc chutes, and blades in line with manufacturer recommendations	• Routine 5 yearly maintenance
Distribution switchgear	All	Painting, galvanising or greasing individual switches near coastal areas	• Corrosion is observed during routine inspections

12.15.4 How renewal decisions are made on the fleet

Table 129 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast). CBARMM is used to forecast asset renewals for reclosers, ABSs and RMUs. Pole-mounted drop-out fuses and links are replaced in conjunction with other renewal work or when defective.

When projects are being selected, priority is given to the worst performing feeders (refer to Section 4.5.9).

Table 129: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Reclosers	Renewal forecasts	The current forecast is based on recent inspection and operational data, which is being reviewed
	Renewal and refurbishment Projects	The replacement programme is being revised and will be included in the 2026 AMP
ABSs	Renewal forecasts	Includes all assets where the risk increases above RG4
	Renewal and refurbishment Projects	Specific renewal or refurbishment projects are defined based on the presence of end-of-life drivers, including type issues (Mahanga ABSs), fractures of porcelain insulators, tracking on polymer insulators, deterioration of mounting bracket
Drop-out fuses as links	Renewal forecasts	Based on historical replacement rates
	Renewal and refurbishment Projects	No specific projects were identified. Renewal coordinated with other projects or initiated from defects or fault
RMUs	Renewal forecasts	Includes all assets where the risk increases above RG4 and any known type-issues
	Renewal and refurbishment Projects	Projects are defined based on asset condition, risk grade and type issues. RMUs with a high public safety risk will be marked for accelerated replacement.

12.15.5 Asset renewal and refurbishment forecasts

Table 130 shows the forecast distribution switchgear asset health, risk, and renewals over the next five years. Based on known condition issues, we estimate that around 6.3% of the recloser fleet will require renewal over the next five years. This estimate is being validated, and a replacement programme will be developed over the coming year.

We have not forecast low-health and high-risk pole-mounted switches in this AMP. We have good data on our ABS fleet but less reliable data on pole-mounted fuses and lines. The forecast renewals for this fleet relate to the ABS replacement programmes (in Table 131), and an estimate of the renewal of drop-out fuses and links during reconductoring, pole replacements, pole-mounted transformer replacements and pothead replacements (due to the unreliability of our drop-out fuse and link health data we do not have a specific renewal programme for these assets, but instead they are replaced in conjunction with other renewal programmes or where defects are identified).

Table 130: Current and forecast asset risk and renewals

Asset	Type	Population[147]	5 Year forecast of assets with low health grade[148]	5 Year forecast of assets with high risk and above[149]	5 Year forecast renewals and refurbishment
Pole-mounted switchgear	Reclosers and sectionalisers	73	45.8%	39.6%	6.3%
	Switches and fuses	3,014	-	-	7.1%
Ground-mounted switchgear	RMUs	184	4.3%	3.2%	4.5%

[147] As at 31 March 2024.

[148] HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

[149] Risk Grade 4 and 5. Before renewal or refurbishment intervention.

12.15.6 Asset renewal and refurbishment programmes

Table 131 shows the distribution switchgear renewal programmes. Additional ABSs are being replaced in our reliability improvement programmes (refer to Section 11.10.4).

Table 131: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY26-30	FY31-FY25	Total
Pole-mounted switchgear				
ABS replacements, Mahanga	Risk-driven replacement of Mahanga ABSs. 10 units p.a. to FY30	1,643	-	1,643
ABS replacement, Other	Asset health/risk replacement of 4 ABSs p.a. This includes the replacement of non-operational switches.	657	660	1,317
Recloser replacement	Programme is under development	-	-	-
Unplanned replacement	Fault and defect replacement of ABSs, drop-out fuses, automated switches and reclosers	347	348	694
Ground-mounted switchgear				
RMU replacements	Asset health/risk replacement of 1 RMU in FY26 and 2 p.a. from FY27	509	-	509
Unplanned replacement	Fault and defect replacement of RMUs	283	284	1,075
Total	**Asset replacement and renewal capex**	**3,439**	**1,292**	**4,730**

Table 132: Asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Distribution switchgear	641	695	697	702	703	258	258	258	258	259	4,730

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.16 Distribution Transformer Fleet Plan

12.16.1 Fleet Overview and Strategy

Electra's distribution transformers range from rural single-phase 5kVA pole-mounted transformers with basic fuse protection to three-phase 1,000kVA ground-mounted transformers with ring-main-unit and circuit-breaker protection.

Electra has 1,645 distribution pole-mounted transformers and 1,011 ground-mounted transformers.[150] These assets convert electricity from 11kV to 400V, which is distributed via the LV network to homes and businesses. Distribution transformers may supply electricity to a single large consumer, several large consumers or many small consumers.

Pole-mounted transformer installations include 11kV fuse protection. Before 2021, all ground-mounted transformers include 11kV fuses in the tank. Newer transformers are unfused, as protection is provided by fusing in the associated RMU.

[150] As at 31 March 2024.

Figure 151: Transformers

Pole-Mounted Transformer (recently removed from service)

Ground-Mounted Transformer (being installed)

There are generally low consequences of failure for distribution transformers, so we operate these assets at higher risk levels where there are no public safety issues.

Some of these assets are located in coastal locations, reducing their expected life and driving renewal earlier than expected under normal conditions.

Electra had a historical practice of daisy-chaining multiple ground-mounted transformers together between switching points (that is, underground cables were directly connected to the transformer HV bushings rather than being connected through an RMU, which is the modern practice). This has operational and protection implications due to the potential for incorrect fusing and reduced ability to reduce isolation segments. There is a programme to install RMUs at transformer sites and remove daisy-chaining (refer to Section 11.10.3).

All two-pole transformer structures have been seismically assessed, and all remediation work completed.

The 10-year fleet strategy is as follows:

Our strategy for the fleet is to:

- Due to the lower consequence of failure associated with distribution transformers, we target replacement at Risk Grade 5. However, where public safety risks are present, replacement occurs earlier at Risk Grade 4;
- Progressively remove the daisy-chaining of multiple ground-mounted transformers;
- Ensure earthing remains compliant and expansion of earthing systems when required;
- Ensure that public safety risks are managed as required under our Public Safety Management System.

12.16.2 What is driving our fleet strategy

Current fleet performance

The transformer fleet operates reliably and has a defective equipment fault rate of 3.2 per 1000 units/year for pole-mounted transformers and 4.0 per 1000 units/year for ground-mounted transformers.[151] Given the low number of defective equipment failures, there is no observable deteriorating trend.

Damage from lightning is the only performance issue relating to pole-mounted transformers.

For ground-mounted transformers, other than the daisy-chaining issues (which limits operational flexibility), there are no performance issues relating to the fleet.

Specific fleet risks and failure modes

Table 133 shows the top risks and failure modes for distribution transformers. The key risks are corrosion, in-tank liquid fusing, 11kV pitch-filled potheads, and public access.

Table 133: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Pole-mounted transformers	Exposure to coastal conditions causing corrosion and early failure	Corrosion detection as part of routine inspection, with remediation as required. Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate (which advances their renewal commensurate with risk)
	Leaking of oil due to tank or gasket due to corrosion	Routine inspection and replacement of assets if the tank is affected. Refurbishment of assets if gasket or bushings
	Lightning strikes	There is a programme to install lightning arrestors in areas with historical lightning strikes (refer to Section 11.10.4).
	Vehicle damage	Additional physical protection or asset relocation in areas of known vehicle damage risks
Ground-mounted transformers	Exposure to coastal conditions causing corrosion and early failure	Corrosion detection as part of routine inspection, with remediation as required (see corrosion below) Proximity to the coast is considered in CBARMM, and accelerated deterioration rates are included where appropriate
	Some transformers have liquid CF4 fuses inside the tank that can fail and interrupt the supply	These transformers have increased condition deterioration with CBARMM The renewal programme prioritises the replacement of transformers with CF4 fuses
	Pitch-filled terminations to connect on 11kV bushings	These transformers have increased condition deterioration with CBARMM. The installation of RMUs (Section 11.10.3) prioritises transformers with Pitch-filled potheads.
	Corrosion, including: • Surface rust on bays and tank • Penetrating rust exposing live components in bays • Rust of cooling fins or tank causing oil leakage	Controls include: • Refurbishment through rust removal and painting • Temporary measures to restrict access to bays. Refurbishment through rust removal, painting, and replacement of bays/doors • Temporary measures to limit leaks. Refurbishment of cooling fins or replacement for issues on tanks
	Overloading due to increased load from existing customer connections	Schedule of work to upgrade transformers with capacity issues (refer to Section 11.11.2)

[151] For FY20 to FY24. Benchmark data is not readily available.

Asset	Risk/failure mode	Current controls or treatments
	Public access to equipment and exposure to live parts	Implementation of our Public Safety Management System, which includes various public safety checks

Fleet population and age

Table 134 shows the population and age of distribution transformers. 20% of pole-mounted and 9% of ground-mounted transformers are within five years of NEL.

Table 134: Asset fleet quantity and age

Asset	Type	Population[152]	Average Age (years)[145]	NEL[153] (years)	Population within 5 years of NEL
Pole-mounted transformers	All types	1,645	23.3	45	323
Ground-mounted transformers	All types	1,011	17.3	45	95

Fleet health and risk

Asset health and risk are determined using CBARMM (refer to Figure 152 and Figure 153). For distribution transformers, we calculated asset health using a combination of asset age, asset location, asset type reliability, asset material, and inspected condition. We have good data on distribution transformers, and the forecasts are reliable.

The main driver for high-risk assets is the condition of the transformer tank due to the exposure to the coastal environments.

Figure 152: Asset Health and Risk, Pole-Mounted Transformers

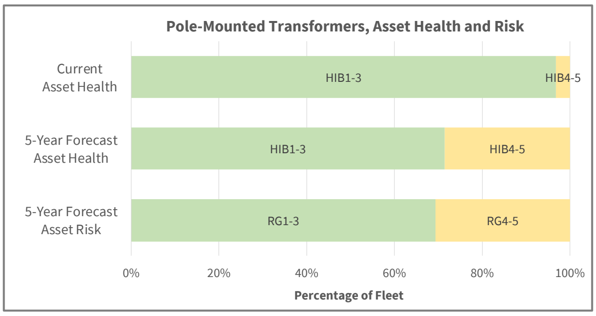
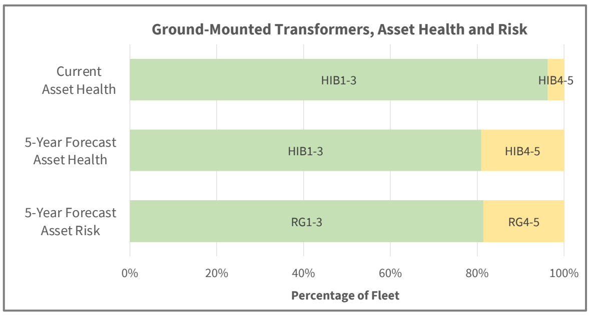


Figure 153: Asset Health and Risk, Ground-Mounted Transformers



12.16.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Table 135 summarises the current inspection and testing regime for distribution transformers. The condition data informs CBARMM, identifies defects, and defines specific renewal projects.

Table 135: Condition assessments

Asset	Type	Scope of assessment	Trigger
Pole-mounted transformers	Observed	Routine inspection, including for oil leaks, rust, missing hold-down bolts, earth connections	Time-based, 5 yearly
	Measured	Earth impedance test	Time-based, 5 yearly

152 As at 31 March 2024.

153 Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

Asset	Type	Scope of assessment	Trigger
Pole-mounted transformers	Observed	Routine inspection, including for oil leaks, rust, missing hold-down bolts, vegetation, graffiti, depreciated cable breakout constructions	Time-based, 2 yearly
	Measured	Earth impedance tests	Time-based, 2 yearly

Maintaining the asset

A summary of the typical distribution transformer maintenance is shown in Table 136.

Table 136: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Pole-mounted transformers	Corrective	Extension of earthing system to meet required impedance standard	• Routine 5 yearly testing: Earthing impedance above required standards
Ground-mounted transformers	Corrective	Extension of earthing system to meet required impedance standard	• Routine 2 yearly testing: Earthing impedance above required standards
	Corrective	Transformer HV and LV bay clearing, removing of spiderwebs, vegetation, or other obstructions	• Routine 2 yearly Inspections where obstructions are observed
	Corrective	Painting, rust that has not penetrated through to live parts or tank	• Routine 2 yearly Inspections where corrosion is observed
	Preventative	Replacement of liquid fuses with HRC fuses	• Undertaken in conjunction with any planned work on transformers with liquid fuses installed

12.16.4 How renewal decisions are made on the fleet

Table 137 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast).

Table 137: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Pole-mounted transformers	Renewal forecasts	Includes all assets where the risk is forecast to transition to RG5
	Renewal and refurbishment Projects	For large transformers, projects are defined based on the presence of end-of-life drivers (from routine inspections) and risk grade, including oil leaks, damage to LV or 11kV bushings, and surface or penetrating corrosion. No specific projects are defined for small PM transformers where renewal is coordinated with other projects or initiated from defects of fault
Ground-mounted transformers	Renewal forecasts	Includes all assets where the risk is forecast to transition to RG5
	Renewal and refurbishment Projects	Projects are defined based on the presence of end-of-life drivers (from routine inspections) and risk grade, including measured loading over-rated limits, the risk of public access to live components, oil leaks, equipment design and configuration that is inconsistent with current design standards

12.16.5 Asset renewal and refurbishment forecasts

Table 138 shows the forecast distribution transformer asset health, risk, and renewals over the next five years. Due to the lower consequence of failure associated with distribution transformers, we are forecasting replacing assets that transition to RG5 (that is, in most cases, we expect to operate these assets at RG4). Hence, we are operating some assets older than NEL. However, where there is a high public safety risk, we will replace the transformer at RG4.

Table 138: Current and forecast asset risk and renewals

Asset	Type	Population[154]	5 Year forecast of assets with low health grade[155]	5 Year forecast of assets with high risk and above[156]	5 Year forecast renewals and refurbishment
Pole-mounted transformers	All types	1,645	28.6%	30.7% (2.1% at RG5)	3.0%
Ground-mounted transformers	All types	1,011	19.1%	18.5% (5.5% at RG5)	6.6%

12.16.6 Asset renewal and refurbishment programmes

Table 139 shows the distribution transformer renewal programmes. Additional transformers are being replaced during capacity upgrades and as part of the LV logger installation programme (refer to Section 11.11.2 and 11.11.4).

Table 139: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY26-30	FY31-FY25	Total
Pole-mounted transformer				
Condition-based replacements	Condition-driven replacement of pole-mounted transformers (based on routine inspections). 8 transformer replacements p.a.	633	636	1,269
Unplanned replacements	Defect and fault replacement of pole-mounted transformers	151	151	302
Ground-mounted transformer				
Risk-based replacements	Risk-driven replacement of ground-mounted transformers (based on CBARMM and routine inspections) 8 transformer replacement p.a.	1,643	1,650	3,294
Unplanned replacements	Defect and fault replacement of ground-mounted transformers	280	281	561
Total	**Asset replacement and renewal capex**	**2,707**	**2,718**	**5,425**

Table 140: Asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Distribution switchgear	540	539	540	544	544	543	543	543	543	545	5,425

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.17 OH/UG Consumer Service Connections Fleet Plan

12.17.1 Fleet Overview and Strategy

Electra has 47,904 LV connections, which comprise overhead pole fuse connections and ground-mounted pillar box connections.[157]

Pole fuse connections are replaced in conjunction with other projects or when they fail.

[154] As at 31 March 2024.

[155] HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

[156] Risk Grade 4 and 5. Before renewal or refurbishment intervention.

[157] As at 31 March 2024.

Electra has approximately 11,795 ground-mounted LV service pillar boxes, LV link boxes, and LV joint boxes. There are 2,687 old steel pillars, which pose additional safety risks. The new pillar boxes are plastic. In urban areas, pillar boxes typically supply two customers.

LV link boxes interconnect LV circuits, allowing customers to be supplied from adjacent distribution transformers in the event of a planned or unplanned outage. Steel link boxes have potential safety issues; all are scheduled for replacement by FY30.

Ground-mounted pillars and link boxes are inspected, and their health is monitored.

Figure 154: Example of pillar and link boxes

The 10-year fleet strategy is as follows:
Our strategy for the fleet is to: • Replace all steel link boxes by FY30 due to design issues and increased public safety risk; • Replace all steel pillars by FY35 due to increased public safety risk; • Replace other assets commensurate with their risk—at Risk Grade 4 and 5; • Ensure that public safety risks are managed as required under our Public Safety Management System.

12.17.2 What is driving our fleet strategy

Specific fleet risks and failure modes

Table 141 shows LV pillars and link boxes' top risks and failure modes. The key risks are corrosion and damage to steel boxes, a design issue concerning steel link boxes, and public safety.

Table 141: Specific risks

Asset	Risk/failure mode	Current controls or treatments
Steel pillars	Corrosion of base, lid, or locking mechanisms creates the potential for exposure of live parts	Replacement of all steel pillar boxes by FY35
	Exposure to coastal conditions causing corrosion and early failure, and the potential for livening of metal parts	Corrosion detection as part of routine inspection, with replacement as required Replacement of all steel pillar boxes by FY35
	Damage to locking mechanisms and the potential for exposure of live parts	Damage detection as part of routine inspection, with replacement as required.

Asset	Risk/failure mode	Current controls or treatments
		Replacement of all steel pillar boxes by FY35
Steel link pillars	These were designed with the neutral link close to the external housing, which creates a potential hazard should the neutral contact the housing	All 160 of these link boxes are scheduled for replacement by FY30
Pillars, all	Vehicle damage or vandalism resulting in exposure to live parts	Damage assessment as part of routine inspection or fault reporting. Repair or replacements are implemented as required Implementation of our Public Safety Management System

Fleet population and age

Table 142 shows the population and age of LV pillars and link boxes. Over 95% of steel pillars are within five years of NEL. There are only a few plastic pillars with five years of NEL. We do not carry information on the age profile of overhead pole fuse connections.

Table 142: Asset fleet quantity and age

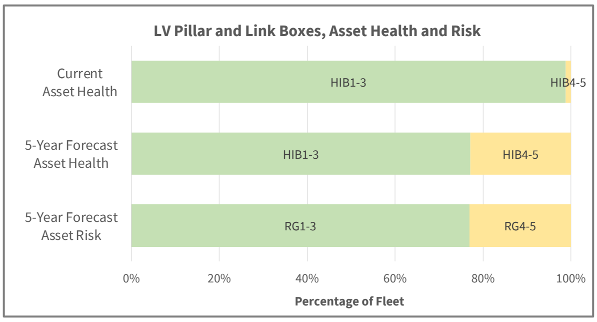
Asset	Type	Population[158]	Average Age (years)[145]	NEL[159] (years)	Population within 5 years of NEL
Plastic LV pillars	Pillar and link boxes	8018	16.1	45	111
Steel LV pillars	Pillar and link boxes	2,687	45.2	45	2,601

Fleet health and risk

Asset health and risk are determined using CBARMM (refer to Figure 155). For LV pillars, we calculated asset health using a combination of asset age, asset location, asset type reliability, asset material, and inspected condition. We do not assess health and risk for overhead pole fuse connections.

The driver for high-risk assets is the older steel pillar and link box assets.

Figure 155: Asset Health and Risk, Pillar and Link Boxes



Note: The health data for OH/UG consumer service connections in Schedule 12a only relates to pillar and link boxes.

158 As at 31 March 2024.

159 Nominal expected life. This is the age when it would be expected to first observe significant deterioration. This represents the average service life of the asset. Assets can operate longer than NEL based on active monitoring of condition.

12.17.3 How the asset fleet is operated, monitored and maintained

Condition assessment

Table 143 summarises the current inspection and testing regime for LV pillars and link boxes. The condition data informs CBARMM, identifies defects, and defines specific renewal projects.

Pole fuse connections are inspected during the routine overhead inspections, and defects are identified and remediated as required.

Table 143: Condition assessments

Asset	Type	Scope of assessment	Trigger
Plastic Pillars	Observed	Routine inspection, including for broken locks, deteriorated fuses/holders, damaged lids/bases	Time-based, 5 yearly
Steel Pillars	Observed	Routine inspection, including for rusted bases, damaged locking bolts, deteriorated fuses/fuse mounts	Time-based, 5 yearly

Maintaining the asset

A summary of the typical LV pillar maintenance is shown in Table 144. We do not maintain steel pillars and link boxes—any issues observed during the routine inspection result in the box being scheduled for replacement.

Table 144: Corrective and preventive maintenance

Asset	Type	Scope of maintenance	Trigger
Plastic Pillars	Corrective	Replacement of locking mechanism. Replacement of lid if alterations to locking systems have been made to make the pillar safe.	• Routine 5 yearly Inspections where a pillar was inaccessible due to locking mechanism failures

12.17.4 How renewal decisions are made on the fleet

Table 145 shows the specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast).

Table 145: Drivers and triggers for renewal forecasts and projects

Asset	Type	Drivers/triggers
Plastic Pillars	Renewal forecasts	Includes all assets where the risk increases above RG4
	Renewal and refurbishment Projects	Specific projects are defined from the most recent inspections. Assets in high-risk areas are prioritised
Steel Pillars	Renewal forecasts	All steel pillar and link boxes are scheduled for renewal by FY35
	Renewal and refurbishment Projects	Specific projects are defined from the most recent inspections. Assets in high-risk areas are prioritised
Overhead connections	Renewal forecasts	No renewal forecasts or projects are prepared for these assets. These assets are replaced in conjunction with other projects or on failure
	Renewal projects	

12.17.5 Asset renewal and refurbishment forecasts

Table 146 shows the forecast LV pillar and link box asset health, risk, and renewals over the next five years. The forecast renewals are mostly steel pillars and reflect all steel pillars being replaced by FY35. Plastic boxes are performing better than the risk-based forecasting suggests, and their replacement is an estimate based on prior inspection-driven replacement rates.

Table 146: Current and forecast asset risk and renewals

Asset	Type	Population[160]	5 Year forecast of assets with low health grade[161]	5 Year forecast of assets with high risk and above[162]	5 Year forecast renewals and refurbishment
OH/UG consumer service connections	Pillar and link boxes	11,795	22.9%	23.1%	11.7%
	Overhead connections	No data available			

12.17.6 Asset renewal and refurbishment programmes

Table 147 and Table 148 show the LV pillar renewal and safety replacement programmes.

Table 147: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY26-FY30	FY31-FY25	Total
Plastic LV pillar replacement programme	Inspection-driven replacement of plastic LV pillars, ~45 p.a.	1,157	1,162	2,319
Steel LV pillar replacement programme	Inspection-driven replacement of steel LV pillars, ~200 p.a.	5,667	6,198	11,865
Unplanned replacements	Defect and fault replacement of LV pillars	471	473	943
Total	**Asset replacement and renewal capex**	**7,295**	**7,832**	**15,127**

Table 148: Safety Improvement Programme (Real $000)

Project/Programme	Description	FY26-FY30	FY31-FY25	Total
Steel link pillar replacements	The programme will replace all 160 steel link pillars due to safety risks associated with a design issue (32 p.a.).	988	-	988
Total	**Other reliability, safety and environmental capex**	**988**	**-**	**988**

Table 149: Asset replacement and renewal capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
LV connections and pillar boxes	1,052	1,552	1,556	1,566	1,568	1,566	1,565	1,566	1,565	1,571	15,127

Table 150: Other reliability, safety and environmental capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Steel link pillar	197	196	197	198	199	-	-	-	-	-	988

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.18 Management of Other Network Assets

12.18.1 Zone substation buildings

Electra has ten zone substation buildings that typically house the 11kV circuit breakers and secondary systems. The 33kV circuit breakers are housed indoors at most substations (Shannon, Ōtaki, Waikanae,

160 As at 31 March 2024.

161 HIB4 and HIB5 (equivalent to EEA health index of H2 and H1). Before renewal or refurbishment intervention.

162 Risk Grade 4 and 5. Before renewal or refurbishment intervention.

Paraparaumu East, Paraparaumu West, Raumati). The zone substation building fleet ranges in age from 15 to 50 years. The NEL varies based on the building's construction, and all are appropriately maintained.

Our fleet strategy for zone substation buildings for new zone substations is to:

- Meet our resilience standard (as defined in Section 11.4.6) and for all existing zone substations when it is practical and economic to do so;
- Be inspected and maintained to ensure that there are no defects or other issues that cause the building condition to deteriorate to HIB4 or HIB5;

Zone substation buildings are inspected during the routine bi-monthly and annual inspections. Appropriately skilled people address any defects or maintenance requirements.

CBARMM is not used to determine the health of zone substation buildings. Health is determined based on information from routine inspections or specific building assessments, the results of which are included in Schedule 12a.

The key work on the substation fleet is the seismic upgrade programme (to meet the resilience standard). Seismic upgrades have been completed on six of the ten substation buildings, with work at Foxton and Paekākāriki due for completion in FY26 and Paraparaumu East in FY27. The solution for Levin West is under consideration. Expenditure forecasts for the seismic upgrade programme at zone substations are included in Section 11.9.4.

There are no forecast renewals for zone substation buildings.

12.18.2 Load control plant

Electra operates the following load control plant:

- One Zellweger 80kVA SFU-K/203 injection plant at Shannon which provides ripple control signals to the northern area. This was installed in 2011 as part of the substation rebuild;
- One Landis + Gyr 200kVA SFU-K/403 injection plant at Paraparaumu East zone substation which provides ripple control signals to the southern area. This was installed in 2016;

Both the Shannon and the Valley Road plants inject into the 33kV at 283Hz. There are no known capacity, security, or reliability constraints with Electra's load control plant.

We have two Zellweger 80kVA SFU-K/203 injection plant controllers and coupling cell components in storage as critical spares.

The plants are tested and maintained in line with manufacturers' requirements. These include visual inspections, regular testing to confirm signal frequency and strength, and a five-year rolling inspection and maintenance contract with Landis+Gyr to ensure plant reliability.

The load control plants are in good condition (HIB2 and HIB3). Table 151 shows the planned refurbishment of the load control plant. We are planning to refurbish the plant at Shannon in FY28. The expected life of these assets is around 20 years; at this stage, we are not forecasting replacing these plants, given the future uncertainty concerning traditional load control (refer to Section 10). However, this project has not been fully scoped, and further testing may determine that a more powerful signal generator is required to cater for the expanding network.

Table 151: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY26-FY30	FY31-FY25	Total
Refurbishment of injection plant	Refurbishment of the Zellweger plant at Shannon in FY28	102	-	102
Total	**Asset replacement and renewal capex**	**102**	**-**	**102**

12.18.3 Load control relays

The energy retailer owns most customer load control relays. However, Electra still owns 1,924 relays for controlling streetlights, under veranda lighting and pilot-wire load control. There are 1,486 load control relays of unknown age. We do not have good data on this fleet, and the relays are replaced upon failure (relays are quick to replace and have minimal service impact should they fail). We are indicating that around 10% of the relay fleet will need to be replaced in the next five years, which equates to about 40 p.a. These low-value asset replacements are included in the opex forecasts.

12.18.4 LV OH/UG Streetlight circuits

We have around 64km of overhead and underground streetlighting circuits and forecast to replace around 1% of the fleet over the next five years. The inspection of overhead streetlighting occurs during routine overhead line inspections. Underground streetlight circuits are not inspected. We do not maintain health data on this fleet, and these assets are renewed in conjunction with other projects or when faults or defects are identified.

12.18.5 Communication system, RTUs and IoT

Electra’s communication system consists of fibre, point-to-point microwave, point-to-point radio and multi-access channel radio. Microwave radio and voice connect all sites with a self-healing topology. Its primary purpose is to carry voice and data communication to operate and control the network.

The data communication links connect the SCADA master station (discussed in Sections 8 and 9) with the substation’s remote terminal units (RTUs). SCADA is one of our key operational technology systems and is being upgraded over the next few years (as discussed in Section 9.4.1).

To improve the reliability of the communication system and support the protection scheme upgrades, we are upgrading several links from Radio to Fibre (refer to Section 11.12.3). We are also upgrading the Levin West substation's communications tower and the Southern region's backup communications container (refer to Table 152).

Electra uses IoT (Industrial Internet of Things) communications technology to gather network status data to further improve network reliability, customer services, and asset investment decisions. Fifteen LoRaWAN gateways, installed in the last two years, are deployed in the Electra region at key locations, including substations and eight repeater sites. The gateways are recent additions to the Electra communications network and are in Class 1 (new) condition.

Gateways have an expected lifespan of 7 to 10 years; however, technology changes are more likely to drive upgrades before failure.

There are no known systemic issues or constraints with Electra's IoT platform. Resilience, reliability, and cyber security are key design parameters for deployment.

Table 152: Renewal and refurbishment programmes (Real $000)

Project/Programme	Description	FY26-FY30	FY31-FY25	Total
Back-up communication container	Fit out a container to hold comms equipment in Southern Area. Current main site and backup are both in Northern Area. The project is planned for FY26	305	-	305
Refurbishment of Levin West Comms Tower	Refurbishment of the communications tower at Levin West substation in FY26-27	335	-	335
Total	**Asset replacement and renewal capex**	**640**	**-**	**640**

Forecasts for fault repair, inspection and maintenance of these assets are included within the network opex forecasts contained in Section 12.19.

12.19 Network Operations and Maintenance

12.19.1 System Interruption and Emergency

System interruption and emergency (**SIE**) response (also known as fault response and restoration) relates to the response to an unplanned event or incident that impacts the normal operation of the network. At Electra, this typically involves first and second-call fault response. First-call is where a fault person responds to a fault on the network (which may have been identified from the SCADA, ADMS, a notification from a retailer or a notification from a customer through to our call centre). The second-call response is where additional crews are called in to respond. This occurs when the first-call fault person cannot restore supply, and in this case, they make the site safe until other personnel can attend. Specialist personnel may be required depending on the nature of the fault.

Electra's fault staff are all from our its in-house Service Delivery team. The in-house team maintains a roster of first- and second-call fault personnel and specialist staff to respond to any fault on the network.

We may deploy mobile generators where restoration could take some time (or the critical customers or infrastructure is interrupted).

We are forecasting an increase in system interruption and emergency opex due to an expected increase in 11kV underground faults (which we have seen in recent years due to the aging of that fleet) and an increase in typical year adverse weather (due to climate change). Underground faults can be difficult and costly to repair (including using generators), and the cost increases reflect this. We also expect to increase expenditure on fault response as the network expands.

Most of the expenditure relates to fault response on the overhead network (due to the higher fault rate associated with those assets).

Table 153: System Interruption and Emergency Opex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Historical average SIE	2,337	2,337	2,337	2,337	2,337	2,337	2,337	2,337	2,337	2,337	23,366
Changes in work scope	176	176	176	176	176	176	176	176	176	176	1,757

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Additional SIE to cater for network growth	28	56	85	142	201	262	323	386	483	583	2,549
Total	**2,540**	**2,568**	**2,597**	**2,655**	**2,714**	**2,774**	**2,836**	**2,899**	**2,995**	**3,095**	**27,672**

Note: The forecasts assume a typical year for adverse weather and do not include a contingency for significant weather events.

12.19.2 Vegetation Management

Obligation to manage vegetation near lines

Electra's overhead lines are surrounded by trees of varying heights, types, growth rates and ownership, and we have significant obligations under the Electricity (Hazards from Trees) Regulations 2003 to provide security of supply and safety to the public by keeping trees clear of conductors. The regulation prescribes a process for managing trees within defined growth limit and notice zones. Many vegetation outages on the network are from trees outside the notice zone, which is not supported by regulations.[163]

We adhere to the ENA/EEA's risk-based methods as recommended by the Risk-Based Vegetation Management Guide, which provides direction on how to proactively manage vegetation risk to improve supply reliability, security, performance and the safety of our network.

Section 4.5.6 provides a detailed analysis of our vegetation outage performance. In recent years, vegetation-related outages have been concentrated on a few feeders, and climate change is likely to exacerbate vegetation contact. Our approach and operational plans have been prioritised to address the worst-performing feeders (for vegetation).

Management Approach

Our vegetation management process integrates a planned programme where cyclic trimming is undertaken based on a risk-based assessment strategy.

Our vegetation control team continue to survey the network, issue hazard warning notices and cut-or-trim to tree owners and complete follow-up hazard warning and cut-or-trim jobs. We continue to use a vegetation management database to record all notices that are issued, be it hazard warning notices or cut-or-trim notices, including tree owner, contact details, number of trees identified, species, voltage involved, between pole/plant numbers, work completion date and information regarding the work site or ownership. Using this system to its full potential, we build a site history, including reinspection intervals.

The primary objective of our vegetation management activities is to ensure the safety of the public, customers, and Electra personnel. Other drivers include mitigating the risk of supply interruption by maintaining minimum clearances (specified in the tree regulations), removing out-of-zone trees that present a fall risk to the network, and mitigating the encroachment of tree roots to cables and ground-mounted assets.

The criteria for maintenance include:

- Number of customers at risk of interruption from specific tree contacts;
- Branches or leaves encroach into minimum clearances specified in the Regulations;

[163] The Electricity (Hazards from Trees) Regulations 2003 specifies minimum distances from overhead power lines that vegetation must be clear from, with distances varying depending on voltage and conductor span length (the GLZ). While these zones provide clearance from interference from branches (although greater clearance would be useful), they are inadequate to manage tree fall risk and interference during storm events, where greater separation is needed.

- Roots that are interfering with ground-mounted assets;
- Unsafe trees within the fall zone.

Priority is given to our worst-performing feeders (refer to Section 4.5.9).

We are forecasting an increase in our vegetation management spend. This additional expenditure is in response to an increase in vegetation growth rates, an increase in typical year adverse weather (due to climate change), the high cost of addressing out-of-zone trees, and targeting vegetation management on our worst-performing feeders.

Table 154: Vegetation Management Opex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Base vegetation management	1,969	1,969	1,969	1,969	1,969	1,969	1,969	1,969	1,969	1,969	19,688
Increase in vegetation management	98	202	310	310	310	310	310	310	310	310	2,783
Total	**2,067**	**2,171**	**2,279**	**2,279**	**2,279**	**2,279**	**2,279**	**2,279**	**2,279**	**2,279**	**22,471**

Note: The forecasts assume a typical year for adverse weather and do not include a contingency for significant weather events.

12.19.3 Reactive and Corrective Maintenance and Inspections

Reactive and corrective maintenance and inspections (**RCMI**) means operational expenditure for routine inspection, testing and maintenance. We are continually improving our inspection and testing to ensure that we can capture appropriate condition information on network assets. This enables us to more accurately determine the health of the assets and optimise the timing for maintenance, renewal or refurbishment.

Around 50% of the expenditure relates to the inspection and follow-up maintenance on the overhead networks (due to the high number of assets and the time taken to inspect). 15% is spent on zone substation inspection and maintenance, and just over 10% each for ground-mounted distribution assets and pillar and link boxes.

We have recently changed the inspection regimes for some zone substation assets, distribution overhead lines, ground-mounted transformers and pole-mounted switches. These changes have increased the cost of the inspection work—we expect to see better optimisation of our asset renewals in future AMPs as new data is utilised. Zone substation tapchanger maintenance is now included in RCMI (having been transferred from asset replacement and renewal). RCMI costs also increase as the network expands (as there are more assets to inspect and maintain).

Table 155: Reactive and Corrective Maintenance and Inspection Opex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Historical average RCMI	1,330	1,330	1,330	1,330	1,330	1,330	1,330	1,330	1,330	1,330	13,299
5-year 110kV assets condition assessment						123					123
Changes in scope	331	331	331	331	331	331	331	331	331	331	3,309
Additional RCMI to cater for network growth	18	37	56	94	133	173	214	255	319	385	1,685
Total	**1,679**	**1,698**	**1,717**	**1,755**	**1,794**	**1,956**	**1,874**	**1,916**	**1,980**	**2,046**	**18,416**

12.19.4 Asset replacement and renewal (opex)

Asset replacement and renewal (**ARR**) opex relates to replacing subcomponents of assets that are not capital items. This includes preventative replacement programmes and replacement of low-value assets (i.e., single batteries at zone substations, ripple control relays, fuse elements). Over 60% of the expenditure relates to zone substation assets, and another 20% relates to ground-mounted distribution transformers. Again, ARR costs are increasing as the network expands.

The reduction in work scope relates to the transfer of zone substation tapchanger maintenance to RCMI.

Table 156: Asset Replacement and Renewal Opex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Historical average ARR	794	794	794	794	794	794	794	794	794	794	7,936
Changes in work scope	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(373)
Additional ARR to cater for network growth	2	5	8	14	21	28	35	42	52	63	269
Total	**758**	**761**	**764**	**771**	**777**	**784**	**791**	**798**	**809**	**820**	**7,833**

12.19.5 Total non-network opex

Table 157 summarises the total non-network opex by asset category.

Table 157: Total Non-Network Opex by Asset Category (Real $000)

Asset Categories	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Zone substations	773	777	780	787	794	801	808	815	827	838	7,999
Subtransmission lines	214	217	219	224	229	357	239	245	253	261	2,459
Subtransmission cables	1	1	1	1	1	1	1	2	2	2	14
Distribution lines	736	744	752	769	786	803	821	839	867	896	8,014
Distribution cables	364	368	372	380	389	397	406	415	429	443	3,962
Distribution switchgear	105	106	107	109	112	114	117	120	123	128	1,141
Distribution transformers	425	430	434	444	454	464	474	485	501	518	4,629
Low voltage lines	207	209	212	216	221	226	231	236	244	252	2,256
Low voltage cables	6	6	6	7	7	7	7	7	7	8	68
Other network assets	24	24	24	25	25	26	26	27	28	29	256
Unspecified network assets	4,086	4,211	4,343	4,389	4,435	4,483	4,532	4,582	4,659	4,739	44,460
Other non-network assets	104	106	107	109	112	114	117	119	123	127	1,138
Total non-network opex	**7,045**	**7,198**	**7,358**	**7,460**	**7,564**	**7,794**	**7,781**	**7,892**	**8,063**	**8,240**	**76,396**

13. Delivery Capability

13.1 Introduction

In this section, we describe our resourcing to enable the business to deliver:

- The asset management strategy (Section 6);
- The asset management improvement plan (Section 9);
- The energy transformation roadmap (Section 10); and,
- The asset lifecycle plans (Sections 11 and 12).

We also describe our safety management system, which is critical to ensure the safety of our staff, contractors, and the public.

13.2 Drivers of our resourcing strategy

Our resourcing strategy and Electra's in-house resources have evolved over decades to support the needs of the business. Our resourcing strategy continues to evolve, and we have identified seven key drivers shaping the current strategy. These include:

Alignment to corporate strategy

Electra's corporate strategy is to develop our people, keep everyone safe, and maintain operational excellence.

Consistent with our approach to operational excellence, we maintain in-house corporate and asset management resources and in-house construction, maintenance, and fault capability to deliver most of our fieldwork programmes.

Our current strategy is to utilise external contractors for:

- Specialist work (where it would be inefficient to maintain those capabilities in-house);
- Civil work activities that can be well-defined and where a local competitive market exists, such as trenching, directional drilling and building/general construction;
- As a transition whilst we build in-house capability and manage peaks;
- Where we decide it is more efficient and effective.

Any changes to this strategy will consider our ability to maintain competency in-house, utilisation (i.e. likely work volumes), the cost competitiveness of the external market, and the overall impact on work costs.

Customer connection design and installation works are currently provided by two approved contractors and Electra.

Alignment to our asset management strategy

Having suitable resources in all areas of the business is necessary to support the delivery of the asset management strategy. This is particularly important for:

- **#2 Implementing the energy transformation roadmap**—where complexity will increase as we need to manage more significant penetration of DERs, utilise flexibility and other non-network alternatives, and support customers as they use the network differently;

- **#5 Improve asset management maturity to level 3**—as set out in Section [9], we have a wide-ranging improvement programme that needs to be supported. We have a near-term focus on improving our front-end engineering design (FEED) and outsourcing processes to support fieldwork delivery.

Addressing recent work delivery performance

Delivering the capex works program relies on design, property rights, procurement, materials availability, and field resources availability. As discussed in Section 4.7, our capital works delivery has been behind plan in recent years due to constraints in the delivery process. Most of these delays were related to non-field issues (e.g. FEED, land procurement and materials).

Regarding opex, the only constraint in recent years related to asset inspections, where the retirement and recruitment delays impacted the workforce. These constraints have now been resolved.

Changing nature of fieldwork

We are observing an increasing operational technology (**OT**) content in fieldwork due to the increasing monitoring and control of network devices. Field staff are now required to program devices and undertake additional commissioning testing and fault diagnostics. This type of work will increase as the addition of monitoring and control devices to the network is set to continue.

Increasing work volumes

In this AMP, we are forecasting an increase in fieldwork. Over the next five years, we are forecasting:

- An 80% increase in work on the subtransmission, distribution and LV networks;
- Asset replacement and renewal drivers requiring substantial renewal works at zone substations including to communication and protection systems;
- System growth and customer connection drivers requiring new zone substations to be built and commissioned;
- New connections increasing from around 400 to 800 per annum;
- The development or upgrading of most of our significant IT/OT systems, including the EAMS, ERP, GIS, SCADA and ADMS.

Additional in-house planning, design, project management, and field resources are required to support this growth. Some of our internal staff will also be involved in the IT/OT projects. Our use of external contractors will also need to increase across all aspects.

National market constraints

Our growth is consistent with that of most other distribution businesses nationally and internationally. This creates national constraints on field resources and puts upward pressure on field staff wages and external contractor costs. There is also a ready market for skilled field staff, creating staff retention issues upon completion of training.

Aging workforce

We have an aging workforce. 25% of our field staff will reach retirement age over the next 10 years. Over the same period, 18% of the asset management and planning teams and 21% of the corporate teams will also reach retirement age. Many of the field staff reaching retirement age hold team leadership responsibilities.

13.3 Resourcing strategy

The following sections cover our resourcing approach to support the business.

13.3.1 Asset management and planning team

Since our last AMP we have increased resourcing in asset management and planning from 11 to 19 FTE positions and established a two-year graduate engineer programme with two engineering graduates now recruited into the teams. We intend to continue our graduate engineering programme and create at least one new graduate engineer role each year.

We are establishing a new engineering team focused on network performance, resilience, engineering standards and delivery. This team is partly established and will focus on setting engineering standards, assurance to those standards and providing engineering oversight of major projects.

Given the increasing use of information, we have moved the network information team into the asset management and planning teams to ensure they work closely with the planning and engineering staff. Growth is expected in the team.

These changes respond to our strategy to improve asset management maturity, increasing work volumes and our aging workforce.

13.3.2 Corporate (including IT/OT team)

As part of our evolving strategic direction, our People, Safety and Culture team refined their operating model to better support the business. We introduced two dedicated business partner roles to support field services, asset management, planning, and corporate services. This targeted approach allows us to provide more specialised, aligned, and effective support to each area.

Complementing this approach, we will be undertaking a review of our recruitment practices and strategies to enhance our ability to attract top talent, improve efficiency, strengthen our internal capabilities, and continue to strengthen our recruitment brand.

In the Finance team, we have seen roles and functions change with the divestment of Electra's subsidiaries. We are working towards a business partner operating model to support the increasing distribution network work programme. The change in focus will be provided within our existing headcount.

As part of our strategic shift, we recently established a Commercial team, bringing expertise in the regulatory, pricing and commercial in-house. The team's scope will evolve over the coming years, responding to areas of focus and requirements for investment delivery while balancing the needs of managing via an in-house versus outsourced model.

Following the divestment of its subsidiaries, Electra has recently established an in-house Customer Experience team to support the business with all activities related to customer engagement, communication around planned and unplanned outages, complaints, and community connection. This function is supported by an external contact centre to deliver 24x7 support around unplanned outages.

In addition to our efforts across the Information Technology domain, the team has recently added the Operational Technology infrastructure and systems to the digital portfolio, where opportunities have been identified for standardisation and efficiency. A programme of work has been developed to implement systems of strategic importance over the coming years. The resource plan to support the delivery of these systems will be balanced and includes upskilling our current team, recruiting specialised expertise, and outsourcing additional expertise as required.

13.3.3 In-house field services

Our in-house field services team also provides construction and maintenance across our subtransmission, zone substation, distribution, and LV networks, as well as vegetation management. The team's capabilities include in-house design, estimation, scheduling, and project management.

Since our last AMP, we have continued building our internal field resource capability from within. This included creating 12 new roles for trainee line mechanics, cable jointers, arborists, technicians, electricians, and a control room operator. We continue to pursue a range of other strategies, including:

- Multi-skilling—part of the capability matrix is to upskill 30% of the workforce to be multi-skilled in different disciplines to provide operational flexibility. In particular, training line mechanics in cable jointing will address the respective surplus and shortfall issues;
- Upskilling—there looks to be a need for upskilling given the increasing OT requirement for field work, as mentioned in the issues Section 5.6;
- Building capabilities in-house—we have a programme of recruiting 5-7 new apprentices annually as part of our long-term succession planning;
- Leveraging skills and experiences—adjusting field crew makeup, leveraging the skills and experience of experienced members of the team for network inspection, methodology and scoping, which then provides development and leadership opportunities for others in the teams;
- Improving utilisation—utilisation rates for the last two years have remained static at 79%. Using improved processes and systems, we aim to increase this to over 80% in the coming years.

These changes respond to recent delivery performance, national resource constraints, increasing work volumes and our aging workforce.

13.3.4 Use of contractors and consultants

We currently use a wide range of external contractors and consultants who provide additional resources and skills in areas such as:

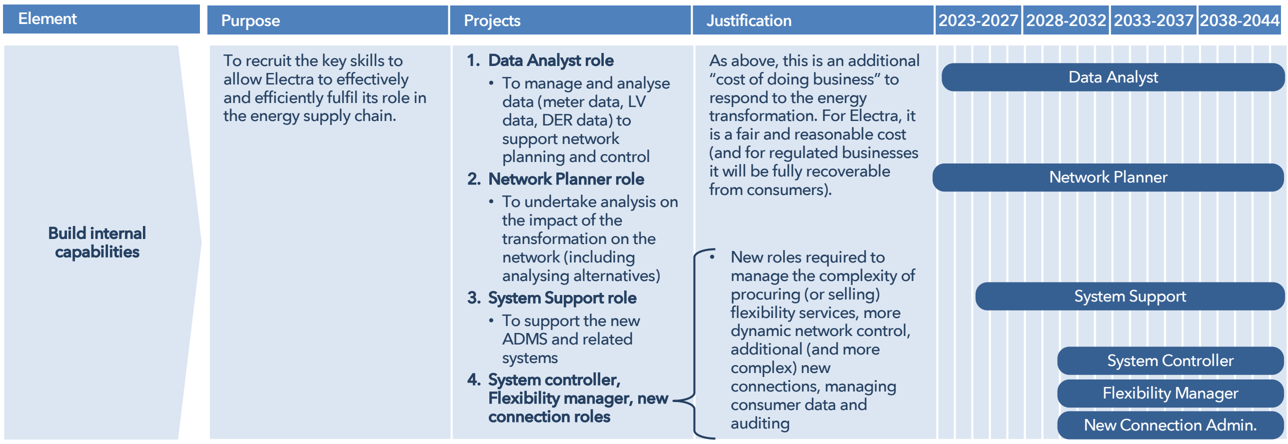
- Subject matter experts on asset management, data, systems, safety, risk management and protection studies.
- Detailed designs (mainly relating to zone substations);
- Operational technology, including communications systems and SCADA;
- Civil works, including trenching, directional drilling, duct and cable laying, and reinstatement;
- Traffic management;
- Specialised inspections, maintenance and investigations (mainly on power transformers and tap-changers).

Our approach is to work closely and deeply engage with trusted contractors. We highly value the resource flexibility and the skills that they provide. Within the next two years, we aim to provide contractors with a detailed 24-month view of our forecast work programme. We recognise that their resources are not finite and are in high demand, and being able to schedule commitments well in advance benefits both parties.

13.3.5 Future resources required to deliver energy transformation roadmap

Section [10] describes our energy transformation roadmap (**ETR**). In the roadmap, we have identified the need to recruit the key skills to allow Electra to effectively and efficiently fulfil its role in the energy supply change (Figure 156). We have already recruited additional resources for network planning. The timing for recruiting additional Data Analyst, System Support, System Controllers, Flexibility Managers and Connection Administrators will depend on the pace of flexibility management developments and the uptake of DERs. This is not yet certain.

Figure 156: ETR, new capability requirements



13.4 Safety management system

We are committed to ensuring the safety of our customers, employees, contractors, and the public. Electra's overarching safety goal is to make sure people go home safe and well every day (no serious harm and zero LTIs from critical risks).

Operating and maintaining an electrical network involves hazardous situations with risks that cannot always be eliminated. For this reason, we operate a mature safety management system (**SMS**) and continuously seek improvement.

The core elements of our SMS are:

- **Competency management**—All staff and contractors are required to adhere to our competency requirements and undertake regular refresher training. This ensures we have a highly competent workforce;
- **Contractor approval process**— Contractors undergo a thorough process to become approved to work on our network. This involves an initial pre-qualification questionnaire, followed by a visit by our Health and Safety Team to meet and review their systems and processes. This is repeated annually, with frequent interaction with contractors on work sites to verify their systems are managing their risks.
- **Fieldwork auditing**—All people leaders have key performance indicators for engaging with our field teams and approved contractors, including site safety observations and, where applicable, safety and quality audits. The number of engagements is increasing, focusing on critical safety risks and the effectiveness of controls used to mitigate them.
- **Hazard identification, management, and communication**—Our SMS includes hazard and risk management identification procedures and processes supported by a critical risk framework. Safety starts in our design and planning processes (refer to Section 11.5.2). At the worksite, on-site tailgate

start-up meetings identify hazards, risks, and mitigations before starting work. Communication between all parties, including our approved contractors and the public, is a key feature of our work systems.

- **Safe Operating Procedures**—The EEA Safety Management-Electricity Industry (**SM-EI**) rules govern much of what we do and how we do it. These form the basis of our procedures, from project inception through to delivery. These procedures are incorporated in our SMS. Standards are introduced and reviewed through an internal Standards Review Forum, which meets regularly.
- **Live line procedures**—We have comprehensive live line procedures covering all live line work. Our procedures are compliant with SM-EI and are reviewed annually. The live line crews are fully trained and undergo refresher training and certification at prescribed periods. Their work and equipment are being audited regularly.
- **Public safety management system (PSMS)**—The PSMS operates to safeguard the public and their property from safety-related risks arising from the presence or operation of the electricity network. Our PSMS complies with all elements of NZS7901 and is independently audited by Telarc annually.

13.5 Offices, depots, vehicles and tools

13.5.1 Offices and depots

Electra currently has three key buildings where staff are located:

- Bristol St, Levin —This supports most corporate, IT/OT, asset management staff and the control room;
- Coventry St, Levin—This depot supports our service delivery team in the Northern region;
- Tongariro St, Paraparaumu—This supports our service delivery team in the Southern region together with some corporate and asset management staff.

Our offices and depots aim to provide a safe and comfortable working environment, site resilience and flexible working arrangements. The Coventry St, Levin site is no longer fit for purpose, and a new property has been acquired, and the facilities will be developed later in 2025. The plan is to consolidate the Bristol St and the Coventry St sites to this new site in 2025/26.

Table 158: Offices and depots, non-network capex

Project	Driver	Cost/Year	Justification/options considered
Premise security	Replacement, renewal and upgrade to security of all depots, offices and substations	$364k FY26-35	• End-of-life replacement of existing system and expanding camera coverage across all sites
New Levin Depot	Development for Roe Street property to accommodate the field services team (FY26) and the Levin office staff (FY27)	$5.8m FY26-27	• The current depot is no longer fit-for-purpose and there is not workable upgrading option. We are using the opportunity to consolidate the Levin office and depot and will sell the current Levin office when staff have been relocated.
EV chargers	Expanding internal EV charging network at existing premises	$30k FY29, FY31	• As we expand our fleet of EVs we will increase the access to EV chargers at our sites
Office equipment replacements	General provision for the renewal of office equipment at offices and depots	$531k FY26-35	• n/a
Minor building works	General provision for minor external works at offices and depots	$612k FY26-35	• n/a
Total	**Non-network capex**	**$7.3m**	**FY26-35**

13.5.2 Vehicle fleet

Electra supports New Zealand's transition into a low-carbon economy and transport decarbonisation initiatives. We are transitioning our vehicle fleet to EVs and have installed EV chargers at all our zone substations and a number at each of our office and depots.

Our vehicle policy is to:

- Evaluate ownership versus leasing for each vehicle purchase. We currently have many vehicles on lease; as these become due for replacement (some still have over three years remaining), ownership will be assessed;
- Replace light vehicles (non-utility) at 5 years/180,000. EV or PEHV will be adopted as replacements where possible;
- Replace vans and utes at 6 years/280,000. We are monitoring the market for viable EV or PEHV alternatives;
- Truck and other specialist vehicle replacements are evaluated individually, typically every 13 years.

Factors considered for replacement include load capacity, terrain capability, and range (to align with key network features), as well as passenger requirements, cargo, and towing capacity. We are monitoring the market for viable EV alternatives.

Table 159: Offices and depots, non-network capex

Project	Driver	Cost/Year	Justification/options considered
Vehicle replacements	Ongoing replacement of Electra fleet, including contracting (trucks, utes, , mulchers, trailers, digger) and office fleet (EVs and pool vehicles)	$14.4m FY26-35	• Electra owns its vehicle fleet and the vehicles are replaced as required to keep the fleet operational
Total	**Non-network capex**	**$14.4m**	**FY26-35**

13.5.3 Tools and equipment

We operate all tools and equipment (including specialist testing equipment) as required to develop, monitor, and maintain the assets. Where possible, we replace petrol equipment with battery alternatives. Tools and equipment are typically replaced in accordance with the expected depreciation or when their condition or functionality declines. We are monitoring advances in asset condition monitoring and will adopt new test equipment when appropriate.

Table 160: Offices and depots, non-network capex

Project	Driver	Cost/Year	Justification/options considered
Testing equipment	General provision for the upgrade or replacement of test equipment	$225k FY26-35	• n/a
Field services equipment	Replacement, renewal and upgrade of tools and equipment	$3.5m FY26-35	• n/a
Total	**Non-network capex**	**$3.7m**	**FY26-35**

13.6 Forecast Expenditure

The forecast for non-network capex for offices, depots, vehicles, tools and equipment is shown in Table 161.

Table 161: Depot, offices, vehicles and tools non-network capex (Real $000)

Item	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	Total
Offices and depots	3,434	2,795	132	148	133	148	133	133	133	133	7,323
Vehicles	1,565	2,381	1,641	1,488	871	1,053	1,329	1,381	1,329	1,333	14,370
Tools and equipment	412	327	381	332	353	373	383	424	373	385	3,744
Total	**5,411**	**5,503**	**2,154**	**1,969**	**1,357**	**1,574**	**1,845**	**1,938**	**1,834**	**1,851**	**25,436**

Except for items #3 and #4 identified in the ETR, the proposed increases in in-house resourcing are included in expenditure forecasts in Sections 9.8, 9.9 and 14.

Other non-network capex related to IT/OT systems is included in Sections 9.8 and 9.9.

14. Risk management

14.1 Introduction

Electra is exposed to a wide range of risks, not just those inherent in operating an electrical network but also those from external influences such as legislation and regulation, environmental changes, and stakeholder satisfaction. Aside from the obvious physical risks, such as cars hitting poles, vandalism, public safety, and storm damage, the network business is exposed to a broader range of risks that need to be considered. As a lifeline utility, we recognise our responsibility to ensure the network is safe, secure, and resilient.

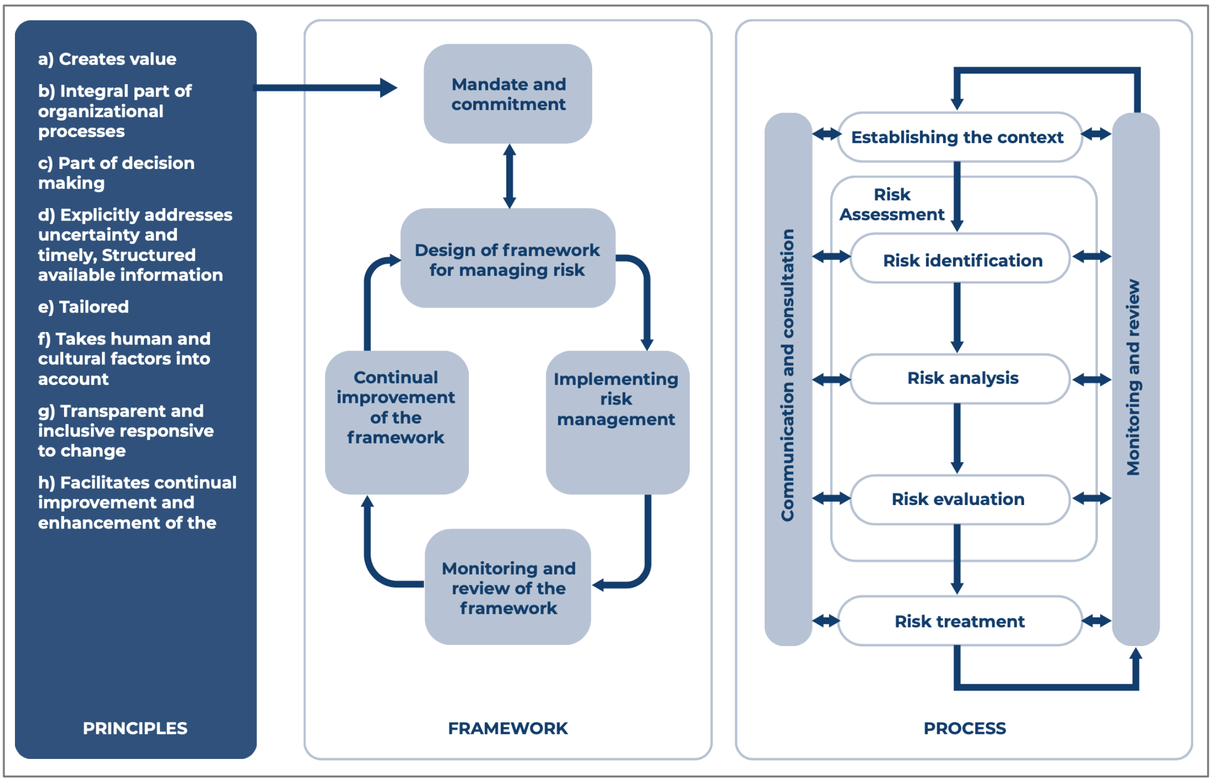
In this section, we describe our risk management framework and system, business and network risks, our resilience strategy and our emergency response and readiness activities.

14.2 Risk management framework

14.2.1 Overview

Electra has a risk management policy and framework based on the internationally recognised standard AS/NZS ISO 31000:2018 (Figure 157).

Figure 157: Electra's risk management framework



This framework uses well-established processes based on AS/NZS ISO 31000 to:

- Identify risks that could impact the safety (of staff, contractors and the public), customer service, finance, and the environment;
- Assess the consequence and likelihood of the risk occurring;
- Identify controls that will mitigate the risk;
- Assess the effectiveness of controls;

- Identify the top residual risks (after controls have been applied);
- Regularly assess the residual risk to assess whether additional treatments could further minimise risks.

An essential part of this process is the identification of workplace hazards and maintaining a register of incidents and accidents consistent with the Health and Safety at Work Act (**HSWA**).

14.2.2 Risk management system

Electra uses the Vault risk management system to record and manage all risks, incidents, injuries, illnesses, near misses and incident investigations. Vault is a stand-alone cloud-based risk management and incident reporting tool available to staff via desktop or mobile application.

We apply a consistent risk evaluation and scoring system (Figure 158), which enables us to readily identifies the greatest risks to the business.

Figure 158: Risk rating

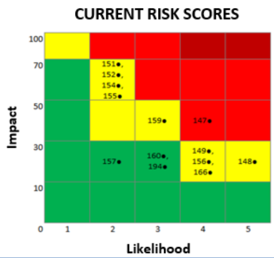
	Minor	Moderate	Serious	Major	Catastrophic
Frequent	50-Low	150-Medium	250-High	350-Very High	500-Very High
Probable	40-Low	120-Medium	200-High	280-High	400-Very High
Occasional	30-Low	90-Low	150-Medium	210-High	300-High
Remote	20-Low	60-Low	100-Medium	140-Medium	200-High
Improbable	10-Low	30-Low	50-Low	70-Low	100-Medium

14.2.3 Risk register

Electra's risk register identifies and quantifies risks based on a scoring mechanism. A risk's raw risk score is based on the probability of it occurring and the consequences of it; its current (or residual) risk score is calculated after existing controls are applied, and the target risk score after additional treatments are applied (Figure 159). The risk register also tracks actions against any agreed risk treatment.

Figure 159: Sample output from the risk register

Risk ID	Subject	Raw Probability	Raw Consequence	Raw Risk Score	Current Probability	Current Consequence	Current Risk Score	Target Probability	Target Consequence	Target Risk Score
166	Climate Risk & Sustainability	3	50	150	4	30	120	2	30	60
194	Asset Planning & Management	4	50	200	3	30	90	2	30	60
147	Regulatory Change	4	70	280	4	50	200	2	50	100
157	Theft or Fraud	4	70	280	2	30	60	1	30	30



14.2.4 Legal compliance

Directors, Management and key staff complete a Legal and Statutory Compliance survey quarterly using the ComplyWith system. The process ensures that we monitor our legal obligations and educate our staff on legal requirements. ComplyWith includes regular reporting of changes to legislation sent directly to the ‘obligation holder’ to inform and update them of new or altered requirements. This proactive approach ensures that Electra keeps abreast of its legal compliance requirements and with the aid of ComplyWith’s information function, staff can check what compliance means for each particular requirement.

The most recent certification process covered 44 pieces of legislation, with 415 responses completed. There were no non-compliances identified.

14.3 Responsibilities for risk management

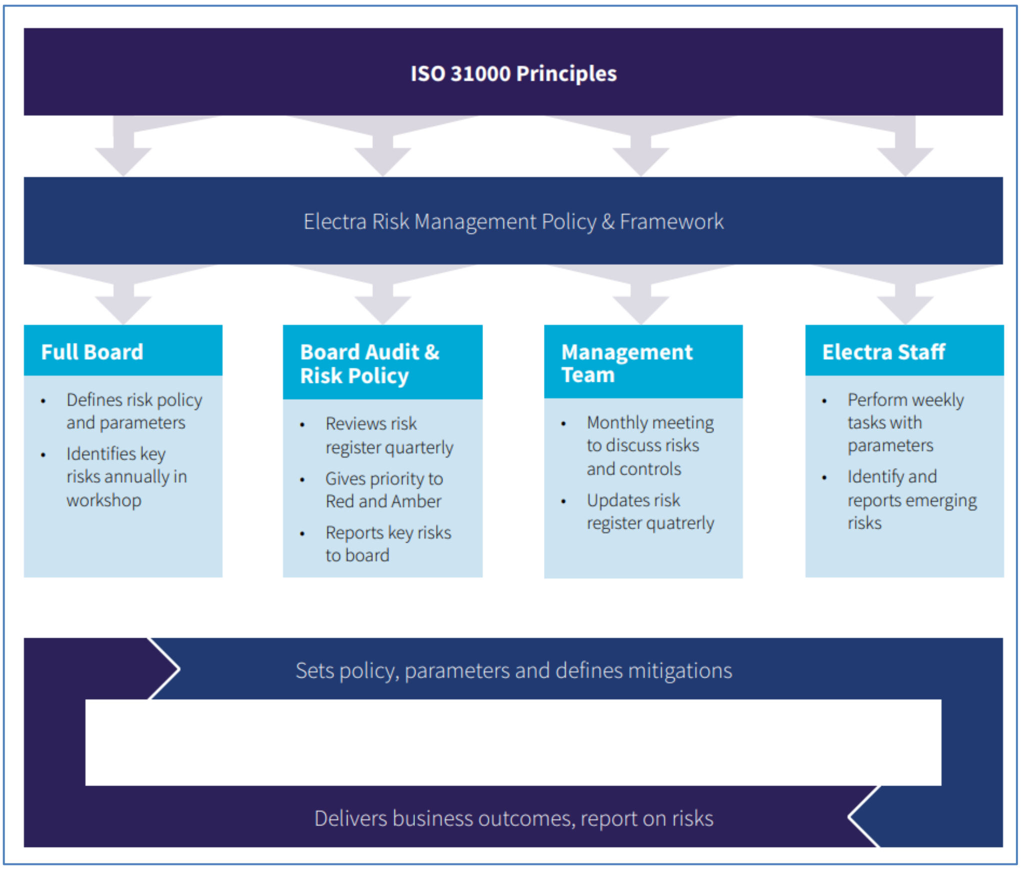
All staff are responsible for risk management (Figure 160). Our approach includes line-of-sight linkages from risk governance to detailed risk identification and mitigation. We have a well-established Audit and Risk Committee, with the GM Commercial acting as the company’s Risk Manager. The Audit and Risk Committee reviews key risks and engages in a schedule of ‘deep dives’ into Electra’s key and emerging risks.

Staff regularly complete comprehensive risk analysis on the network and the business. The risk analysis is reviewed and agreed by the Audit and Risk Committee comprised of Electra Directors, the Chief Executive, Chief Financial Officer, and the Risk Manager.

In October 2024 the Board participated in a risk workshop facilitated by external consultants. The objective was to begin resetting and refreshing Electra’s risk appetite and tolerance statements. The impetus for this resetting work was the shift in strategy to *focusing on the core network operations* and to ensure that risk appetite and tolerance aligns with the strategy.

There is a programme of work underway to redevelop our risk approach, framework and policies to ensure it is fit-for-purpose. This will involve workshops with the Senior Leadership Team and key staff, followed by an embedding of a suitable risk culture across all staff and contractors.

Figure 160: Responsibilities for risk management



14.4 Significant business risks

Electra has identified significant business risks: regulatory change, staff retention and recruitment, climate change and sustainability, decarbonisation, harm to workers and the public, and cyber security. These are discussed below.

14.4.1 Harm to workers and the public

Operating and maintaining an electrical network involves hazardous situations with risks that cannot be entirely eliminated. We are committed to ensuring the safety of our customers, employees, contractors, and the public. We have developed a health, safety and wellbeing policy supported by a comprehensive safety management system (**SMS**). Implementation of the SMS is our key control for safety (refer Section 13.4).

Some of the key aspects of the health, safety and wellbeing policy and our SMS are to:

- Identify and control hazards by eliminating, isolating, or minimising them;
- Workers actively identify, report and deal with any potential hazard and associated risk to them or any other person while at work;
- Provide and maintain training and information to enable team members to fulfil their own and the Company's personal obligations for health, safety and wellbeing;
- Any accident, health and safety incident, near miss or significant health or safety issue must be reported;

- Following investigation into the causes of any accident, incident, near miss or significant safety issue identified Electra will, so far as is reasonably practicable, action any recommendations arising to prevent a recurrence through a process of elimination or minimisation;
- Worksite safety observations and auditing.

14.4.2 Regulatory change

Regulatory reform of the energy sector has been identified as the most significant current risk for Electra. This includes:

- Uncertainty associated with the implementation of government-initiated electricity pricing review;
- Uncertainty of how regulators may influence the adoption of emerging energy technologies, load control and flexible services, and electrification of transport and process heat;
- Uncertainty related to increasing regulation of connection process and pricing; and
- Greater regulation increasing the cost to customers;

To better understand the changes and influence the industry by responding to regulatory consultations, Electra is participating more in industry forums, workshops, and working groups provided by the EA, ENA, FNF and EEA.

The volume of regulatory reform has increased substantially in recent years. A regulatory team, including external experts, has been established to oversee consultations and the response required. Electra responds both individually or as part of a collective of distributors.

14.4.3 Staff retention and recruitment

With increasing demands for highly skilled and competent employees, the past years have been challenging in recruiting and retaining staff, particularly in engineering and finance. The investment programme will require additional resources, and in some cases new expertise that Electra does not currently have inhouse. Recruitment campaigns have been successful, however, other businesses also looking for staff with these specific skill sets are making employment offers Electra is sometimes unable to match. The additional cost Electra faces to recruit necessary roles flows through to increased prices for consumers, at a time when affordability is a risk identified by the Board and Management. Electra has begun an engineering graduate programme to provide experience and possible career paths for future engineers and looks to benefit from this going forward.

14.4.4 Changing climate and sustainability

Changing climate features (sea level rise, changing rainfall patterns, increased air temperatures and increasing windy days) are widely regarded as the single most significant risk facing civilisation in general and built infrastructure. A Sustainability Group has been established to provide strategic guidance on sustainability issues, material issues and risks relevant to the performance of the business. The Group's responsibilities include reviewing, evaluating, and endorsing relevant sustainability policies, frameworks, strategies, and targets as well as integrating sustainability considerations into business planning, risk management, prioritising sustainability activities, and analysing the impact of our sustainability policies and practices.

Two critical projects have been launched to define and shape our sustainability strategy:

- Sustainably materiality assessment: We interviewed both internal and external stakeholder to gauge their views on the importance and impact on Electra's sustainability objectives and our findings has

enabled Electra to prioritise sustainability activities that are vital and will have a significant impact, not just for Electra but for our community
- Target-setting for greenhouse gas (GHG) reduction: Electra's carbon footprint baseline assessment has helped us understand where emissions are being generated and more importantly, allow us to set a target to manage a reduction in our GHG or Greenhouse Gas emissions in line with New Zealand's target under the Climate Change Response Act 2002 for net zero emissions by 2050.

The Ministry for the Environment has identified the top 42 climate risks for New Zealand in their 2020 National Climate Change Risk Assessment report.[164] Based on these risks, we have prioritised those that required the most action and assessed the climate impact on our physical assets as well as on our commercial and regulatory impacts of our business in the short, medium and long term.

Electra is committed to reduce the human impact on climate change and ensure we understand how Electra's activities can materially impact this change. Our network is not immune to changes in the environment like coastal erosion and the rising sea level and we are exploring how these types of changes impact the way we build and support our network with a view of augmenting our procedures and processes to enable a more resilient network into the future.

Electra also participates in relevant national workgroups and events and maintains a watching brief on the journeys of our peers. Further, we have committed to establishing sustainability as a core part of our operations. This includes:
- A commitment towards establishing a sustainability strategy and roadmap;
- Hiring a Sustainability Lead to focus and lead our overall sustainability plan;
- Establishing the ideal environmental, sustainability and governance reporting framework for Electra;
- Identifying clear in-house sustainability initiatives with increasing funding made available.

We are in the process of updating our Sustainability Policy and framework. The results of this review will be included in the 2026 AMP.

14.4.5 Decarbonisation

Electra is committed to supporting the government's low-carbon initiatives delivered through EECA and other government agencies. Converting process heat from coal and gas to clean energy and decarbonising the transport sector by moving operators from petroleum products are major opportunities for Electra.

To support these government initiatives, we are:
- Regularly meeting local government and councils to discuss plans;
- Providing pricing options to encourage adoption of clean energy;
- Approaching and working with customers that may benefit from moving from fossil fuels;
- Participating in relevant national workgroups and events.

To ensure we know what areas we need to prioritise, Electra has contracted an external party to conduct a baseline carbon footprint assessment, designed to give us a view of our current carbon emissions and provide insight on how we can reduce or eliminate such effects. Electra will look to define the targets to support carbon emissions and integrate low or zero-emission technology into its business.

[164] https://environment.govt.nz/publications/national-climate-change-risk-assessment-for-new-zealand-main-report/

14.4.6 Cyber Security

As cyber-related attacks continue to increase globally and in New Zealand, Electra has carried out a series of assessments and have undertaken a series of activities on cyber security controls. Networking with similar EDBs is on-going to drive the sharing of knowledge and key learnings in the industry around cyber security controls, policy, and framework for information security management.

Operational Technology (**OT**) cybersecurity is a critical area of focus. As we continue to build on the Purdue model, we are implementing an effective cyber-physical system (**CPS**) designed to provide robust exposure management, network protection, secure access, and threat detection. This comprehensive approach ensures that all layers of our control systems are fortified against potential cyber threats, safeguarding our critical infrastructure.

The Purdue model is a hierarchical framework for developing secure control systems and is the foundation for our OT cybersecurity strategy. By integrating advanced CPS, we enhance our ability to monitor and protect each level of the Purdue architecture, from the enterprise network to the physical process. Our focus extends beyond traditional IT security measures to encompass the unique requirements of OT environments, where the convergence of digital and physical systems necessitates a nuanced approach to security.

Complementing this cyber-physical system is our unified IT/OT Security Operations Centre (**SOC**) service. The SOC plays a pivotal role in monitoring and analysing anomalous activity across IT and OT domains. By leveraging sophisticated automated response mechanisms, the SOC effectively stops any detected threats. This unified approach enhances our security posture and facilitates seamless collaboration between IT and OT security teams, fostering a culture of shared responsibility and continuous improvement in our cybersecurity efforts.

This work programme is dedicated to establishing a resilient and secure cyber-physical ecosystem. By building on the Purdue model and integrating state-of-the-art CPS and SOC services, we are committed to providing robust protection for our operational technology environments against the evolving landscape of cyber threats. This proactive and holistic approach to OT cybersecurity is essential for maintaining the integrity, availability, and safety of our critical infrastructure.

14.5 Resilience strategy

14.5.1 High Impact Low Probability (HILP) Events

HILP events have a higher impact than what typically occurs during the normal network operation. These include multiple contingency events at a significant site or widespread outages that impact many assets. It is difficult to predict these events, and some examples of HILP events include the following:

- February 2011: Christchurch earthquake where electricity to 75% of the city was cut;
- October 2014: Penrose cable trench fire causing blackouts to 85,000 Auckland customers;
- February 2023: Cyclone Gabrielle that resulted in the loss of supply to 240,000 customers across the North Island.

HILP events can cause long-duration outages that can cause significant economic and social impacts on communities. Our resilience strategy has been developed to reduce the risk of these events and minimise the consequences through effective readiness and response processes. Our resilience strategy covers:

- Risk identification: understand the type and impact of the events the network could potentially experience;

- Risk reduction: minimise the consequence of these events with investment in new technologies and asset renewal and replacement;
- Readiness: reduce the impact of these events by improving network resilience;
- Response: develop plans in our business processes to respond to such events, including contingency plans to invoke a staged and controlled network restoration.

14.5.2 Importance of resilience

The increasing use of electricity to decarbonise transport, industrial process heat, and commercial and domestic heating will increase the reliance on electricity and reduce fuel diversity. As a result, in the future, a loss of supply will have more significant community and economic consequences and impact more sectors. Therefore, Electra's (and the electricity sector's) resilience must be commensurate with its increasing dominance and linkage of electricity supply to economic activity.

14.5.3 Definition of resilience

In the modern context, resilience means:

- The capacity of the network to absorb a shock; recover from disruptions; adapt to changing conditions; and retain essentially the same function as it had before;
- Having the capacity to adapt to those shocks and rapidly recover, even if that means providing services differently.

For the electricity distribution businesses, this means:

- Minimising the potential number of customers interrupted during a major event (generally by way of risk reduction);
- Minimising the duration of the interruptions that occur during a major event (generally by way of readiness and response);
- Communicating with customers and stakeholders so that they can be informed in their decision-making and so that restoration can be effectively coordinated and targeted; allowing us to optimise between what the network can reasonably deliver and how long it may take to recover against what customers can tolerate and what they can do to give them greater control and certainty.
- Recovering to the pre-event state.

14.5.4 Objectives of our Resilience Strategy

The objective of our resilience strategy is to improve the resilience of our network to reduce the impact of HILP events within acceptable customer tolerances.

Our approach to improving network resilience is to identify which assets are at risk, quantify that risk, and compare the cost of remediation against its current asset health index and expected life cycle. This approach that will see efficient investments consistent with our customers' interests and appetite for risk.

The outcomes of this strategy will be:

- An improvement in our RMMAT score to 3 in all areas and 4 in critical areas;
- A reduction in the duration of loss of supply to customers and the number of customers affected during major adverse weather events and other natural hazards (in particular to asset failures and vegetation outages);
- Assessment and adaption to climate change;

- Improved emergency management response and community support.

The resilience strategy supports our asset management strategy #4, which is to *continuously improve the security, reliability and resilience of the distribution network*.

Our objective focuses on resilience to various natural and other hazards and excludes cyber security. However, this is not excluded from a business perspective, and our work on cyber security is discussed in Section 14.4.6. We will include our implementation timeline in the 2026 AMP.

14.5.5 Resilience strategy

Improving resilience will take a multi-faceted approach over the next decade. This will be addressed principally through risk reduction, readiness and response activities. To provide a comprehensive view of resilience, our strategy includes new initiatives and existing programmes that enhance resilience. Our strategy is shown in Figure 161.

Figure 161: Resilience strategy

Community engagement

	Strategy action	Description	Status
Review	Conduct annual RMMAT assessment FY25	Assess our resilience maturity and determine improvement activities	Assessment complete
Risk identification actions	Resilience Explorer GIS layers	The resilience explorer developed by Urban intelligence will be used to assess our network vulnerabilities to natural hazards (wind, seismic, snow/ice, river flooding, coastal inundation, peak rainfall, land stability), as well as the impact of climate change on these hazards.	To to be completed in FY26
	Resilience & Condition based asset risk management methodology	Apply resilience-based risks & probabilities on top of current condition-based asset risk management methodology.	In progress
Risk mitigation actions	Increase the physical resilience of critical assets in vulnerable locations	Assess the options to increase the resilience of critical assets that are vulnerable to natural hazards	To commence in FY26
	Resilience process implementation	Process controls to prevent new assets from being installed in vulnerable locations. Where alternative locations are not possible, additional strengthening and engineering signoff will be required.	In progress
Response and readiness actions	Diversity of critical spares storage	Establish additional storage locations for critical spares. Both northern and southern locations to increase resilience and access to critical spares in an emergency.	In progress
	Improve major event response	Review of response to storms and implement actions to improve our processes Develop switching contingency plans	Continuous improvement process
	Enhance community support	Following Cyclone Gabrielle, the government is looking at increasing support of community resilience. We will support these initiatives	Awaiting government recommendation

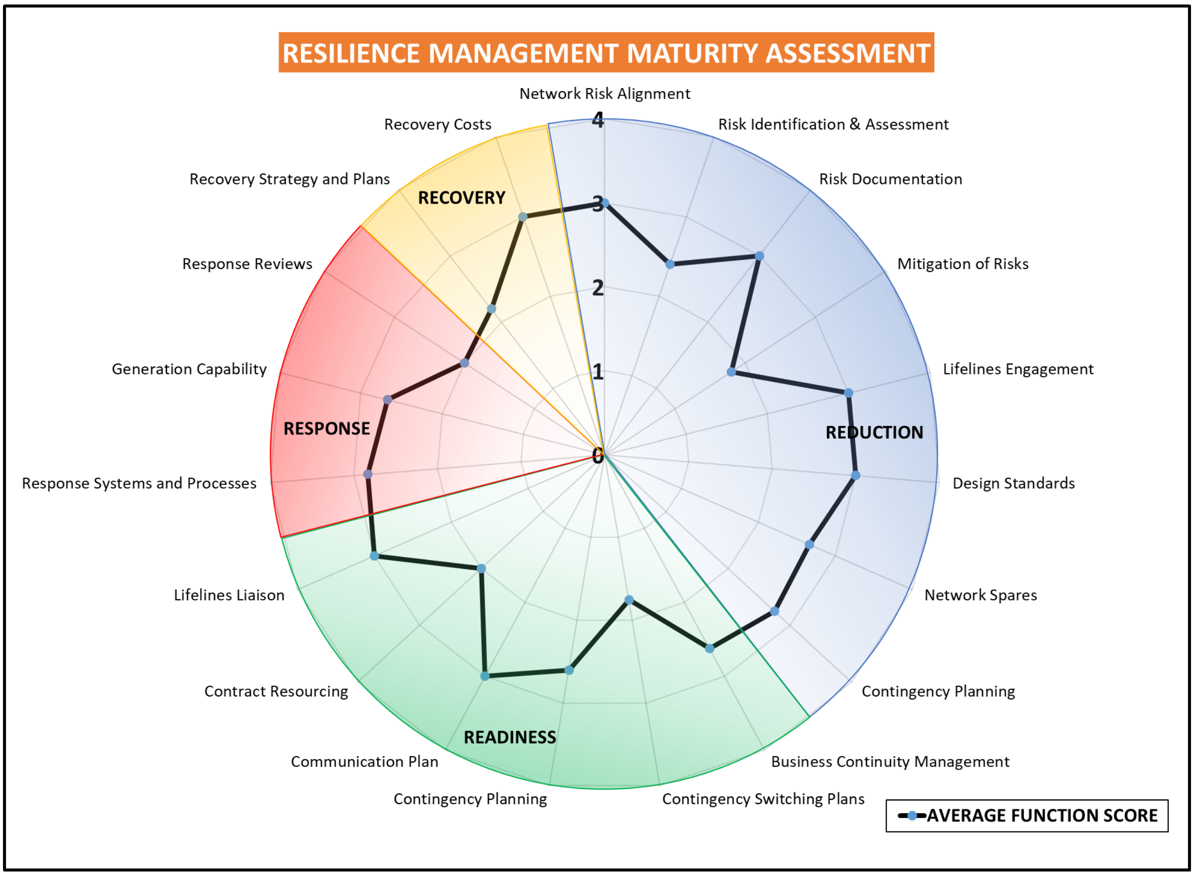
Improvement in asset resilience

We have commented further on the resilience activities below.

14.5.6 The outcome of the recent resilience review

Figure 162 shows the results of the self-assessment of our resilience practices. The RMMAT assessed our work on reduction, readiness, response and recovery (the 4Rs of resilience). The areas for improvement identified in the review were risk assessment and reduction, contingency planning and response systems. The resilience strategy incorporates a range of actions that address these areas. We expect to see consistent improvements in our RMMAT score in the near future, with our long-term goal to achieve RMMAT scores of 3 in all areas and scores of 4 in key areas.

Figure 162: Resilience management maturity assessment



14.5.7 Risk identification and assessment

Two tools are in development that will allow a more structured approach to risk identification and assessment, these being:

- Resilience and condition-based asset risk management methodology (R-CBARMM): This is an extension of the CBARMM (refer to Section 12.4.1). R-CBARMM incorporates resilience-based risks and probabilities, such as quantifying the impact of a flood on each asset class using return periods consistent with the importance or security level of the asset.[165] This is used to determine risk exposure in $ values;
- Resilience explorer: These GIS-based layers visually represent each hazard overlayed upon our network. Each hazard layer is based on published environmental studies. This is used to determine which assets will be affected during different hazard scenarios.

14.5.8 Increasing the physical resilience of critical assets in vulnerable locations

We are already in a good position regarding the extensive usage of modern concrete/steel structures throughout our network, and our substation assets are progressively being upgraded to better withstand

165 The importance level or security level defines the standard of post-disaster performance required by the assets. Refer to our resilience planning standard in Section 11.4.6.

seismic hazard. Following the development and expected implementation of the risk identification and assessment tools, there may be other resilience-driven projects (under network development) or changes in asset renewal priorities (in the fleet plans).

Whilst this strategy focuses on natural hazards, resilience is also supported by our work on reducing the impact of third-party damage incidence, outlined in the distribution structure fleet plan (Section 10.11.4).

14.5.9 Resilience process implementation and revision to design standards

We are in the process of reviewing our network design standards. This presents the opportunity to improve resilience steadily through scheduled network renewal projects and as new assets are installed. Following the revision, there may be other resilience-driven projects (under network development) or changes in asset renewal priorities (in the fleet plans).

14.5.10 Minimising the impact of outages where they occur

Reducing outages through sectionalisation, automation and improving backfeed capabilities are existing development programmes (refer to Sections 11.10.3 and 11.10.4). These programmes improve reliability and resilience. As we progress on our resilience journey, the priorities and targeting of these programmes may be altered.

14.5.11 Diversity of critical spares storage

We have two storage locations, one at Levin East and the other at Paraparaumu East Zone substations. These locations give us good diversity, with each location able to serve either the Northern or Southern regions, providing a degree of resilience should access over the Ōtaki River be compromised in an event.

14.5.12 Improve major event response

The RMMAT review highlighted the need to improve some of our operational processes and practices. We have identified a range of activities that will enhance our response to major events and emergencies, and these include:

- Develop switching contingency plans. While we have the basic methodology to follow during a major event, we need to develop switching contingency plans to guide Network Controllers when restoring power during a widespread network event.
- Undertake a critical load study to identify high-sensitivity customers that must be prioritised during power restoration, such as medical facilities, community centres, etc.

These process improvements will enhance our response to natural and other major events.

14.5.13 Resilience expenditure

Our expenditure forecasts include current programmes and projects that link to resilience. This includes work on seismic strengthening of zone substations, sectionalisation and automation. These are already included in the expenditure forecasts.

There will be a minor increase in opex to cover the implementation and ongoing support for the resilience explorer tool. Once this tool is completed and implemented into our workflows, we expect an increase in our forecast for resilience-related capex expenditure to address critical areas of the network identified as at risk.

14.6 Network risk management

In addition to our resilience strategy, we manage risk through various measures. These include supply security and other physical and operational controls that reduce the probability of occurrence or potential consequences of the risk.

14.6.1 Risk mitigation due to supply security

The consequences of a network fault (from whatever cause) are mitigated through our security of supply arrangements. The security of supply is a planning standard that the network is designed to meet (refer to Section 11.4.2). It provides for redundancy or backup supply in the event of a fault on the network. This minimises supply interruptions.

14.6.2 Risk mitigation due to our asset renewal strategy

Assets are more likely to fail towards the end of their useful life. All network assets are inspected to ensure we understand their condition and to identify any end-of-life drivers. We have developed comprehensive fleet plans that use a condition-based asset risk model to determine an asset's health and risk and schedule the asset for replacement ahead of failure (refer to Section 12.4). This approach reduces the risk of asset failures.

14.6.3 Typical asset-specific risks and controls

Table 162 summarises typical asset-specific risk and controls applied at Electra. Our risk register contains a comprehensive register of all network risks and controls.

Table 162: Typical network risks and controls

Typical risks	Asset	Controls
Oil leaks and contamination of the environment	Transformers and switchgear	• All zone transformers have individual oil containment and water/oil separators • Oil spill kits located at each zone substation in case of other spills • Where a distribution transformer or switchgear has leaked, all affected ground is removed and suitably disposed of in accordance with local by-laws
Building damage due to seismic, wind or snow*	Buildings and zone substations	• All buildings are designed to an appropriate importance level (refer to the resilience standard in Section 11.4.6) • All power transformers seismically engineered bracing • Aspirating smoke detection systems for fire containment are installed at each zone substation's switchgear building • All zone transformers and switchboards have annual diagnostic testing to locate potential faults before they occur
Line damage due to wind, snow or ice loadings*	Overhead lines	• All new lines are designed to AS/NZS 7000 to security level 3, and relevant legislative requirements • Safety in design principles are followed during the design process • All lines are inspected on a five year cycle and asset health and risk is monitored. Lines with degrading health or risk are replaced
Line damage due to vehicles*	Overhead lines and ground mounted equipment	• Electra's line poles are generally set back from the road carriageway. A recent study indicated that most vehicle damage incidents occur on long straight sections of road, where our poles were not located in a vulnerable position. • All ground mounted assets are located away from the road carriageway or physical barriers are installed. • We review all vehicle damage incidents to see if improvements need to be made.
Line damage due to vegetation*	Overhead lines	• We have implemented a vegetation management strategy as presented in Section 12.19.2.
Cable damage due to contractor damage*	Underground cables	• All contractors excavating in the road reserve are required to obtain plans for all underground utilities.

Typical risks	Asset	Controls
		• We maintain accurate plans of our underground assets in the GIS. • Cable location and safety stand-over services are also provided as required. • We review all contractor damage incidents to see if improvements need to be made.
Harm to employees and contractors working on the network	All	• We operate a mature safety management system (refer to Section 13.4). The system comprises: competency management, contractor approval process, fieldwork auditing, hazard identification, management and communication, safe operating procedure, live line procedures, and management of change
Harm to the public caused by network	All	• We operate a public safety management system (**PSMS**). The PSMS operates to safeguard the public and their property from safety-related risks arising from the presence or operation of the electricity network. Our PSMS complies with all elements of NZS7901 and is independently audited annually.
Supply chain constraints leading to project delays	All	• We are improving our front-end engineering design to ensure we begin the procurement process well in advance of need to ensure that purchases are efficient and delivery meets project requirements
Poor work quality leading to asset failure*	All	• We operate a web portal for approved contractors which gives access to our latest technical and construction standards. These standards are being revised and updated and a number of new standards and standard drawing are being drafted. • We have implemented a commissioning standard for new installations to ensure consistency across contractors. This is planned to be expanded further to encompass refurbishment to existing assets or for after fault events. • All significant works are audited upon completion and any defects found are notified to the contractor for remediation. While there are some minor gaps in our standard documentation we are relying more heavily on this audit process.
Inability to connect new customers due to insufficient capacity	All	• Electra undertakes demand forecasting and network planning to ensure that the network is developed to meet the future needs of customers. Our development plans are outlined in Section 11. • Active engagement with customers and developers to understand their requirements well in advance of need.
Inability to respond to the changing needs of customers	All	• We have developed an energy transformation roadmap (**ETR**) to prepare the network for the future needs of customers (refer to Section 10)
Inability to access the network to operate or maintenance	Assets on private property	• All new assets on private property are suitably protected by registered easements or are protected by existing use rights
Unauthorised access to assets that could result in damage or harm to people	Zone substation and ground-mounted assets	• All zone substations, switchgear and distribution transformers access locks use a controlled and tiered key system. Access keys are only provided to employees and contractors on a “need to have” basis. • Security fences at zone substations. • Bi-monthly visual inspections of all zone substations, which includes all security arrangements. Any necessary repairs are scheduled immediately
Loss of network records	n/a	• Electra records asset information electronically. The principal servers are located within Electra’s head office. The inherent risk with this is reduced by both cloud and offsite storage of computer backups, including SCADA, and contracts with suppliers to provide temporary support if required. • Scheduled recovery tests occur in our accordance with the Electra IT Security Policy • Access controls include the use of Microsoft Active Directory and expected antimalware and behaviour monitoring software.

* The asset damage may cause an outage to customers depending on the network configuration and location.

14.7 Emergency response and readiness activities

14.7.1 Business Continuity Management Plan

Electra has an active Business Continuity Management Plan (**BCMP**), which is reviewed and updated regularly. Recent inclusions and updates include pandemic, climate change and seismic threats. An event simulation exercise was conducted in mid-2024 and learnings are being incorporated into a revised BCMP.

14.7.2 Emergency response plans

Electra has a Major Network Event Guideline that is used in a storm or other major network event affecting supply to Electra's customers. The document guides what needs to occur in the lead-up to an event, at the announcement of an event and during the event. It defines the roles and responsibilities of team members involved in managing the event. It is planned to further develop this guide to include for other events.

14.7.3 Contingency plans

Contingency plans concerning minimum critical spares and an evacuation of the control room are included in our standard documents. We have also undertaken a double contingency risk analysis of our sub-transmission network to evaluate the supply options should a second contingency occur while an existing event occurs.

We have a Participant Rolling Outage Plan to comply with the Electricity Industry Participant Code 2010. The plan defines our response to major generation shortages and/or significant transmission constraints. It defines how we will shed load when requested by the System Operator. Reducing demand by disconnecting supply to customers is a last resort after all other forms of savings, including voluntary savings, have been exhausted.

For our IT/OT we have incident response plans in the event of a cyber-attack.

14.7.4 Readiness Activities

Biennial simulation exercises are undertaken to ensure the BCMP remains relevant. The Major Network Event Guideline are tested regularly and also tested during major storm events.

14.8 Critical spares

Electra holds an appropriate inventory of modern equivalent spares covering the most commonly used assets. These are located at the Paraparaumu and Levin depots. Overall, our spares holdings are sufficient to respond to a significant event. However, until the power transformer renewal project at Paraparaumu East in FY27 we have no critical spare transformer, which presents a risk to Electra. The spare we had was used at Paekākāriki in Q4 of FY24.

Individual zone substations have site-specific spares stored at each site as appropriate. We are enhancing substation spares and have a project in Section [11.9.4] to add a 33kV outdoor modular switchgear. We are also reviewing our approach to holding a spare power transformer.

14.9 Insurance

Electra uses insurance to transfer risk where it is economic to do so. Electra's insurance program covers professional and director's indemnity, public liability, material damage, fire and business interruption for buildings and plant, and vehicle cover. Other than zone substations, Electra cannot economically insure the electricity network for material damage.

In the past years, with several natural disasters affecting New Zealand, the cost of insurance cover has risen substantially. To manage costs Electra undertakes an annual review of its cover programme and retained limits. In 2023 Electra widened the marketing of its insurance programme to add new insurers and provide a range of future flexibility for increasing limits and cover. A full review of the insurance strategy will follow the risk review in 2025.

Electra requires design consultants to hold professional indemnity insurance and contractors to hold contract work and public liability insurance.

15. Expenditure Forecasts

15.1 Introduction

This Section summarises the material drivers in forecast expenditure and the material changes from the 2024 AMP. All the commentary in this Section references 2025 AMP real$ (constant prices)[166]. We have focused our commentary on the first five years (FY26 to FY30) as our forecasts reflect known projects and programmes for this period. The expenditure forecasts in the outer years (FY31 to FY35) indicate our current view of the required expenditure. However, there are fewer specific projects and programmes in this period. Where these exist, the timing and costs may change if economic conditions, electrification demand, subdivision activity, asset health or asset risk change.

15.2 Material drivers for the change in expenditure forecasts

15.2.1 Summary of changes

Our forecast capital expenditure (**capex**) and operational expenditure (**opex**) have increased over the 2024 AMP.

The capex forecast for the next five years is $153m; for the 10-year planning period, it is $280 m (Table 163)[167]. Compared to the 2024 AMP, this is an increase of $12.3m (9%) over the next five years and $4.4m (2%) to FY34[168].

The material drivers of the increase in capex over the first five years were:

- A $2.5m increase in system growth capex relating to voltage support at the Ōtaki substation (and some minor changes to the scope and timing of other projects) in response to growing demand (refer to Section 11.9);
- A $16m increase in asset renewals due to a forecast increase in asset risks for 33kV zone substation switchgear, zone substation transformers, pole, crossarm and LV conductor (refer to Sections 12.8, 12.9, 12.12 and 12.13);
- A $4.5m increase in non-network capex due to the change in timing for the development of a new Levin depot and higher vehicle replacement costs for the contracting division (refer to Section 13.5);
- A $3.0m increase in asset relocation capex (which are mostly funded by capital contributions, refer to Section 11.14);
- These increases were offset by an $11m reduction in customer connection capex (now classified as vested assets) and $2.8m reduction in quality of supply project capex.

Table 163: Capex Forecast (Real 2025 $000)[167]

Forecast	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Capex 2025 AMP	30,061	37,117	36,459	25,469	24,030	26,025	26,323	25,610	26,392	22,439
Capex 2024 AMP	33,654	27,634	27,557	25,837	26,196	26,222	27,901	28,671	28,747	
Change	**(3,593)**	**9,483**	**8,902**	**(368)**	**(2,165)**	**(197)**	**(1,578)**	**(3,061)**	**(2,354)**	

166 The 2024 AMP forecasts in real$ have been inflated to 2025 AMP real$. CPI between September 2023 and September 2024 was used.

167 Before adding Vested Assets and deducting Capital Contributions.

168 When comparing forecasts to the 2024 AMP, we can only compare to FY34 as this was the extent of the forecasts included in that AMP. Before adding Vested Assets and deducting Capital Contributions.

The network opex forecast for the next five years is $131m; for the 10-year planning period, it is $264m (Table 164). Compared to the 2024 AMP, this is an increase of $12.3m (10%) over the next five years and $20.4m (9%) to FY34.

The material drivers of the increase in opex over the first five years were:

- A $18m increase in business support costs. This was primarily due to additional IT costs, improving the maturity of the business, and changes in the business structure (refer to Section 9.8). A large portion of the increases relate to SaaS (Software as a Service) and employee and consulting costs relating to the data transformation roadmap. SaaS is a shift in our cost structure, where IT licence and development costs were traditionally capex. We are also forecasting higher finance, commercial, communication and people and culture costs as we improve the maturity of our operations, risk management, and people support;
- A $2m increase in service interruption and vegetation management costs to better reflect current fault management costs, expand our vegetation management programme, and account for the network's growing scale (refer Sections 12.19.1 and 12.19.2);
- These were offset by a $6.5m reduction in system operations and network support and changes in preventative maintenance.

Table 164: Opex Forecast (Real 2025 $000)

Forecast	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Opex 2025 AMP	25,693	26,888	26,466	26,058	26,218	26,347	26,284	26,395	26,567	26,725
Opex 2024 AMP	22,611	24,138	24,040	24,013	24,169	24,256	24,344	24,432	24,554	
Change	**3,082**	**2,750**	**2,426**	**2,045**	**2,049**	**2,091**	**1,940**	**1,964**	**2,013**	

15.2.2 The impact of inflation

The escalation of real costs between the 2024 AMP and this AMP has been modest (CPI was 2.6% and PPI was 1.3%)[169], which is less than half that experienced in the year prior.[170] We reviewed significant projects for this AMP and adjusted costs based on our assessment of current material and labour costs. Where project costs were not reviewed, we applied a CPI adjustment to bring prior costs to 2025 real$ (constant prices). We used CPI as our team considered it more reflective of recent cost increases than PPI.

15.2.3 Forecasts in normal dollars

Schedule 11a(i) and 11b(i) provide capex and opex forecasts in nominal dollars. We have applied forecast CPI to escalate the real$ (constant price) forecasts to nominal (refer to Table 165). Our forecasts reflect Westpac's forecasts to FY28, then 2.0% after that (the middle of the Reserve Bank's target for inflation). We are comfortable with our project and programme estimates for FY2026. Hence, no inflation was applied to that year.

Table 165: Real to Nominal price inflation

Forecast	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Nominal price inflator	0.0%	1.85%	2.03%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

[169] Source Stats NZ for September 2023 to September 2024. CPI included all goods. PPI is the construction cost for energy generation, transmission, and distribution.

[170] Source Stats NZ. CPI for the prior year to September 2023 was 5.6% and PPI was 4.0%.

15.3 System Growth Capex

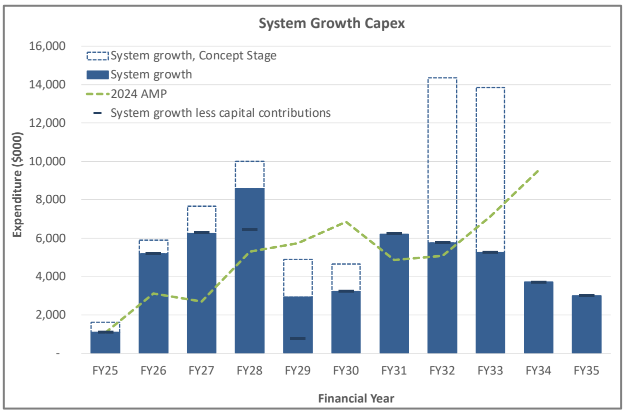
System growth expenditure is related to the development of the network to meet growth requirements across subtransmission, zone substations, distribution, and LV assets (refer to Section 11). System growth amounts to $26m (net of capital contributions) over the first five years and $46m over the planning period (Figure 163). The material drivers for expenditure in the first five years are:

- The development of two mini-zone substations and procurement of land for a third (refer to Section 11.9.3);
- The installation of Statcom voltage support at the Ōtaki zone substation (refer to Section 11.9.3);
- Capacity upgrades of two subtransmission lines in the Northern region (refer to Section 11.9.3);
- The development of seven new 11kV feeders (a total of 13 are forecast to be required over the planning period), (refer to Section 11.10.2);
- Distribution transformer capacity upgrades (refer to Section 11.11.2).

Over the first five years, system growth expenditure has increased by $2.5m compared to the prior AMP due primarily to Ōtaki voltage support and some minor changes to the scope and timing of other projects. These projects are predominately in the FY26 to FY28 period, where most of the change in expenditure occurs.

Figure 163 also shows the value of projects still in the concept phase. This work relates to subtransmission developments associated with a new Northern region GXP. This is a significant project that is still under consideration (refer to Section 11.8).

Figure 163: System Growth Capex



15.4 Asset Replacement and Renewal Capex

Asset replacement and renewal capex relates to the end-of-life replacement of assets and is the most significant area of expenditure on the network. Assets are replaced when the risk of continued operation is considered too high (defined in the relevant fleet plans included in Section 12). Asset replacement and renewal amounts to $78m over the first five years and $154m over the planning period (Figure 164).

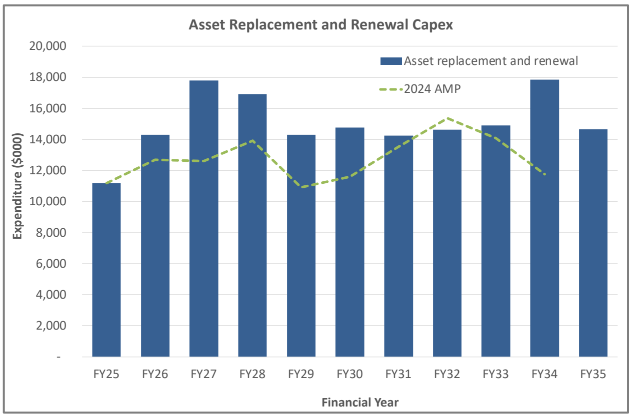
Expenditure in the first five years is being driven by:

- The replacement of crossarms and poles;
- The replacement of LV and 11kV conductor;
- Zone substation transformers, switchgear and protection relays;
- Pillar box replacements.

These programmes contribute to reducing reliability risk mentioned in Section 7.3.

Over the first five years, asset replacement and renewal expenditure has increased by $16m compared to the prior AMP due primarily to higher zone substation switchgear, zone substation transformers, protection relays, pole, crossarm and LV conductor replacement. This increase is in response to the increasing asset risks associated with these fleets.

Figure 164: Asset Replacement and Renewal Capex



15.5 Reliability, Safety and Environmental Capex

Reliability, safety and environment capex relates to improving the security of supply or reliability and addressing regulatory environment, safety or resilience issues. Security, reliability, regulatory, environmental and resilience projects are included in Section 11 and safety projects in Section 12.

Reliability, safety and environment capex amounts to $28m over the first five years and $40m over the planning period (Figure 165, Figure 166 and Figure 167). The material drivers for expenditure in the first five years are:

- Enhancing subtransmission and distribution protection (refer to Section 11.12.3);
- Improving distribution and LV network security, reliability and automation (refer to Sections 11.10.3, 11.10.4 and 11.11.3);
- Adding additional GM switches to improve the security of the underground distribution network (refer to Section 11.10.3);
- Safety programmes to remove pitch-filled 11kV cable potheads, remove 11kV in-line cable joints on poles, and remove LV steel link boxes (refer to Section 12.14);
- Substation resilience, critical spares and environmental improvements (refer to Section 11.9.4 and 11.9.5).

The security and reliability programmes contribute to reducing reliability risk mentioned in Section 7.3.

Over the first five years, reliability, safety and environment capex has reduced by $2m compared to the prior AMP. This has been driven by a reduction in security and automation programmes.

Figure 165: Quality of Supply Capex

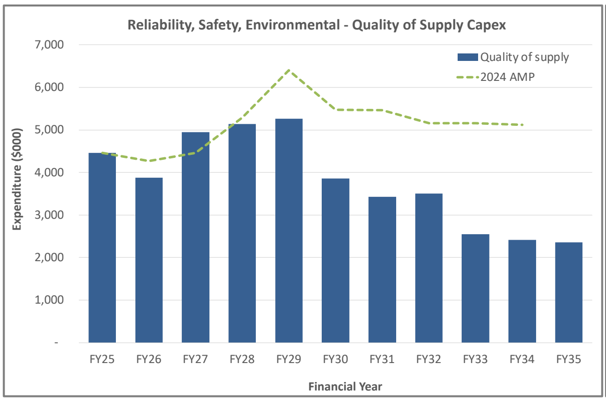


Figure 166: Legislative and Regulatory Capex[171]

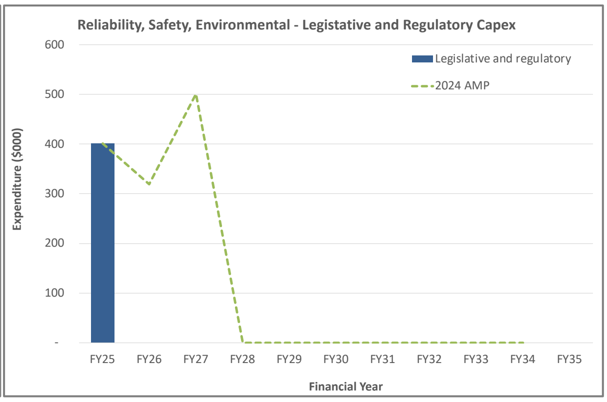
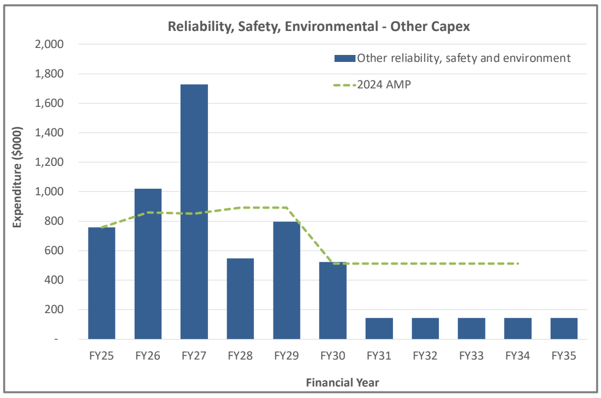


Figure 167: Other Reliability, Safety and Environmental Capex[172]



15.6 Customer Connections, Vested Assets and Asset Relocations Capex

Customer connection and vested asset capex relates to connecting new customers or upgrading supply arrangements for existing customers. We have amended our forecasts compared to the 2024 AMP to reflect historical expenditure trends, our current connection process and the expected growth in new connections (refer to Section 11.13). New connection work is undertaken by an approved contractor (which includes a team within Electra's Service Delivery division). The customer pays the entire cost of the connection work and then Electra acquires the network asset portion (as a vested asset). Vested asset capex amounts to $2.3m over the first five years and $4.6m over the planning period (refer to Figure 168 and Figure 169). The actual value of the connection work is significantly higher than the value of vested assets.

Asset relocation capex relates to the cost of moving our lines and cables to meet the needs of other utility providers. This mainly relates to the O2NL project. The effective cost to Electra is the net cost (asset relocations less capital contributions), which amounts to $300k over the first five years (refer Figure 170). Asset relocation capex is volatile as the scope and timing are controlled by others.

[171] The reduction in legislative and regulatory compliance related to zone substation seismic strengthening, which is now classified as other reliability, safety and environmental capex.

[172] The increase in other reliability, safety and environmental capex relates to the transfer of zone substation seismic strengthening from legislative and regulatory compliance capex.

Figure 168: Customer Connection Capex

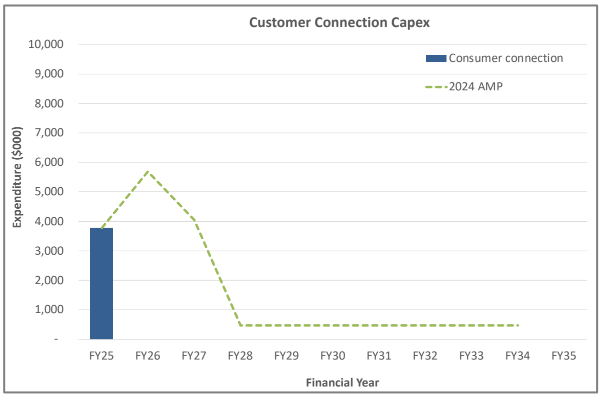


Figure 169: Vested Assets Capex

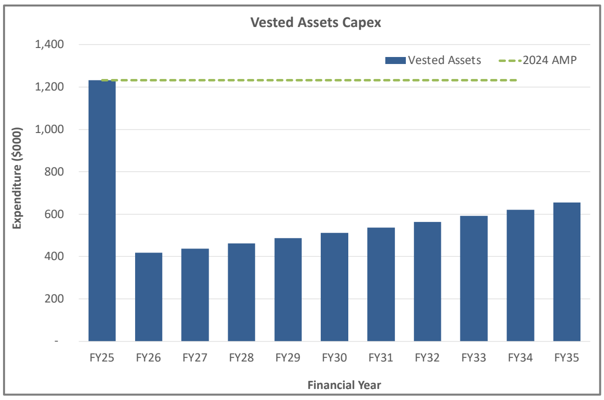
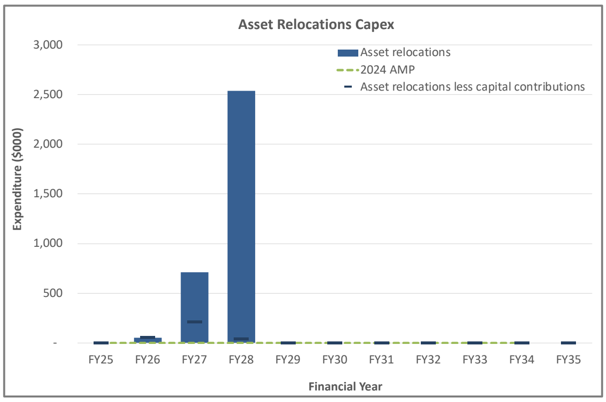


Figure 170: Asset Relocations Capex



15.7 Non-Network Capex

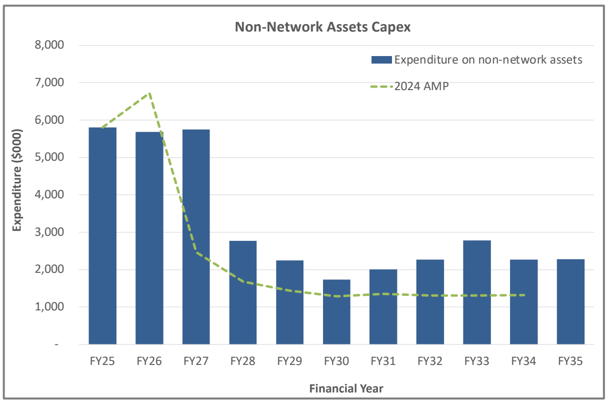
Non-network capex amounts to $18m over the first five years and $28m over the planning period (Figure 171). The material drivers for expenditure in the first five years are:

- The new Levin depot;
- Vehicle replacement costs for the contracting division;
- IT and OT hardware costs.

On a comparable basis, non-network expenditure has increased materially; however, much of this increase is now included in Business Support opex. Of the remaining non-network capex, there are two key changes:

- Phasing in the development of the new Levin site, which has increased capex in FY27;
- A material increase in vehicle investment which reflects a shift from leasing to internal ownership.

Figure 171: Non-Network Capex



15.8 Network opex

Our network opex forecasts are shown in Figure 172 to Figure 175. Network opex amounts to $37m over the first five years and $68m over the planning period. Network opex covers response and restoration of faults[173], vegetation management, inspection and maintenance of the assets, and replacement of subcomponents of assets[174] that are not large enough to constitute an asset. We discuss these opex categories further in Section 12.19.

Our forecasting approach for these opex categories has changed. We are now forecasting network opex based on historical average costs (less material one-off costs), plus changes in scope, increases in network scale, increases in real$ costs, and less efficiency improvements. In this AMP, we have not forecast real cost increases or efficiency gains, which will be assessed over the coming 12 months.

Over the first five years, network opex has increased by $0.6m compared to the prior AMP. This has been driven by:

- Higher fault management costs, which reflect a material increase in overhead and underground fault costs in the past couple of years;
- An increase in vegetation work—we are expanding the program (refer to Section 12.19.2) to reduce reliability risk (refer to Section 7.3);
- An increase in the replacement of subcomponents—the change reflects improvements to our forecasting approach;
- These increases were partially offset by a reduction in inspection and maintenance costs—the scope of this work has increased; however, the change compared to the prior AMP reflects improvements to the way we have forecasts expenditure (refer to Section 12.19.3);

Our real$ (constant price) forecasts are increasing over the forecast period. This reflects an expected increase in network scale (i.e., more assets to inspect, maintain, and respond to faults). This was not included in prior forecasts.

173 Service interruptions and emergencies

174 Asset replacement and renewal opex

Figure 172: Service Interruptions and Emergencies Opex

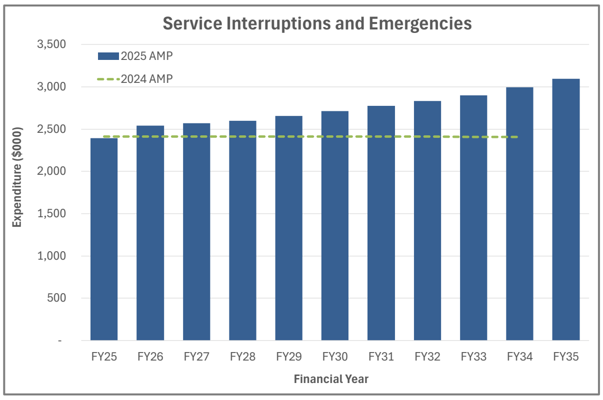


Figure 173: Vegetation Management Opex

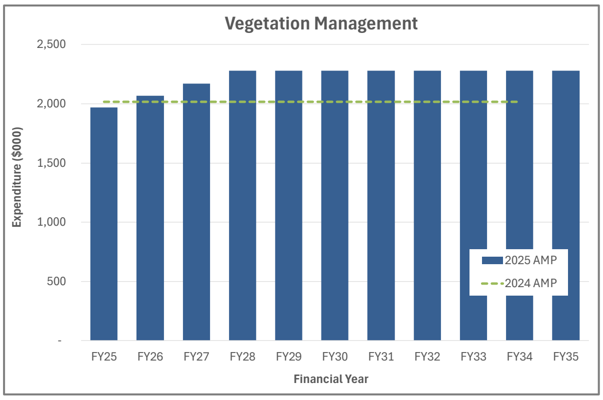


Figure 174: Reactive, Corrective Maintenance and Inspection Opex

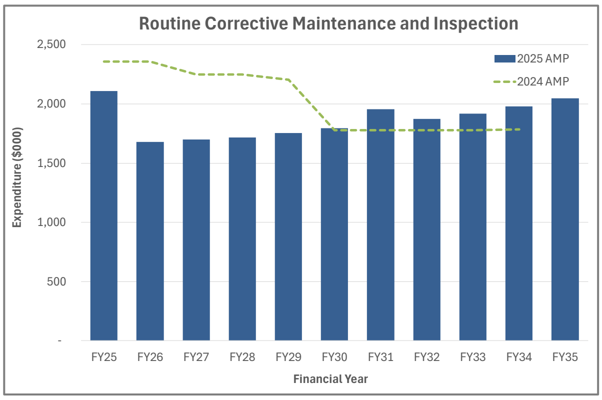
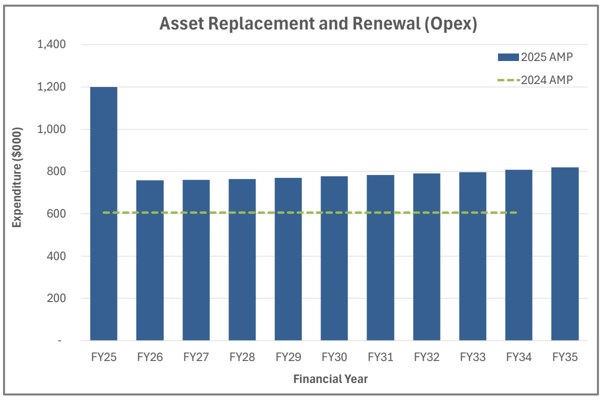


Figure 175: Asset Replacement and Renewal Opex



15.9 Non-network opex

15.9.1 System operations and network support

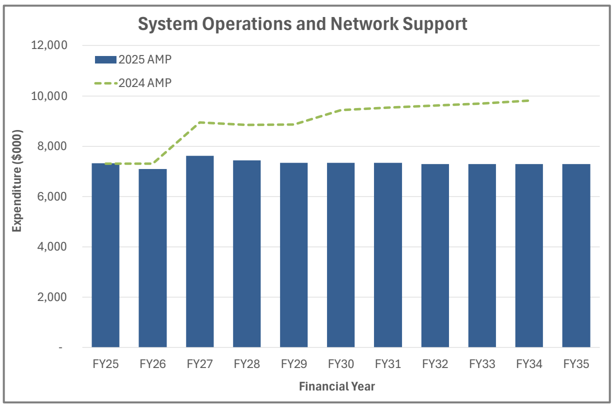
System operations and network support (**SONS**) expenditure relate to the management and operation of the network and is discussed in Section 9.9. It includes the operations team, control centre, asset information team, engineering team and planning team. The human resource requirements primarily drive this expenditure. A large portion relates to direct staff costs. These costs are forecasts based on the resources and internal costs, net of any capitalisation of design and project management work on capex projects.

These costs now include software as a service expenditure (Saas), which has not been accounted for historically under this category.

SONS expenditure is $43m over the first five years and $82m over the planning period.

Over the first five years, SONS expenditure has reduced by $6.5m compared to the prior AMP. The 2024 AMP included various costs associated with the energy transformation roadmap implementation (refer to Section 10 and 13.3.5). These additional costs have been removed from this AMP as we are now less sure of the timing. We will be reviewing the roadmap over the next year and may include additional costs in future AMPs

Figure 176: System Operations and Network Support Opex



15.9.2 Business Support Costs

Business support costs relate to the corporate overhead costs required to operate Electra. These include corporate support: Board, executive management, finance, treasury, regulatory and internal legal. It also includes corporate IT support, corporate IT Saas, insurance, HR, external legal, audit and assurance fees, professional advice and office costs.

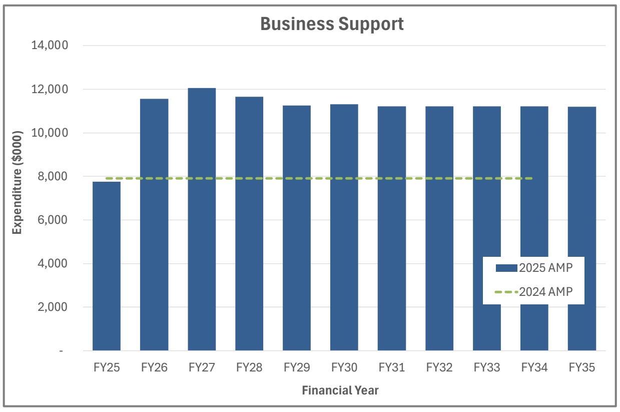
Most of these costs relate to salaries, wages, and related staff costs (training, travel, accommodation, etc.). Staff numbers, Electra's strategic work programme, the scale of the field work programme these overheads support, and changes to other non-regulated subsidiaries that overhead expenses are shared across, drive these costs.

Business support opex amounts to $58m over the first five years and $103m over the planning period.

The step change in costs from FY26 reflects that Electra has exited all of our non-core subsidiaries as we re-focuses on our core electricity distribution services. Corporate overheads previously shared across other subsidies are now all applied to Electric regulated business. These overhead resources are being used to deliver Electra's strategic initiatives that will improve the maturity of our operations, risk management, and people support. The strategic initiatives include the shift to software-as-a-service, improving our cyber protection and data transformation.

Following the exit of our subsidiaries in 2024, we are also reviewing our overhead resources and related expenses to ensure that expenditure is prudent. Any changes to our cost structure will be included in future iterations of our AMP.

Figure 177: Business Support Opex



15.10 Detailed expenditure forecasts

Detailed expenditure forecasts are included in Schedule 11a and 11b in Appendix 4 and 5.

Appendices

Appendix 1: Reconciliation of Asset Management Plan to Electricity Distribution Information Disclosure Determination 2012

The following table reconciles the sections of this AMP to Attachment A of the Electricity Distribution Information Disclosure Determination 2012 (consolidated to February 2024)[175].

Determination Clause (Attachment A of Determination[175])	AMP Section(s)
Contents of the AMP 3. The AMP must include the following-	n/a
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	Section 1
3.2 Details of the background and objectives of the EDB's asset management and planning processes;	Section 2.4, 2.5 Section 5 Section 6 Section 8.2 Section 11.3 and 12.3
3.3 A purpose statement which-	n/a
3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes;	Section 2.2, 2.3 Section 6.2 and 6.3 Section 11.3 and 12.3
3.3.2 states the corporate mission or vision as it relates to asset management;	Section 2.5 Section 6.2 and 6.3
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	Section 8.2 and 8.3
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and	Section 2.9 Section 8.2 and 8.3
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans; *The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest.*	Section 2.9 Section 8.2 and 8.3
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed; *Good asset management practice recognises the greater accuracy of short-to-medium term planning, and will allow for this in the AMP. The asset management planning information for the second five years of the AMP planning period need not be presented in the same detail as the first 5 years.*	Section 2.1
3.5 The date that it was approved by the directors;	Section 2.1
3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	Section 2.4
3.6.1 how the interests of stakeholders are identified	Section 2.4
3.6.2 what these interests are;	Section 2.4
3.6.3 how these interests are accommodated in asset management practices; and	Section 2.4
3.6.4 how conflicting interests are managed;	Section 2.4
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	Section 2.7
3.7.1 governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors;	Section 2.7 Section 8.2
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and	Section 2.7

[175] Commerce Commission, "Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024", 29 February 2024.

Determination Clause (Attachment A of Determination[175])	AMP Section(s)
3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	Section 13.3
3.8 All significant assumptions-	n/a
3.8.1 quantified where possible;	Appendix 2
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including-	Appendix 2
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business;	n/a
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	Appendix 2
3.8.5 the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b	Section 15.2.2 and 15.2.3
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;	Appendix 2
3.10 An overview of asset management strategy and delivery; *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify-* • *how the asset management strategy is consistent with the EDB's other strategy and policies;* • *how the asset strategy takes into account the life cycle of the assets;* • *the link between asset management strategy and the AMP; and* • *processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.*	Section 6.1 and 6.2 Section 12 Section 4
3.11 An overview of systems and information management data;	Section 8.4 and 8.5 Section 9.4 and 9.5
3.11.1 To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe- (a) the processes used to identify asset management data requirements that cover the whole of life cycle of the assets; (b) the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets; (c) the systems and controls to ensure the quality and accuracy of asset management information; (d) the extent to which these systems, processes and controls are integrated; (e) how asset management data informs the models that an EDB develops and uses to assess asset health; and (f) how the outputs of these models are used in developing capital expenditure projections.	Section 8.5 Section 9.5 Section 12.5 Section 8.2, 8.3 and 8.4 Section 11.4 Section 12.4
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data; *Discussion of the limitations of asset management data is intended to enhance the transparency of the AMP and identify gaps in the asset management system*	Section 8.4 Section 9.5
3.13 A description of the processes used within the EDB for-	n/a
3.13.1 managing routine asset inspections and network maintenance;	Refer to the asset inspection and maintenance sections included in all fleet plans. Refer to Section 12.8 to 12.18.
3.13.2 planning and implementing network development projects; and	Section 11.3 and 11.4
3.13.3 measuring network performance;	Section 9.4.1 and 9.4.2 Section 4
3.14 An overview of asset management documentation, controls and review processes.	Section 8.4 Section 2.7

Determination Clause (Attachment A of Determination[175])	AMP Section(s)
To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should- *(i) identify the documentation that describes the key components of the asset management system and the links between the key components;* *(ii) describe the processes developed around documentation, control and review of key components of the asset management system* *(iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;* *(iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and* *(v) audit or review procedures undertaken in respect of the asset management system*	
3.15 An overview of communication and participation processes; *To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should* *(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and* (ii) *demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.*	Section 2.8
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	Yes. The AMP uses constant price NZ dollars. This is generally referred to as real$ in the AMP
3.17 The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	Yes. The AMP is structured in three parts. • Part 1: The key issues facing our network; • Part 2: Strategies to address the key issues and performance; • Part 3: How we are implementing our strategy.
<u>Assets covered</u> 4. The AMP must provide details of the assets covered and non-network solutions, including-	Section 3.5
4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	Section 3.2
4.1.1 the region(s) covered;	Section 3.2
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities;	Section 3.3 and 3.4
4.1.3 description of the load characteristics for different parts of the network;	Section 3.3 and 3.4
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	Section 3.4
4.2 a description of the network configuration, including-	Section 3.5
4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	Section 3.5 and 3.7 Section 11.9.6
4.2.2 A description of the sub transmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the sub transmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x sub transmission security or by providing alternative security class ratings;	Section 3.5.2 Section 11.8 and 11.9.2
4.2.3 a description of the distribution system, including the extent to which it is underground;	Section 3.5.3
4.2.4 a brief description of the network's distribution substation arrangements;	Section 3.5.3 and Section 12.16
4.2.5 a description of the low voltage network including the extent to which it is underground;	Section 3.5.4 and Section 12.13 and 12.14

Determination Clause (Attachment A of Determination[175])	AMP Section(s)
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems; and	Section 12.11 and 12.18
4.2.7 a quantification of the contribution each non-network solution makes towards solving a network risk or constraint, and a description of the extent to which those non-network solutions are provided by a related party or third party. *To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.*	Section 3.7 (DG) Section 10.8 (demand control) Consideration of non-network solutions is discussed on proposed projects (where relevant). Refer to Section 11.
4.3 If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	n/a
<u>Network assets by category</u> 4.4 The AMP must describe the network assets by providing the following information for each asset category-	Refer to fleet plan in Section 12.8 to 12.18.
4.4.1 voltage levels;	Voltage levels are discussed in each fleet plan. Refer to Section 12.8 to 12.18.
4.4.2 description and quantity of assets;	Description and quantities of assets is discussed in each fleet plan. Refer to Section 12.8 to 12.18.
4.4.3 age profiles; and	Section 5.4 Fleet age is discussed in each fleet plan. Refer to Section 12.8 to 12.18.
4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	Asset health and risk of assets is discussed in each fleet plan. Refer to Section 12.8 to 12.18.
4.5 The asset categories discussed in clause 4.4 should include at least the following-	n/a
4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	Yes. Fleet plans are in more detail. Refer to Section 12.8 to 12.18
4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others;	Not material
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	Section 3.5.5
4.5.4 other generation plant owned by the EDB.	Section 3.5.5
<u>Service Levels</u> 5. The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	Section 6 Section 7
6. Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	Section 4.3 Section 7.3
7. Performance indicators for which targets have been defined in clause 5 should also include-	n/a
7.1 Consumer oriented indicators that preferably differentiate between different consumer types; and	Section 4.3 and 4.4 Section 7.3
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	Section 4.5 Section 7.5
8. The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	Section 7
9. Targets should be compared to historic values where available to provide context and scale to the reader.	Yes. Section 7
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	Yes. Section 7.3

Determination Clause (Attachment A of Determination[175])	AMP Section(s)
Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.	
Network Development Planning 11. AMPs must provide a detailed description of network development plans, including—	Section 11
11.1 A description of the planning criteria and assumptions for network development;	Section 11.4 and 11.5
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	Section 11.4 and 11.5
11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	Section 11.5.5
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	n/a
11.4.1 the categories of assets and designs that are standardised; and	Section 11.5.3 and 11.5.4
11.4.2 the approach used to identify standard designs;	Section 11.5.3
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network; *The energy efficient operation of the network could be promoted, for example, though network design strategies, demand side management strategies and asset purchasing strategies.*	Section 11.5.5
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network; *The criteria described should relate to the EDB's philosophy in managing planning risks.*	Section 11.4.2 and 11.5.4
11.7 A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision;	Section 11.4.9
11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	Section 10.8
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	Section 10.8
11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts,	Section 11.9.2
11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	Section 11.8.1, 11.9.3 and 11.10.2
11.8.4 discuss the impact on the load forecasts of any anticipated levels of non-network solutions in a network;	Section 11.8.1, 11.9.3 and 11.10.2
11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	Section 11.8.1, 11.9.3, 11.10.2, 11.10.3, 11.10.3, 11.11.2 and 11.11.3
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	Covered in all the description of proposed projects through Section 11
11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and	Covered in all the description of proposed projects and the sections on the justification for projects and expenditure discussed through Section 11
11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	Section 11.6 Innovation is also discussed in the fleet plans in Section 12.8 to 12.18 where relevant
11.10 A description and identification of the network development programme including non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	Section 11
11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	All material projects are presented in each development section (Section 11), for each fleet plan (Section 12) and for IT/OT projects (Section 9)

Determination Clause (Attachment A of Determination[175])	AMP Section(s)
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	All material projects are presented in each development section (Section 11), for each fleet plan (Section 12) and for IT/OT projects (Section 9)
11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period; *For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including a detailed description of the investigations undertaken in respect of the potential for non-network solutions to be more cost effective than network augmentations and vice versa. This should specify if any third parties were approached in relation to non-network solutions, and if so, whether those third parties are related parties. For the purposes of disclosing the information described in clause 11.10.3, an EDB is not required to include commercially sensitive or confidential information.*	All material projects are presented in each development section (Section 11), for each fleet plan (Section 12) and for IT/OT projects (Section 9)
11.11 A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated; and	Section 11.4.8
11.12 A description of the EDB's policies on non-network solutions, including-	Section 11.8.4, 11.9.8, 11.10.8, and 11.11.7
11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	Section 11.8.4, 11.9.8, 11.10.8, and 11.11.7
11.12.2 the potential for non-network solutions to address network problems or constraints; and	Section 11.8.4, 11.9.8, 11.10.8, and 11.11.7
11.12.3 how information on current and forecast constraints (both load and injection) is shared with potential providers of non-network solutions. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2 of Attachment A.	Section 10.5
Lifecycle Asset Management Planning (Maintenance and Renewal) 12. The AMP must provide a detailed description of the lifecycle asset management processes, including—	n/a
12.1 The key drivers for maintenance planning and assumptions;	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	Section 12.19.5
12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	An overview is presented in Section 12.3. This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.3.2 a description of innovations that have deferred asset replacements;	This is provided in all fleet plans when relevant. Refer to Section 12.8 to 12.18.
12.3.3 a description of the projects currently underway or planned for the next 12 months;	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.3.4 a summary of the projects planned for the following four years (where known); and	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.

Determination Clause (Attachment A of Determination[175])	AMP Section(s)
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	n/a
12.5 Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of:	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.5.1 the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.5.2 the rationale for using the approach for each asset category.	This is provided in all fleet plans. Refer to Section 12.8 to 12.18.
12.6 Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance.	Section 12.19.2
12.7 The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB used to inform these expenditure projections;	This is provided in all fleet plans when relevant. Refer to Section 12.8 to 12.18.
<u>Non-Network Development, Maintenance and Renewal</u> 13. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	Section 13.5
13.1 a description of non-network assets;	Section 9 Section 13.5
13.2 development, maintenance and renewal policies that cover them;	Section 13.5
13.3 a description of material capital expenditure projects (where known) planned for the next five years; and	Section 9 Section 13.5
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	Section 9 Section 13.5
<u>Risk Management</u> 14. AMPs must provide details of risk policies, assessment, and mitigation, including—	Section 14
14.1 Methods, details and conclusions of risk analysis;	Section 14.2
14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	Section 14.5
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	Section 14.4 and 14.6
14.4 Details of emergency response and contingency plans. *Asset risk management forms a component of an EDB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.*	Section 14.7
<u>Evaluation of performance</u> 15. AMPs must provide details of performance measurement, evaluation, and improvement, including—	Section 4
15.1 A review of progress against plan, both physical and financial; • *referring to the most recent disclosures* • *or other problems experienced; and* • *commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.*	Section 4.2 to 4.8
15.2 An evaluation and comparison of actual service level performance against targeted performance; • *in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.*	Section 4.2 to 4.8
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	Section 9.2

Determination Clause (Attachment A of Determination[175])	AMP Section(s)
15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Section 4.2 to 4.8 Section 5.5 Section 9.2
<u>Capability to deliver</u> 16. AMPs must describe the processes used by the EDB to ensure that-	Section 13
16.1 The AMP is realistic and the objectives set out in the plan can be achieved; and	Yes. This has been considered in the development of the plan. Refer Section 13.2 and 13.3
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Refer Section 13.2 and 13.3
<u>Requirements to provide qualitative information in narrative form</u> 17 AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	n/a
Notice of planned and unplanned interruptions 17.1 a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions;	Section 6.4.3
Voltage quality and constraints 17.2.1 monitoring voltage, including: (a) the EDB's practices for monitoring voltage quality on its low voltage network; (b) work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010; (c) how the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder; (d) how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and (e) any plans for improvements to any of the practices outlined at clauses (a)-(d) above;	Section 10.10
17.2.2 monitoring load and injection constraints, including: (a) any challenges, and progress, towards collecting or procuring data required to inform the EDB of current and forecast constraints on its low voltage network, including historical consumption data; and (b) any analysis and modelling (including any assumptions and limitations) the EDB undertakes, or intends to undertake, with the data described in clause 17.2.2(a).	Section 10.10
Customer service practices *There may be a degree of overlap between the information required under this clause and the information required in respect of customer charters under clause 2.5.3. For the avoidance of doubt, if there is overlap, EDBs should disclose the information in both places.*	Section 6.4
17.3 a description of the EDB's customer service practices, including:	Section 4.4 Section 6.4
17.3.1 the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services;	Section 4.4 Section 6.4.1 and 6.4.2
17.3.2 the EDB's approach to planning and managing customer complaint resolution;	Section 6.4.1
Practices for connecting new consumers and altering existing connections 17.4 a description of the EDB's practices for connecting consumers, including:	Section 11.13.2
17.4.1 the EDB's approach to planning and management of- (a) connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and (b) alterations to existing connections (offtake and injection connections);	Section 11.13.2
17.4.2 how the EDB is seeking to minimise the cost to consumers of new or altered connections;	Section 11.13.2

Determination Clause (Attachment A of Determination[175])	AMP Section(s)
17.4.3 the EDB's approach to planning and managing communication with consumers about new or altered connections;	Section 11.13.2
17.4.4 commonly encountered delays and potential timeframes for different connections; and.	Section 11.13.2
17.4.5 the EDB's approach to sharing information on current and forecast constraints (both load and injection) with potential new consumers. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2(a) of Attachment A.	Section 11.13.2
New connections likely to have a significant impact on network operations or asset management priorities *The following requirements focus on the EDB's capability and risk management regarding demand, generation, or storage capacity that the EDB considers are likely to have a significant impact on its network operations or asset management priorities. The EDB may consider voltage, network location, or other factors in making this assessment.*	n/a
17.5 A description of the following:	n/a
17.5.1 how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity; (b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account; (c) how the EDB takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and	Section 11.13.2
17.5.2 how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	Section 11.13.2 Section 10.8
Innovation practices 17.6 a description of the following:	n/a
17.6.1 any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials;	Section 10.7 (flextalk) Section 11.9.4 (Vista switchgear) Section 11.12.3 (tripsaver) Section 12.8.4 (moisture probe) Section 11.6
17.6.2 the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	Section 10.7 (flextalk) Section 11.12.3 (tripsaver)
17.6.3 how the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices;	Section 11.6
17.6.4 how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and	Section 11.6 Section 10.7 (flextalk)
17.6.5 the types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information.	Section 11.6
17.7 For the purpose of disclosing the information required under clauses 17.6.1-17.6.5 above, an EDB is not required to include commercially sensitive or confidential information.	No commercially sensitive information has been included

Appendix 2: Significant Assumptions

Introduction

This appendix contains details of:

- The significant assumptions used in this AMP;
- Sources of uncertainty.

Significant assumptions

The significant assumptions for this AMP are:

Assumption	Assumption	Response if assumption occurs	Response if the assumption *does not* occur
Resident population growth	• Horowhenua District Council view on population growth (75th percentile view). Our current review implies a compounding annual growth rate of 2.1% over the AMP forecast period. • Kāpiti Coast District Council view on population growth (75th percentile view). Our current review implies a compounding annual growth rate of 1.7% over the AMP forecast period. • Refer to Section 5.2	Implement development plan (in response to capacity and security) projects as planned in Section 10.	Our approach to demand uncertainty is outlined in Sections 11.7, 11.8.3, 11.9.7, 11.10.7 and 11.11.6
Future electricity intensity	• This factor accounts for future changes in the efficiency of electricity • Continued improvement in efficiency of 0.6% is assumed • Informed by Transpower's "accelerated electrification" scenario[176]	Implement development plan (in response to capacity and security) projects as planned in Section 10 (for controlled demand outturn).	As above
Uptake of electric vehicles	• 6 MW increase in demand by 2050 • Penetration of EVs is forecast to be 51% in the Northern region and 61% in the Southern region by 2050 • The impact on ADMD is 0.13 kW per ICP with an EV. This accounts for the diversity of controlled charging • Informed by Transpower's accelerated electrification scenario[64], but moderated by average income levels across our two regions • The forecasts have been reduced over the next ten years due to the recent changes in Government policy	As above	As above
Electrification of gas	• 17 MW increase in demand by 2050 • 5.6 MW relates to the electrification of boiler load[177] • ~22% of Electra's customers currently use natural gas or LPG, with an average annual consumption of 24 GJ for residential and 374 GJ for commercial customers • These customers are all assumed to use low and medium heat and switch to electricity by 2050, consistent with accelerated electrification[64]	As above	As above

[176] Transpower, “Whakamana i Te Mauri Hiko”, 2020

[177] Based on a report of potential low temperature heat conversion. The report was prepared by DETA in 2024.

Assumption	Assumption	Response if assumption occurs	Response if the assumption *does not* occur
Demand control	• Demand reduces by 0.4 MW by 2050 • Electra's current demand control amounts to 10 MW (refer to Section 3.4) • Existing ripple control is by-passed (as per the uncontrolled scenario); however, effective demand response is available through flexibility market or other means, which increases the level of demand response	As above	As above
Uptake of distributed energy resources	• Controllable DERs reduce demand by 11 MW by 2050 • DERs uptake based on accelerated electrification penetration rate for both controllable and non-controllable DERs[64], moderated for regional sunshine hours • External financing is assumed to overcome household income differences	As above	As above
Controlled on uncontrolled demand	• We revised our demand forecasts (included in Section [10]), and they indicate material growth due to the impact of electrification. There is significant uncertainty regarding the extent of demand growth, and material reductions are possible using flexibility from EV smart charging and other sources of demand response.	As above	As above
Constant price inflation	Our future price inflation is set out in Section 15.2.3. Schedule 11a(i) and 11b(i) provide capex and opex forecasts in nominal dollars. We have applied forecast CPI to escalate the real$ (constant price) forecasts to nominal (refer to Table 2). Our forecasts reflect Westpac's forecasts to FY28, then 2.0% after that (the middle of the Reserve Bank's target for inflation).	n/a	Future expenditure forecasts may change.
Asset health	We have developed a Condition-Based Asset Risk Management Model (CBARMM) to forecast asset risk and renewals. The model is based on the DNO Methodology. CBARMM models have been developed for all network assets. These models apply a risk-based, information-driven approach to asset renewal forecasting. The health assessment inputs include nominal expected life, location, duty, asset age, operations, reliability, and condition inputs. Location factors are principally used to assess the impact of the coastal environment on an asset's expected life. Duty factors are used where equipment loading can impact an asset's expected life. The number of operations (typically under fault conditions) is used, and this impacts the condition of the assets over time. The reliability factor is applied to an asset class based on the asset's performance history and experience in managing and operating the asset. Condition inputs include those observed (through inspections) and those measured (through standardised testing). Refer to Section 12.4	The forecast asset renewal and associated expenditure forecasts will be as set out in Section 12.	The forecasts will be adjusted based on the latest asset health information.

Assumption	Assumption	Response if assumption occurs	Response if the assumption *does not* occur
Availability of field resources	Field resources are available to complete the planned work.	The work will be delivered as per this AMP.	Additional external resources will be engaged to complete the work programme. This may result in some short-term delays.
Material costs	The cost of materials increases at the forecast rate of inflation	n/a	n/a
Public policy	Public policy concerning Net Zero 2050, climate change response and the emissions reduction plan continues on its current course (as set out in Sections 5.3 and 10).	Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control above.	Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control above.
Council land use policy	No significant changes in Council land use policy that will increase the cost of Electra doing work	Continue locating assets on Council land with no increase in costs	Electra may have to purchase land for new network assets, increasing capex
NZTA and KiwiRail land use policy	No significant changes in land access policy by NZTA or by KiwiRail that will increase the cost of Electra doing work	Continue locating assets on NZTA or KiwiRail land with no increase in costs	
Wellington Northern Roading corridor	The Wellington northern roading corridor development will continue as stated in the Roads of National Significance (the NZTA's website)	People may move northwards from Wellington to Kāpiti and from Kāpiti to Horowhenua. This has been included in our population growth forecasts	Kāpiti population growth may not be as high as forecast, such that Growth CAPEX projects can be deferred

Sources of uncertainty and impact on future disclosures

Factors that may result in material differences between this AMP and future disclosures include:

Assumption	Factors that could change	Impact on future disclosures
Resident population growth	• Growth could be higher • Growth could be lower	• Higher growth could result in additional system growth capex • Lower growth could result in a reduction in system growth capex
Future electricity intensity	• Electricity intensity could be lower • Electricity intensity could be lower	• Lower intensity could result in additional system growth capex • Higher intensity could result in a reduction in system growth capex
Uptake of electric vehicles	• EV uptake could be higher • EV uptake could be lower	• Higher EV uptake could result in additional system growth capex • Lower EV uptake could result in a reduction in system growth capex
Electrification of gas	• Electrification of gas could be higher • Electrification of gas could be lower	• Higher electrification of gas could result in additional system growth capex • Lower electrification of gas could result in a reduction in system growth capex
Demand control	• Demand response could be lower • Demand response could be higher	• Lower demand response could result in additional system growth capex and require the energy transformation roadmap implementation to be delayed • Higher demand response could result in a reduction in system growth capex and require the energy transformation roadmap implementation to be advanced
Uptake of distributed energy resources	• Uptake of distributed energy resources could be lower	• Lower uptake of distributed energy resources could result in additional system growth capex and require the energy transformation roadmap implementation to be delayed

Assumption	Factors that could change	Impact on future disclosures
	• Uptake of distributed energy resources could be higher	• Higher uptake of distributed energy resources could result in a reduction in system growth capex and require the energy transformation roadmap implementation to be advanced
Controlled on uncontrolled demand	• Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control above.	• Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control above.
Constant price inflation	• Inflation could be higher • Inflation could be lower	• Higher inflation will lead to higher capex and opex, which will lead to higher prices • Lower inflation will lead to lower capex and opex, which will lead to higher prices
Asset health	• Asset health could be lower than currently assessed • Asset health could be better than currently assessed	• Lower asset health could lead to an increase in asset replacement and renewal capex and maintenance-related opex • Better asset health could lead to a decrease in asset replacement and renewal capex and maintenance-related opex
Availability of field resources	• n/a	• n/a
Material costs	• Material costs could be higher • Material costs could be lower	• Higher material costs will lead to higher capex and opex, which will lead to higher prices • Lower material costs will lead to lower capex and opex, which will lead to higher prices
Public policy	• These could impact the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control	• Refer to the assumptions on future electricity intensity, uptake of electric vehicles, electrification of gas and demand control
Council land use policy	• Land use policies could become more restrictive • Land use policies could become more permissive	• Restrictive land use policies could delay project work, increase project costs, and increase forecast capex • Permissive land use policies could reduce project costs and lower forecast capex
NZTA and KiwiRail land use policy	• As above	• As above
Wellington Northern Roading corridor	• The project could be delayed	• Growth assumptions could be overstated (particularly in the Northern region); hence, system growth capex could be reduced or delayed

Appendix 3: Glossary

Term	Description
ABS	Air Break Switch
ADMS	Advanced Distribution Management System
Adverse environment cause outages	All unplanned interruptions where the primary cause is adverse environment, such as slips or seismic events.
Adverse weather cause outages	All unplanned interruptions where the primary cause is adverse weather, other than those caused by directly by lightning, vegetation contact or adverse environment
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
ARMM	Asset Risk Management Model
ARR	Asset Replacement & Renewal
AUFLS	Automatic Underfrequency Load Shedding
BCMP	Business Continuity Management Plan
CAIDI	Customer Average Interruption Duration Index is the average total duration of interruptions per interrupted customer
Capacity utilisation	A ratio which measures the utilisation of transformers in the system. It is calculated as the maximum demand experienced on an electricity network in a year divided by the transformer capacity on that network.
Capex	Capital Expenditure used to buy, improve, or maintain fixed assets i.e., vehicles, buildings, equipment
CB	Circuit Breaker
CBARMM	Condition-Based Asset Risk Management Model
CBD	Central Business District
CO_2e	Represents an amount of a greenhouse gas (GHG) whose atmospheric impact has been standardized to that of one unit mass of carbon dioxide (CO2), based on the global warming potential (GWP) of the gas.
CoF	Consequence of failure
Conductor	Includes overhead lines which can be covered (insulated) or bare (not insulated), and underground cables which are insulated
Continuous rating	The constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely affecting its characteristics.
Controllable DER	DERs whose output or consumption can be increased or decreased on demand – for example, diesel generation, batteries, and controllable EV chargers, but not intermittent renewable generation like wind or solar. The impact of controllable DERs is flexibility.
CRM	Customer Relationship Management an approach to manage and record interactions with current and potential customers
CT	Current transformer
Current	The movement of electricity through a conductor, measured in amperes.
DDO	Drop-out fuse
Defective equipment cause outages	All unplanned customer interruptions resulting from equipment failure, either mechanical or electrical
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DNO	Distribution Network Operators
DNP	Distributed Network Protocol
DPP	Default Price Path (Commerce Commission)
DSO	Distribution System Operator. Entities responsible for managing energy and other services (like flexibility services) across the distribution network.
Distribution substation	A kiosk, outdoor ground mounted substation or pole mounted substation taking its supply at 11kV and distributing at 400V.

Term	Description
ECP	Electrical Code of Practice
EDB	Electricity Distribution Business
EF	Earth fault
EOL	End of Life
EV	Electric vehicle
EVSE	Electric vehicle supply equipment
Feeder	A physical grouping of conductors that originate from a district substation circuit breaker.
Flexibility	Customers (or merchant providers) changing their usage patterns by either switching on generators or reducing consumption in response to a signal
Flexibility Purchaser	These are buyers of flexibility services and could be: • Energy retailers or generators who buy alternatives to energy on the spot market; • System operator who buys reserve energy alternatives or ancillary services alternatives; • Transpower, who buys alternatives to transmission assets; • Distributors, who buys alternatives to distribution assets.
Flexibility Markets	Mechanisms for matching and rewarding traders of controllable DERs, including providing dispatch instruction in response to prices.
Flexibility resources	Flexibility resources are delivered through DERs that are controllable. Distributed solar without a battery is not a flexibility resource because it is not controllable.
Flexibility Traders	Owners of DER portfolios who manage their DERs portfolio to allocate it to its highest value usage. Flexibility traders interact with flexibility buyers to provide the flexibility that they require. Importantly, flexibility traders maximise the value of DERs by allocating them to their highest value use ("value stacking") rather than dedicating individual DERs to one use.
Frequency	On AC circuits, the designated number of times per second that polarity alternates from positive to negative and back again, expressed in Hertz (Hz)
FLISR	Fault location, isolation and service restoration
FY	Financial Year e.g., FY2021 is Financial Year 2021 which covers 1st April 2020 to 31st March 2021
GWh	Gigawatt hours
GXP or Grid Exit Point	The point at which Transpower's Grid is connected to Electra's equipment
H1 or HIB5	A measure of asset heath. End of serviceable life. Immediate intervention required.[178]
H2 or HIB4	A measure of asset heath. Material deterioration but condition still within serviceable life parameters. Intervention likely within three years.[178]
H3 or HIB3	A measure of asset heath. Normal deterioration requiring regular monitoring[178] , but with an increasing risk of failure.
H4 or HIB2	A measure of asset heath. Normal deterioration requiring regular monitoring.[178]
H5 or HIB1	A measure of asset heath. As new condition.178
H&S	Health & Safety
Harmonics (wave for distortion)	A distortion to the supply voltage which can be caused by network equipment and equipment owned by consumers including electric motors or even computer equipment.
High voltage	Voltage exceeding 1,000 volts, generally 11,000 volts (known as 11kV)
HILP	High Impact Low Probability
Hosting Capacity	The amount of new production or consumption that can be connected to the network without endangering the reliability or voltage quality for other customers.
HR	Human Resources
Human error cause outages	All unplanned customer interruptions resulting from contractors or staff, commissioning errors, incorrect protection settings, SCADA problems, switching errors, dig-in and overhead contact
HV	High Voltage. Voltages typically above 1,000 Volts.
ICP	Installation connection point. The point of connection for an electricity consumer.
IP	Internet Protocol
IT	Information Technology

[178] EEA Asset Health Indicator definition.

Term	Description
IoT	Internet of things
Interruption	An electricity supply outage caused by either an unplanned event (e.g., Weather, trees) or a planned even (e.g., Planned maintenance).
kV	Kilovolt
kW	Kilowatt
kWh	kilowatt hour
kVA	kilovolt amp output rating designates the output which a transformer can deliver for a specified time at rated secondary voltage and rated frequency.
LCP	Load Control Plant
LED	Light-emitting diode
Lightning cause outages	All unplanned customer interruptions where the primary cause is a lightning strike, resulting in insulation breakdown and or flashovers. Typically protection is the only observable operation
Load Factor	The measure of annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in a given year.
LoRaWAN	Long Range Wide Area Network
Low Voltage (LV)	Voltage not exceeding 1,000 volts, generally 230 or 400 volts
Maximum Demand (peak demand)	The maximum demand for electricity during the course of the year
$MtCO_2e$	Abbreviation of a million tonnes of carbon dioxide equivalent (see also CO_2e)
m	Million
MD	Maximum Demand. The peak demand (measured in MW or MVA) for the network, element of the network, or load.
MDI	Maximum Demand Indicator
MED	Major Event Day
MPL	Maximum Practical Life. The age at which the majority of assets can be expected to have been removed from service. Approximately defined as the age where nominally 95% of assets from the population would be retired for end-of-life reasons.
MVA	megavolt amp
MW	megawatt
MWh	megawatt hour (one million watt hour)
N-1 Security	A load is said to have N-1 security if for the loss of any one item of equipment supply to that load is not interrupted or can be restored in the time taken to switch to alternate supplies.
NEL	Nominal Expected Life. The time (in years) in an asset's life when it would be expected to first observed significant deterioration based on consideration of the asset alone (equivalent to a health score of 5.5).
NIMs	A Network Information Management System which contains geospatial information for all assets including asset description, location, age, electrical attributes, etc.
OC	Overcurrent
OCPI	Open charge point interphase
OCPP	Open charge point protocol
ODRC	Optimised Depreciated Replacement Cost.
ODV	Optimised Deprival Value.
ONAF	Oil Natural Air Forced
ONAN	Oil Natural Air Natural
Opex	Operational Expenditure an ongoing expense for running a business e.g., rent, power. wages
OT	Operations technology, which means digital technology used for process control, protection of machinery and assurance of product quality
PILC	Paper-insulated, lead-covered - a type of cable insulation.
PoF	Probability of failure
PQ	Power quality
PRV	Pressure relief valve
Photovoltaic	The conversion of light into electricity using solar panels

Term	Description
Ripple Control system	A system used to control the electrical load on the network by, for example switching domestic water heaters, street lighting.
REF	Restricted earth fault
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index is the average total duration of interruptions per connected customer
SAIFI	System Average Interruption Frequency Index is the average number of interruptions per connected customers
SCADA	Electra's computerized System Control and Data Acquisition System being the primary tool for monitoring and controlling access and switching operations for Electra's Network.
SCI	Statement of Corporate Intent
Subtransmission	The lines and cables that connect zone substation and the GXP.
SWER	Single Wire Earth Return
Transformer	A device that changes voltage up to a higher voltage or down to a lower voltage.
Transpower	The state-owned enterprise that operates New Zealand's transmission network. Transpower delivers electricity from generators to various networks around the country.
Third party interference cause outages	All unplanned customer interruptions resulting from external contractors or members of the public and includes dig-in, overhead contact, vandalism, and vehicle damage
UG	Underground
UHF	Ultra-High Frequency
Unknown cause outages	All unplanned interruptions where the cause is not known
Vegetation cause outages	All unplanned customer interruptions resulting from vegetation contact, includes debris, grass and tree contact
VHF	Very High Frequency
VT	Voltage Transformer
Voltage	Electric pressure; the force which causes current to flow through an electrical conductor.
Voltage Regulator	An electrical device that keeps the voltage at which electricity is supplied to consumers at a constant level, regardless of load fluctuations.
WACC	Weighted Average Cost of Capital
Wildlife cause outages	All unplanned customer interruptions resulting from wildlife contact - includes birds, possums, vermin, cats etc
XLPE	Cross linked Polyethylene. Type of insulation for cables.
Zone Substation	A major building substation and/or switchyard with associated high voltage structure where voltage is transformed from 33kV to 11kV.

Appendix 4: Forecast Capital Expenditure (Schedule 11a)

Company Name **Electra Limited**
AMP Planning Period **1 April 2025 – 31 March 2035**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8			**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	3,777	-	-	-	-	-	-	-	-	-	-
11		System growth	1,094	5,185	6,370	8,930	3,102	3,481	6,856	6,474	6,021	4,343	3,589
12		Asset replacement and renewal	11,199	14,241	18,051	17,530	15,093	15,882	15,699	16,470	17,088	20,905	17,489
13		Asset relocations	-	51	722	2,639	-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	4,457	3,878	5,041	5,337	5,576	4,177	3,778	3,947	2,925	2,822	2,812
16		Legislative and regulatory	401	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	759	1,022	1,761	570	845	565	158	161	164	167	171
18		**Total reliability, safety and environment**	5,617	4,899	6,802	5,907	6,422	4,741	3,936	4,108	3,089	2,990	2,984
19		**Expenditure on network assets**	21,687	24,376	31,945	35,006	24,618	24,105	26,491	27,052	26,198	28,238	24,061
20		Expenditure on non-network assets	5,799	5,685	5,858	2,882	2,380	1,877	2,210	2,558	3,186	2,649	2,724
21		**Expenditure on assets**	27,486	30,061	37,803	37,888	26,997	25,981	28,701	29,610	29,384	30,887	26,786
22													
23	*plus*	Cost of financing	-	301	378	379	270	260	287	296	294	309	268
24	*less*	Value of capital contributions	1,675	-	509	4,843	2,290	-	-	-	-	-	-
25	*plus*	Value of vested assets	1,200	418	446	479	517	554	592	634	680	727	782
26													
27		**Capital expenditure forecast**	27,011	30,780	38,118	33,904	25,494	26,795	29,580	30,540	30,357	31,923	27,835
28													
29		Assets commissioned	16,838	29,838	36,284	34,957	27,597	26,470	28,884	30,300	30,403	31,532	28,857
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31			**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
32			**$000 (in constant prices)**										
33		Consumer connection	3,777	-	-	-	-	-	-	-	-	-	-
34		System growth	1,094	5,185	6,254	8,594	2,927	3,220	6,217	5,755	5,247	3,711	3,007
35		Asset replacement and renewal	11,199	14,241	17,723	16,868	14,239	14,689	14,236	14,642	14,894	17,863	14,651
36		Asset relocations	-	51	709	2,540	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	4,457	3,878	4,949	5,136	5,261	3,863	3,426	3,509	2,549	2,411	2,356
39		Legislative and regulatory	401	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	759	1,022	1,729	548	798	522	143	143	143	143	144
41		**Total reliability, safety and environment**	5,617	4,899	6,679	5,684	6,059	4,385	3,569	3,652	2,693	2,555	2,499
42		**Expenditure on network assets**	21,687	24,376	31,365	33,686	23,224	22,295	24,021	24,049	22,834	24,129	20,157
43		Expenditure on non-network assets	5,799	5,685	5,751	2,774	2,245	1,736	2,004	2,274	2,776	2,264	2,282
44		**Expenditure on assets**	27,486	30,061	37,117	36,459	25,469	24,030	26,025	26,323	25,610	26,392	22,439
45													
46		**Subcomponents of expenditure on assets (where known)**											

**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*

																				Company Name	Electra Limited
AMP Planning Period	1 April 2025 – 31 March 2035

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref												
47	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion	-	-	-	-	-	-	-	-	-	-	-
49	Research and development	-	-	-	-	-	-	-	-	-	-	-
50	Cybersecurity (Commission only)	-	-	-	-	-	-	-	-	-	-	-
51												
52		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
53		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
54	**Difference between nominal and constant price forecasts**	**$000**										
55	Consumer connection	-	-	-	-	-	-	-	-	-	-	-
56	System growth	-	-	116	337	176	261	639	719	773	632	582
57	Asset replacement and renewal	-	-	328	661	854	1,193	1,464	1,828	2,195	3,042	2,838
58	Asset relocations	-	-	13	100	-	-	-	-	-	-	-
59	Reliability, safety and environment:											
60	Quality of supply	-	-	92	201	316	314	352	438	376	411	456
61	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
62	Other reliability, safety and environment	-	-	32	21	48	42	15	18	21	24	28
63	**Total reliability, safety and environment**	-	-	123	223	363	356	367	456	397	435	484
64	**Expenditure on network assets**	-	-	580	1,321	1,393	1,810	2,470	3,003	3,365	4,109	3,905
65	Expenditure on non-network assets	-	-	106	109	135	141	206	284	409	386	442
66	**Expenditure on assets**	-	-	686	1,429	1,528	1,951	2,676	3,287	3,774	4,495	4,347
67												
68	**Commentary on options and considerations made in the assessment of forecast expenditure**											
69	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15*											
70												
71												
72		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
73	**11a(ii): Consumer Connection**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
74	*Consumer types defined by EDB**	**$000 (in constant prices)**										
75	Customer connections	3,777	-	-	-	-	-	-	-	-	-	-
76		-										
77		-										
78		-										
79		-										
80	**include additional rows if needed*											
81	**Consumer connection expenditure**	3,777	-	-	-	-	-	-	-	-	-	-
82	*less* Capital contributions funding consumer connection	611	-	-	-	-	-	-	-	-	-	-
83	**Consumer connection less capital contributions**	3,167	-	-	-	-	-	-	-	-	-	-
84	**11a(iii): System Growth**											
85	Subtransmission	137	102	76	76	-	51	767	2,248	2,250	715	-
86	Zone substations	-	2,693	4,864	2,032	-	-	-	-	-	-	-
87	Distribution and LV lines	-	-	-	-	-	-	-	-	-	-	-

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref												
88	Distribution and LV cables	957	2,226	1,151	4,113	2,762	3,004	5,285	3,342	2,833	2,831	2,841
89	Distribution substations and transformers	-	164	163	164	165	165	165	165	165	165	165
90	Distribution switchgear	-	-	-	-	-	-	-	-	-	-	-
91	Other network assets	-	-	-	2,209	-	-	-	-	-	-	-
92	**System growth expenditure**	1,094	5,185	6,254	8,594	2,927	3,220	6,217	5,755	5,247	3,711	3,007
93	*less* Capital contributions funding system growth	-	-	-	2,160	2,160	-	-	-	-	-	-
94	**System growth less capital contributions**	1,094	5,185	6,254	6,434	767	3,220	6,217	5,755	5,247	3,711	3,007
95												

96		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
97		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
98	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**										
99	Subtransmission	798	797	795	797	802	803	802	802	802	802	805
100	Zone substations	2,873	2,729	3,050	3,102	330	1,663	2,045	2,454	1,880	4,603	1,341
101	Distribution and LV lines	4,554	5,208	8,591	8,613	8,672	8,683	8,667	8,665	8,670	8,664	8,696
102	Distribution and LV cables	970	1,079	1,579	1,584	1,594	1,596	1,593	1,593	1,594	1,593	1,599
103	Distribution substations and transformers	845	540	539	540	544	544	543	543	543	543	545
104	Distribution switchgear	216	641	695	697	702	703	258	258	258	258	259
105	Other network assets	941	3,245	2,474	1,535	1,596	696	327	327	1,145	1,400	1,405
106	**Asset replacement and renewal expenditure**	11,199	14,241	17,723	16,868	14,239	14,689	14,236	14,642	14,894	17,863	14,651
107	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
108	**Asset replacement and renewal less capital contributions**	11,199	14,241	17,723	16,868	14,239	14,689	14,236	14,642	14,894	17,863	14,651
109												

110		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
111		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
112	**11a(v): Asset Relocations**											
113	*Project or programme**	**$000 (in constant prices)**										
114	NZTA and Council asset relocations	-	51	608	508	-	-	-	-	-	-	-
115	Other	-	-	101	2,032	-	-	-	-	-	-	-
116												
117												
118												
119	**include additional rows if needed*											
120	All other project or programmes - asset relocations											
121	**Asset relocations expenditure**	-	51	709	2,540	-	-	-	-	-	-	-
122	*less* Capital contributions funding asset relocations	-	-	500	2,500	-	-	-	-	-	-	-
123	**Asset relocations less capital contributions**	-	51	209	40	-	-	-	-	-	-	-
124												

125		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
126		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**

	Company Name	Electra Limited
	AMP Planning Period	1 April 2025 – 31 March 2035

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref												
127	**11a(vi): Quality of Supply**											
128	*Project or programme**	$000 (in constant prices)										
129	Network protection enhancements	1,163	615	1,246	2,004	2,249	1,115	811	811	184	184	185
130	Network interconnection enhancements	1,318	1,114	1,433	727	528	528	527	869	599	527	529
	Network automation and sectionalisation enhancements	1,267	855	916	983	989	991	860	667	667	667	669
	Network switching enhancements	-	1,028	1,089	1,156	1,228	1,230	1,227	1,163	1,099	1,034	973
	Fault locator enhancements	272	-	-	-	-	-	-	-	-	-	-
131	Voltage improvement	438	266	265	265	267	-	-	-	-	-	-
132		-	-	-	-	-	-	-	-	-	-	-
134	**include additional rows if needed*	-										
135	All other projects or programmes - quality of supply	-	-	-	-	-	-	-	-	-	-	-
136	**Quality of supply expenditure**	4,457	3,878	4,949	5,136	5,261	3,863	3,426	3,509	2,549	2,411	2,356
137	*less* Capital contributions funding quality of supply	-	-	-	-	-	-	-	-	-	-	-
138	**Quality of supply less capital contributions**	4,457	3,878	4,949	5,136	5,261	3,863	3,426	3,509	2,549	2,411	2,356
139												
140		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
141		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
142	**11a(vii): Legislative and Regulatory**											
143	*Project or programme**	$000 (in constant prices)										
144	Electricity code compliance programme	-	-	-	-	-	-	-	-	-	-	-
145	High-load crossing improvement programme	-	-	-	-	-	-	-	-	-	-	-
146												
147												
148												
149	**include additional rows if needed*											
150	All other projects or programmes - legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
151	**Legislative and regulatory expenditure**	-	-	-	-	-	-	-	-	-	-	-
152	*less* Capital contributions funding legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
153	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-	-	-	-	-	-
154												
155		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
156	**11a(viii): Other Reliability, Safety and Environment**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
157	*Project or programme**	$000 (in constant prices)										
158	Seismic resilience improvements	401	381	598	-	-	-	-	-	-	-	-
159	Weather and environmental resilience improvements	-	-	-	-	-	-	-	-	-	-	-
	Other resilience improvements	-	-	456	-	-	-	-	-	-	-	-
	Safety improvements	759	518	517	518	521	522	143	143	143	143	144
	Environmental improvements	-	122	159	30	276	-	-	-	-	-	-
160		-										
163	**include additional rows if needed*	-										

	Company Name	**Electra Limited**
	AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref												
164	All other projects or programmes - other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	
165	**Other reliability, safety and environment expenditure**	1,160	1,022	1,729	548	798	522	143	143	143	143	144
166	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
167	**Other reliability, safety and environment less capital contributions**	1,160	1,022	1,729	548	798	522	143	143	143	143	144
168												
169		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
170		**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**	**31 Mar 34**	**31 Mar 35**
171	**11a(ix): Non-Network Assets**											
172	**Routine expenditure**											
173	*Project or programme**	**$000 (in constant prices)**										
174	Land	3,577	-	-	-	-	-	-	-	-	-	-
175	Office buildings, depots and workshops	74	3,312	2,795	81	97	82	97	82	82	82	82
176	Office furniture, fittings, and office equipment	61	122	-	51	51	51	51	51	51	51	51
177	Tools, plant, machinery and PEE	644	1,977	2,708	2,022	1,821	1,224	1,426	1,712	1,805	1,702	1,718
	Business Information Systems	214	-	-	-	-	205	204	204	205	204	205
	IT Hardware	231	234	198	569	276	174	225	225	634	225	226
	Network Information Systems	371	41	51	51	-	-	-	-	-	-	-
178	OT Hardware	628	-	-	-	-	-	-	-	-	-	-
179	**include additional rows if needed*											
180	All other projects or programmes - routine expenditure	-	-	-	-	-	-	-	-	-	-	-
181	**Routine expenditure**	5,799	5,685	5,751	2,774	2,245	1,736	2,004	2,274	2,776	2,264	2,282
182	**Atypical expenditure**											
183	*Project or programme**											
188												
189	**include additional rows if needed*											
190	All other projects or programmes - atypical expenditure	-	-	-	-	-	-	-	-	-	-	-
191	**Atypical expenditure**	-	-	-	-	-	-	-	-	-	-	-
192												
193	**Expenditure on non-network assets**	5,799	5,685	5,751	2,774	2,245	1,736	2,004	2,274	2,776	2,264	2,282
194												

Appendix 5: Forecast Operational Expenditure (Schedule 11)

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

sch ref

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
Operational Expenditure Forecast	**$000 (in nominal dollars)**										
Service interruptions and emergencies	2,395	2,540	2,616	2,699	2,814	2,934	3,059	3,190	3,326	3,505	3,695
Vegetation management	1,969	2,067	2,211	2,369	2,416	2,464	2,513	2,564	2,615	2,667	2,721
Routine and corrective maintenance and inspection	2,108	1,680	1,730	1,784	1,861	1,940	2,158	2,109	2,199	2,318	2,443
Asset replacement and renewal	1,200	758	775	794	817	840	865	890	915	946	978
Network Opex	7,671	7,045	7,332	7,646	7,907	8,179	8,595	8,752	9,055	9,437	9,837
System operations and network support	7,328	7,087	7,766	7,737	7,775	7,931	8,090	8,195	8,359	8,526	8,697
Business support	7,767	11,561	12,288	12,120	11,938	12,237	12,371	12,619	12,871	13,128	13,369
Non-network opex	15,095	18,648	20,054	19,857	19,714	20,168	20,461	20,814	21,230	21,654	22,065
Operational expenditure	22,766	25,693	27,386	27,503	27,621	28,346	29,056	29,566	30,285	31,091	31,902

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
	$000 (in constant prices)										
Service interruptions and emergencies	2,395	2,540	2,568	2,597	2,655	2,714	2,774	2,836	2,899	2,995	3,095
Vegetation management	1,969	2,067	2,171	2,279	2,279	2,279	2,279	2,279	2,279	2,279	2,279
Routine and corrective maintenance and inspection	2,108	1,680	1,698	1,717	1,755	1,794	1,957	1,875	1,917	1,981	2,047
Asset replacement and renewal	1,200	758	761	764	771	777	784	791	798	809	820
Network Opex	7,671	7,045	7,198	7,358	7,460	7,564	7,794	7,781	7,892	8,063	8,240
System operations and network support	7,328	7,087	7,625	7,445	7,335	7,335	7,335	7,285	7,285	7,285	7,285
Business support	7,767	11,561	12,065	11,663	11,263	11,318	11,218	11,218	11,218	11,218	11,199
Non-network opex	15,095	18,648	19,690	19,108	18,598	18,653	18,553	18,503	18,503	18,503	18,485
Operational expenditure	22,766	25,693	26,888	26,466	26,058	26,218	26,347	26,284	26,395	26,567	26,725

Subcomponents of operational expenditure (where known)

**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
Energy efficiency and demand side management, reduction of energy losses											
Direct billing*											
Research and Development											
Insurance	948	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177	1,177
Cybersecurity (Commission only)											

** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
Difference between nominal and real forecasts	**$000**										
Service interruptions and emergencies	-	-	47	102	159	220	285	354	427	510	600
Vegetation management	-	-	40	89	137	185	234	285	336	388	442
Routine and corrective maintenance and inspection	-	-	31	67	105	146	201	234	282	337	396
Asset replacement and renewal	-	-	14	30	46	63	81	99	118	138	159
Network Opex	-	-	133	288	447	614	801	972	1,163	1,373	1,596
System operations and network support	-	-	141	292	440	596	754	910	1,074	1,241	1,411
Business support	-	-	223	457	676	919	1,153	1,401	1,653	1,911	2,169
Non-network opex	-	-	364	749	1,116	1,514	1,907	2,310	2,727	3,151	3,581
Operational expenditure	-	-	497	1,037	1,563	2,128	2,709	3,282	3,890	4,525	5,177

Appendix 6: Asset Condition (Schedule 12a)

Company Name **Electra Limited**

AMP Planning Period **1 April 2025 – 31 March 2035**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)							
7	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.02%	27.60%	52.68%	19.46%	0.25%	3	6.28%
11	All	Overhead Line	Wood poles	No.	2.14%	11.67%	65.76%	17.90%	2.53%	-	2	9.73%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	13.61%	-	34.92%	21.77%	29.70%	-	4	0.18%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	26.40%	71.95%	1.65%	4	2.23%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km							N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							N/A	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	20.00%	20.00%	60.00%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	9.09%	-	4.55%	86.36%	-	4	36.36%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	7.89%	31.58%	55.26%	5.26%	-	3	13.16%
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.							N/A	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	7.59%	92.41%	-	4	22.78%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	5.26%	5.26%	15.79%	73.68%	-	4	21.05%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.20%	4.30%	1.49%	0.51%	92.25%	1.26%	3	6.53%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km							N/A	

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	2.56%	0.86%	-	35.15%	59.63%	1.79%	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	6.80%	-	3.90%	86.41%	2.58%	0.31%	3	0.24%
45	HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	31.25%	6.25%	22.92%	27.08%	12.50%	3	6.25%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.							N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	-	4.02%	0.50%	89.95%	5.53%	3	7.14%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	4.26%	0.53%	95.21%	-	3	4.52%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	3.19%	30.19%	4.69%	61.82%	0.12%	4	3.01%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	3.76%	19.19%	5.69%	71.17%	0.19%	4	6.56%
53	HV	Distribution Transformer	Voltage regulators	No.							N/A	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.							N/A	
55	LV	LV Line	LV OH Conductor	km	-	40.73%	10.21%	15.75%	33.30%	0.01%	3	14.57%
56	LV	LV Cable	LV UG Cable	km	1.29%	9.62%	15.83%	37.56%	35.42%	0.28%	3	0.09%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km						100.00%	2	1.00%
58	LV	Connections	OH/UG consumer service connections	No.	0.30%	0.93%	21.76%	0.87%	73.40%	2.74%	3	11.68%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	9.04%	-	19.77%	10.73%	60.45%	-	4	35.59%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	14.29%	64.29%	21.43%	-	3	35.71%
61	All	Capacitor Banks	Capacitors including controls	No.							N/A	
62	All	Load Control	Centralised plant	Lot			50.00%	50.00%			4	50.00%
63	All	Load Control	Relays	No.						100.00%	2	10.00%
64	All	Civils	Cable Tunnels	km							N/A	

Appendix 7: Forecast Capacity (Schedule 12b)

Company Name **Electra Limited**
AMP Planning Period **1 April 2025 – 31 March 2035**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current peak load (MVA)	*Not Required before DY2025* Current peak load period	*Not Required before DY2025* Installed operating capacity (MVA)	*Not Required before DY2025* Current security of supply classification (type)	*Not Required before DY2025* Current constraint type	*before DY2025* Current available capacity (MVA)	*Not Required before DY2025* Peak load period +5 yrs	*Not Required before DY2025* Available capacity +5 yrs (MVA)	*Not Required before DY2025* Security of supply classification +5 yrs (type)	*Not Required before DY2025* Peak load period +10 yrs	*Not Required before DY2025* Min. available capacity +10 yrs (MVA)	*Not Required before DY2025* Max. available capacity +10 yrs (MVA)	*Not Required before DY2025* Security of supply classification +10 yrs (type)	*Not Required before DY2025* Forecast constraint type	*Not Required before DY2025* Year of any forecast constraint	*Not Required before DY2025* Constraint primary cause	*Not Required before DY2025* Constraint solution type	*Not Required before DY2025* Constraint solution progress	*Not Required before DY2025* Temporary constraint solution remaining lifespan	Explanation
8																					
9	Shannon	4.70	Winter	5	N-1	No constraint	0.30	Winter	-0.1	N-1	Winter	-0.4	-1.7	N-1	Capacity	5	Zone substation transformer	Divert load to alternative substation	Planning stage	Not applicable	Load managed by feeder reconfiguration and transfer to other zone feeders
10	Foxton	7.20	Winter	23	N-1	No constraint	15.80	Winter	14.90	N-1	Winter	13.90	11.40	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
11	Levin West	14.70	Winter	23	N-1	No constraint	8.30	Winter	6.70	N-1	Winter	4.80	0.20	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
12	Levin East	13.10	Winter	23	N-1	No constraint	9.90	Winter	8.10	N-1	Winter	6.10	1.20	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
13	Otaki	12.50	Winter	23	N-1	No constraint	0.00	Winter	-0.60	N-1	Winter	-1.20	-3.40	N-1	Capacity	3	Reactive voltage support	Network upgrade	Planning stage	> 3 years	No constraint when supplied from the South, There is a voltage constraint from FY26 when supplied fron the North at high load times. Contingency plans are avialable until voltage support is installed in FY28
14	Waikanae	15.30	Winter	23	N-1	No constraint	7.70	Winter	6.30	N-1	Winter	4.70	-1.10	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Constraint ay Year 210 only occurs for uncontrolled demand. Planning is for a controlled demand
15	Paraparaumu East	13.00	Winter	23	N-1	No constraint	10.00	Winter	8.60	N-1	Winter	7.10	3.40	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
16	Paraparaumu West	12.00	Winter	23	N-1	No constraint	11.00	Winter	9.80	N-1	Winter	8.40	4.10	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
17	Raumati	9.60	Winter	23	N-1	No constraint	13.40	Winter	12.50	N-1	Winter	11.50	7.80	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
18	Paekakariki	3.20	Winter	-	N-1 switched	No constraint	1.8	Winter	1.4	N-1 switched	Winter	0.9	0	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Automatic changeover to Raumati using fault monitors and motorised switches
19																					
20																					
21																					
22																					
23																					
24																					
25																					
26																					
27																					
28																					

29 [1] *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

Appendix 8: Forecast Demand (Schedule 12c)

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected during year by consumer type*			**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10								
11		*Consumer types defined by EDB**						
12		All	533	530	626	724	827	852
13								
14								
15								
16								
17		**Connections total**	533	530	626	724	827	852
18		**include additional rows if needed*						
19								
20								
21								
22		**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23		Number of connections made in year	374	423	498	520	534	509
24		Capacity of distributed generation installed in year (MVA)	2.3	3.91	3.94	3.97	4.00	4.03
25		**12c(ii) System Demand**						
26			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27		**Maximum coincident system demand (MW)**						
28		GXP demand	76	83	85	87	89	92
29	*plus*	Distributed generation output at HV and above	26	26	26	26	26	26
30		**Maximum coincident system demand**	102	109	111	113	115	118
31	*less*	Net transfers to (from) other EDBs at HV and above						
32		**Demand on system for supply to consumers' connection points**	102	109	111	113	115	118
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	340	332	336	341	351	362
35	*less*	Electricity exports to GXPs						
36	*plus*	Electricity supplied from distributed generation	124	124	124	124	124	124
37	*less*	Net electricity supplied to (from) other EDBs						
38		**Electricity entering system for supply to ICPs**	463	456	460	465	475	486
39	*less*	Total energy delivered to ICPs	434	427	431	436	444	455
40		**Losses**	29	29	29	30	30	31
41								
42		**Load factor**	52%	48%	47%	47%	47%	47%
43		**Loss ratio**	6.3%	6.4%	6.4%	6.4%	6.4%	6.4%

Appendix 9: Forecast Interruptions and Duration (Schedule 12)

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Network / Sub-network Name	**All**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	35.0	35.0	35.0	35.0	35.0	35.0
12	Class C (unplanned interruptions on the network)	63.0	63.0	63.0	63.0	63.0	63.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.15	0.15	0.15	0.15	0.15	0.15
15	Class C (unplanned interruptions on the network)	1.40	1.40	1.40	1.40	1.40	1.40

Appendix 10: Asset Management Maturity (Schedule 13)

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Asset Management Standard Applied	**AS/NZS/ISO 55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	A Board approved asset management policy exists and published (AMP Section 6). A revised policy was approved in FY25 and it has been published and communicated to relevant staff.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	There are clearly articulated asset management strategies included in th AMP (AMP Section 6). There are clear linkages between Electra's strategic plan, stakeholder needs and the asset management strategies, which are explained in the AMP (AMP Section 6 and 8).	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	The combination of the key issues section (AMP Section 5), the asset management strategy (Section 6), and fleet strategies in the fleet plans (AMP Sections 12.6, 12.8 to 12.18) takes account of the lifecycle of all of its assets, asset types and asset systems. There is a robust linkage between the asset management strategies and the fleet strategies.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Asset Management Standard Applied	**AS/NZS/ISO 55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2.5	The combination of the development plan (AMP Section 11), fleet plans (AMP Section 12), asset management system (AMP Section 8), and asset management improvement plans (AMP Section 9) demonstrates that plans are established and documented for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle. There is direct line-of-sight from the asset risk and the asset fleet plans (AMP Section 12.8 to 12.18).	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2.5	The work plans described in the development plans (AMP Section 11) and the fleet plans (AMP Section 12) are communicated by the asset management team to the service delivery team and external contractors (where they are doing network work). The asset management improvement plan (AMP Section 9) is communicated to relevant internal and external service providers to ensure the projects are scoped and delivered.	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2.5	Section 2 of the AMP documents the responsibilities for asset management. These responsibilitiies are also documented in relevant position descriptions.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2.5	The development plans, fleet plans, and asset management improvement plans are delivered as per Electra's procurement/outsourcing policy and procedures. Electra's procurement/outsourcing policy and procedures defines policy and processes to ensure efficiency delivery of work. Project management processes currently in place provide for the effective project delivery.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Asset Management Standard Applied	**AS/NZS/ISO 55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2.5	Electra has various guidelines for the management of major network events. These guidelines define escalation actions, key roles and communication requirements. The current suite of contingency plans & emergency response plans are appropriate for the business.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Section 2 of the AMP documents the responsibilities for asset management. The relevant authorities are documented in the Board approved delegated authority policy.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	A sucession planning model and a talent matrix were examined (HRs database), however this stops short of a specific numbers of each staff category required over the timeframe.For asset mangagemnt work a process is established and followed by contracting division by forecasting labour requirement over the AMP period.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2.7	Key asset management planning and works delivery requirements are planned and monitored. This includes fortnightly Progress To Plan and other project managemernt practices to ensure that works are completed to target. There is also a monthly business unit meeting that includes field staff that deals with operational issues (eg. issuing of latest schematics), safety, quality and some works progress. The CE and Board also monitor progress through the monthly reporting process.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Asset Management Standard Applied	**AS/NZS/ISO 55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.3	There is appropraite project governancein place controlling development plans and fleet plans delivery. The development plans, fleet plans are delivered as per Electra's procurement/outsourcing policy and procedures.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2.5	Section 13 of the AMP summarises the resourcing strategy across corporate, asset management and service delivery. THe development of the strategy, and it implementation is the responsibility of HR and the senior leadership team	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2.5	There is a competency framework (HR's database). This has transitioned to the OurHub system. It will contain position descriptions and training requirements for all roles. Population of OurHub is ongoing.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2.5	There is a competency framework with the OurHub system, which is monitored by HR and Managers to ensure competency is maintained. Field staff competency is also controlled under NZQA framework and authorisation/entry competency framework.	A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	The development plans, fleet plans, and asset management improvement plans are communicated to relevant service delivery people. Operational information is communicated by the Control Centre, and escalated to relevant staff as required.	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.

Company Name	**Electra Limited**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Asset Management Standard Applied	**AS/NZS/ISO 55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2.5	A high level overview of the asset management system is included in the AMP (Section 8). There is supporting policy, procedure and standard documentation with the Electra document management system. This document is reviewed and updated as required.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2.5	The asset management system, asset management data, and asset management improvement plans (that include system and data improvements) are included in the AMP (AMP Section 8 and 9).	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	The asset management system, asset management data, and asset management improvement plans (that include system and data improvements) are included in the AMP (AMP Section 8 and 9).	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2.5	The asset management system, asset management data, and asset management improvement plans (that include system and data improvements) are included in the AMP (AMP Section 8 and 9).	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.

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Asset Management Standard Applied	**AS/NZS/ISO 55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	The risk management framewrok is defined in thr AMP Section 13. The fleet plans (AMP Section 12.8 to 12.18) contains details of the material asset risks and controls. Electra also operates a safery management system that idenifies risks. This includes a process to implement mitigations or controls.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2.5	Asset risks are identified in the fleet plans (AMP Section 12.8 to 12.18).. Relevant operational risks are communicated to the service delivery team and contractors via safety forums.	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	Electra uses Comply With to maximise its legal and regulatory compliance. Electra regularly completesComply With survey to ensure ongoing compliance.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2.5	Electra has Standards for design and construction of works to minimise non-conformance. A wide range of operating policies ensure compliant operation.Electra's standards closely follow the Powerco standards to help lower costs for suppliers, contractors, training and our engineering . These standards are currently being reviewed and updated.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2.5	Electra has a range of inspection, testing, maintenance standards. These are presently being reviewed and revised as required.The inspection and testing standards are being aligned to the requirements for CBARMM.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2.5	Conditon is measured by the condition and testing standards (mentioned in Q91). these are summarised in the fleet plans (AMP Section 12.8 to 12.18). The operational performance of the assets is measures via the control room and the Milsoft OMS.	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2.5	There is a process For Investigation Of Network Incidents. A minor and major fault (i.e. ICAM) process is being developed.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Process auditing is currently limited to safety. The PSMS Internal Audit and the TELARC Revalidation have been inspected.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2	Corrective and preventative actions are initiated via the Control Room in relation to network faults. Corrective and preventative actions are initiated via Network Engineers where they are identified during routine inspection and testing. Typical corrective and prentative maintenance is described in the fleet plans (AMP Section 12.8 to 12.18)	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2.3	We have introduced the energy trilemma balance into the 2025 AMP as the principle basis to measure the balance between cost and performance, namely security/reliability and sustainability (AMP Section 7). The balance between lifecycle risks, asset condition and costs is addressed by the fleet strategies in the fleet plans (AMP Section 12.8 to 12.18).	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2.7	Electra current obtains data via the EEA and manufacturers. Attendance of Electra staff at industry events has been observed. Comparative analysis work was examined.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Appendix 11: Mandatory Explanatory Notes on Forecast Information (Schedule 14A)

Company Name Electra Limited

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

There is no difference between nominal and constant prices for the current year (FY25) and for FY26. Our project and programme cost estimates are appropriate for FY26.

We have allowed for cost inflation over the 10 year planning period. This is shown in Table 165 in the AMP. This accounts for projected increases in construction and compliance costs.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

There is no difference between nominal and constant prices for the current year (FY25) and for FY26. Our operational and manintenance cost estimates are appropriate for FY26.

We have allowed for cost inflation over the 10 year planning period. This is shown in Table 165 in the AMP. This accounts for projected increases in construction and compliance costs.

Appendix 12: Director Certification

We, Stephen Robert Armstrong and James Albert Carmichael, being directors of Electra Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

(a) the following attached information of Electra Limited prepared for the purposes of clauses 2.6.1, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

(b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

(c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Electra Limited's corporate vision and strategy and are documented in retained records.

Signed

Stephen Robert Armstrong

James Albert Carmichael

27 March 2025

Report Ends.