Asset Management Plan 2021 – 2031

1 April 2021

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Executive summary

It gives me great pleasure to present Electra's Asset Management Plan (AMP) for March 2021, which sets out the asset management strategies and investment plans for the next 10 years.

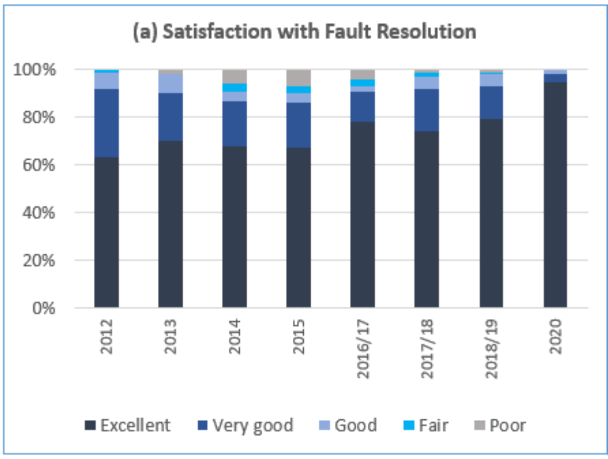
This has been a challenging year with the global effects of Covid-19 impacting our people, customers, and business operation. Electra responded quickly by adapting work practices to safely deliver the essential services and AMP programme.

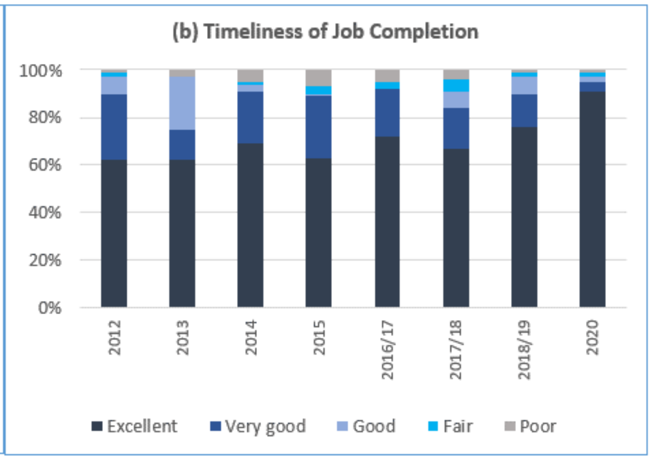
Electra has made excellent progress on the delivery of the focus areas identified in the previous year 2020 Asset Management Plan (AMP) and Electra Group Strategic goals with the focus on improved customer service, initiatives to reach the zero-harm target and maintain our mix of high reliability and cost-conscious operation.

- **Focus on Customers**

Electra is seeing positive signs that the initiatives applied over the last three years are resulting in material improvement in customer service. In April 2020, we reduced line charges amounting to $3M across most customer groups. New pricing plans were published including time-of-use (ToU) structures promoted as differentiated peak, off peak and shoulder pricing to encourage electricity usage outside of distribution and transmission peaks.

It pleasing to note that the 2020 customer survey has reported greater brand recognition and positive experiences with our people as portrayed in the graphs below. I expect this reflects our focus on communication with our customers, investment in outage systems and staff development programmes.





During the year Electra collaborated with ChargeNet NZ, the Kapiti Coast and Horowhenua District Councils, and with support from EECA, installed and commissioned two rapid electric vehicle (EV) charging stations at Shannon. The project completes the total of chargers installed by Electra to eleven, covering the length of the network. This achievement support government initiatives, increases Electra's profile and provides our customers with greater services.

- **Progress towards a target of zero harm (zero LTI's)**

Electra is committed to ensuring the safety of its customers, employees, contractors and the public at large, as noted in the 2020 Annual Report. Key asset management and system implications of this commitment to safety include continuing replacement of components such as pitch-filled metallic cable terminations, metal link pillar boxes, oil-filled switches, and development of the Vault as an H&S incident recording and analysis platform.

Electra has a mature safety management system in place to support attainment of the ‘zero harm’ goal set by the Electra Board of Directors. An intentional strategy of encouraging reporting has tripled the number of reported near-miss and safety observations as compared to last year (Section 3.5).

The upgrade of the network electrical protection systems of the high voltage network is progressing well with Line Current Differential expected to be fully applied to the southern network by the end 2020. The focus will shift to implementing similar changes to the network in our northern region from 2021 onwards.

- **High Reliability and cost-conscious operation**

Electra has undertaken a comprehensive analysis based on the last five years disclosure data[1] performed to better understand its costs and performance against a peer group of eight lines businesses based on network characteristics, network density and customer size. These peers include Alpine, Aurora, Counties Power, Horizon, Network Tasman, The Lines Co and Top Energy and comparison is also made to the overall industry of 29 electricity distributions businesses. This analysis concludes the following:

Measure for period from financial years 2016 to 2020	Position within peer group	Position within overall industry
Revenue per customer	Best (lowest)	Best (lowest)
OPEX per customer	Best (lowest)	Within lowest quartile (rank 5th)
CAPEX per customer	Second lowest	Within lowest quartile (rank 8th)
Planned & unplanned interruptions (Classes B&C SAIDI)	Best (lowest)	Within lowest quartile (rank 5th)
Planned & unplanned interruptions (Classes B&C CAIDI)	Best (lowest)	Within lowest quartile (rank 3rd)

Electra’s asset strategy and works programmes will continue to focus on maintaining this high reliability while controlling costs. Electra has completed trials of Internet of Things (IoT) and learnt much during the journey. The 2021 AMP reflects that we are now focussing on deployment of low-cost sensors within distribution assets and line fault indicators (LFI) on the electricity distribution network. The multi-year programme will improve asset management decision making and extend the life of our distribution assets. The capital and operation costs of these new technologies are significantly less than the traditional technologies.

Outlook

The Electra region is predicted to grow by 1.8% per year, over the next 10 years. This is more quickly than the national population of 1.2% per year and more quickly than previous predictions from Statistics NZ (Sense Partners - Oct 2020).

The combination of affordability, location, and government investment in roading to greater Wellington region is making the Kapiti and Horowhenua region an attractive place to live, work and play. The regional annual demand growth is forecasted to increase at 1.2% at Mangahao GXP and 1.6% at Valley Road Paraparaumu GXP (Section 4.7.4).

The government led decarbonisation initiatives will encourage electrification of transport and process heat. Scenario analysis (Section 4.5) evaluates the network impact of the electrification to consider the risks and benefits to the network.

Climate change, regulatory changes, the impact of photovoltaics and ongoing economic impact of Covid-19 are all significant considerations that have been highlighted in Risk Management Section 7. These

1 Sources: Commerce Commission Information Disclosure data for financial years 2016-2019; 2020 data is extracted from Information Disclosure schedules from the relevant EDB’s website.

risks are managed in the company risk register, alongside traditional non-network risks such as cyber dangers, seismic threats and terrorism.

We continue to maintain a watching brief on the signalled implementation of Electricity Pricing Review and phased removal of LFCs. Electra continues to participate in the working groups that are considering changes to the removal of the Transpower Pricing Methodology to ensure optimal customer outcomes.

Key work streams going forward

Electra's asset management strategies, tactical programmes and work plans have always been aligned to the wider strategic direction. We have paid attention to make that alignment more visible by setting out the linkages (Figure 1-4: Asset Management Framework) between the group strategy and the asset management activities at the start of Section 1. This is also consistent with the line-of-sight principle of ISO 55001.

The key initiatives are

- Commence multi-year project to align business to ISO 55000 practices for improved asset management maturity
- Implement an Enterprise Asset Management system
- Improve performance, manage risk and control costs, with a view to reduce SAIDI and OPEX.
- Develop strategy to guide the company response to the challenges and opportunities of the electrification of transport sector
- Develop strategy for transition to a transactive network while maintaining watching brief on DERMS and participation in industry working groups
- Enhancing evidence-based investment decisions with risk and criticality dimensions to quantify and prioritise investments.
- Enhancing and supporting sustainability, climate change and renewables initiatives.

These will in turn result in more detailed year-by-year actions included in the annual business plan and work programmes.

Material projects

In deriving the programmes for network development (Section 4), Electra optimises expenditure to consider demand growth, existing network conditions and capacity, customer input and service levels for reliability, quality, and safety. The significant programmes for the planning period include the following projects:

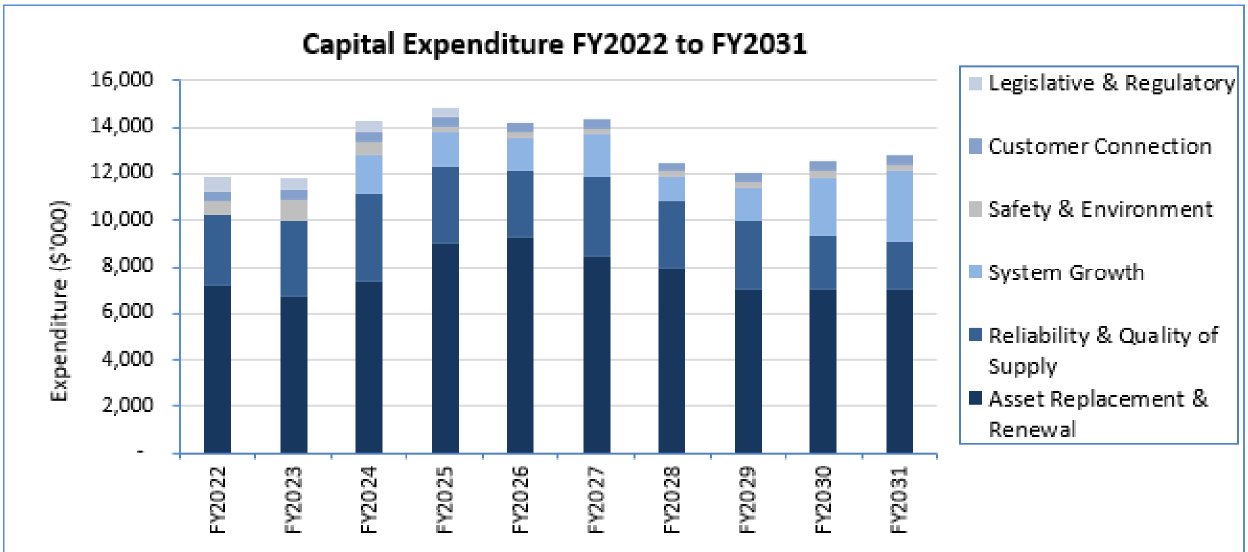
Description	Main driver	Proposed timing
Upgrade of ERP – Business Central	ICT	FY2022
Acquisition of an Asset Management System	ICT	FY2022
Electrical Protection Upgrade	Quality of Supply	FY2022-FY2031
New feeder from Levin East Substation	Growth	FY2024
Mangahao to Levin East 33kV Sub transmission Line Upgrade	Renewal	FY2024-FY2027
Levin East Zone Power Transformer Replacement	Renewal	FY2024-FY2028
Paraparaumu new 11kV feeder to transfer load off feeder 405	Growth	FY2025

Description	Main driver	Proposed timing
Rebuild Raumati Substation	Renewal	FY2025-FY2026
Rebuild Foxton Substation	Renewal	FY2025-FY2026
Otaki Zone Substation: New 11kV feeder to transfer load off feeder L351	Growth	FY2027
Foxton to Levin West 33kV Sub transmission Line Upgrade	Growth	FY2028-FY2030
Replacement of 12 km of 35mm2 copper conductor along Foxton-Shannon Road	Renewal	FY2028-FY2031
New Tokomaru Zone Sub	Growth	FY2030-FY2031
Rural Substation at Waikawa Beach Road	Growth	FY2031

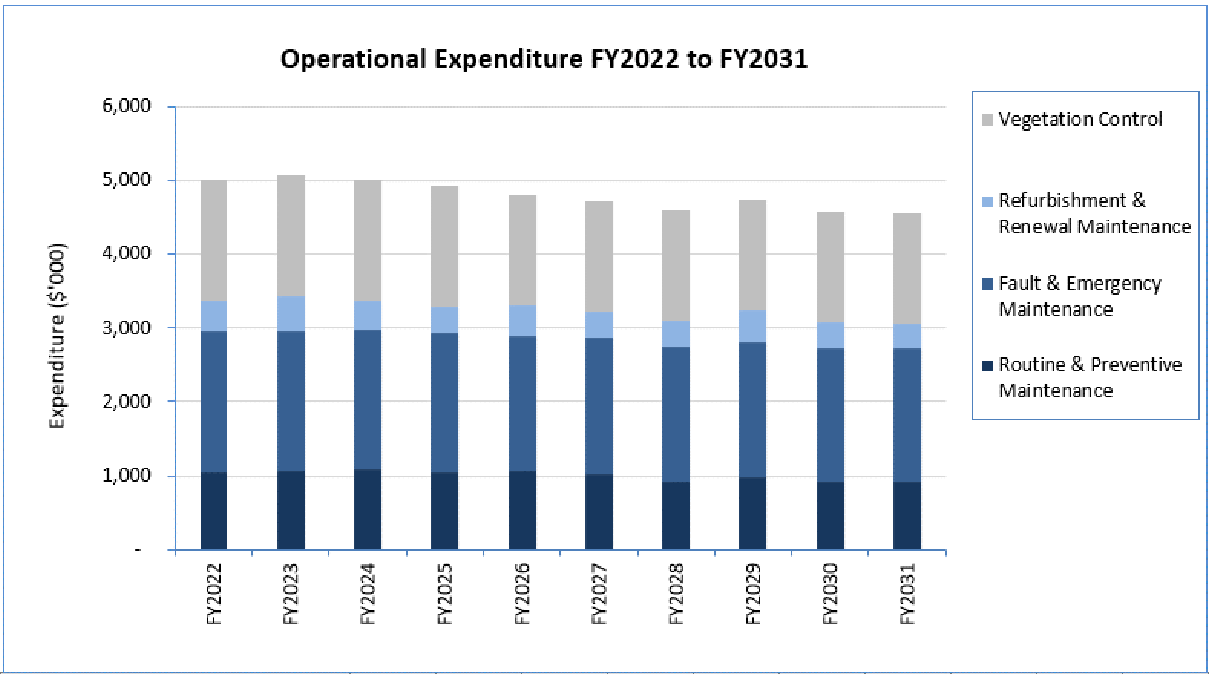
Forecast expenditure

Projected capital expenditure drivers over the next 10 years are expected to be 11% for system growth, 23% for reliability or supply quality, 58% for renewal and replacement work, and 7% for legislative, safety and environmental requirements. Capital costs (depicted in Figure A) are expected to average $13.1M per year over the next 10 years while operational costs (Figure B) are expected to average $4.8M per year over the same period. Electra has the flexibility to adjust this investment if growth accelerates beyond our expectations. The expenditure forecasts are based on 2020 constant New Zealand dollars.

Figure A: Projected Capital Expenditure from FY2022 to FY2031



Capital Expenditure (Current $'000)	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Asset Replacement & Renewal	7,147	6,657	7,335	8,966	9,219	8,446	7,889	7,014	6,994	6,994
Reliability & Quality of Supply	3,057	3,346	3,795	3,290	2,925	3,426	2,901	2,981	2,331	2,081
System Growth	-	-	1,650	1,500	1,410	1,810	1,050	1,400	2,475	3,050
Safety & Environment	635	920	615	250	250	250	250	250	340	250
Customer Connection	400	400	400	400	400	400	400	400	400	400
Legislative & Regulatory	600	450	450	450	-	-	-	-	-	-
Total (CAPEX):	11,839	11,773	14,245	14,856	14,204	14,332	12,490	12,045	12,540	12,775



Operations & Maintenance (Current $'000)	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Routine & Preventive Maintenance	1,050	1,060	1,085	1,035	1,057	1,032	912	987	912	912
Fault & Emergency Maintenance	1,894	1,894	1,894	1,894	1,832	1,832	1,832	1,812	1,812	1,812
Refurbishment & Renewal Maintenance	418	478	383	358	423	358	358	443	358	338
Vegetation Control	1,645	1,645	1,645	1,645	1,488	1,488	1,488	1,488	1,488	1,488
Total (OPEX) :	**5,007**	**5,077**	**5,007**	**4,932**	**4,800**	**4,710**	**4,590**	**4,730**	**4,570**	**4,550**

Figure B: Projected OPEX from FY2022 to FY2031

We have produced a trifold pamphlet as shown in the next two pages, to summarise the key themes and highlight the important network parameters. To facilitate understanding of terms and abbreviations used, we have prepared a glossary of terminology and abbreviations in Appendix 11 of this document.

Electra's AMP is an important and evolving document for which your feedback is welcome. Our General Manager – Lines Business and I would be happy to hear from you.

Kind regards

Neil Simmonds
Chief Executive

AMP 2021-2031

Kia ora

We are committed to enhancing the Horowhenua and Kapiti Coast communities and their regional development through the provision of 21st century infrastructure and new technologies.

Our Asset Management Plan (AMP) sets out how we will build, operate and maintain this infrastructure to maximise long-term value for consumers and owners. It shows how we will do this through competitive prices and quality services with safe and efficient operations. The AMP sets out our asset management strategies and investment plans for the next 10 years and demonstrates how this supports the Electra Group's wider corporate strategies.

This has been a challenging year with the global effects of Covid-19 impacting our people, customers and business operation. We responded quickly by adapting work practices and reformulating how to continue to deliver our essential services and AMP programme while keeping everyone and their families safe.

We have made excellent progress on the key focus areas identified in the 2020 AMP, including improved customer service and initiatives to reach our zero-harm target while maintaining our mix of high reliability and low-cost delivery.

This document provides you with the key highlights from our AMP 2021. The full document is available on our website. We welcome your questions and feedback.

Nga mihi

Neil Simmonds
Chief Executive

OUR PLANNED NETWORK INVESTMENT

CAPEX
$131.1M
TOTAL CAPITAL EXPENDITURE (AVERAGE $13.1M p.a.)

OPEX
$48.0M
TOTAL OPERATIONAL EXPENDITURE (AVERAGE $4.8M p.a.)

Electra
EMPOWERING YOUR FUTURE

NETWORK BRIEFING

An overview of the key aspects of Electra's Asset Management Plan 2021-2031

View full AMP online
www.electra.co.nz/our-company/disclosures

ELECTRA - Registered Office, Corner Bristol and Exeter Streets - PO Box 244, Levin 5540

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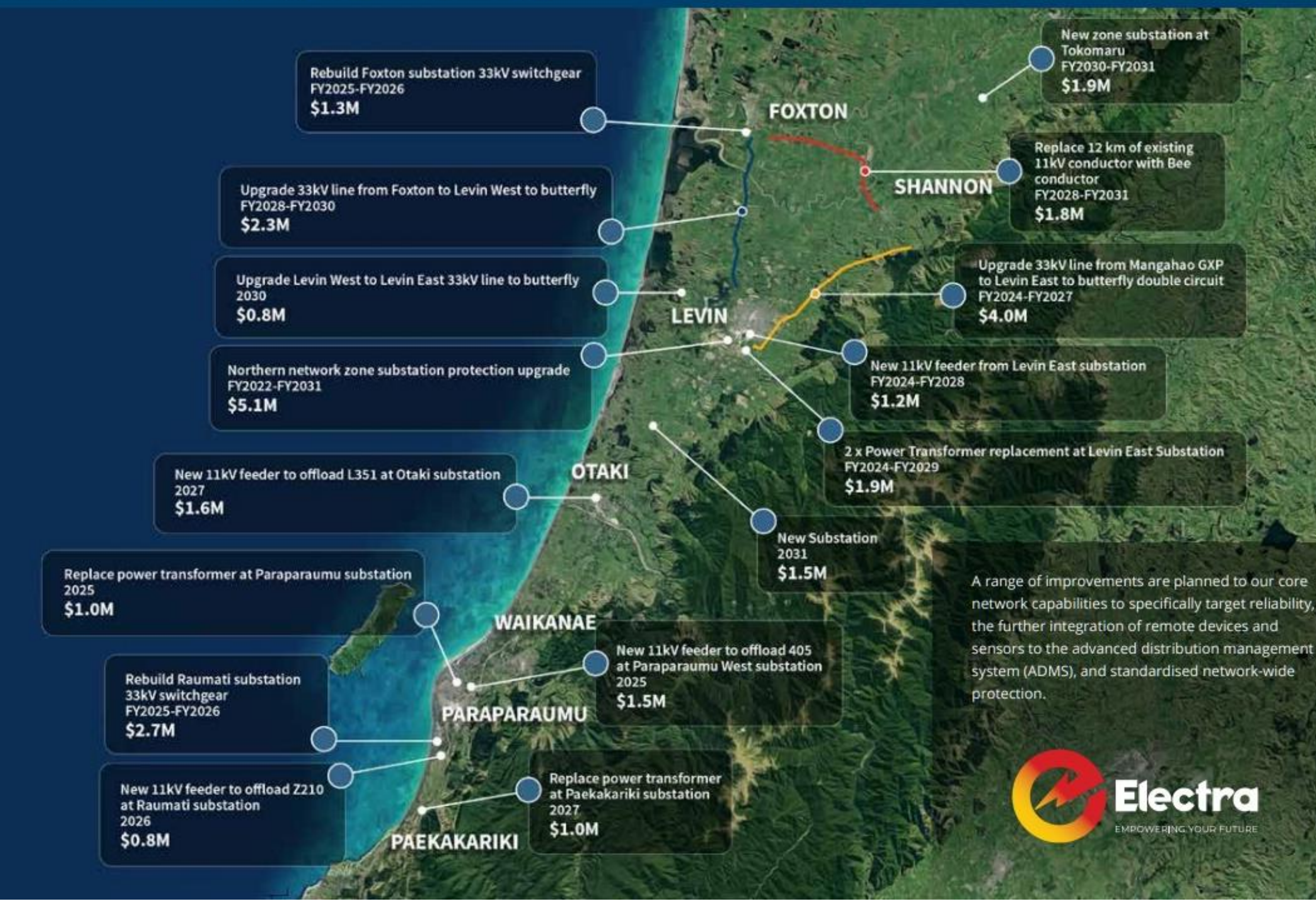
Key network projects: 2021-2031



A range of improvements are planned to our core network capabilities to specifically target reliability, the further integration of remote devices and sensors to the advanced distribution management system (ADMS), and standardised network-wide protection.

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Network Projects

FY2022

No	Category	Work Description	Region	Total
1	Quality	Substation protection and communication work	Northern network (Mangahao, Shannon, Foxton, Levin West and Levin East)	$650,000
2	Legislative	Seismic strengthening of zone substation buildings	Levin West and Otaki Zone Substations	$600,000
3	Quality	Install pole mounted sectionalisers on specified feeders to reduce number of customers affected by faults	Various locations	$400,000
4	Renewal	Replace 16mm² overhead 11kV conductor with Gopher conductor	Mangahao Rd, Shannon	$290,000
5	Quality	Install Low Voltage (LV) - power quality monitors	Various locations	$250,000
6	Renewal	Replace existing Gopher overhead 11kV conductor with Gopher conductor	Takapu Road, Otaki	$247,000
7	Renewal	Replace 1.5km of Rango overhead 11kV conductor with Bee conductor	Waitohu Valley Road, Otaki	$235,000
8	Renewal	Replace 35mm² overhead 11kV conductor with Bee conductor	SH57, Shannon	$205,000
9	Quality	Install additional permanent fault indicators to allow quicker location of faults	Various locations	$200,000
10	Quality	Automation of ground mounted switchgear to improve the reliability	Various locations	$190,000

Investments will be prioritised and quantified using enhanced evidence-based investment decision making.

Customer outages (SAIDI) and operating costs will be reduced through risk, performance and cost balancing.

Sustainability, climate change and renewables initiatives will be supported and enhanced.

Our Network

We own and operate the electricity network in the Kapiti and Horowhenua regions, stretching from Foxton and Tokomaru in the north, to Paekakariki in the south.

Our network of 2,323km in circuits supplies 45,192 consumers across an area of 1,628km², making us New Zealand's ninth largest lines company in terms of connections to the network.

TOTAL NETWORK ASSET VALUATION
$202 M

TOTAL ELECTRICITY DELIVERED
415 GWh

AVERAGE CONSUMPTION PER CUSTOMER
9,183 kWh

MAXIMUM DEMAND
101 MW

NETWORK AREA
1,628 km²

TRANSMISSION & DISTRIBUTION
2,323 km

TRANSFORMER CAPACITY
337 MVA

As at 31st March 2020

DELIVERING FOR OUR CUSTOMERS

Customers are at the heart of our decision-making which is why "focus on customer" is a core strategic objective.

We engage with our customers in many ways and are constantly seeking their feedback. Fault and outage data helps to shape investment decisions, while affordability informs our pricing methodology.

Safety is a key component and Electra strives to ensure that assets and network systems are safe for our customers as well as our contractors.

We use technology to keep our customers informed. We have significantly improved the outage information available on our website, providing customers with easy-to-understand icons and up-to-date access to detailed outage information including the location of fault vehicles. Our Electra Customer Outage App makes this information available on mobile devices.

Over the last year customer-focused initiatives have included:

- the appointment of a Customer Relationship Manager
- using digital channels to deliver improved communications around planned and unplanned outages
- enhancement of communication and information on topics such as how to prepare for outages, how to connect solar equipment (including a list of approved inverters), and how to select appropriate pricing plans (e.g. for electric vehicles, to manage load, etc).

Customer satisfaction levels reflect how well we are doing in meeting, and exceeding, the high service levels we have set. Our surveys not only measure satisfaction levels but also customers' preferred communication channels and information sources.

We continue to achieve significantly high levels of customer satisfaction, with 98% of respondents rating our service 'excellent', 'very good' or 'good', while 95% of respondents found our faults resolution timeliness to be 'excellent' or 'very good'.

ADOPTING INTERNATIONAL BEST PRACTICE

We are focused on aligning our business to international best practices in asset management. For network businesses in New Zealand, the Commerce Commission bases its Asset Management Maturity Assessment Tool (AMMAT) on ISO 55001.

In February 2020 we engaged Covaris to conduct an independent ISO 55000 (AMMAT) audit of our asset management practice and performance, and an additional independent AMMAT report.

This review confirmed that we are performing to best practice standards, scoring our approach to asset management higher with the documented evidence indicating our approach is appropriate considering the network topology, social alignment and services delivery. In its report Covaris stated: "While it could be argued that with its lean team, Electra does not have the same depth in some aspects of asset management as larger EDBs, what it has in place is competent."

GROWING OUR PEOPLE

Our people are the most valuable asset to our business and its success. Their safety, working environment, well-being and job satisfaction are of paramount importance.

We are proud of our diverse and inclusive workplace that recognises and values our employee's individuality and authenticity.

We invest in a comprehensive training and development programme to develop our workforce with increased competencies and career pathways. Our people achieved 3,700 training hours and attained 22 National Certificates in FY2020.

At the same time, we are focused on addressing key strategic workforce issues, including the increasing demand for ICT skills in the field, changing field crew demographics and the retention of qualified staff.

SUSTAINABILITY AND EMERGING TECHNOLOGIES A KEY FOCUS

Sustainability is a key strategic driver for our business, with environmental risk, climate change and decarbonisation important considerations in our decision-making process.

The growth of emerging technologies such as solar photovoltaic cells (PVs), batteries and electric vehicles (EVs) have a significant impact on traditional networks.

Our own organisation has been an early adopter of emerging technologies such as industrial Internet of Things (IoTs). Over the last five years we have invested in distributed energy resource (DER) or DER solutions and low voltage network monitoring.

At the same time, we have been closely monitoring the increasing uptake of domestic and commercial PVs, energy storage systems and EVs, and assessing how (and when) these customer trends and demand side technologies can be integrated into our network.

Part of this involves working with other industry partners. We are also investing in several emerging technologies including smart grids, IoTs and EVs and trialling them on our network to better understand the uncertainties of their emergence and to incorporate their requirements and standards into our plans. This investment allows better technology adoption and cost integration into our network development planning.

1 Introduction

Purpose of the Asset Management Plan

This Asset Management Plan (AMP) documents Electra's strategy to manage our electricity distribution assets. It is structured to meet regulatory compliance of the Electricity Distribution Information Disclosure Determination 2012. These requirements include target service levels, asset details, lifecycle management plans, network development, risk management, performance measurement, evaluation and improvement initiatives.

This AMP documents Electra's governance and management framework, applying Electra's asset management thinking, systems and processes to develop and deliver work programmes aimed at achieving intended customer and community experience of supply reliability, pricing and safety.

1.1 Company strategy

This AMP is supported by key strategic documents of Electra namely the Statement of Corporate Intent, company strategic plan and pricing methodology. These documents are further explained in the following sub-sections. Section 1.3 contains the details of other documents and the relationship between these key documents.

1.1.1 Mission and vision

Electra's Statement of Corporate Intent (SCI) identifies the Group's vision and mission as "***to enhance the Horowhenua/Kapiti Coast community and its regional development through the provision of 21st Century infrastructure and new technologies***".

More specifically, this AMP sets out how Electra will build, operate and maintain infrastructure to maximise long-term value for consumers and owners through competitive prices and quality services with safe and efficient operations.

1.1.2 Key strategies

The SCI identifies five focus areas for the company as depicted in Figure 1-1. These key business strategies are:

- **A focus on customers**: to establish world-class communication with customers and meet the needs and wants of customers and build strong community ties with customers and businesses to support regional growth.
- **Excellence in operation**: to improve system reliability performance and operational efficiency by managing cost and procurement processes while implementing greater automation in the operation of the business.
- **Develop our people and keep safe**: improve safety and environment for public, staff and contractors and create a culture of organisational learning.
- **Prepare for change**: to improve knowledge and information management in rapidly changing industries.
- **Develop the new and grow**: to grow our existing businesses and continue to scan for complementary and infrastructure opportunities.

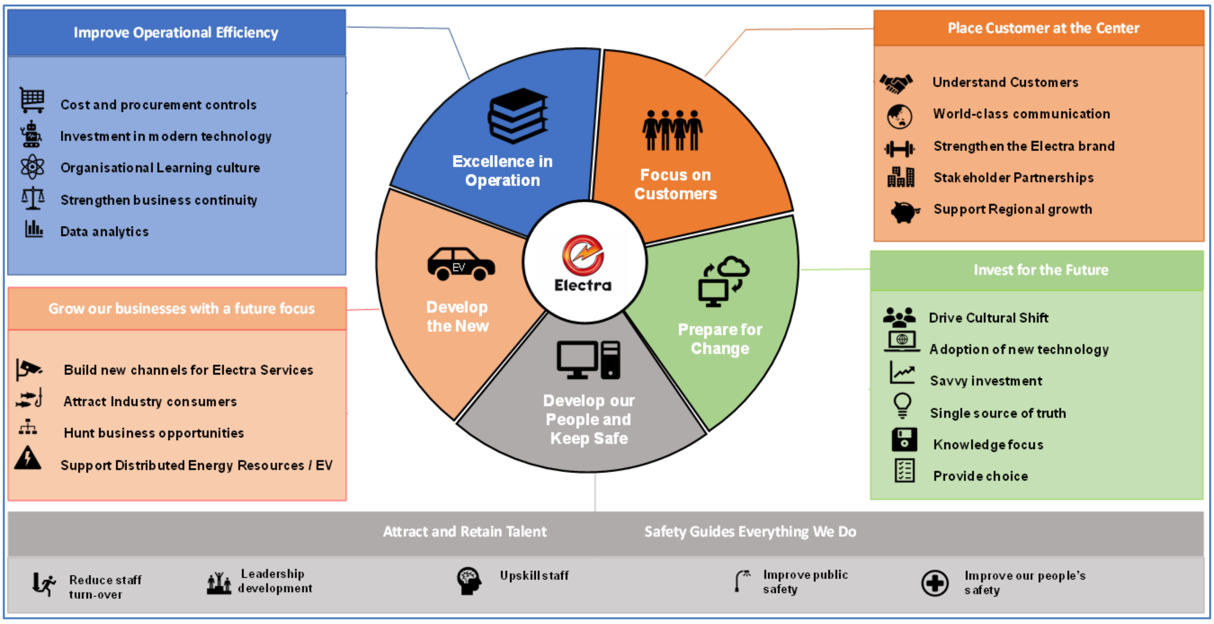


Figure 1-1: Electra Group strategic model for FY2021 to FY2025

1.1.3 Values

Electra's corporate values are:

- **Safety:** safety guides everything we do - we will stop work if it is unsafe.
- **Respect:** we all treat our customers and colleagues as they would want to be treated.
- **Professional:** our people have the knowledge, skills and ethics to perform their roles at a consistently high standard.
- **Accountable:** we account for and accept responsibility for our activities.
- **Integrity:** we always do the right thing in all circumstances, no matter what the consequences will be.

1.1.4 Pricing methodology

Electra's pricing methodology allows the company to safely and reliably build, operate and maintain an electricity network to serve electricity customers in the Horowhenua and Kapiti Coast region. It complies with regulatory requirements and promotes cost reflective distribution price options and transparency to customers. The cost-reflective price-setting methodology is depicted in Figure 1-2 and further information and these principles are reflected in the investment of suitable infrastructure and asset management reflected in the AMP. Details of the pricing methodology are available on Electra's website.

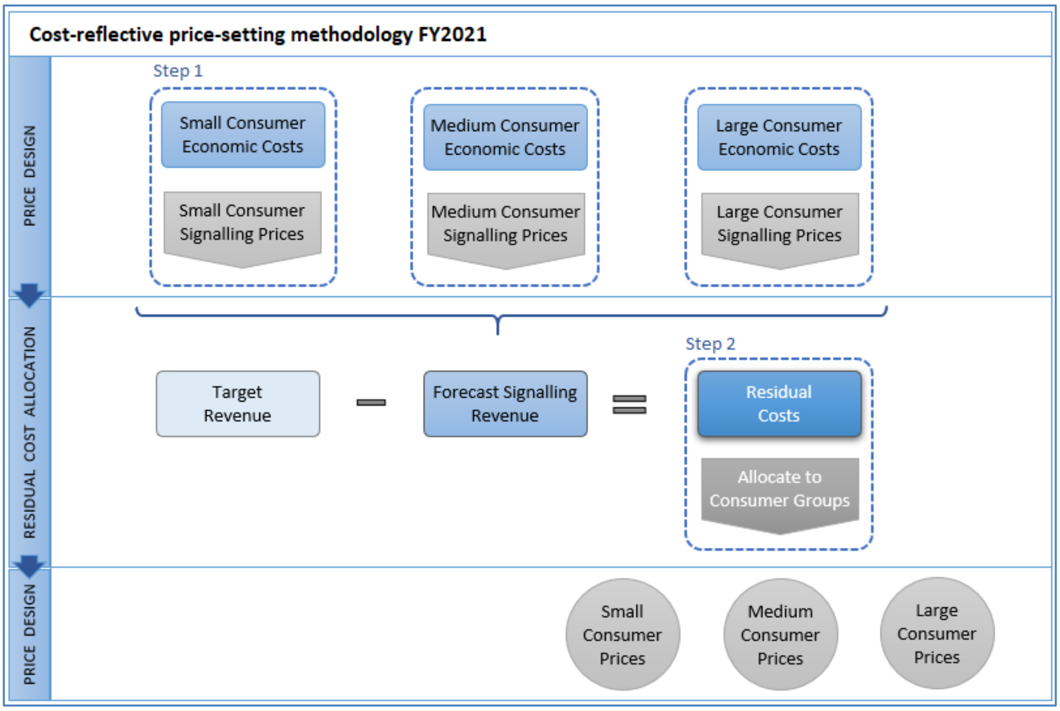


Figure 1-2: FY2021 Cost-reflective price-setting methodology

1.2 Asset management system

1.2.1 Asset management policy

Asset management is a broad strategic framework encompassing many disciplines and involves the entire organisation. Our asset management policies have been developed to guide the lines business on the application of sound technical, social and economic principles that considers present and future needs of users of, and the service from our network assets, and to set the direction for managing our electricity network assets. To achieve asset management outcomes, we will:

- Maintain and manage our network assets at defined levels to enable the safe, efficient and effective delivery of electricity to our customers
- Monitor standards and service levels to ensure that they meet/support customer and Board goals and objectives
- Develop and maintain asset inventories of our entire infrastructure
- Establish infrastructure replacement strategies using full life cycle costing principles
- Plan financially for the appropriate level of maintenance and replacement of assets to deliver service levels and extend the useful life of assets
- Plan for and provide stable long-term pricing/funding to replace and/or renew and/or decommission infrastructure assets
- Report to customers and other stakeholders on the status and performance of work related to the implementation of this asset management policy.

1.2.2 Asset management strategy

Our asset management policies have been developed to achieve the following aims:

- Describe how the asset management policy is used to develop asset management objectives

- Support the delivery of best value services to our customers
- Help to achieve Electra's core function as a lines business by safely and reliably delivering electricity to our customers
- Drive our continuous improvement programme to ensure we continue to be an efficient, forward-thinking network business
- Ensure our asset management practices deliver on the overall corporate objectives.

Based on the five key corporate strategies, key asset management themes in line with our group's strategies in Section 1.1.2 are:

- Excellence in operation
- Safety and people
- Develop the new and support regional development
- Focus on customers
- Invest for the future (ready for change).

They reflect our lifecycle asset management approach and consider all aspects of asset decision-making and activities from inception to decommissioning.

Key asset management strategies and tactics in line with corporate strategies are tabulated in Figure 1-3.

	Strategies	Tactics
	Excellence in operation	
1	Recognised as a high reliability and low-cost network	• Development an implementation programme with industry leader • Continued development of asset risk models based on OFGEM • Develop targeted improvements in asset management • Implementing further switching, sensors and data/operational analysis • Continued deployment of protection systems, seismic protection and business continuity • Operate in a way that is efficient and effective
2	Excellence in Asset Management practices to align with ISO 55000	
3	Continued development of smart/future network	
4	Improved network resilience	
5	Service delivery is recognised as high performing	
	Safety and people	
1	Attract and retain talent	• Identify and grow future leaders • Deliver a competency programme for all staff • Leaders need to foster and demonstrate positive behaviours • The standard that you walk by is the standard you expect • Deploy lone worker devices • Site visits need to have a vision, purpose, and outcome • Capture and communicate decisions, visions … Plan, do, act and check
2	Empower people to do the right thing through skills, knowledge, and tools	
3	Focus on lead indicators and safety conversations	
4	Driving improved safety of our people, assets, public	
5	Create an environment of continuous learning and improvement	
	Develop the new (growth)	
1	Attract large energy users	• Refresh network extension policy • Advertising campaigns • Proactive in engagement with movers and shakers • Website promotes focus on growth • Better promotion for brand recognition • Deliver the operational excellence commitment
2	Grow third party revenue	
3	Work with land developers	
	Focus on customers	
1	Deliver safe, reliable, affordable services	• Implement sustainability in the workplace/operation initiative • Demonstrating environmental responsibility initiatives for workspace and work site • Invite and select local artist's/school murals on transformers • Greater engagement with our communities • Refresh website/social media to reflect what customers want/do • Improved communication of planned work, fault restoration and great customer service • Delivery of targeted media campaigns • Recognised as the customers first choice/preferred delivery partner
2	Understand customers wants, needs and satisfaction	
3	Reflect what the community values	
4	Building strong relationships with decision makers in our region	
	Invest for the future (ready for change)	
1	Embrace customer Distributed Energy Resources	• Create DER and renewables strategy • Cost reflective pricing fixed charge provide platform • Adopt flexible working and focus on outcomes rather than function • Implement a strategy of improving valued data sets • Improve digital systems that include EAM, ADMS and job management • Improve management systems for controlled documents (EDMS) • Participate in industry working groups and consultation processes
2	Make information a core asset of the company	
3	Investment in digital systems to deliver operational excellence	
4	Maintain compliance and awareness of Regulatory environment	

Figure 1-3: Alignment of Group Strategies to Asset Management and Tactics

Key features of Electra's asset strategy and delivery include:

- A visible alignment with the SCI and the Group strategic plan
- Visible inclusion of each phase of an asset's lifecycle
- Consideration of reliability, safety and lifecycle costs as an integral part of managing assets lifecycle (safety in design)
- Migration from a simple condition-based approach to a more comprehensive criticality and health (risk) based approach
- Seeking lower cost methods of carrying out required OPEX and CAPEX identified by the AMP.

Electra's key focus areas namely - customers, employees as well as sustainability, climate change and new energy futures are elaborated in the following sections.

1.3 Asset management framework

Electra's asset management framework, which includes the elements within ISO 55001, is under development and depicted in Figure 1-5. This framework provides structure and identifies the systems and processes in the development of the AMP. It ensures that:

- Objectives, plans and actions are in alignment with our vision, values and corporate goals
- Top level representation of asset management functionality
- Services are delivered to meet service levels and resilience to respond to high impact low probability events
- Quality control in asset management life cycle processes and continual improvement
- Advancement towards a target of zero harm (zero LTI's).

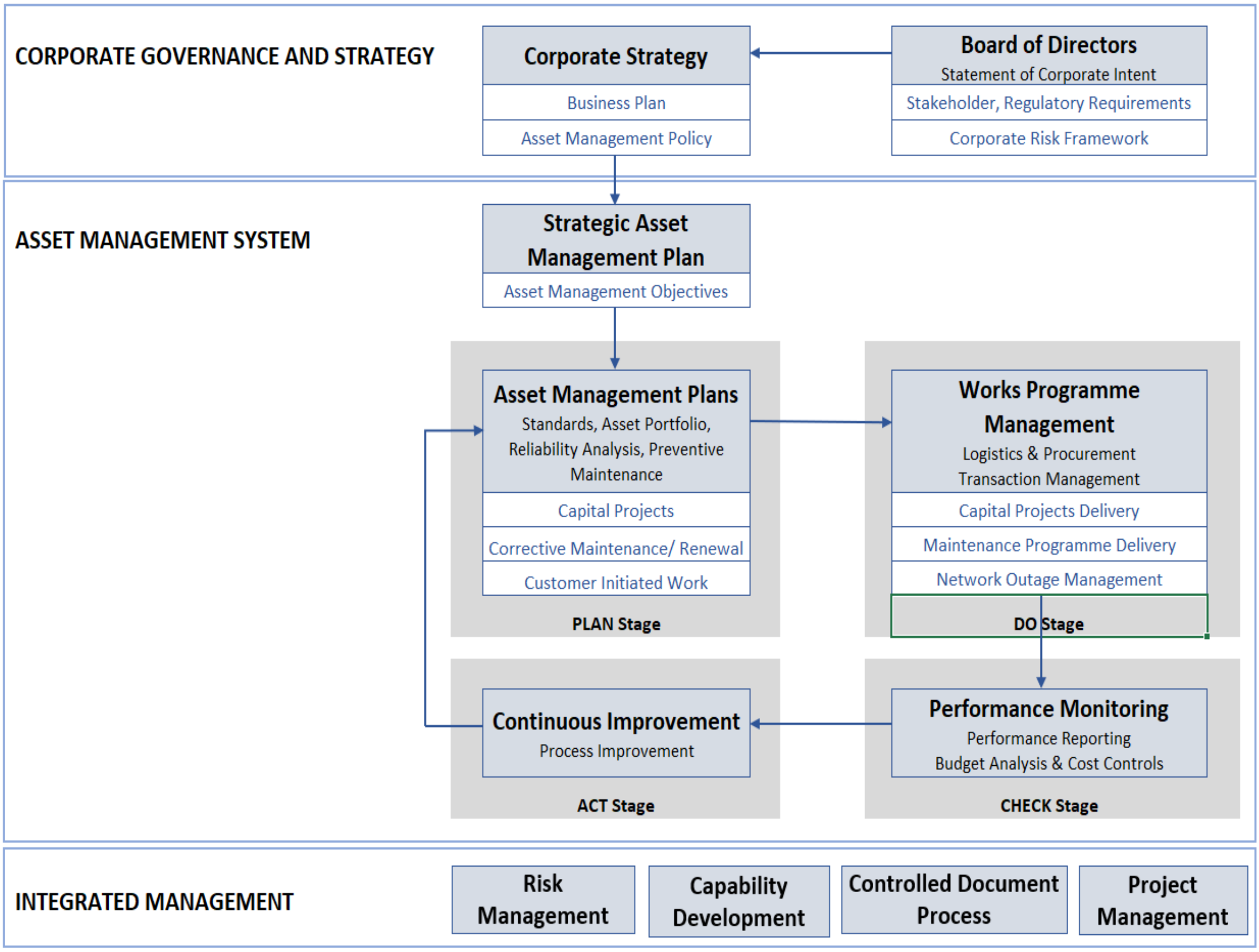


Figure 1-4: Asset Management Framework

1.3.1 Key plans and documents

Electra's key plans and documents include:

Document title	Purpose
Statement of Corporate Intent (SCI)	Articulates key strategies, governance philosophy, scope of activities and high-level goals of business performance and customer experience. The SCI is approved by the Trust as the owner of the company.
Group strategic plan	Consolidates the strategic plans of Electra's subsidiaries into a coordinated Group plan.
Pricing methodology	Provides the details of pricing including principles and objectives.
Asset management plan	Connects management of long-life assets to Electra's strategic direction.
Annual group business plan and financial plans	Presents the tactical plans for the year ahead and allocates resources.
Annual network business plan and annual works programme	Define detail of specific works on a 12-month basis.

1.3.2 Relationship between plans and documents

The relationship between Electra's key plans and documents is depicted in Figure 1-5 which shows key communication links between the major asset management documents used in Electra.

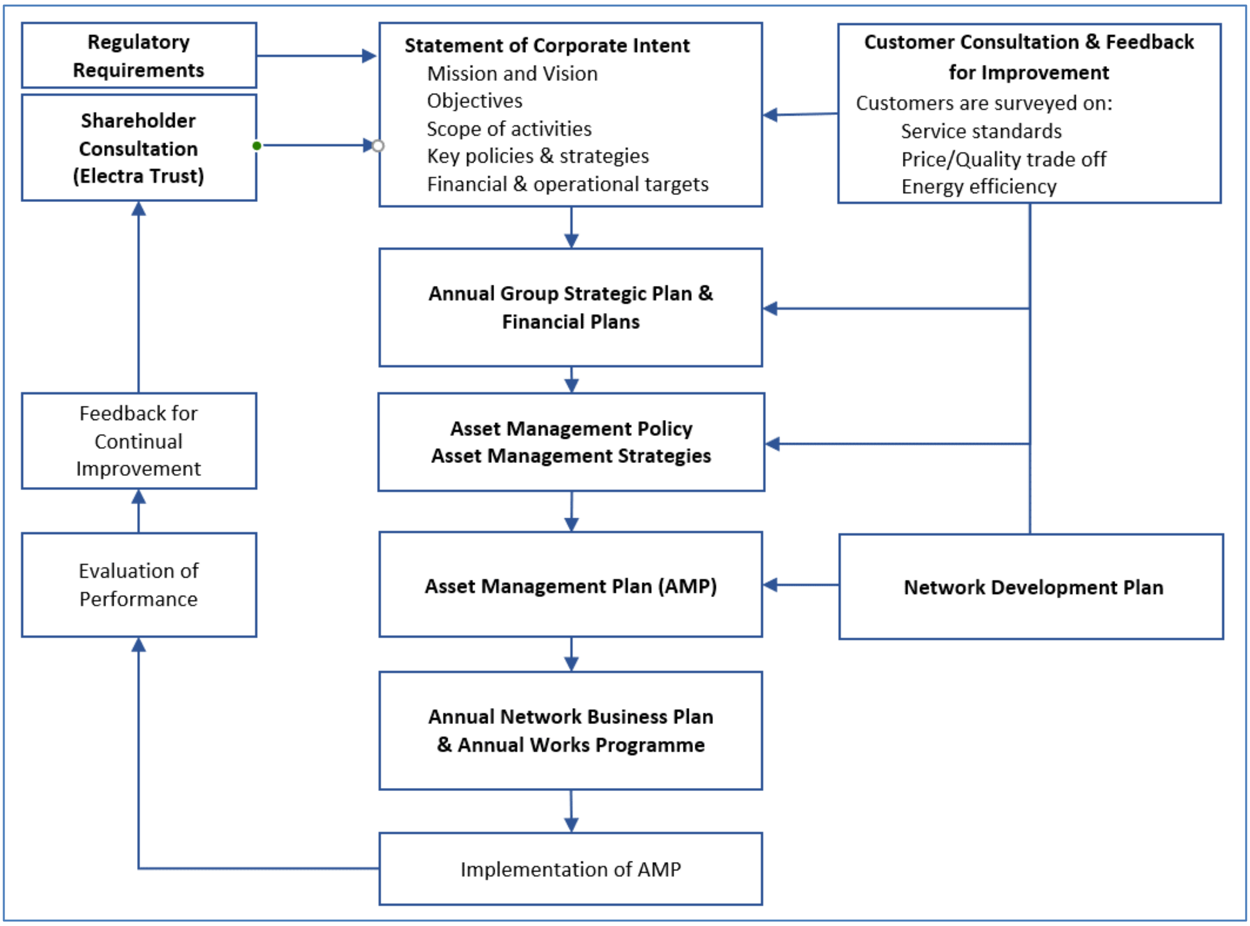


Figure 1-5: Asset Management Document Links

1.3.3 Linkages between planning goals

The above sub-sections emphasize the line-of-sight and progressive refinement of our approach from the strategic model through to tactical programmes to operational plans and budgets. This is complemented by a small and close working environment.

1.4 Planning period

The planning period for this AMP is 1 April 2021 to 31 March 2031. The AMP embodies three levels of increasing certainty for nearer term plans:

Period	Scope	Cost	Timing
1 April 2021 – 31 March 2022	Firm, approved in principle	±5%	Quarter/month
1 April 2022 – 31 March 2027	Major components	±10%	Quarter
1 April 2027 – 31 March 2031	Indicative	±25%	Year

1.5 Board approval

This AMP was submitted in draft to the December Board meeting to allow for inclusion of the Board's comments before final approval on 26th February 2021.

1.6 Stakeholder interests

Electra defines stakeholders as any person or organisation who affects or are affected by Electra's business.

1.6.1 Stakeholder interests and how they are identified

Electra defines stakeholders as any person, class of persons or organization that does or may do one or more of the following:

- Have a financial interest in Electra (be it equity or debt)
- Be physically connected to Electra's network (a customer)
- Uses Electra's network for conveying electricity
- Supplies Electra with goods or services
- Is affected by the existence, nature or condition of Electra's network (especially if it is in an unsafe condition), or
- Has a statutory obligation to perform an activity in relation to the network's existence (such as request disclosure data or regulate the location of assets).

Electra has identified the following specific stakeholder interests:

Stakeholder	**Key** stakeholder interests				**How those interests are identified**
	Viability	**Supply** quality	**Safety**	**Compliance**	
Electra Trust	✓	✓	✓		• Statement of Corporate Intent • Quarterly briefings • Informal discussions with the Board and Chief Executive
Bankers	✓				• Terms and conditions of financing arrangements • Quarterly meetings • General negotiations
Connected customers	✓	✓	✓		• Enquiries via 0800 phone number and website enquiry section • Questions and comments at AGM • Customer survey responses • Community feedback • Media comment
Energy retailers	✓	✓			• Negotiation of terms and conditions • Pricing amendments • Regular meetings • Informal communication • Resolution of billing disputes
Mass-market representative groups	✓	✓			• AGM • Feedback from interest groups. • Electricity Networks Association (ENA) focus groups
Industry representative groups	✓	✓			• Annually via meetings and conferences

Stakeholder	Key stakeholder interests				How those interests are identified
	Viability	Supply quality	Safety	Compliance	
Staff and contractors	✓	✓	✓	✓	• Weekly staff meeting • Monthly contractor meetings • As required for specific projects • General workplace interactions • Performance appraisals
Suppliers of goods and services	✓				• General interactions during service deliveries • Price and volume negotiations
Public (as distinct from customers)			✓		• As required via 0800 phone number and website enquiry section • General interactions
Landowners			✓	✓	• As required for specific projects
Councils (excluding as a consumer)			✓	✓	• Monthly Emergency Management meeting • Annual planning disclosure • As required for specific projects • During and after drills and actual events
Land Transport			✓	✓	• Reading of bulletins • Meetings to discuss specific projects
Ministry of Business Innovation and Employment			✓	✓	• Reading of bulletins • Attending seminars • Responding to consultations
Energy Safety Service			✓	✓	• Reading of bulletins • general interaction around safety requirements • Incident investigations
Commerce Commission	✓	✓		✓	• Reading bulletins and determinations • Attending seminars and workshops • Complying with determinations and disclosure requirements
Electricity Authority				✓	• Reading bulletins and determinations • Attending seminars and workshops • Complying with Code requirements
Utilities Disputes		✓		✓	• Reading bulletins, responding to complaint investigations
Ministry of Consumer Affairs		✓		✓	• Reading bulletins • Responding to complaint investigations
Transpower	✓	✓	✓	✓	• Quarterly updates • Annual planning meetings • General interactions about grid connections • Discussions about specific grid connection issues such as price and capacity

1.6.2 Linking stakeholder interests to asset management practices

Electra's stakeholders' interests are linked to asset management practices as follows:

Safety	➔	Electra keeps the public at large safe by keeping all above-ground assets structurally sound, live conductors are well out of reach, all enclosures are secure, and all exposed metal is earthed Electra's Safety Management System (SMS) provides a structured approach to maintaining public safety Electra maintains safety of the staff and contractors by providing all necessary equipment, improving safe work practices, and stopping work in unsafe conditions Motoring safety is assisted by placing above-ground structures as far as practically possible from the carriage way within the constraints of private land and road reserve
Supply quality	➔	Electra will accommodate stakeholders' needs for supply quality by focussing resources on continuity and restoration. Many of the renewal jobs discussed in this AMP are aimed at maintaining Electra's security of supply. Electra's most recent mass-market survey (October 2020) indicated a general satisfaction with the present supply quality
Viability	➔	Electra will accommodate stakeholders' needs for long-term viability by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return on capital employed. In general terms this will need to be at least as good as Electra's owners could obtain from a term deposit at the bank plus a margin to reflect the risks to capital from opportunities associated with emerging energy technologies and regulatory settings Price is the key to viability but must be managed to be in line with similar network companies, other energy options and to provide a satisfactory discount to Electra's consumer/owners
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 Electra discloses performance information in a timely and compliant fashion.

1.6.3 Managing conflicting stakeholder interests

Stakeholder interests are managed in the following order of priority:

- Safety of the public, our staff and contractors: this will be achieved for new works by developing design and construction options through the application of safety in design principles, and by routine inspection, hazard assessments and targeted renewals during the assets operating life
- Customer's requirements for a reliable and efficient energy supply will be given second priority
- Non-safety compliance
- Viability.

1.7 Sustainability and climate change

Electra's overarching sustainability policy is built around the three pillars of sustainability: environmental, economic and social (depicted in Figure 1-6).

In line with our strategic tactics to: (a) Implement sustainability in the workplace/operations initiative, (b) Demonstrate environmental responsibility initiatives for workspace and work site, Electra strives to sustainably manage the environmental, economic and social effects of our business to achieve strong connected communities, a healthy environment and a prosperous economy. By acting ethically, responsibly and with transparency, we can create long-term value for Electra, its shareholders and wider communities.

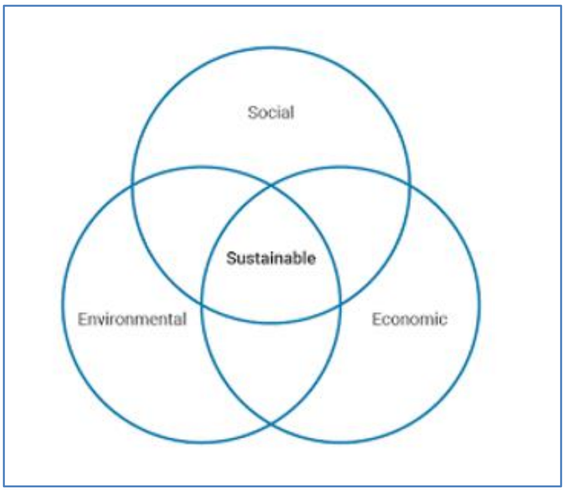


Figure 1-6: Three pillars of sustainability: Electra strives to sustainably manage the environmental, economic and social effects of our business

One of our key strategic themes is the protection of our environment. We integrate environmental sustainability into planning and delivery activities from three viewpoints; minimising the impact on the environment, improving our resilience to changing environmental conditions and facilitating the adoption of new energy technologies or renewables that support the decarbonising of our regional and the wider New Zealand economies.

Reducing our environmental impact spans the tools and equipment we use, longer life and recycling of consumables, the sustainability of the materials we procure, regularly reviewing risks in our Public Safety Management System, improving operational efficiency and carefully managing risky materials, particularly oils and SF_6 gas.

Over recent years, parts of the network have been impacted by: (a) high rainfall causing previously stable land to slip, and (b) increasing populations of birds resulting in higher incidents of bird strikes. Also, the prevailing north-westerly winds and coastal marine environment have contributed to consumption of asset life. As a result, Electra considers current and emerging environmental risks in network planning and eventual designs and asset lifecycle management plans.

New Zealand Government declared a climate change emergency in December 2020 and the government has committed to a carbon-neutral government by 2025. The decarbonization program includes a phase out of coal, a requirement for government agencies to use electric vehicles and a green standard for public buildings. Further elaboration about the risks of decarbonisation and climate change is included in Sections 7.2.8 and 7.2.9 respectively.

In 2020, Electra completed an employee-wide survey to assess the actions and attitudes of sustainability within the Electra group. The response rate was 48% and the responses provided great insight on the progress and direction Electra is taking on its sustainability journey. We identified several short and long term areas of focus such as:

- the formation of a corporate-wide sustainability team with a single nominated champion to develop actions and targets for our environmental, economic and social pillars of sustainability
- the team is strategically resourced with employees from across all areas of our business and being actively support by management.

Our group policy on the “Disposal of Assets and Waste Material” demonstrates our commitment to sustainability and further information on its principles are in Section 5.1.10.

1.8 Accountabilities for asset management

Electra’s organisational structure emphasising the lines business is shown in Figure 1-7.

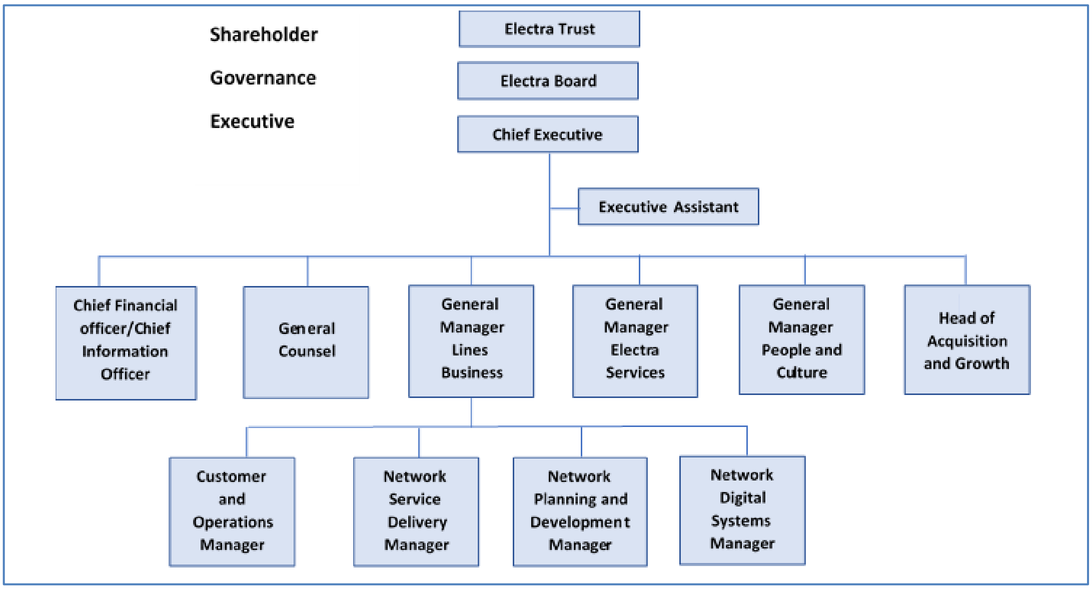


Figure 1-7: Organisational Chart

This chart emphasises the short distance between the lines business managers (aiding line of sight), and the logical alignment of the three lines business managers with the asset lifecycle.

Accountability at the governance level is by two mechanisms, namely:

- Electra’s Board of Directors are obliged to govern the company commercially, on behalf of the Trust as beneficial owners via the Statement of Corporate Intent
- The Electra Trust are accountable to the connected consumers through the Trustee elections.

Accountability at management level is primarily through the performance criteria set out in employment contracts and achievement of planning goals. The Chief Executive is accountable to the Board while the General Manager (Lines Business) is accountable to the Chief Executive. There are four managers accountable to the General Manager (Lines Business) as shown in the organisational chart.

Accountability at field operations level is primarily with the Programme Manager and the Service Delivery Manager for overall delivery of work packages.

1.8.1 Summary of roles, delegated authorities and reporting

The roles, delegated authorities and reporting are summarised as follows:

Activity	Board	Chief Executive	GM – Lines Business
Preparing SCI	Key role in preparing and amending under instruction from the Trust	Key role under direct delegation from the Board	Consulted for contribution
Role with strategic plan	Input - key role is reviewing and approving	Preparation, submit to Board for approval	Contributes together with the Executive Team

Activity	Board	Chief Executive	GM – Lines Business
Role with AMP	Approval	Provide strategic direction, submit to Board for approval	Preparation
Role with annual business plan	Approval	Preparation	Preparation
Approval of works from approved budget	In excess of Chief Executive's authority	In excess of GM – Lines Business authority ($1,000,000)	In excess of Lines Business Managers' authorities ($200,000)
Approval of works not from approved budget	In excess of Chief Executive's authority	In excess of GM – Lines Business authority ($100,000)	In excess of Lines Business Managers' authorities ($50,000)
Reviewing performance of works and projects	Noting progress of projects over $500,000 or that are strategically significant	Notes progress of all works programmes and significant projects	Responsible for detailed oversight of all works programmes
Reporting of outages	Summary included in monthly Board reports	Summary included in monthly Board reports, immediate involvement in major events	Receives a report of incidents, causes and follow up actions

1.8.2 Use of external contractors and advisers

Electra uses a range of external contractors and advisers in the following circumstances:

- Where specific expertise is required
- Where additional resourcing is required due to temporary overflow of requirement
- Where an independent viewpoint is required (typically by a statutory agency).

Electra's preference is to retain frequently required core expertise in-house, and to use external advisers or contractors for work that is encountered infrequently or backfilling extended vacancies or efficiently providing commoditised services. Parties contracted for work directly by Electra include:

- Connetics for procurement, project stock management and overflow field work
- Covaris for asset management assessment
- Eagle Technology of Wellington for GIS support for the ESRI system used by several other EDB's and Local Authorities
- Energia of New Plymouth for regulatory and valuation advice
- HV Diagnostix for testing and diagnostics of substation equipment
- ICONA Ltd of Ashurst are contracted to maintain SCADA and Control Centre radio communications
- PLP Inspection Services for drone inspections of sub-transmission and distribution assets Sandfield provide SQL database provisioning
- Spark provide primary telecommunications and digital procurement services
- Tatana Contracting and PEL for civil works and traffic management
- Tesla Consultants for engineering design and drafting.

1.9 Asset management systems and information management

Electra engaged Covaris to undertake an Asset Management Maturity Assessment (AMMAT) in late 2019. The purpose of this engagement was to assess asset management maturity levels and receive recommendations on how we can improve AMMAT in strategic alignment with the principles of ISO 55000. The assessment identified that the implementation of a comprehensive Asset Management Information Systems (AMIS) should be a primary focus.

Electra initiated the Borabora project (ERP Upgrade and EAM implementation) to evaluate and select an AMIS in early 2020. It is expected that the AMIS will be implemented before the end of March 2022.

Our asset management road map links the improvement and alignment of our asset management practices to the implementation of the transactive grid, the best in class supporting initiatives as well as the elements of ISO 55001.

Electra has the following data repositories and software that are used to capture, manage and derive insights to support asset management decisions:

System	Data held	What the data is used for	Extent of integration	Initiatives/ Improvement
Advanced Distribution Management System (ADMS), commissioned in 2018	An integrated system containing geospatial information of assets, customers and engineering model takes input from SCADA displaying load flows	Used by field, real-time operators, planning and project management staff to update customer outage, obtain asset information and carrying out engineering studies	Integrated with GIS, SCADA, Field Service Management, IoT, customer outage mobile application, customer web outage viewer and business intelligence reporting and analytics	• Integration with the new EAMS • Automated customer notifications via multiple platforms (i.e. Social media) • Identify additional value from data • Serve to distributed workforce and remote offices.
ADMS incident tracking	System outages, location, duration, cause, number of consumers affected	Used to identify assets that are causing outages and to report on SAIFI/SAIDI and CAIDI	Integrated with other ADMS applications	
AXOS Billing System, commissioned in 2018	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	
AMP project website	Central depository of AMP requirements	Links from this site to required documents used within the AMP	LAN links to documents from SMS or attached to tasks	
Customer Relationship Management (CRM) commissioned 2019	Customer Information, complaint information, 3rd party service requests and customer queries	Customer relations and service delivery management	Integrates with electricity registry, Business Central, Office 365, email and SharePoint Online	• Increase adoption and functionality to optimize operational activities

System	Data held	What the data is used for	Extent of integration	Initiatives/ Improvement
Electra Data Lake	The Electra Data Lake holds copies of information from SCADA and IoT platforms as well as from Electra controlled EV chargers and the head office PV battery system. This data includes network status information as well as digital and analogue readings from field devices, sensors and other systems	Primarily used for post analysis and network data mining without the security risks of operators having direct access to live platforms while offloading compute away from critical systems	Integrated with ADMS, IoT, SCADA business systems (Power BI) and third-party analysis tools	• Ingest more information and commit resources to analyse and interpret data to identify additional value.
Electronic Document Management System (EDMS) (Microsoft Office 365 SharePoint Online Platform)	Corporate policies, processes and general information	Provision of information on the Intranet, easily accessible to staff and to serve as a document management system and single source of truth	Integrates with Office 365 for emailing functionality	
IoT network status monitoring	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	IoT communications can have significant latency so 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	Integrated with the Data Lake, ADMS and SCADA. IoT devices can report to the control room in the same way as SCADA/ADMS	• Increase the number of sensors on our network. • Integrate the data into our ADMS and EAMS solutions. • Ingres data from 3rd party devices or services to increase sources of loss-of-power event reports
iAuditor (part of NIMS)	GPS co-ordinates for all scheduled maintenance assets. This information includes, but is not limited to asset ID, date of inspection and condition of asset	Used to determine the maintenance work for the following year	Fully integrated	• Consider as part of ArcGis Upgrade
Information Disclosure Compilation Tool	Network asset data	Compilation of Information disclosure data for various schedules as well as the generation of age profiles	Manual upload of GIS data with automated macros to produce schedules and charts	• Link to server data under review

System	Data held	What the data is used for	Extent of integration	Initiatives/ Improvement
NIMS (GIS)	Contains geospatial information for all assets including asset description, location, age, electrical attributes, condition 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.	• Upgrade to latest version of ArcGis
SCADA	System Control and Data Acquisition System being 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	Measuring load on various parts of the network. This is used for assessing security, load forecasts and feeder configurations	Low level of integration with outage web page	• Infrastructure upgrade
Safety Management System	Electronic library of safety documents held in the EDMS	Used by all staff to obtain safety information, policies and operational standards		
Strategic Vegetation Management Database	Tree owners, requests, trimming works, proactive and reactive plans	Monitoring of requests, works, costs, proactive and reactive planning, reporting	Manual input of tree requests	• Integrate with new EAMS
Vault	Risk register (organisation and H&S): incidents, injury, illness and near miss, plus associated injury management and rehabilitation	Used by H&S for managing risk register and incidents; used by employees to report H&S and public safety incident; used to report to senior leaders and Board; automatically notifies the above for critical events; audit and checks through mobile apps	Stand-alone system	
iServer	Enterprise Architecture	Capturing the current and future state of our technology stack	Integrates into Active Directory and the Microsoft Office suite of products.	
Plexus Gateway	Legal Documents such as contracts, supplier agreements etc.	Legal document storage and execution	Integrates with Microsoft Azure Active Directory	

1.9.1 Data integrity

Electra is in the process of establishing a multi-year road map focussed on the continual improvement of the quality and accuracy of our network information. The road map will focus on network and asset data and information including:

- Schematic and Engineering Model accuracy of HV network
- Schematic and Engineering Model accuracy of LV network
- LV transformer schematic diagrams
- Network details i.e. conductor, fuse and cables sizes
- Customer phase verification
- Geographical location data of network and assets.

Reconciliation between the various data sets indicate improvement in data quality levels as summarised for the following assets:

Asset type	**Information** held	**Information** quality	**Methods for ensuring data accuracy**
33kV Lines/ Cables	Size and material	Accurate	• Documents recording installation • Site inspection
	Age	Accurate to within 6 months	• Documents recording installation
11kV Lines/Cables	Size and material	Accurate	• Documents recording installation • Site inspection
	Age	Accurate to within 6 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation
400V Lines/ Cables Poles Pillars	Size and material	Accurate post 1995 70% accurate pre 1995	• Documents recording installation • Site inspection
	Age	Accurate to within 3 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation
Transformers RMUs Circuit breakers	Rating, manufacturer, age	Accurate	• Site inspection • Documents recording installation
Other Switches	Rating, manufacturer	Accurate	• Documents recording installation
	Age	Accurate to within 3 months post 1995 Accurate to within 5 years pre 1995	• Documents recording installation

Asset condition information is recorded as part of the regular inspection cycle for each asset class as described in Section 5.

Further, with the Electronic Documentation Management System and Lines Business Reference Library which went live in March 2019, the sharing of centralised information on the Intranet means that relevant documents are readily assessable for all staff and users. Feedback surveys on its availability and ease of access are being conducted with the objective of transforming this site to be the "single source of truth" for the lines business.

1.10 Overview of key lifecycle processes

The summary of the key processes follow in the sub-sections and details of asset management performance and improvement processes are included in Section 8.4.

1.10.1 Routine inspections

Electra routinely inspects all classes of assets on a time basis. The timing and scope of inspections varies by asset class, asset health and criticality, and public safety risk and are described in detail in Section 5.

1.10.2 Maintenance drivers

Electra uses the following range of maintenance strategies where the timing and scope of most maintenance is driven by the results of condition inspections, subject to manufacturer's minimum requirements or industry safety recommendations. Low value, low risk components are managed on a run-to-breakdown basis.

1.10.3 Development project drivers

The key drivers of all development projects are:

- Demand growth within existing network capacity (requiring a customer connection and minor network change)
- Demand growth in excess of existing network capacity
- Demand growth that requires network extension.

Electra considers the following approaches to meeting new demand:

Approach	Effect on asset utilisation	Effect on failure risk
Supplying the demand without any alterations to either asset capacity or operational processes (the "do-nothing yet" approach). This approach will be adopted if a risk analysis has confirmed that the overall risk exposures (particularly of in-service asset failure) remain acceptable	Increases (capacity headroom declines)	Increases
Supplying the demand through an operational process e.g. insisting that new load is controllable or designing a tariff that encourages off-peak use	Increases in some locations (capacity headroom declines) but declines in other locations. The net effect is minimal change in asset utilisation	Ideally nil, probably minimal in practice
If the above approaches are both unacceptable, Electra will invest in new assets	Ideally nil (capacity headroom maintained by matching investment level to demand increase). In practice, a decrease if the next highest rated component is installed	Nil, possibly decrease depending on how much capacity is added

These are described more fully in Section 4.

1.10.4 Measuring performance

Electra measure the performance within the following areas:

- Performance of the overall network (reliability)
- Performance of individual asset classes and assets (reliability, efficiency)
- Works delivery performance (timeliness, budget and unit costs)
- Asset management performance (alignment to long-term company objectives).

We have adopted the approach that it is not only important for both physical and financial budgets to be met, but also critical that those budgets accurately reflect the network condition and capacity utilisation to avoid a long-term accumulation of asset deterioration.

1.11 Overview of documentation and controls

Electra manages our documentation and information records through controls of various levels. These include:

- Allocation of a unique numerical identifier to all key documents that is traceable
- Assigning an authorisation level for altering or approving documents
- Specifications for the nature and accuracy of asset data that is to be returned from field services staff and contractors.

These documentation and data controls are described in Section 1.9.1.

1.12 Overview of communication processes

Electra communicates the key features of asset management planning and activities to the staff and contractors in the following ways:

- Asset Planning & Development staff prepare the AMP and its associated work programmes and budgets
- The Finance team compile budgets for personnel, IT, AMP and non-network assets
- Our Programme Management, Service Delivery and Operations teams are advised of the key AMP themes and trends and consulted on the scope, method, timing and budgets of the works programme
- We have a panel of pre-qualified field service contractors that are available to meet overflow work. They are informed when Electra identifies a likely overflow of work volumes
- Consultants can obtain the public copy of the AMP to understand our priorities and work programmes.

These communication processes are described in the AMMAT section in Section 8.4.

1.13 Significant assumptions

Significant assumptions for this AMP are:

Assumption class	Assumption	Tactic if assumption occurs	Tactic if assumption *does not* occur
Resident population growth	Horowhenua District's resident population is forecasted to increase by 8,600 people over the next 20 years, including an expected 4,900 houses and 3,000 jobs created From the 2018 census[2] released by Statistics New Zealand, the district has a population of 32,949, which increased at a rate of 2% per year since 2013. Horowhenua District Council's review during the Covid-19 lockdown predicts an increase to 2.6% growth every year between now and 2029 and expected to outstrip the national average of 1.2% annually[3].	Implement Growth CAPEX projects as planned	Implication would be a mismatch of asset capacity and demand, which can be minimised by regularly monitoring demand growth and either advancing or delaying capital projects
	The Kapiti Coast District's resident population is forecast to increase by 6,300 people over the next 15 years The 2018 census[2] identified a population of 53,940 residents; the growth rate was 1.9% per annum since 2013.		
Technology uptake	As the Government is increasing the incentives and subsidies for EV's, uptake is expected to be about 640 in Kapiti and 160 in Horowhenua by 2021, with a further 270 EV's travelling the SH1 corridor daily[4]	Implement Growth CAPEX projects as demand requires	Implication would be a mismatch of asset capacity (primarily network, but possibly also chargers) and demand. Any mismatch can be minimised by regularly monitoring EV numbers and also by encouraging off-peak charging[5]
	That EV fast charging rates may increase from the current 50kW to 300kW as vehicle size and range increases and the recharging period emerges as the barrier to EV uptake	Implement Growth CAPEX projects as demand requires (minimal overall impact, as there would only be a few within the network area)	Fast charging rates remain at about 50kW, reducing the need for network reinforcement
	The number of roof-top solar and battery installations will increase, possibly to the point of creating localised voltage disturbances	Active control of LV system voltage may be required	Voltage disturbances will be less likely

[2] Statistics New Zealand, Dataset: "Age and sex by ethnic group (grouped total responses), for census night population counts, 2006, 2013, and 2018 Censuses"

[3] Horowhenua District Council Media Release, 15 October 2020

[4] Source – "Compiling an EV charging strategy" prepared for Electra by Utility Consultants.

[5] Mercury recently noted that even a 10% price discount has been enough to encourage EV owners to shift charging to off-peak periods.

Assumption class	Assumption	Tactic if assumption occurs	Tactic if assumption *does not* occur
	Evolving application of device interconnectivity (the internet of things) will expand into energy transmission and network operations	Opportunities will emerge to increase the number and nature of asset condition monitoring	The existing level of monitoring will continue
	Penetration of LED streetlighting increases, leading to further reductions kWh sales	kWh revenue will decline	Existing level of kWh sales will prevail
Financial parameters	The rate of inflation for the Planning Period will be 1.5%, which is based on the ANZ Bank forecasts	Actual costs and margins should align with budgets	Actual revenues, costs and margins may vary from budget, budgets may need to be revised, with the possibility that work volumes may need to be reduced
Public policy	That the Government's climate change initiatives will see increased emphasis on renewable generation	Generation mix likely to include more renewables, possibly leading to price increases and declining kWh sales	Generation mix and hence prices and kWh consumption likely to stay the same
	That the Government's climate change initiatives will see substitution of electricity for oil (transport) and coal (industrial)	Increased generation (almost certainly requiring new capacity), and increased kWh sales	kWh consumption likely to remain similar to current levels
	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, cost of additional land access requirements will need to be recovered either from specific customers or at large
	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	
	The Wellington Northern Corridor roading development will continue as stated in the Roads of National Significance (the NZTA's website)	Declining diversity between Kapiti zone substations as more commuters arrive home earlier may increase coincident GXP demand. Also, possibility of people moving northwards from Wellington to Kapiti, and from Kapiti to Horowhenua	Kapiti population growth may not be as high as forecast, such that Growth CAPEX projects can be deferred
Sector regulation	The current Electricity Authority emphasis on cost reflective pricing will continue.	Could require extensive rebalancing of fixed and variable charges	Tariffs and revenue principles should be able to remain similar to present
	That trust owned EDB's will continue to be exempted from revenue and quality regulation	Continue to set own revenue and quality targets	Compliance costs would increase, possibility that revenue may be reduced

1.13.1 Causes of possible material differences

Key factors that may result in material differences between this AMP and future disclosures include:

Class of cause	Cause	Result	Possible response(s)	Ability to recover costs of response
Transport policy	Variations to the established motorway development plans, most likely a deferral	Gradual increase in Horowhenua population growth	Delay CAPEX to meet demand	Currently strong
	A shift in Government policy towards a more aggressive uptake of EV's that could provide subsidies for EV's and restrictions for gasoline vehicles	Possible increase in peak demand unless charging is incentivised to off-peak periods	Growth CAPEX to meet demand, introduce peak pricing to manage demand	Currently strong, possibility that ability to recover costs may be weakened[6]
	An inability to manage electric car recharging to off-peak periods (whether through policy or otherwise)	Likely increase in peak demand		
Costs	Variations from forecast labour and material costs	Actual costs may exceed budget	Either increase total budget or reduce work volumes to fit within existing budget subject to risk assessment	Currently strong
	Increased health, safety and traffic management requirements that increase the cost of work	Increased time per job, resulting in increased costs per job	Decrease work volumes to fit within budget subject to risk assessment	Currently strong
	Increased requirements for access to land by NZTA or KiwiRail that increase the cost of work	Increased time per job and costs per job	Reduce number of jobs to fit within budget, subject to risk assessment	Currently strong
Performance	Migration of tree trimming from a responsive approach to a planned approach may reduce SAIDI to below forecasts	Possible that actual SAIDI will be below long-term targets	Reduce tree trimming budget in the long-term	Currently strong
Asset condition	A previously unknown widespread asset defect emerges that effects a number of assets	Requires an accelerated replacement programme	Increased Replacement CAPEX after performing specific risk assessment	Currently strong
Customer behaviour	Changes to the rate of customer adoption of new technologies	Variations between actual and forecast demand	Advance or delay Growth CAPEX	Currently strong
Sector regulation	Shifts in government preference for electricity sector regulation	Possible increase in compliance costs	Recover costs through increased prices, or reduce consumer discount	Possibility of reduced cost recovery

[6] It is noted that investor-owned electric companies in California were restricted in their ability to recover the full costs of peak-time charging.

1.13.2 Financial forecasts

During the planning period, we will face different input price pressures to those captured by a general measure of inflation, such as the consumers price index (CPI) where pricing will be based on global demand for commodities as well as market trends for various assets. These are then applied to our real expenditure forecasts to produce the forecasts in nominal dollars for our budgets as well as Information Disclosure schedules in Appendix 2 (CAPEX forecast) and Appendix 3 (OPEX forecast), which are based on 2020 constant New Zealand dollars.

1.13.3 Limitations of this AMP

Compilation of this AMP has revealed the following possible limitations:

- Some classes of asset condition data are either known or thought to be inaccurate; an on-going identification and cleansing process is in place.
- Demand forecasting methods have historically used linear extrapolations. We recognise that demand forecasting particularly for the southern network includes an increasing number of variables that are more complicated to predict and we intend to develop a more comprehensive methodology that will include consideration of emerging technologies, declining kWh consumption and increasing kW demand.
- Rapid changes in technology and uncertain rates of technology uptake make a 10-year forecast less certain than in previous years.
- Despite the less certain long-term view, we remain confident that we can continue to operate and maintain a safe, reliable network and recover the true economic cost of the network.

2 Network overview

2.1 Network area

2.1.1 Regions covered

Electra's assets are spread over the Horowhenua and Kapiti districts on the narrow strip of land between the Tasman Sea and the Tararua Ranges, stretching from Foxton and Tokomaru in the north to Paekakariki in the south, as illustrated below. The network covers approximately 1,628 km^2.

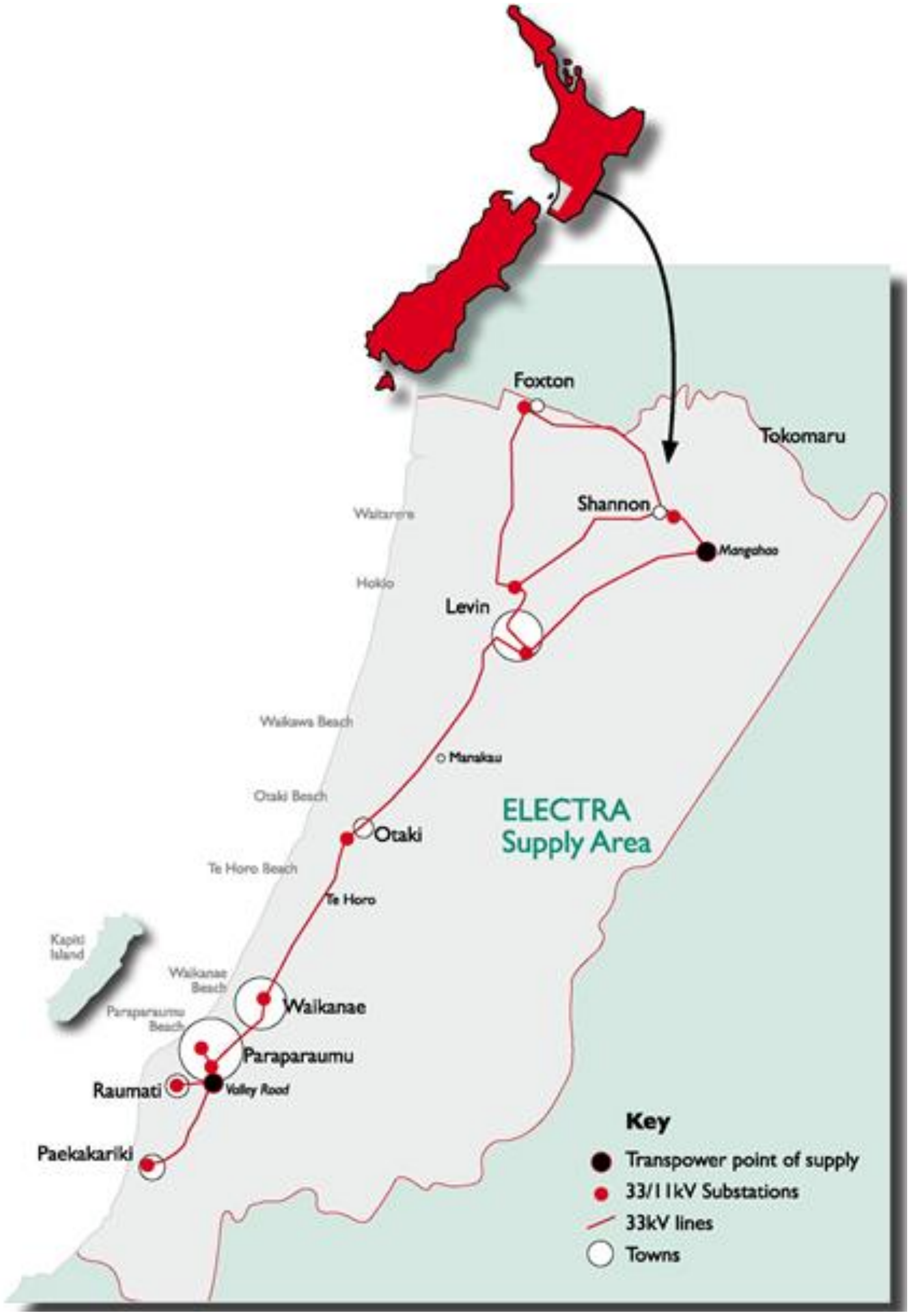


Figure 2-1: Electra sub-transmission 33kV network with 33/11kV substations and Transpower GXPs

2.1.2 Large consumers

Electra's largest network customers are:

- Kapiti Coast District Council
- Foodstuffs North Island Ltd
- Alliance Group, Levin
- Horowhenua District Council
- KiwiRail Ltd
- Woolworths New Zealand Ltd
- Unisys New Zealand Ltd
- Turks Poultry Farm
- Case Central
- Metlifecare Coastal Villas Ltd.

These consumers represent 5.4% of the energy conveyed through our network. Accordingly, Electra faces a low revenue risk from its large industrial consumers' consumption trends.

Each of these consumers forecast demand and security requirements are discussed with Electra's key account manager, and specific requirements are included in the AMP as required.

2.1.3 Network load characteristics

While Electra's network is electrically contiguous, it is best considered as two market segments:

- A northern network depicted in Figure 2-2 supplied predominantly from the Mangahao GXP, and embedded Mangahao generation supplying Levin, Foxton and Shannon in a ring configuration. The economy of this market segment is strongly tied to both root and leaf vegetable prices, and dairy prices, and has demonstrated low growth in both MW demand and ICP numbers.
- A southern network Figure 2-3 supplied predominantly from Valley Road Paraparaumu GXP; supplying Paekakariki, Paraparaumu, Raumati, Waikanae and Otaki by a double spur configuration. This market segment has a broader demographic comprising a range of features including strongly urbanised through to lifestyle rural to agricultural production. A key feature of the southern network is that because many people in this area commute to Wellington, the day-time demand is considerably less than the evening demand, leading to a low load factor.

About 42% of the energy conveyed by Electra is through the northern network, and about 58% through the southern network.

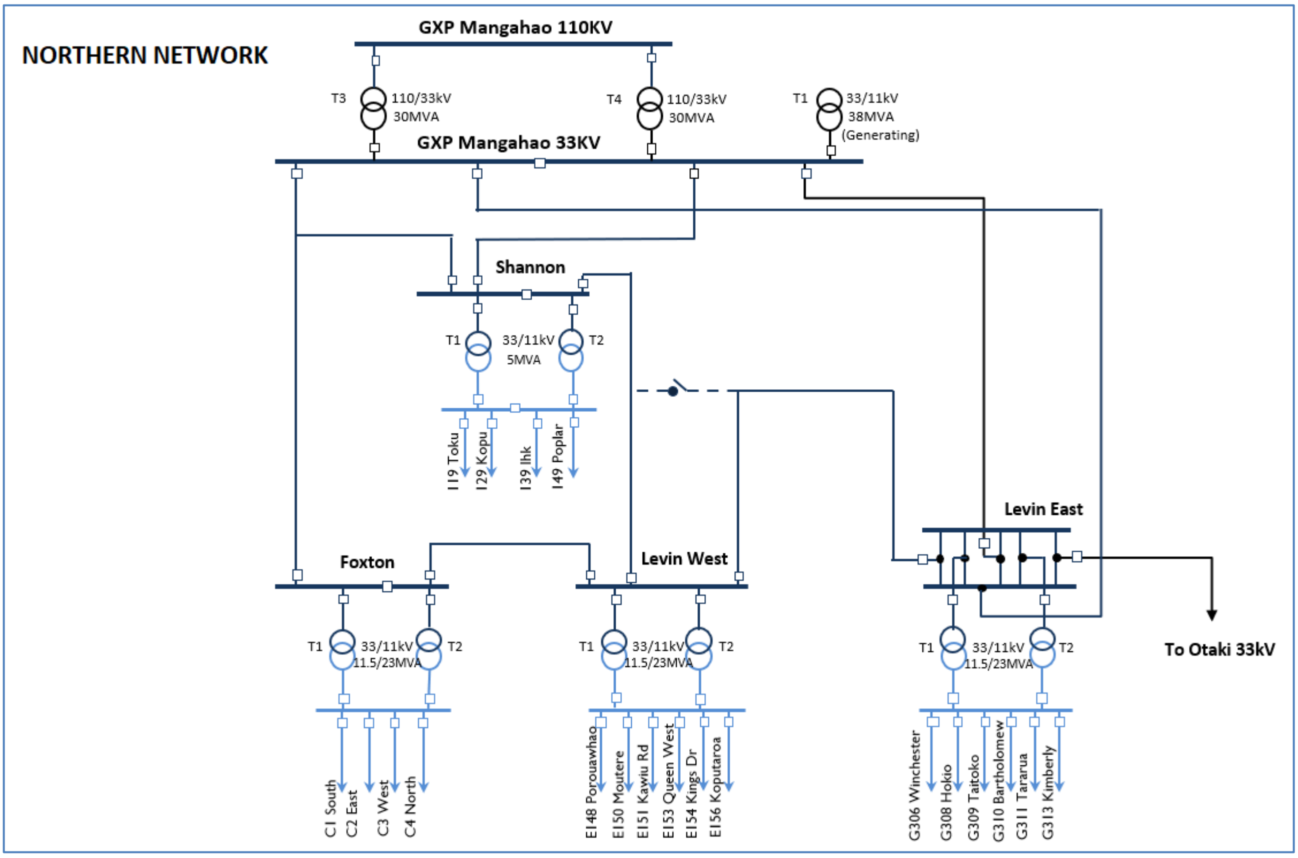


Figure 2-2: Northern 33/11kV network

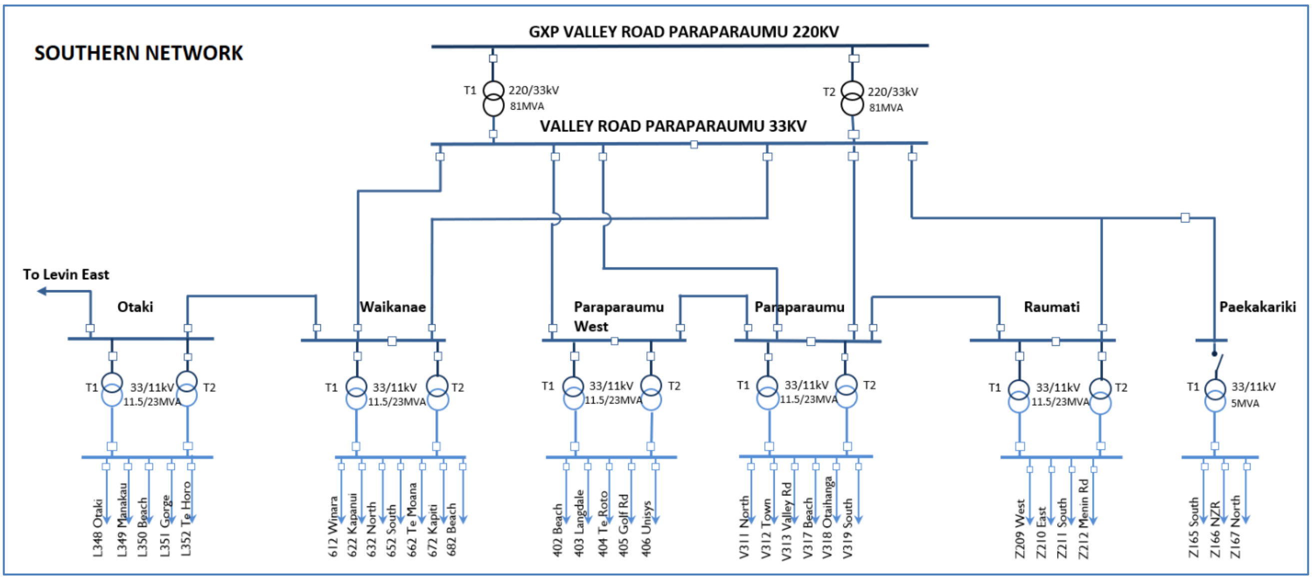


Figure 2-3: Southern 33/11kV network

2.1.4 Demand and energy

Key parameters of Electra's network as of 31 March 2020 are:

Parameters	Quantity
Average number of customers in disclosure year	45,192
Maximum demand	101 MW
Annual electricity conveyance	450 GWh

Parameters	Quantity
Line and cable length	2,323 km
Number of zone substations	10
Number of distribution transformers	2,563
Network asset valuation	$202m

As demonstrated by the graph in Figure 2-4(a), ICP growth has been slowly increasing at a rate of about 1% annually between 2014 to 2020 versus a 0.2% average yearly increase of the total system length during the same period. The number of ICPs is extracted from the Registry for active customers up to 30/9/2020 and is based on the ICP creation date. The ICP growth rate in the region is expected to increase as depicted in Figure 2-4(b), the population change map between the 2013 and 2018 census.

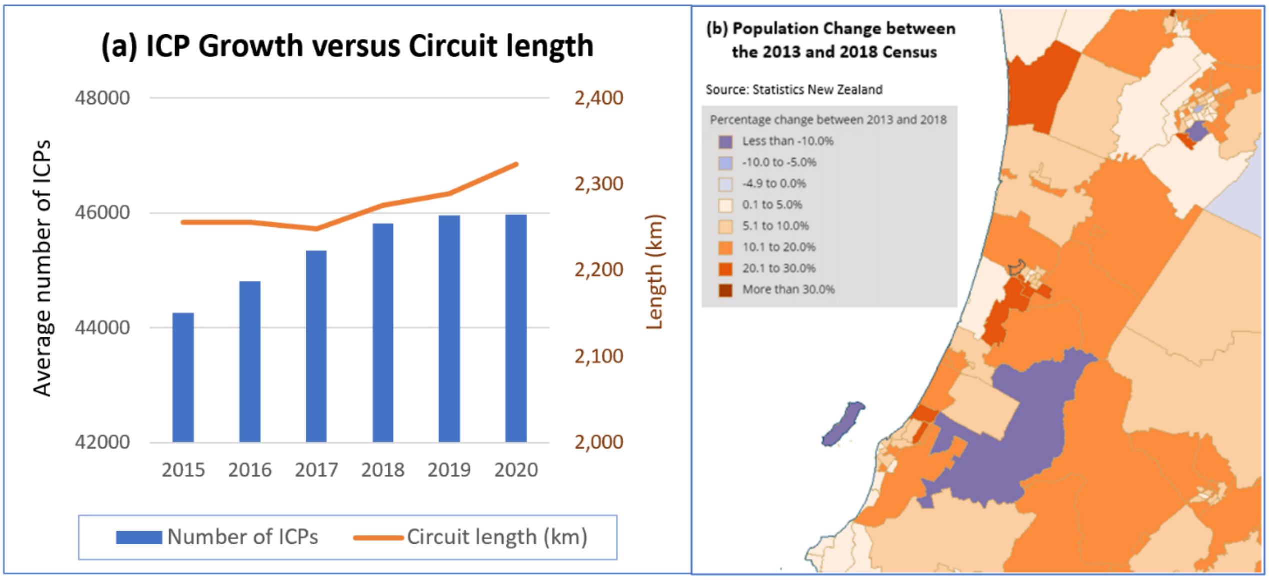


Figure 2-4: (a) Growth of ICPs and circuit length, and (b) Population change between the 2013 and 2018 census

2.2 Network configuration

Electra takes bulk supply from the following two GXPs:

- Mangahao GXP, which supplies the northern area
- Valley Road Paraparaumu GXP, which supplies the southern area.

Otaki zone substation may be supplied from either GXP but it is usually supplied from Valley Road.

Key features of these bulk supply points are:

GXP	Winter firm capacity (MVA)	Peak demand (MVA)	
		2019	2020
Mangahao	30	38.5	39.2
Paraparaumu	120	63.3	64.5

The 38 MW Mangahao hydro generation station is embedded in Electra’s network with a direct connection to Transpower’s 33 kV bus at Mangahao to resolve constraints of Mangahao’s (n-1) firm capacity, which has been exceeded since 2015. Further analysis is included in Section 4.7.4.

Key “at a glance” features of Electra’s network follow with details of individual asset categories and lifecycle management of these assets set out in Section 5.

System level	Key features at a glance
Bulk supply and embedded generation	GXP's supplying a coincident maximum demand of 101 MW Embedded hydro generation of 38 MW (Mangahao) About 689 solar installations with a total capacity of 2.72MW
Sub-transmission	33 km of overhead 110kV line that are being operated at 33kV 152 km of overhead 33kV line 31 km of underground 33kV cable
	Four zone substations supplied from Mangahao GXP Five zone substations supplied from Valley Road GXP One zone substation that can be supplied from either Valley Road or Mangahao
Distribution network	849 km of overhead line 246 km of underground cable
Distribution substations	2,563 substations ranging in capacity from 5 kVA to 1,000 kVA

The network lengths of Electra's sub-transmission and distribution network follow:

Description	Length in km as of 30-Sep-2020				Network %
	33kV	11kV	Low Voltage (LV)	Sub-total	
Underground cables	31	246	497	774	33%
Overhead lines	185	849	522	1,556	67%
Total:	216	1,095	1,019	2,330	100%

Figure 2-5: Network circuit lengths of overhead lines and underground cables

As per Figure 2-5, we have 849 km of 11kV overhead lines and 246 km of 11kV cables connecting our ten zone substations to distribution substations. This 11kV network is constructed mainly of:

- CBD areas are almost exclusively supplied by underground cable. In older urban areas with low load growth such as Levin and Foxton, these cables are of PILC 185mm^2 aluminium construction. New installations are constructed of XLPE cables.
- Suburban areas tend to be a mix of overhead lines and underground cables depending on whether the area was developed before or after undergrounding was widely adopted around 1970. Underground cable construction tends to be PILC aluminium conductor, whilst overhead conductors are a variety of Bee, 19/0.064" and 7/0.083" copper, almost totally on concrete poles.
- Rural areas are mostly of overhead line construction but with increasing lengths are being cabled. These lines are Gopher or 7/0.064".

Electra has 522 km of overhead LV or low voltage line (400V) and 497 km of LV underground cable connecting its distribution substations to its customers, with an associated 10,048 pillars and cabinets.

Distribution overhead line and underground cable lengths by the ten zone substation areas follow:

Zone substation	Distribution network length (km) up to 30/9/2020			LV network length (km) up to 30/9/2020		
	Overhead line	Underground cable	Total	Overhead line	Underground cable	Total
Levin East	125	29	**154**	90	57	**147**
Levin West	122	24	**146**	80	49	**129**
Shannon	185	9	**194**	71	10	**81**
Foxton	105	17	**122**	65	19	**85**
Paraparaumu	26	32	**58**	18	65	**83**
Paraparaumu West	7	31	**38**	12	81	**94**
Raumati	13	13	**26**	26	33	**59**

Zone substation	Distribution network length (km) up to 30/9/2020			LV network length (km) up to 30/9/2020		
	Overhead line	Underground cable	Total	Overhead line	Underground cable	Total
Waikanae	64	47	**111**	48	118	**166**
Paekakariki	15	6	**21**	10	4	**14**
Otaki	186	38	**224**	102	59	**161**
Total	**849**	**246**	**1,095**	**522**	**497**	**1,019**

2.3 Asset valuation (RAB) allocation

Electra's Regulated Asset Base (RAB) increased from $179.6 million to $202.1M from FY2019 to FY2020. The FY2020 RAB comprises of network assets as shown in Figure 2-6.

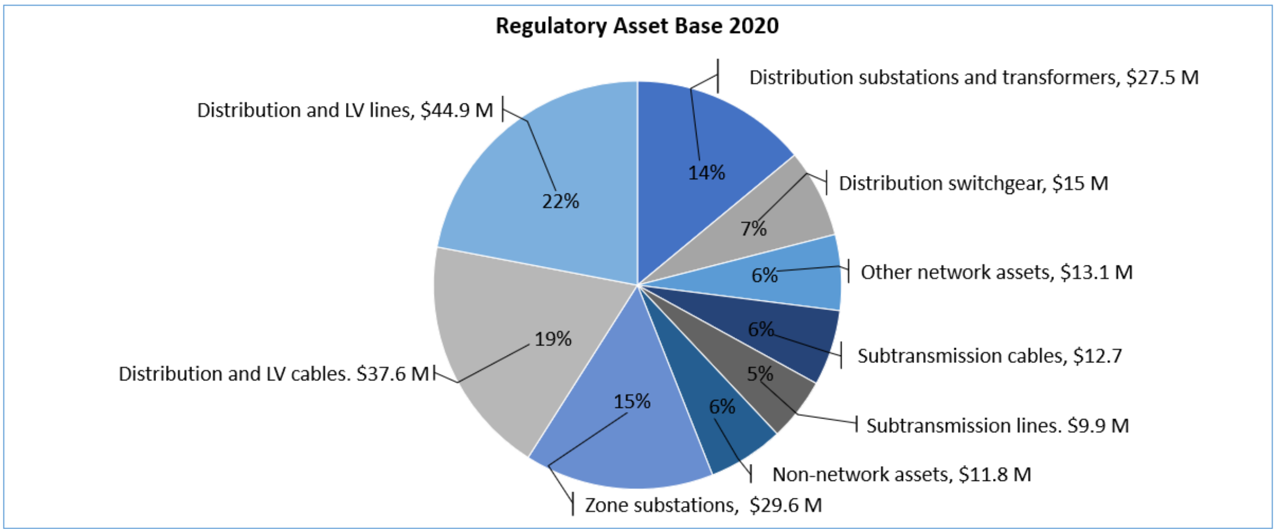


Figure 2-6: Regulatory Asset Base 2020 depicting asset categories and values

3 Service levels

3.1 Our customers

The AMP is developed to serve current and future customers connected to the network. As of September 2020, there are 46,438 consumers connected to our 11kV and 400V distribution networks.

Customers are at the centre of Electra's decision-making as reflected in the strategic plan where "focus on customer" is a strategic objective. This commitment is demonstrated through the annual customer survey, consultations with large electricity users and our community engagement through business forums. The investment in our network considers customer reported faults and disruptions to customers such as the reduction of repeated power failures. Affordability is considered in our pricing methodology.

Safety is a key component and Electra strives to ensure that assets and network systems are safe for our customers as well as our contractors.

Our commitment to our customers is further supported not only by the recent implementation of customer relationship management (CRM) but by the appointment of a Customer Relationship Manager.

The AMP is communicated to our customers by publishing on our website and we have developed a pamphlet that is made readily available at community gatherings and on the website. Electra has deployed new technologies to keep customers informed and has also significantly improved the outage information available on its website. The website now provides customers with up-to-date access to detailed outage information including the location of fault vehicles, easy-to-understand icons as well as creating an Electra Customer Outage App, available for use on mobile devices. Customer-focus initiatives include the following:

- The analysis of areas that suffer repeated outages as well as those that experience outages of long duration
- Enhancement of customers services and communications with the appointment of a Customer Relationship Manager
- Improvement of communications around planned and unplanned outages through the increased use of digital channels to customers and retailers

Enhancement of communication and information sources on:

- how to prepare for outages
- how to connect solar equipment including a list of approved local installers
- how to select appropriate plans for electric vehicles and manage load.

3.2 Primary customer service levels

A key objective of the Asset Management Plan is a focus on customers, on their needs and wants and to support the delivery of best value services to our customers.

3.2.1 Reliability

Electra's primary customer service level is supply continuity and restoration, as measured by using internationally accepted performance measures known as:

- **SAIDI**: System Average Interruption Duration Index indicating the average time in minutes all customers are interrupted
- **SAIFI**: System Average Interruption Frequency Index indicating the average number of interruptions per customer or the frequency of interruptions
- **CAIDI**: Customer Average Interruption Duration Index, indicating the average time in minutes affected customers are interrupted.

Electra does not distinguish between customers in different geographical areas, but the radial configuration of its rural network inevitably means that while all customers will experience a similar frequency of interruptions, those in rural areas are more likely to experience longer supply interruptions.

Electra's historical and SAIDI, SAIFI and CAIDI targets are:

Measure	Actual (historical)					Target ➔				
	FY2016	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025
SAIDI B (Planned)	19.35	17.13	26.73	32.32	19.50	15	15	15	15	15
SAIDI C (Unplanned)	80.71	79.23	95.00	57.00	75.40	68	68	68	68	68
SAIDI	**100.06**	**96.90**	**121.73**	**89.33**	**94.94**	**83**	**83**	**83**	**83**	**83**
SAIFI B (Planned)	0.06	0.05	0.08	0.10	0.06	0.06	0.06	0.06	0.06	0.06
SAIFI C (Unplanned)	1.10	1.45	2.00	1.17	1.81	1.6	1.6	1.6	1.6	1.6
SAIFI	**1.16**	**1.63**	**2.08**	**1.26**	**1.87**	**1.66**	**1.66**	**1.66**	**1.66**	**1.66**
CAIDI B (Planned)	328.02	342.60	321.21	323.20	313.37	250	250	250	250	250
CAIDI C (Unplanned)	73.64	54.64	47.58	48.72	41.75	42.5	42.5	42.5	42.5	42.5
CAIDI	**86.63**	**59.45**	**58.53**	**70.90**	**50.80**	**50**	**50**	**50**	**50**	**50**

Comments on the historical performance include:

- An unplanned interruption on the back up supply to Levin whilst the main 33kV supply was out of service for maintenance meant the FY2016 SAIDI exceeded target.
- Kaikoura earthquake related faults led to FY2017 SAIDI target exceeded.
- A 33kV interruption during the FY2018 year has focused Electra's attention on the resilience of its 33kV network and resulted in specific programmes of work to systematically improve the reliability of sub transmission network through protection improvements and component replacements.
- Unplanned SAIDI for FY2019 was dominated by a major 33kV outage caused by a bird strike resulting in the loss of the northern network, which contributed 10.2 SAIDI minutes.
- For the disclosure year 2020, the main contributors were third party interferences (23.61 minutes), planned work (19.5 minutes), and unknown causes (20.19 minutes). Unknown cause is selected when there is insufficient evidence available to satisfy the criteria for a known cause. The outage is evaluated against each known cause type in turn; if a match fails then the cause type 'Unknown' is selected.

3.2.2 Justification for reliability targets

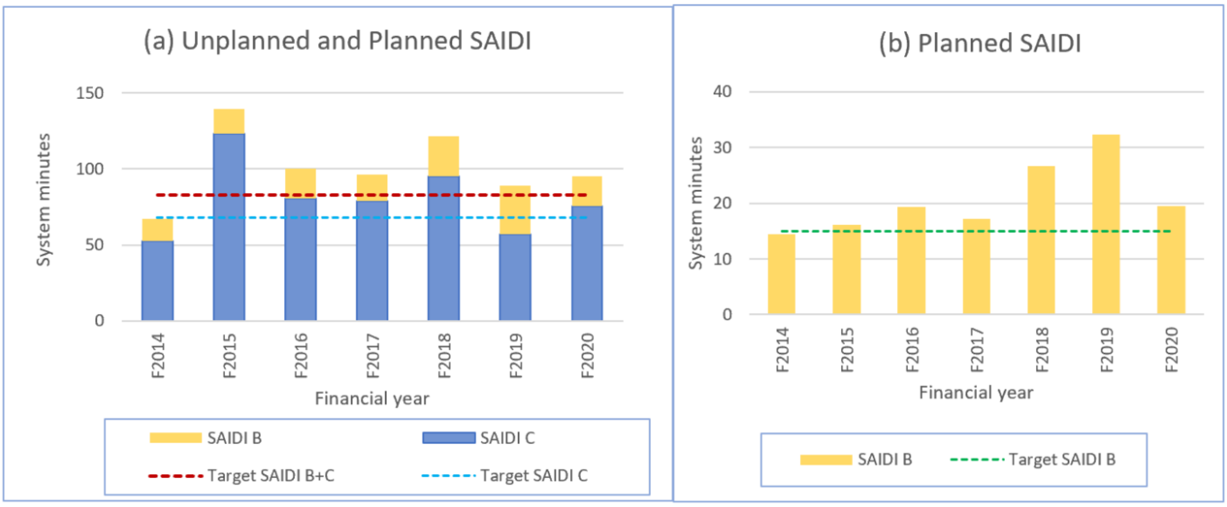


Figure 3-1: Historical unplanned and planned SAIDI trends

Unplanned and planned SAIDI versus the total 83-minute target is shown in Figure 3-1(a) while planned SAIDI against its target is depicted in Figure 3-1 (b). We have maintained our historical 83-minute target and this is shown in Appendix 7 Schedule 12d, the report on forecast interruptions and duration required by the Commerce Commission's Determination. Total SAIDI has decreased from 122 minutes in FY2018 to 90 minutes and 95 minutes in FY2019 and FY2020, respectively. It should be noted that Electra is ranked 5th amongst EDBs for total SAIDI averaged for FY2019-20 (Section 8.2.1).

The frequency of unplanned interruptions or SAIFI has reduced from 2 in FY2018 to 1.17 (FY2019) and 1.81 (FY2020) as demonstrated in Figure 3-2a. Planned SAIFI and CAIDI (in Figure 3-2b and Figure 3-2c respectively) have increased above the targets set due to the increase in asset renewal and replacement programmes to improve network performance. Improved safe work practises have also contributed to the increase in planned reliability indices. Though unplanned CAIDI has reached the target of 43 minutes, Electra's CAIDI is still the best amongst its peer group. For detailed analysis please refer (Section 8.2.1).

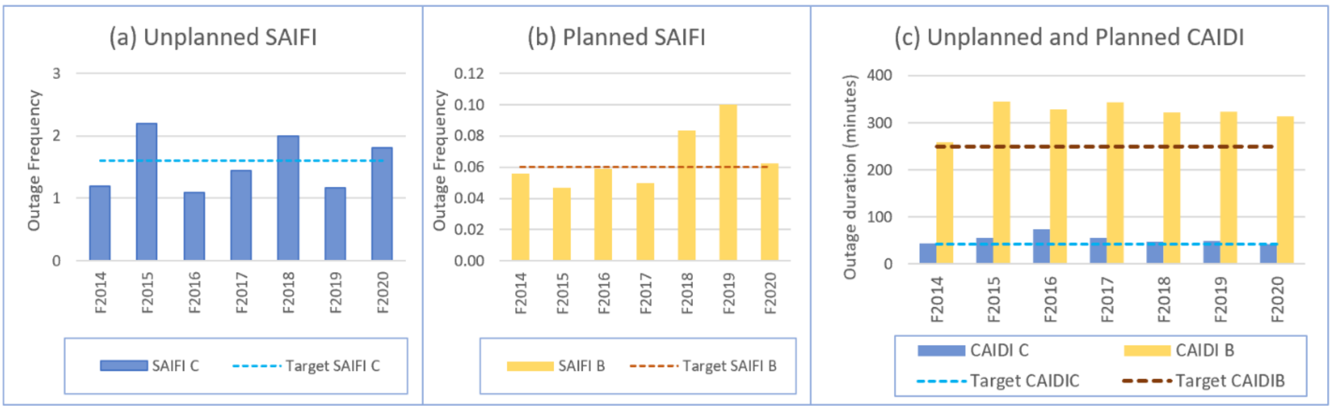


Figure 3-2: Historical unplanned and planned SAIFI and CAIDI trends

Customer consultation and community engagement reveals that Electra's customers prefer not to pay more for further improvements in reliability. Such findings were reported in the recent study by the Electricity Networks Association on the "Quality of Service Regulation"[7]. However, Electra has identified several tactical programmes to maintain the performance at this optimal level and deliver improved customer experience as discussed in Section 3.10.

[7] Electricity Networks Association, "ENA Working Group on Quality of Service Regulation Interim Report to the Commerce Commission", 1 October 2018.

3.3 Secondary customer service levels

Electra's secondary customer service levels include the following aspects:

- Processing an application for a new connection
- Providing technical advice
- Giving sufficient notice for planned shutdowns.

Electra's targets for these secondary customer service levels are as follows:

Attribute	Measure	Target →				
		FY2021	FY2022	FY2023	FY2024	FY2025
Processing new connection application	Number of working days to process	3	3	3	3	3
Providing technical advice	Number of working days to acknowledge by mail	4	4	4	4	4
	Number of working days to acknowledge by phone	2	2	2	2	2
	Number of working days to investigate inquiry or validate complaint	5	5	5	5	5
	Number of working days to provide advice for non-complaint matter	3	3	3	3	3
	Number of working days to resolve proven complaint (unless non-minor asset modification required)	10	10	10	10	10
Notice for planned shutdowns	Number of customers to who 3 working days of a shutdown is not provided.	5	5	5	5	5
	Number of large customers to whom 60 minutes advanced notice of a planned shutdown is not provided.	1	1	1	1	1
	Number of large customers whose preferred shutdown times cannot be accommodated.	2	2	2	2	2

Customer surveys by both Electra and other EDB's have identified these service attributes as less important than supply reliability (continuity and restoration). A key feature of these secondary service attributes is that they are based on processes rather than fixed asset investment.

Electra shares the view of the ENA study (Section 3.2.2) that identified the ease of connection and timely planned outage notification as two key opportunities to positively influence our customer experience.

3.4 Asset performance levels

In order to improve system reliability performance and operational efficiency to achieve our strategy of operational excellence, Electra monitors the following asset performance levels:

- Load factor
- Capacity utilisation
- Network losses
- Economic effectiveness.

Our historical and performance targets are:

Measure	Actual (historical)				Target ➔					
	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026
Load factor	48%	49%	50%	51%	51%	51%	51%	51%	52%	52%
Capacity utilisation	31%	31%	30%	30%	31%	>31%	>31%	32%	32%	32%
Network losses	6.7%	8.4%	6.9%	7.7%	7.4%	7.0%	7.0%	7.0%	7.0%	7.0%

The above values are also included in the Commerce Commission's Determination Schedule 12c, which is the report on forecast network demand (Appendix 6).

3.4.1 Load factor

Load factor is calculated as the average load passing through a network divided by the maximum load experienced in any given year. Electra seeks to optimise load factor as this indicates better utilisation of capacity in the network. The load factor has been increasing gradually from FY2017 (48%) to FY2020 (51%). Section 8.3.1 contains a further discussion on the derivation of the targets for our load factors.

3.4.2 Capacity utilisation

Capacity utilisation ratio measures the utilisation of transformers installed on our network. It is calculated as the maximum demand experienced on the network divided by the distribution transformer capacity on the network. In FY2020, our distribution transformer utilisation was 30% and based on industry utilisation performance versus network density discussed in Section 8.3.2, we have set our utilisation target to be greater than 30%. We aim to ensure maximum economic efficiency by ensuring good design and lifecycle management practices.

3.4.3 Network losses

Electricity networks incur energy losses caused by the technical losses (heating of transformers and conductors) and non-technical losses like meter/billing errors and theft. Electrical losses are the difference between energy (GWh) entering the Electra network and the energy leaving the network at consumer connections. FY2020 losses have increased to 7.7% from 6.9% in 2019. Further studies and increased instrumentation are being scheduled for implementation in 2021 and section 8.3.3 contains further information on measures undertaken and network loss forecast.

3.4.4 Financial efficiency

Financial economic efficiency reflects the asset investment required to provide network services to customers and the operational costs associated with operating and maintaining assets. The measures Electra use to monitor our financial efficiency includes:

Financial ratios	Actual			Target
	FY2018	FY2019	FY2020	
Capital expenditure on assets per total circuit length (km)	$5,148	$5,065	$10,914	Within 5% of the previous year's figures.
Capital expenditure on assets per connection point	$264	$259	$561	
Operational expenditure on assets per total circuit length (km)	$5,306	$5,308	$5,603	
Operational expenditure on assets per connection point	$272	$271	$288	

The above measures are published yearly on Electra's website through Information Disclosure schedules.

The trends in our operational (OPEX) and capital asset expenditure (CAPEX) per ICP and per circuit length (in km) are depicted in Figure 3-3.

Electra aims to maintain its OPEX and CAPEX per ICP and per circuit length (km) within 5% of the previous year's figures. Further evaluation of the above indicators is included in Section 8.3.4.

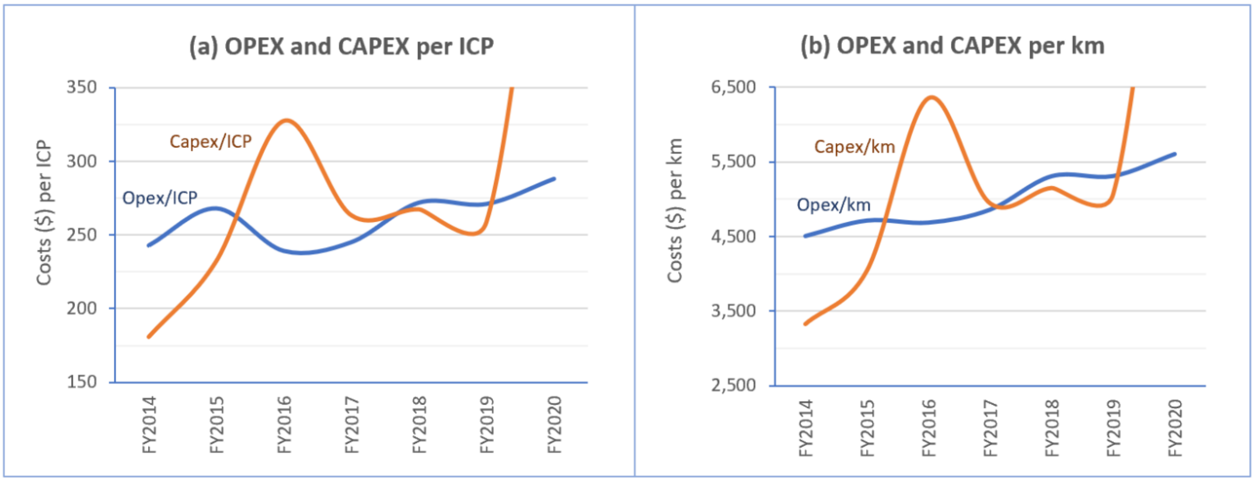


Figure 3-3: OPEX and CAPEX (a) per ICP, and (b) per circuit length (km)

The costs for both OPEX per ICP and per circuit kilometre increased by 6% from FY2019 to FY2020. Further comparison of our performance is included in Section 8.3.4. The OPEX includes direct and indirect costs.

CAPEX per kilometre and per consumer for FY2020 has increased due to a one-off adjustment required to include Network Service Delivery assets and Right of Use assets into our Regulatory Asset Base (RAB). This adjustment comprised $7.4m. The Network CAPEX per kilometre and per consumer is $6,760 and $348 respectively.

3.5 Safety and environmental performance levels

Electra's safety and environmental performance information for the last four financial years as well as our targets are shown in the following table:

Service criteria	Indicator	FY2017	FY2018	FY2019	FY2020	Target and forecast	Performance measurement
Public safety: safety of staff, contractors and the public	Number of incidents	3	8	13	51	Zero harm	Safety audits - zero non-compliance
Personnel safety	Lost Time Injury (LTI)	9	4	3	3	Zero LTI	Annual measurement
Environmental responsibility	Number of environmental incidents	0	0	0	0	Zero harm to the environ-ment	SF_6 Leak rate, transformer leak rate, zone transformers - dissolved gas analysis

Public safety incidents are now captured on Vault, a health, safety, environmental and risk management software. Using Vault, there is more open reporting and analysis of incidents than has been in the past. This process allows real time reporting which has resulted in part to the increase in the reporting of number of public safety incidents since FY2017.

Further, in line with Electra's "Safety and People" strategy, our focus in the last eighteen months has been on preventive measures, improving the record of health and safety interactions which include leading indicators covering safety inspections and audits, health and safety discussions and monitoring. Incident reporting is widely encouraged using mobile applications with much improved incident review and sharing of lessons learned. Such procedures have also impacted on the number of public safety incidents while driving improved safety for our people, the public and protection of our assets.

Such a “Safety and People” strategy has been reflected in the decrease of the number of lost time injury or LTI over the last few years and Electra is continuing to ensure a zero-harm safety incident rate.

3.6 Regulatory performance levels

Regulatory performance levels are set by statutory agencies and include compliance with the legislation listed in Sections 3.5 and 3.8.2 as well as the following:

- Compliance with the operative Horowhenua and Kapiti Coast district plans
- Compliance with the operative Wellington and Horizons regional plans
- Participation in regional disaster recovery initiatives such as Lifelines
- Compliance with New Zealand Transport Agency requirements for locating assets within road reserve, and for working within road corridors
- Compliance with KiwiRail requirements for locating assets near railway lines, and for working within rail corridors
- Compliance with electrical worker certification and training requirements.

Electra has measures in place to fully comply with the above requirements. We are using Comply With, a legal compliance management tool, to identify and monitor our legal compliance risks. Annual surveys are carried out as part of the Legal Compliance programme and our compliance is tracking well, having improved from 98.7% (2019) to 99.3% (2020) as tabulated in the following table.

Service criteria	Indicator	2019	2020	Target and forecast	Performance measurement
Legislation compliance	Compliance with relevant legislation	98.7%	99.3%	Full compliance	Annual measurement using ComplyWith software

The above targets include compliance with applicable safety and environmental legislation covering:

- Health and Safety at Work Act 2015
- Health and Safety (Asbestos) Regulations 2016
- Building Code, Section C5 of the Engineering Assessment Guidelines - Seismic assessment of existing buildings
- Electricity (Safety) Regulations 2010
- Electricity (Hazards from Trees) Regulations 2003
- Resource Management Act 1991
- Maintaining an independently certified Safety Management System, which conforms to the safety management systems for public safety, NZS 7901:2014.

Other legislative requirements are stated in Section 3.8.2.

The General Counsel and the responders monitor the action plans to completion.

3.7 Public good service levels

Electra also provides a range of (non-safety) services that are for the public good. These include:

- Switching of controlled loads, including streetlights and under veranda lighting

- Laying ducts during other parties' excavations to avoid future excavations
- Allowing other parties to suspend cables from Electra's poles
- Allowing other parties to mount signs on Electra's poles
- Relocating assets to better suit other parties, especially near roadways
- Supporting installation of public EV charging infrastructure
- Facilitating the installation of renewable generation.

3.8 Justification for service levels

Electra has adopted its current and planned future service levels based on customer expectations, regulatory requirements, and our group's strategies and objectives.

3.8.1 Customer expectations

Customer service levels are an important input into the development of the AMP. We continuously strive to deliver an outstanding service to meet our customers' expectations. Section 2 provides the details of their expectations and feedback received through yearly customer surveys and focus groups.

Electra gauges customer expectations by conducting yearly Customer Service Surveys since the late 1990s. These surveys involve interviews with 300 customers who have contacted Electra's faults service in the two to three months immediately prior to the survey period. Electra commissioned the 2020 survey[8] to track any changes in perceived service delivery relating to the servicing of faults, compare the satisfaction levels of customers with previous surveys, gain an updated measurement of customers' preferred information sources during interruptions to electricity supply, as well as to offer participating customers the opportunity to provide feedback to Electra's Chief Executive.

The survey was changed this year to provide insights and feedback on areas that have become more relevant due to changes in working and life-style behaviours with the uptake of working from home due to the Covid-19 pandemic.

3.8.1.1 Preferred information source

Research participants were asked to identify which information source would be their preferred choice during a fault. As depicted in Figure 3-4(a), preference was split largely between the '0800 Lost Power information line' (46%) and 'text messaging' which has significantly decreased from 38% to 20% since the last survey. Other sources include a call from Contact Centre (9%), Smartphone App (4%), website (9%, an increase from 3% previously) and Facebook or Twitter (3%). Electra will continue to monitor and enhance the uptake of newer technologies by its customers.

Figure 3-4(b) indicates the information sources gaining prominence with our customers. The internet (37%) continues to be the leading source of information for contact details, followed by the fridge magnet, power bill, telephone directory (all at 13%) and 0800 number (10%).

[8] Data extracted from "Customer Service Survey 2020" Report prepared for Electra by Peter Glen Research, Nov-2020

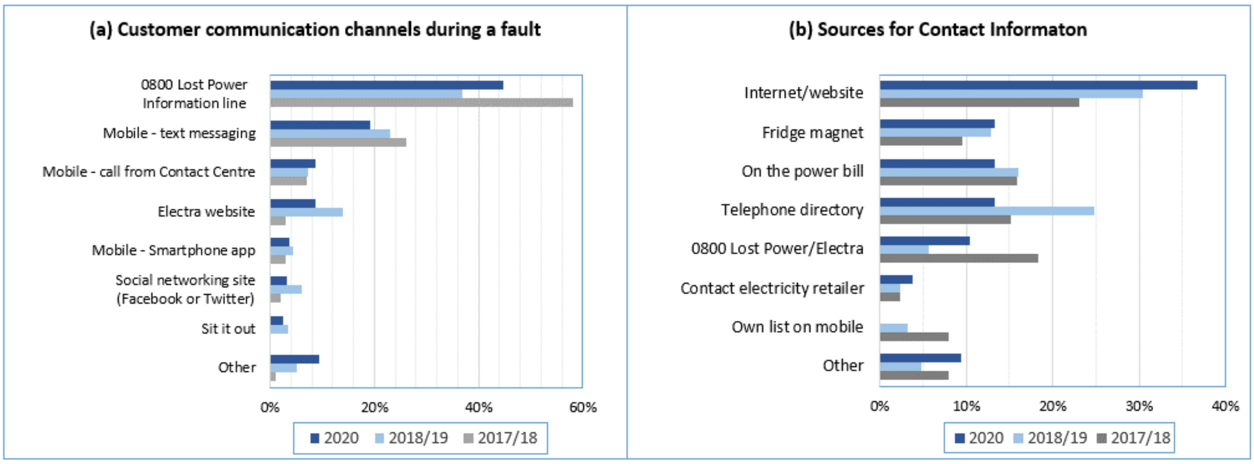


Figure 3-4: (a) Preferred customer communication channels during a fault and (b) Sources of contact information

3.8.1.2 Fault resolution and service delivery

Customer satisfaction with the resolution of faults continues to be very high. 98% of the respondents in the survey rated the service '*excellent'*, '*very good*' or '*good*'. As can be seen in Figure 3-5(a), there has been a notable upswing in the level of *'excellence' from 79% (2019) to 95% (2020)*. The results in Figure 3-5(b) also show a similar upward trend for the '*timeliness of faults resolution'* with 95% of respondents considering it to be '*excellent*' or '*very good'*. There was also a significant movement in the level of 'excellence' from 76% (FY2019) to 91% (2020).

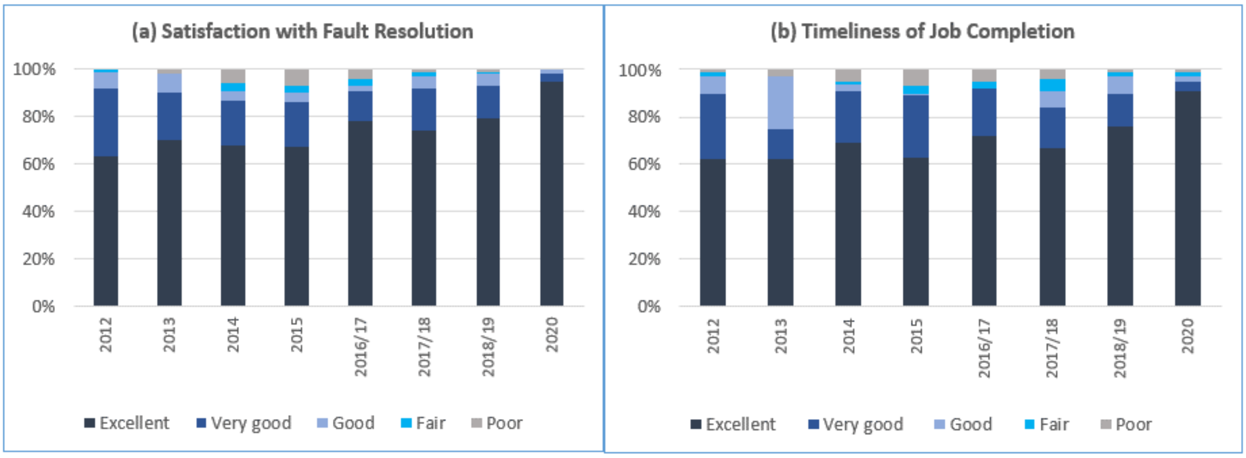


Figure 3-5: (a) Satisfaction with fault resolution, and (b) Timeliness of job completion

When the overall rating of faults service is examined by sub-region, the latest results reveal a consistent level of service delivery. The residents interviewed both north and south of Otaki gave identical ratings in terms of the level of 'excellence' that they experienced from the fault men. Importantly, in this year's survey, none of the end-customers interviewed expressed a negative rating as per the Figure 3-6(a).

36% of customers interviewed indicated that they called Electra's fault service previously in the last twelve months. The majority of these respondents (32%) stated that they had not noticed any change in the level of service provided as shown in Figure 3-6(b) indicating a high level of consistency in the service they received over time and expressed their views in comments such as:

> *"They are always good."*
>
> *"They always respond quickly."*
>
> *"As with last time, they were very good and helpful."*
>
> *"They were very good each time."*

"The service I have received from them has been very consistent. They have been professional, onto it and I have had no problems."

The 4% of customers who detected that service had improved from their earlier calls, had mainly noticed an improvement in response times.

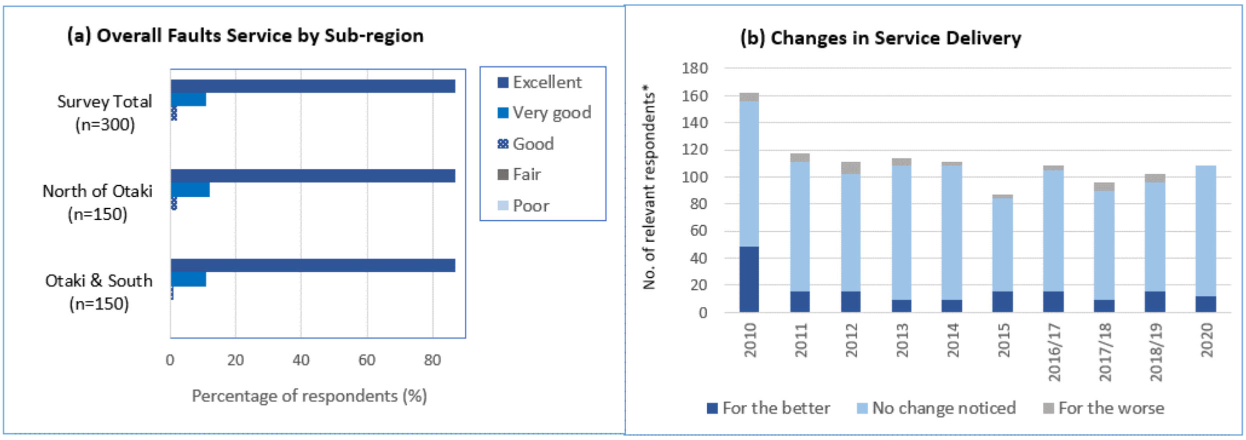


Figure 3-6: Perception of respondents: (a) Overall faults services by sub-region in 2018-19, and (b) Changes in service delivery

The overall results of the 2020 survey show that 97% of customers who contacted the Call Centre, rated the service as '*excellent*' or '*very good'*. This is the highest level of satisfaction achieved by the Call Centre over the past ten surveys as shown in Figure 3-7(a). Similarly, 98% of the customers who experienced a call from a service person, rated the service as '*excellent*' or '*very good'.* These results reveal that the level of excellence has continued its upward trend and is also at its highest reading as depicted in Figure 3-7(b).

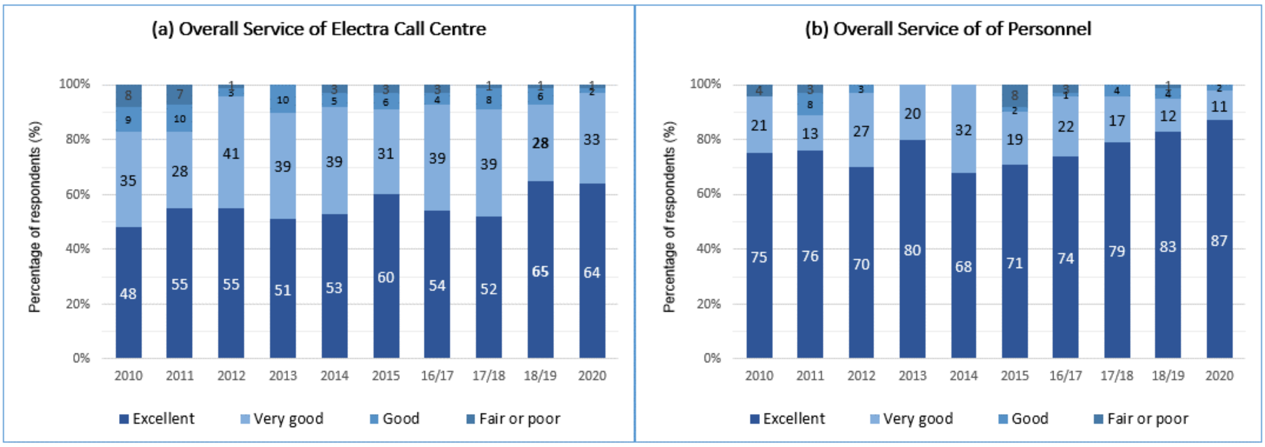


Figure 3-7: Overall services of: (a) Electra Call Centre, and (b) Service personnel

3.8.1.3 Reliability of Supply

This section of the research was introduced to participants by informing them that 'Electra is focused on providing a safe, reliable network whilst striving to keep line charges low'. 95% of participants indicated they were either 'very' or 'quite satisfied' with the reliability of electricity supply as shown in Figure 3-8. Only seven respondents (2%) stated they were 'dissatisfied' with the reliability of supply. These respondents were also asked whether they would be prepared to pay more for a more reliable supply of electricity. Six out of the seven indicated that they would ***not*** be prepared to do so. Their rationale was as follows:

"We pay enough now. It should be reliable."

"Electricity is expensive in NZ, relative to other countries. You expect it to be reliable for what we pay."

"Reliability of service is a 'given'. When people pay for a service, it should be fit for purpose."

"In the past, electricity supply has been pretty reliable. Why the change now? Prices have not gone down, they have gone up over time, so it should still be reliable. I don't see why we should pay a surcharge for it."

"No, I wouldn't be prepared to pay more for it. Just maintain the network and replace lines and equipment when it is needed, before it breaks down."

The one respondent who stated they would be prepared to pay more for a more reliable supply of electricity, indicated they would be prepared to pay an additional $10 for a 50% more reliable supply of electricity.

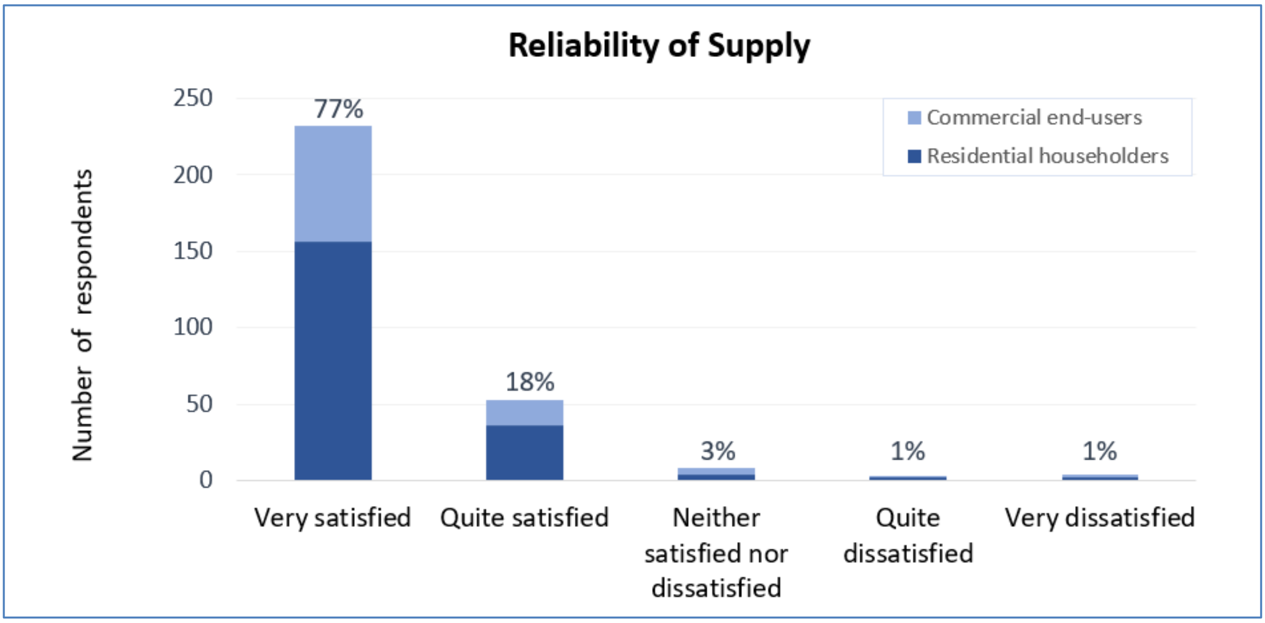


Figure 3-8: Satisfaction responses on supply reliability

3.8.1.4 Pricing and Line Charges

In April 2020, Electra reduced line charges by $3 million most customer groups and introduced new pricing plans for high user and off-peak customers. In line with this reduction, participants were asked whether they could recall either a reduction in their bill from their electricity retailer and/or being moved to a more favourable plan. Only 6% of respondents comprising 16 residential householders and 2 commercial end-users *could* remember receiving a reduction in their bill. Many respondents simply answered that they *'did not know'* or '*could not remember'* in response to the question (see Figure 3-9a).

A similar result emerged about being moved to a more favourable plan as shown in Figure 3-9b. Only 5% of respondents (13 residential householders and 3 commercial end-users) recalled such a move. Again, many respondents simply '*did not know'* or '*could not remember'* the event.

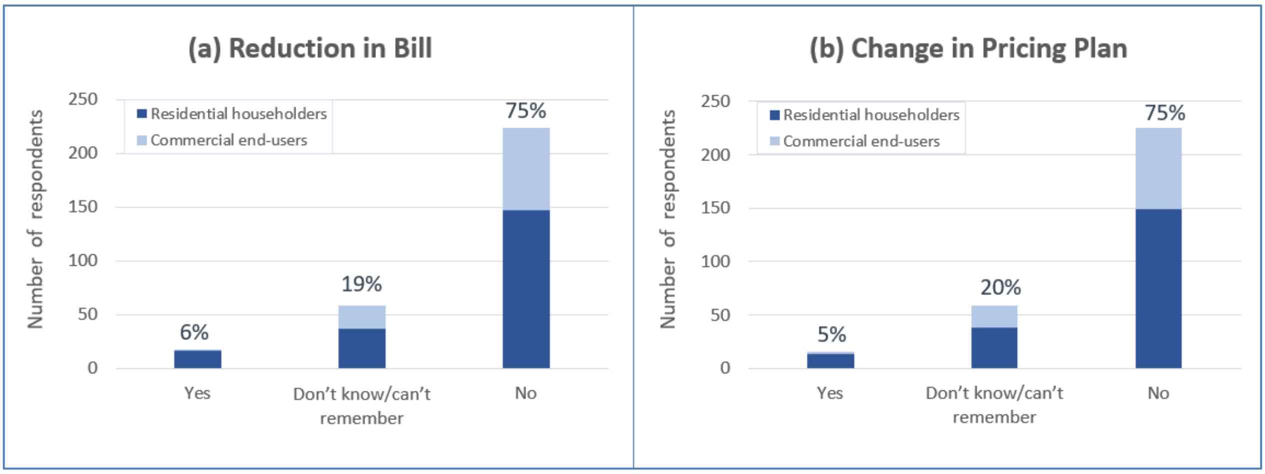


Figure 3-9: Responses on: (a) Reduction in bill, (b) Change in pricing plan

3.8.2 Regulatory compliance

Electra sets service levels to comply with the regulatory obligations applying to the management and operation of electricity networks in New Zealand including:

- The Electricity Act 1992 and Electricity (Safety) Regulations 2010
- Electricity Industry Act 2010 including the Electricity Industry Participation Code 2010
- Health and Safety at Work Act 2015
- Health and Safety (Asbestos) Regulations 2016
- Resource Management Act 1991
- Electricity Codes of Practice (ECPs) such as NZECP 34:2001 on Electrical Safe Distances, NZECP 35:1993 on Power Systems Earthing
- Electricity (Hazard from Trees) Regulations 2003;
- Commerce Act 1986 including the Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018)
- Electricity Distribution Services Input Methodologies Determination 2012 (in as much as that Determination applies to an exempt EDB)
- AS/NZS 3000:2007: Electrical installations (known as the Australian/New Zealand Wiring Rules)
- Building Act 2004 and pursuant Building Code
- Building Code, Section C5 of the Engineering Assessment Guidelines regarding the seismic assessment of existing buildings
- Civil Defence Emergency Management Act 2002
- Horowhenua and Kapiti Coast District Councils requirements.

We use ComplyWith software to assist us with regulatory compliance as explained in Section 3.6.

3.8.3 Group business strategic objectives

Electra's Group business mission, objectives and strategies provide the direction for setting key service levels as outlined in Section 1. The Statement of Corporate Intent further identifies the operational targets covering network service performance standards, network reliability and safety targets identified in this AMP.

3.9 Translating stakeholder needs into service levels

Electra translates stakeholders' needs into service levels as follows:

Service level attribute		Consumer response		Service levels
What do consumers want the most?	➔	Continuity and restoration first and foremost	➔	Give priority to continuity and restoration of supply first and foremost
How much do they want?	➔	About the same as they are currently getting	➔	Maintain continuity and restoration performance at about the current level
How much do they want to pay?	➔	About the same as they are currently paying	➔	Keep line charges at about the same level as they currently are
Are the consumers happy?	➔	Yes	➔	Keep delivering similar service levels for other attributes

3.10 Tactical programmes

In order to meet its service level targets, Electra has identified the following tactical programmes to improve the resilience of the 33kV sub transmission and 11 kV distribution networks:

Issue/concern	Requirement	Programme	Linkage to AMP programmes
Increasing number of spurious protection operations on the 33kV	Avoid an increase in the number of unplanned interruptions due to spurious protection outages	33kV protection study and strategy development	4.8.1, 4.8.2
New connections leading to more customers interrupted by any single fault	Reduce the number of customers effected by an unplanned interruption. Reduce the time to restore supply may result from increased interconnection	Increase network sectionalisation	4.4, 4.8.1, 4.8.2
Legacy copper conductor becoming increasingly brittle	Remove brittle conductor which is a safety hazard	Replacement of copper conductors.	5.4
Legacy copper conductor has limited capacity	Reduce the time to restore supply (by allowing more 11kV back-feed options)		
Specific classes or makes of assets known to be of less than acceptable reliability or safety remain in service	Remove specific classes or makes of assets	Reduce number of risky assets	5
Responsive tree-trimming	Improve value of tree-trimming programme by considering improvements to customer reliability	Migration to risk-based tree trimming	5.12
Repeated HV feeder tripping	Reduce the number of repeated 11kV feeder failures (SAIFI) as well as reduce SAIDI minutes	Identification of 11kV Worst Feeders	3.10.6
Thefts of copper earthing	Use alternative earthing installation methods	Replacement of copper earthing	5.8, 5.9

3.10.1 Improvement of 33kV network protection

Technical investigations had revealed that spurious protection tripping due to mutual coupling have resulted in loss of supply and specialists were engaged to review the protection schemes for the Southern and Northern networks. The objectives of that strategy were to:

- Create a roadmap to improve the main and back up protection schemes(standardise) for various asset classes based on cost risk and performance

- Extract value out of Transpower investments e.g. ODID (outdoor to indoor conversion) to install relays supporting unit protection schemes.

Improvements undertaken include:

- **Southern network**: The Kapiti 33kV network protection and communication have been upgraded with six relays being replaced at Paraparaumu GXP substation with SEL-311L relays. A fibre cable has been laid between the GXP and Paraparaumu East substation to enable a line differential protection scheme.
- **Northern network**: The risk of mutual coupling is high on Electra's northern network as overhead circuits share the same poles or corridors. To reduce the risk of having widespread loss of supply, Mangahao 33kV network operation procedures for protection related operational issues has been developed. Furthermore, in the northern network due to the meshed network traditional OC/EF protection settings are limiting the load current carrying capacity.

3.10.2 Sectionalisation of networks

As more customers are added to individual feeders (mainly in Kapiti), the customers at risk of interruption from any single fault increases. Electra intends to insert switches (automated where required) into the 11kV network to:

- Reduce the number of customers exposed to any single fault
- Enable increased meshing of the 11kV to enable restoration by switching rather than by repair.

At this stage, Electra's approach will be to:

- Identify feeders that have exceeded Electra's planning criteria of either 1,500 domestic customers or 5,000kVA of commercial load
- Identify suitable locations for inserting switches that will both reduce the customers at risk and allow for meshing, thus providing a dual win of reduced customers effected by a fault and reduced restoration time.

3.10.3 Replacement of copper conductors

Electra's network includes legacy 7/0.083, 19/0.064 and 19/0.092 copper conductor, which presents the following operational constraints and risks:

- The low current rating of 7/0.083 limits the ability to restore supply by back feeding on the 11kV
- The relatively high impedance of these conductors also contributes to voltage regulation issues
- The conductor has work-hardened and become brittle over many years, increasing the risk of in-service failure
- Field services do not work on live copper lines due to the increased risk of it snapping during work and recoiling onto other conductors. This issue makes jobs expensive due to generator utilisation otherwise, it will be an inconvenience to customers as a result of shutdowns.

Electra will prioritise the replacement of copper conductors due to these contributing drivers other than just condition-based asset renewal.

3.10.4 Reduction of the number of higher risk assets

Electra's network still contains some assets that are now considered to have an unacceptable risk of in-service failure to staff and public such as pitch filled metal pot heads, metallic link pillar boxes, deck mounted transformer structures. Electra has included provisions in the AMP to remove these high-risk assets based on their location and the risk they present.

3.10.5 Migration to planned tree trimming

Electra's vegetation management programme has evolved over recent years. During 2018 Electra has overlaid an additional analytical tool, over and above the requirements of the Electricity (Hazards from Trees) Regulations, to systematically identify the greatest risk to customer service and safety from trees close to network.

The resulting tactical programme strongly reflects two strategic themes:

- Continuing to implement approaches which improve cost, risk and performance
- Implement asset criticality (and the associated medium-term goal of the asset criticality framework driving all network investment decision).

Key features of this strategic improvement include:

• Leveraging the tree regulations to deliver safety and performance outcomes • Tree cutting driven from routine and customer requested survey. • Improve network performance where impacted by vegetation	➔	• Risk rather than performance-based management of safety and SAIDI • Progressively reduce reactive trimming, and instead proactively cutting trees back and engaging with tree owners to implement longer term solutions • Systematically reduce risk in network sections between automated switches and circuit breakers • Leverage data of historical tree work to strategically develop a work programme to systematically reduce vegetation based SAIDI and safety risk

The key features of our strategic vegetation management programme link to the strategic goal of reducing SAIDI follow:

Feature	**Improve** safety and SAIDI		**Reduce** operational expenses	
	Reduce number of customers at risk	**Reduce outage duration**	**Reduce work volume**	**Reduce unit costs**
Key driver will be trees that affect the largest number of customers	•	•		
Augment responsive tree work with plans to reduce risk by feeder section	•			•
Engage with tree owners to implement longer term solutions	•		•	
Stronger connection of tree data with network data	•	•	•	•

3.10.6 Reduction of repeated power failures

The feedback from customers (Section 3.8.1) identified the need to reduce the number of repeated power failures. Besides its 33kV resilience program explained in Section 3.10.1, we regularly monitor the least reliable or "worst" distribution feeders on the network in terms or SAIDI and SAIFI as these high voltage power failures have the greatest impact on customers.

With the feedback on repeated failures, we studied the impact of faults on feeders further in terms of the number of failures over a 3-year period from FY2018 to FY2020. The worst ten 11kV feeders in terms of the number of failures are shown in Figure 3-10 as well as SAIDI (Figure 3-11a) and SAIFI (Figure 3-11b) impact.

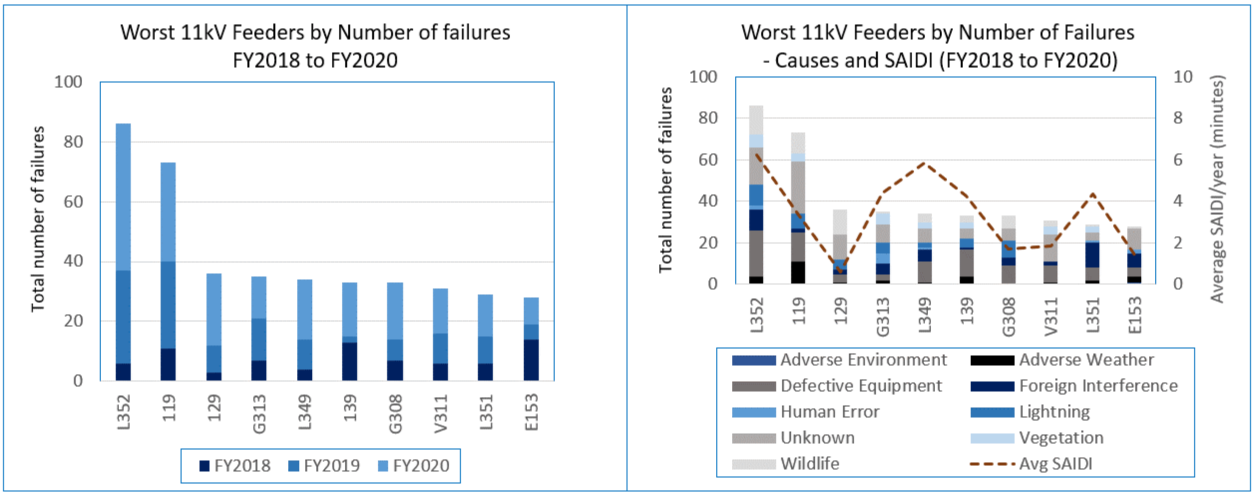


Figure 3-10: Worst 11kV feeders by: (a) the number of faults and (b) related SAIDI and SAIFI impact: FY2018 to FY2020

The worst feeders vary when monitoring by the number of failures (L352, 119, 129), the impact to SAIDI (E151, L352, L349) or SAIFI (L351, L352, G313). We have integrated this analysis as a continuous improvement in our worst feeder monitoring process.

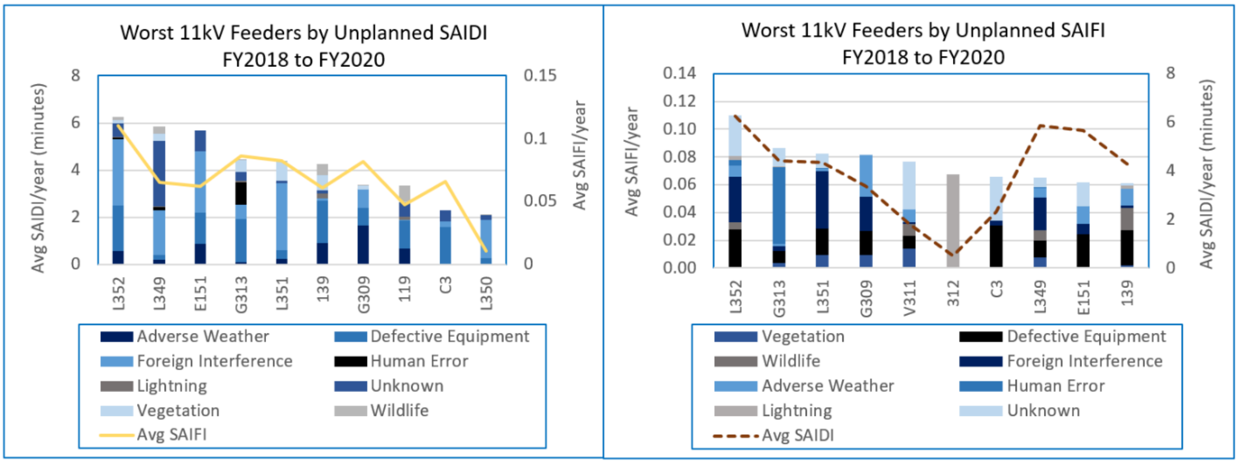


Figure 3-11: Worst 11kV feeders due to faults for FY2018 to FY2020 by: (a) SAIDI and (b) SAIFI

Initiatives such as circuit reconfiguration, sectionalisation, network automation and/or other reinforcement options are then undertaken to reduce the impact of these failures to our customers. Such initiatives are described further in Section 4.8. The prioritisation process for reliability-improvement projects for the worst feeders is discussed further in Section 8.4.7 where the process flow is shown in Figure 8-22: Fault intervention process for worst 11kV distribution feeders. Reporting our worst feeders helps identify and develop appropriate plans to improve the reliability to affected customers. Other ongoing initiatives undertaken to improve our services include:

- Commissioning of the Shannon new feeder 149 with an upgraded protection scheme comprising an intelligent scheme with peer to peer communication between the devices to eliminate the possibility of a recloser to closing onto a faulted section during the restoration sequence
- Enhanced Opiki Loop automation scheme will isolate the fault and restore the fault-free section under one minute without any operator intervention thereby improving network reliability
- Another automation scheme will be installed for feeder 405 so that feeder tripping can be avoided and SAIDI minutes improved
- Using our IoT platform, the status of these feeders is closely monitored by Control Room operators with the installation of fault path indicators and PQ sensors.

3.10.7 Prevention of copper thefts

Since August 2019, a total of 131 copper thefts affecting transformers and switchgear have been uncovered. Copper theft is an industry problem and Electra has engaged a consultancy company to study combat measures as well as working with enforcement authorities and recycling companies to stop these thefts. New guidelines have been released as countermeasures using alternative earthing installation methods and steel-reinforced copper for Electra’s 11kV and 33kV distribution earthing requirements to ensure that safety standards are retained.

The “Public Safety Earthing Standard SMS 56739” revised in May 2020, specifies the requirements for new earthing installations (except zone substations) or earth banks for pole and ground-mounted transformers, switchgear, surge arrestors and three-phase cables. The overall resistance of earthing conductors and earth banks are recorded at the time of installation and then on a routine basis in accordance with Electra’s maintenance program.

4 Network development

4.1 Development context

Electra's development plans are driven primarily by capacity constraints (which almost always occur due to increasing demand), declining reliability, voltage excursions, or security of supply.

At its most fundamental level, demand is created by consumers drawing energy from or by injecting energy into their individual connections. Electra recognises that the issues that have historically led to demand growth are now more complex with the uptake of smart home, business technologies and Distributed Energy Resources (DER).

Electra has been in discussion regarding developments and opportunities with product and service providers, as well as individually with other EDBs and collegially through the ENA and EEA. The ENA work has developed some helpful groupings of consumers based on values and behaviours: Prosumer, Off grid, Grid as Back Up, Set and Forget.

The discussions with individual providers and EDBs have advanced Electra's thinking in the future development of products and services to consumers. Together with organisational changes to strengthen Electra's capabilities to develop new customer products, Electra will now be developing a trial to collaboratively test technologies and price options that enable consumers with options to better manage their energy and enable Electra to manage load from new technologies such as electric vehicle chargers.

4.2 Development criteria

Electra considers the following driving factors as the criteria for developing its network:

- Capacity and voltage
- Reliability
- Security of supply.

4.2.1 Capacity and voltage triggers

If any of the triggers below are exceeded, Electra will intervene which may include adding additional capacity to the network:

Asset category	**System** growth (consider adding capacity)	
	Capacity trigger	**Voltage trigger**
400V lines and cables	Not applicable – tends to manifest as voltage constraint	Voltage at consumers' premises consistently drops below 94% of the nominal value
Distribution substations	Where fitted, MDI reading exceeds 100% of nameplate rating	Voltage at LV terminals consistently drops below 100% of the nominal value
Distribution lines and cables	Conductor current consistently exceeds 70% of thermal rating for more than 3,000 half-hours per year	Voltage at HV terminals of transformer consistently drops below 10.5kV and cannot be compensated by local tap setting
	Conductor current exceeds 100% of thermal rating for more than 10 consecutive half-hours per year	
Zone substations	Max demand consistently exceeds 100% of nameplate rating	11kV voltage Alarms from SCADA as recorded in SCADA Alarm and Event history
Sub-transmission lines and cables	Conductor current consistently exceeds 66% of thermal rating for more than 3,000 half-hours per year	33kV voltage below 31.5kV at Zone substation supplied
	Conductor current exceeds 100% of thermal rating for more than 10 consecutive half-hours per year	Low volts alarms from SCADA and reported in SCADA Alarm and event history

4.2.2 Reliability triggers

In order to limit the load interrupted by any one fault, Electra will consider intervening when the following levels are reached:

- An aggregation of up to 1,500 urban domestic consumer connections on any one feeder
- An aggregation of about 5,000 kVA of urban commercial load on any one feeder.
- Interventions may include:
- Inserting a recloser to reduce the number of customers affected by a fault
- Meshing the 11kV (typically by inserting a ring main unit) to reduce the restoration time
- Constructing a new feeder and moving some customers to that new feeder to reduce the number of customers effected by a fault
- Integration of previously discrete network ICT systems through the Milsoft E&O is expected to reduce restoration times including through more precise dispatch of fault crews.

4.2.3 Security of supply triggers

Electra’s security of supply standards is set out below. In setting target security levels Electra’s preferred means of providing security to urban zone substations will be by alternative sub-transmission assets with any available back-feeding on the 11kV providing a second tier of security.

System level	Load type	First fault	Second fault
GXP	Greater than 12MW or 6,000 consumers	No loss of supply	50% of load restored in 15 minutes, 100% of load restored in 2 hours
Zone substation	Between 4 and 12MW or 2,000 to 6,000 consumers	No loss of supply	All load restored within 60 minutes
Zone substation	Less than 4 MW	Loss of supply, 100 % load restored within 30 minutes from adjacent substations	Fault repair time
11kV feeder	Between 2.0 and 4.0 MW	Loss of supply, supply restored within 30 minutes from adjacent feeders	Loss of supply, supply restored within 4 hours from adjacent feeders
11kV feeder	Between 0.5 and 2.0 MW	Loss of supply, supply restored within 30 minutes from adjacent feeders where available.	Fault repair time
11kV feeder	Less than 0.5 MW	Fault repair time	Fault repair time
400V feeder	About 30 to 40 residential customers	Fault repair time	Fault repair time

4.3 Development policies, standards and methods

4.3.1 Methods and approaches used to standardise activities

Electra uses standards, codes and guidelines to achieve the following purposes (essentially all risk management tools):

Method	Purpose			
	Achieve construction and operational safety and asset performance	Minimise inventory costs	Minimise operating costs	Minimise design and construction costs
Use of standard design concepts			●	●
Use of technical design standards	●		●	
Use of standard asset sizes and configuration		●	●	●
Use of preferred purchasing	●	●		●
Use of in-house field staff	●			●

4.3.2 Consideration of energy efficiency

Electra recognises that total network losses are significant (about 7.7% of energy entering the network), hence the following approaches are used:

- Upgrading of overloaded conductors to reduce the I^2R losses
- Consideration of Iron and Copper losses when purchasing equipment
- Identify and improve poor power factor installations to a minimum of 0.95
- Optimisation of open points.

4.3.3 Policies on embedded generation

Electra's policies for embedded generation are on its website. 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.

4.3.4 Impact of distributed generation

Apart from Mangahao (37MW embedded at the GXP) and Unisys (0.96MW x 2) generators, there are 691 known distributed generation sites on the Electra network with a combined capacity of about 2.72 MW as of September 2020 (as shown in Figure 4-1a). There are likely to be few occasions when that capacity will exceed 20% of the prevailing load that is recognised as the level that complicates operation.

Electra is engaging with prospective customers and partners to integrate dynamic Distributed Energy Resources (DERs) into the network. Concurrently Electra keeps a watching brief on developments in overseas markets and other NZ EDB regions.

Electra has been approached by several large solar and wind farm projects (over 1MW) for potential embedded connections. We are encouraging these start-ups, aiding 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 as well as reducing congestion of embedded generation on the distribution network. Electra has also reviewed its connection and pricing policies as well as formalising the treatment of transmission rebates for large generators in a fair and equitable way.

4.3.4.1 Uptake of photovoltaic panels

Residential solar photovoltaic (PV) generation is growing in New Zealand. The Electricity Authority reported that there are 27,179 New Zealand residential connections who have installed solar panels (as of 30 September 2020), 3,190 more (13% increase) than the same time last year with a combined capacity of 104.9 MW more than a year ago[9].

The energy provided by PVs makes up a low percentage of our network, but this uptake is trending upward as illustrated in Figure 4-1a. This PV yearly uptake rose from 104 connections in FY2019 to 122 connections in FY2020. Most of the PV panels installed are less than 10kW capacity and we will continue to monitor and support the development of distribution generation in line with our policies. Electra has also installed a 3 kW photovoltaic panel (with an 8kWh battery capacity) at our Head Office to better manage and understand the impact (Section 6.3.1) on the network and provide assistance to customers.

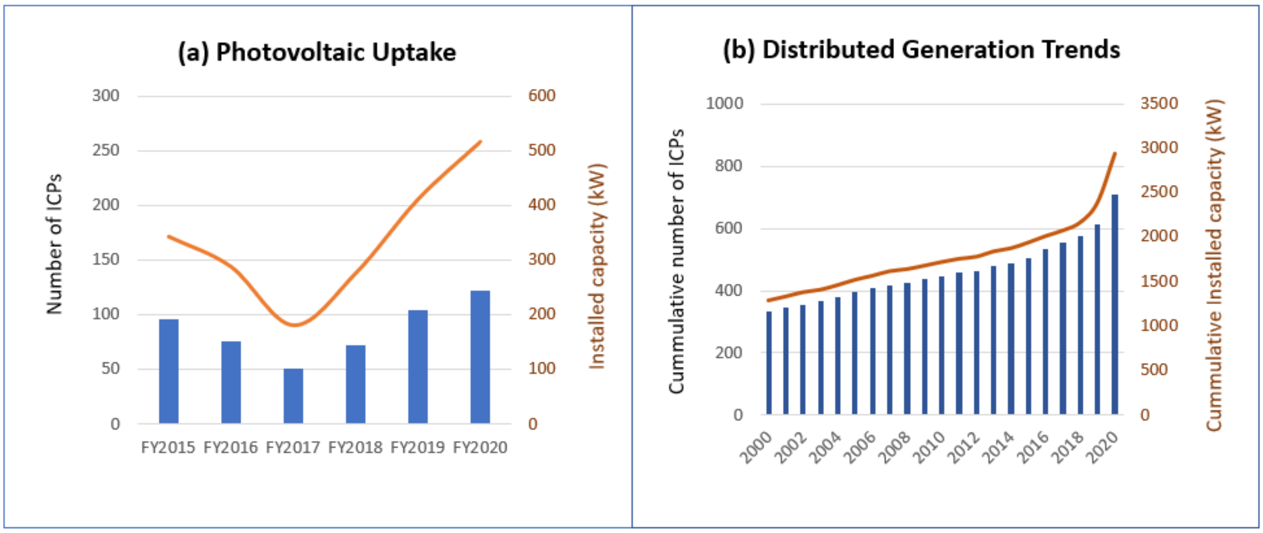


Figure 4-1: Electra (a) Photovoltaic uptake from FY2015 to FY2020; (b) Installed distributed generation trends (solar)

Electra is updating customer facing policies and guidance relating to DER while ensuring Electra is engaging with those considering connecting DER to the electricity network.

4.3.5 Options for meeting or managing demand

Electra considers the following three classes of options for meeting or managing demand:

Class of option	Specific approach	Description
Do nothing		Where one or more parameters have exceeded a trigger point, the “do nothing” option may be a “do nothing yet but watch more frequently” option. Essentially, “do nothing” is acceptable only when Electra is confident that service levels can be maintained, and risks remain acceptable
Non-network (low investment)	Operational activities	Actions such as switching the distribution network to shift load from heavily loaded to lightly loaded feeders or winding up a tap changer to mitigate a voltage problem will be considered. The downside to this approach is that it may increase line losses, reduce security of supply, or compromise protection settings

[9] Electricity Market Information (EMI) website, Electricity Authority at 21/10/2020

Class of option	Specific approach	Description
	Influence consumers to alter their consumption patterns	This allows assets to perform at levels below the trigger points. Examples include shifting demand to different time periods, negotiating interruptible and other tariffs with certain consumers so that overloaded assets can be relieved, or assisting a consumer to adopt a substitute energy source to avoid new capacity
	Install distributed generation or batteries	This allows adjacent assets to perform at levels below the trigger point. Distributed generation may be particularly useful where additional network capacity could eventually be stranded or where primary energy is going to waste (e.g. waste steam from a process)
	Modify an asset	Allowing the trigger point to move to a level that is not exceeded (e.g. by adding forced cooling). This approach is more suited to larger classes of assets such as 33/11kV transformers
	Install voltage regulator	Installing an 11kV voltage regulator may relieve voltage constraints, which defers or avoids the need for upgrading to 33kV
	Retrofitting high-technology devices	These can exploit the features of existing assets, including historically generous design margins (e.g. using remotely switched air-breaks to improve reliability or using advanced software to thermally re-rate heavily loaded lines) Electra expects that installation of smart meters will provide more accurate demand data including the duration of peak loads
Network solution	Install new assets with a greater capacity	This will increase the assets trigger point to a level at which it is not exceeded (e.g. replacing a 200kVA distribution transformer with a 300kVA transformer so that the capacity trigger is not exceeded)

4.4 Known constraints

Electra faces the following significant constraints (all security rather than capacity per se):

Constraint	Description	Intended remedy
Mangahao GXP	Limited rating of Transpower transformers can mean full (n-1) security is not available when Electra is taking full load and Mangahao is not generating	Transpower to install larger transformers as part of replacing existing old transformers (provisionally timed for 2031/32)

The annual planning process has revealed a low rate of demand growth in the Northern area and combined with the fact that there is sufficient capacity for the current planning period, means that it is unlikely that the capacity of any significant assets will be exceeded without sufficient time to react.

Electra does however recognise that demand growth in the Southern area is higher, due to both residential sub-division development in Paraparaumu and Waikanae and retail development around Paraparaumu. Most of the development is 11kV feeder duplication and meshing to increase available capacity and to reduce the number of customers effected by individual faults.

Specific issues which arise from load projections are:

- Increasing air conditioning load is likely to over-lap into peak periods when demand is already high, but possibly with some offset by solar at customer sites. The potential impact on the network is not yet known and feeder loading information is being captured, along with temperature and rainfall to identify any relevant trends. This issue has not been factored into the load forecast.
- The increasing popularity of beach-front settlements will require up-sizing or duplication of existing 11kV lines. This is required to minimise the effects of outages which have an impact on the security levels.

4.5 Emerging technologies and innovation

The growth of emerging technologies such as solar photovoltaic cells (PVs), batteries and electric vehicles (EVs) have a significant impact on traditional networks. While the rate of uptake of these technologies are uncertain, these distributed energy resources(DERs) will have a considerable effect on consumer behaviour and network demand as EVs, PVs and battery storage become more affordable.

Electra is an early adopter of emerging technologies such as industrial IoTs with investment in distributed energy resource or DER solutions and low voltage network monitoring. We are closely monitoring the uptake of domestic and commercial solar or photovoltaics panels, energy storage systems and the increasing uptake of electric vehicles.

Electra monitors demand side technologies and customer behaviours trends to assess how and when these can be integrated into our network; we consider “prosumers” will, in the future, provide critical support to Electra Low Voltage network.

As well as working with other industry partners, the following sections provide a summary of Electra’s uptake and trials of emerging technologies including smart grids, IoTs and EVs. Such investment allows us to manage the uncertainties of their emergence and to incorporate requirements and standards, allowing better technology adoption and cost integration in network development planning.

4.5.1 Distributed Energy Resources

Distributed Energy Resources (DER) are energy systems that can export power back to the grid. Electric vehicles (EVs) and PVs or solar batteries come under DERs. With lowered battery costs and technology improvements, domestic energy storage is now an option for many consumers other than PVs. The addition of energy storage to DER installations creates a fully controllable energy management system and an opportunity to investigate remote DER management.

Electra’s investigations into Distributed Energy Resources have classified DER into four categories:

- **Domestic**: single and three phase systems. Energy export at 3.5kW (approximately) per phase
- **Network**: three phase systems. Energy export 25kW and above
- **Grid**: three phase systems. Energy export 500kW and above
- **PV Battery solutions**: include solutions that support energy arbitrage / recharge & discharge shifting with remote management.

From section 4.3.4, there are approximately 690 known customers with distributed generation on site, which are mainly solar. The installed capacity is about 3MW equating to an average size of 3.5kW per installation. The largest site is around 175kW.

Electra understands that DG could potentially offset demand during off-peak periods and cause over voltages during periods of high generation and low demand. However, we do not expect distributed generation to be of an immediate threat though measures are in place to combat the risk of uncertainty such as the creation of a network planning strategy to consider various scenarios of customer uptakes, impacts on the network. We are also an active member of the Electricity Authority Open Network group that identifies ways for the uptake of new technology on distribution networks.

The innovative solutions using smart grid, Industrial IoT (Internet of Things) as well as EVSE management are three emerging technologies that we have deployed in our network. Besides the mitigation of demand management issues that may arise, we have selected these DERs as the technologies will provide new opportunities and potentially contribute to: (a) system reliability, (b) customer satisfaction and (c) market-related economic benefits. We are supported by specialist resources and our active participation with industry groups allow us to dispatch the relevant DERs to deliver optimal value and achieve the results.

4.5.2 Innovation using Smart Grid

Electra envisage continuing investing the Smart Grid, in the monitoring and controlling of network devices to:

- Improve customer experience with improvements in power quality and reducing the frequency and duration of network outages
- Improve asset utilisation supported by smart meter/PQ and sensor data
- Optimise asset life using condition monitors and modern inspection methods.

In addition to the above benefits, these edge elements will also provide actual network parameters such as load, voltage and power factor readings. This will enable Electra to validate or adjust the simulation models thus optimising asset investment decisions. Furthermore, sensors will provide empirical data sets to validate the impact of DERs such as power quality impacts of electric vehicles and distributed generation.

We are working with a range of partners and products to make up a functioning ecosystem for customers to lower their energy costs as well as participate in a transactive grid where energy is traded across the distribution network.

Application of smart technologies Electra employs on the network include remotely operable sectionalisation, fault passage and line fault indicators to monitor repeated failures, provision of faulted phase and distance-to-fault information and the selection of simple IoT sensing devices for installation across the network to provide richer status information such as voltage levels and power quality along 11 kV feeders and selected 400 V reticulation. IoT development follows in the next section.

4.5.3 Innovation with IoT development

The main vehicle for trialling emerging technologies is our 'IoT Project' that focuses on increased instrumentation (sensors) on high value assets and status indicators embedded throughout the electricity network to monitor power quality and reliability affecting customers.

Commencing with the 2019 Electricity Line Business CIO Forum, we committed to the building and implementation of a communications platform and prototype sensor devices. The trial results exceeded our expectations and a small-scale deployment of different sensors commenced involving a project team of leaders in the lines business delivering a range of project streams.

This IoT project comprises of nine major developments and two presentation streams:

Project Stream	Goal	Outcome
LoRaWAN Gateway (Communication Layer)	99% coverage	Achieved using 15 gateways
Fault Path Indicator	50 devices	25 devices (83 fault paths) deployed at a low build and communication cost and 25 more to be deployed
Power Quality Sensor	50 devices	25 devices deployed and another 25 ready for deployment by April 2021
Low-Cost Nightlight / Customer Outage Sensor	100 devices	10 devices were built but due to poor signal and uneconomical scaling, the project was halted and an alternative, low-cost sensor in a pillar or on a pole is being reviewed
Low-Cost Voltage Sensor (three phase)	10 devices	10 devices ready for installation by April 2021
Distributed Energy Resource (DER) Control	DER profile control	Built and installed at Electra; connectivity and economic returns under evaluation
Electric Vehicle Charger (EVSE) Control	Load Manage EVSE	Domestic: Too costly to establish platform Commercial: Achieved communication using OCPP so will be offered to future customers

Drop Out (DDO) Fuse Sensor	Evaluate DDO Sensor	First DDO sensor failed due to equipment issues and short battery life Development of an Electra Solar DDO sensor has commenced
NZ Electricity Networks IoT Forum	Develop an IoT working group	Established and Chair of NZ Electricity Networks IoT Forum with 8 members
EEA Presentation	EEA Conference 2020	Achieved - EEA Webinar July 2020

4.5.3.1 Low voltage network status monitoring

Our greatest success in the low voltage monitoring arena is our organisational capability to build, produce and deploy low-cost sensors on our network together with a reliable communications infrastructure.

Electra's LoRaWAN (Long Range Wide Area Network) IoT network has a series of gateways (effectively Long-Range Wi-Fi routers) in Levin, Moutere and Forest Heights as shown in Figure 4-2.

We have decided to use LoRaWAN as the technology gives us the right balance between important elements of:

- Coverage: These gateways have typical ranges of 10 km or more depending on antenna placement.
- Low-power consumption: LoRa is a low power communication protocol that allows nodes to run on batteries for up to 10 years; the data volume has a direct impact on the energy consumption of the sensor devices.
- Scalability: The addition and replacement of nodes as the project evolves is easily achieved while maintaining data integrity.
- Reliability: The system is proven to be robust, withstanding interference and the battery powered systems allow monitoring to continue during an outage – a significant advantage for an electricity distribution company.
- Cost efficiency: LoRa operates on an unlicensed spectrum, so there are no direct communication fees; the system is also effective in long-term monitoring by reducing manpower.

Our LoRaWAN network operates on an AU915 frequency plan which is subject to the General User Radio License for Short Range Devices in compliance with the Radiocommunications Regulations 2001[10].

[10] As of 6 November 2020, the current notice enforced is the Radiocommunications Regulations (General User Radio Licence for Short Range Devices) Notice 2020.

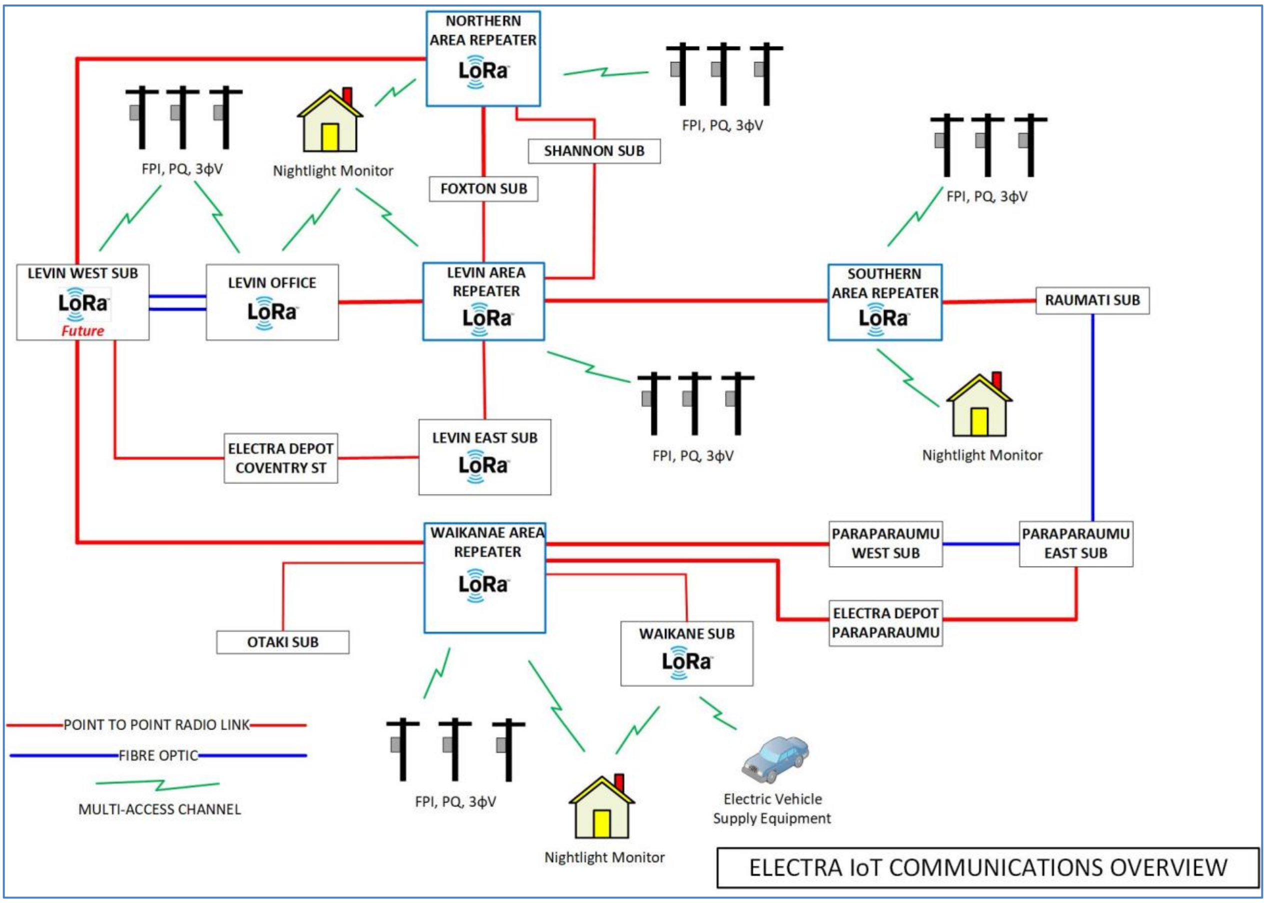


Figure 4-2: Electra IoT communications overview

4.5.3.2 IoT deployment

Electra deployed 25 low-voltage power quality (PQ) meters or sensors at significantly lower costs than traditional devices. The deployment has enabled us to monitor the condition of power transformers, to make informed decisions on the maintenance and replacement of these assets. The resulting telemetry has been used several times to identify and resolve network power quality issues, over-voltage requiring transformer tap change and address customer queries about outages at their premises.

An additional 25 PQ meters and 100 fault path indicators are slated for deployment by March 2021.

Electra has developed the ability to monitor customer premises at a very low cost where we are concerned over supply availability. Previously this required multiple truck rolls to deploy and collect data loggers. The sensors are integrated into SCADA to alert of supply loss and we have proven integration with our ADMS.

Deployment of sensors is now considered Business as Usual with written procedures that can be followed by field crews. Electra has updated the Network Standards and budgeted for all future transformers, 300kVA and over, to include an Electra Power Quality sensor.

We are improving our office-based systems to convert data into actionable insights for greater automation and improved decision-making. Electra seeks to directly benefit the customer with improved reliability, measured by SAIFI and SAIDI, through the future implementation of a Fault Location Isolation and Service Restoration (FLISR) scheme.

Electra is now focusing on producing and deploying the sensors that have proven to be robust and lower cost than alternative. Electra now considers IoT devices as another layer of sensors to be included when developing switching, monitoring and automation schemes to create a more intelligent electricity network.

4.5.4 Electric Vehicle Supply Equipment (EVSE) management

New Zealand's Interim Climate Change Commission has recommended "Accelerated Electrification", to stay within 1.5°C of warming where we need to reduce emissions in New Zealand by around 60% by 2030, a scenario which includes the decarbonising of road transport and the addition of around 2.2 million electric vehicles by 2035. Electra understands the challenges brought by this goal and has embraced the opportunity where we have played a key role in the support of the electrification of the transport sector.

Electra has 406 electric vehicles on the network with a conservative increase of 100 per year. However, Government introduction of additional incentives would dramatically increase this rate. The Electra Charge Net installations in our area average 12.5 sessions per day, with 35.6MWh over 4,620 charging sessions since installation[11]. All indications are that usage will only increase as NZ moves out of Covid-19 restrictions.

With the installation of high-speed DC chargers accelerating in the region, these have the potential to draw enormous loads so a strategy for managing these devices is being developed.

Our EV strategy is to consider cost-effective pricing, charger control and EV uptake based on socio-economic drivers, striking the right balance between responding to the likely increasing number of EVs both residing within and travelling through the network and proactively managing it.

The strategy principles will be to:

- Optimise the location of fast chargers into areas with the most network headroom but which also provide "while we wait" activities such as coffee shops or malls
- Manage and influence the expectations of EV owners around charging speeds, prices, and time periods
- Work closely with charging infrastructure providers and local/regional councils to influence decision making to avoid over investment
- Attend industry meet ups and conferences around EV.

In June 2020, Electra completed the final installation and commissioning of two fast EV 50kW chargers at Shannon Railway Station, in collaboration with ChargeNet NZ, the Kapiti Coast and Horowhenua District Councils, and with support from the EECA. Electra now has eleven chargers located within its network as shown in Figure 4-3[12], including three dual sets of chargers at Foxton, Paraparaumu and Shannon and single chargers at Levin, Otaki, Waikanae, Paekakariki and Waikanae.

[11] Utility Consultants Ltd growth predications published in Transpower's Te Mauri Hiko (2020), Thinkstep's - Decarbonisation of New Zealand's Transport Sector *(2020)*.

[12] Source: ChargeNet, https://charge.net.nz/map/

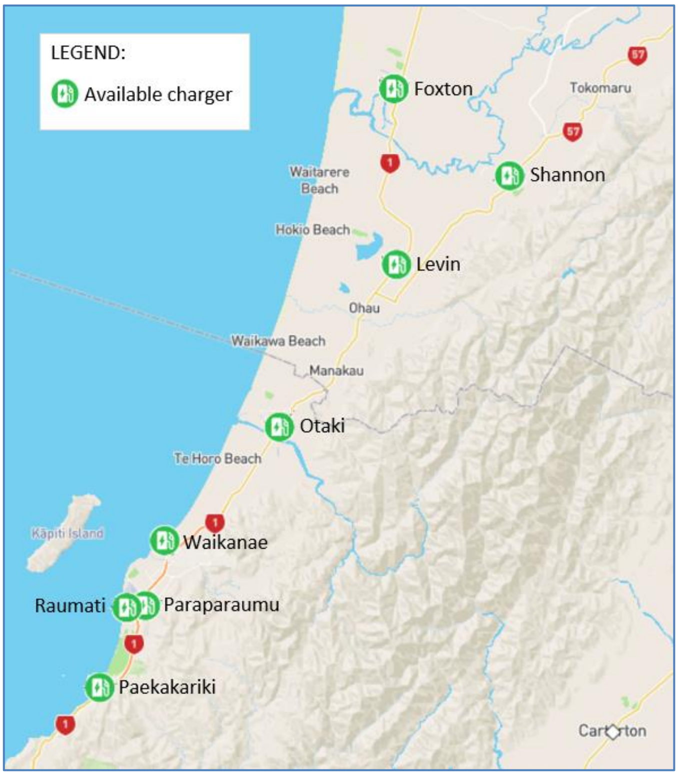


Figure 4-3: Electric vehicle charging network

Electra understands an increased uptake of EV would improve the load factor, line revenue and is in line with sustainability outlook of the company. However, unplanned deployment especially fast chargers could have adverse effect on network performance and thus requiring asset investments. In particular:

- Fast chargers being installed in locations where Electra's network has less capacity headroom
- Consumers becoming used to fast any-time charging at prices that do not correctly signal network loading, congestion or time-of-use.

Electra expects the uptake of EVs to continue and will monitor advancements in both battery capacity of vehicles and charging behaviours to understand the impact to our network. We are also working with local suppliers to understand customer choices and gain visibility of technology advancements.

Electra is also a member of the Wellington Regional EV working group, which has representation from EECA, NZTA, GWRC, Lower & Upper Hut City councils, KCDC, Wellington Electricity, PowerCo and ChargeNet.

4.5.5 Role of the ADMS in choosing options

Adoption of non-network (low investment) solutions requires network status and load information that is disaggregated (possibly to the level of individual ICP's), in real time (for fault indication and restoration) and very accurate (for matching capacity to demand), information that has traditionally not been available.

Electra sees that completion of the ADMS project will provide quality information, which will eliminate the reliance on many of the assumptions that traditional network planning has relied upon. This will increase the confidence and correspondingly reduce the risk associated with adopting non-network or low-investment options. Our goal is to implement a Fault Location Isolation and Service Restoration (FLISR) scheme where the control systems will automatically operate in specific instances. This would directly benefit the customer with improve reliability measured by SAIFI and SAIDI performance.

4.6 Development prioritisation

The finite funds that are available each year (both from revenue and from borrowing) require development work to be prioritised or ranked by their contribution to Electra's goals. These goals closely reflect the priority of stakeholder interests and how competing or conflicting interests will be managed (described in Section 1.6).

Prioritisation is also strongly linked to risk management (Section 7). Projects that reduce risks with high likelihood and high consequence are assigned a higher priority.

Each of the possible approaches to meeting demand that are outlined in Section 4.3.5 provide potential solutions that are considered.

4.7 Demand forecasts

Historically Electra has used a simple linear projection of recent zone substation demand growth rates to forecast demand and has supplemented these by inclusion of localised factors (e.g. known industrial developments, observations of farmland being sold for residential development). The uncertain implications of emerging technologies mean that such an approach is less likely to accurately forecast demand. Electra has started work on the following proposed scenario-based forecasting methodology and expects to progress this work through to individual substation and possibly 11kV levels.

4.7.1 Forecasting approach

Electra has adopted the following forecasting approach:

Identify demand drivers	→	Compile scenarios	→	Translate scenarios into kW demand	→	Compile zone sub forecasts	→	Aggregate to GXP

4.7.2 Demand drivers

Electra considers the following demand drivers (which reflect the assumptions set out in 1.13) that will impact on:

- Demand per customer connection, noting that this could range from negative (predominantly exporting) to very high (home-based EV charging)
- Number of customer connections.

Class of driver	Detailed driver	Impact on demand per customer	Impact on number of customers
Resident population growth	Organic population growth at large	Minimal of itself	Increase
	Property price differentials between the Wellington metro area, Kapiti and Horowhenua encouraging northward migration, and in particular any housing policies that cause property prices to retreat	Minimal of itself	Increase
	Residential sub-division growth around Waikanae and Paraparaumu	Minimal of itself	Increase
	Commercial growth around Paraparaumu	Minimal of itself	Increase
Transport policy	Slowdown in established motorway build programme	Minimal of itself, but likely to preserve existing diversity between zone substations if commute times remain the same	Possible decline in new house growth in Horowhenua
	Uptake of EV's, compounded by any policies that require any-time charging	Potentially large especially if policies don't discourage any-time charging	Minimal
Customer preferences	Increasing use of domestic air conditioning	Potentially significant if installed cost of air conditioners declines	Minimal
	Increased expectation of air conditioning in retail and commercial premises	Possibly significant	Minimal
	Increasing popularity of beach front settlements	Possibly significant if existing beach houses have air conditioning installed	Increase if new beach houses are built
Air quality policies	Policies that restrict solid fuel home heating, and essentially require a shift to electric heating	Potentially significant	Minimal
Emerging technologies	Uptake of rooftop solar and batteries	Potential to reduce demand if policy incentives are correct, but also possibility of disrupting existing kWh-based revenue model	Minimal
	Affordability of devices, especially battery-power devices, power tools, garden tools	Possibly significant depending on user preferences for recharging	Minimal

The following specific technologies and their likely implications for demand growth or contraction have been considered:

Specific technology	Mode of operation	Implications for Electra
Conventional, well understood loads	Consumption	• Increasing demand per customer
Inverter heat pumps	Consumption	• Increasing peak demand, but with no commensurate increase in kWh • Declining load factor • Declining power factor • Increasing harmonics
Roof top solar	Injection	• Possible off-set of GXP demand (but probably not during peak periods) • Possible increase in peak loading of some feeders, possibly leading to export congestion • Over voltages during periods of high generation and low demand • Increased bi-directional power flows that require changes to protection and control settings • Reduced kWh sales if located behind the meter • Peak seen by the GXP's may shift later into summer evenings

Specific technology	Mode of operation	Implications for Electra
Batteries	Consumption	• Possible improving load factor if charging restricted to off-peak.
	Injection	• Possible off-set of GXP demand • Ability to maintain supply during faults may reduce criticality of fault restoration processes
Electric vehicles	Consumption	• Possible improving load factor if charging restricted to off-peak • Increased demand if charging unmanaged
	Injection	• This is speculative and application of this capability will be monitored
Low energy interior lighting	Consumption	• Reduced demand and consumption
Low energy streetlighting	Consumption	• Reduced demand and consumption. Lower consumption-based revenue will impact the value of this supply business

4.7.3 Zone substation demand forecasts

Electra's zone substation demand forecasts are set out below based on the following growth assumptions:

Zone substation	Nature of growth	Average annual demand growth		Annual average population growth[13]	Provision for growth
		2019	2020		
Shannon	Mainly lifestyle blocks around Tokomaru	2.3%	1.8%	2.9%	None required
Foxton	Mainly residential development at Foxton Beach	2.2%	2.7%	2.3%	None required
Levin East	Mainly commercial and lifestyle blocks to the south and east of Levin. Possible large off-peak industrial load growth	2.0%	1.8%	2.2%	None required
Levin West	Mainly residential properties at Waitarere Beach and lifestyle properties to the north and west of Levin	2.1%	1.9%	2.2%	None required
Otaki	Mainly lifestyle blocks in Manakau and Te Horo	2.3%	2.2%	2.4%	Load is being managed by redistribution amongst existing feeders. An additional feeder is proposed within the planning period to offload Feeder L351 and meet the increasing demand
Waikanae	Mainly residential	3%	2.9%	3%	Capacity on existing feeders continues to increase before end of life replacement. An additional feeder is proposed to Te Moana Road to offload Feeder 662 and supply the increasing load
Paraparaumu	Mainly commercial and residential infill	1.5%	1.4%	1.7%	Increased utilisation of existing capacity. The construction of Paraparaumu West has allowed much of the former load to be transferred
Paraparaumu West	Mainly commercial and residential infill	1.7%	1.3%	1.7%	An additional 11kV feeder is proposed to Kapiti Rd to off-load Feeder 405 and also to supply the increasing demand

[13] Statistics New Zealand, Dataset: Age and sex by ethnic group (grouped total responses), for census night population counts, 2006, 2013, and 2018 Censuses (RC, TA, SA2, DHB)

Zone substation	Nature of growth	Average annual demand growth		Annual average population growth[13]	Provision for growth
		2019	2020		
Raumati	Mainly residential infill	1.7%	0.9%	1.6%	An additional feeder is proposed to Matai Rd to offload Feeder Z210 and supply the increasing demand
Paekakariki	Mainly residential infill	1%	0.8%	0.8%	No loading parameters are expected to be exceeded during the planning period; therefore no growth-related projects are proposed either

Figure 4-4: Zone substations demand forecasts

The Covid-19 pandemic which affected many businesses, had little impact on the maximum demand (MD) of our zone substations with the exception of Shannon where MD reduced slightly from 4.6 MVA (2019) to 4.2 MVA (2020); Levin East's reduction was negligible that is – from 14.1 MVA (2019) to 14.0 MVA (2020).

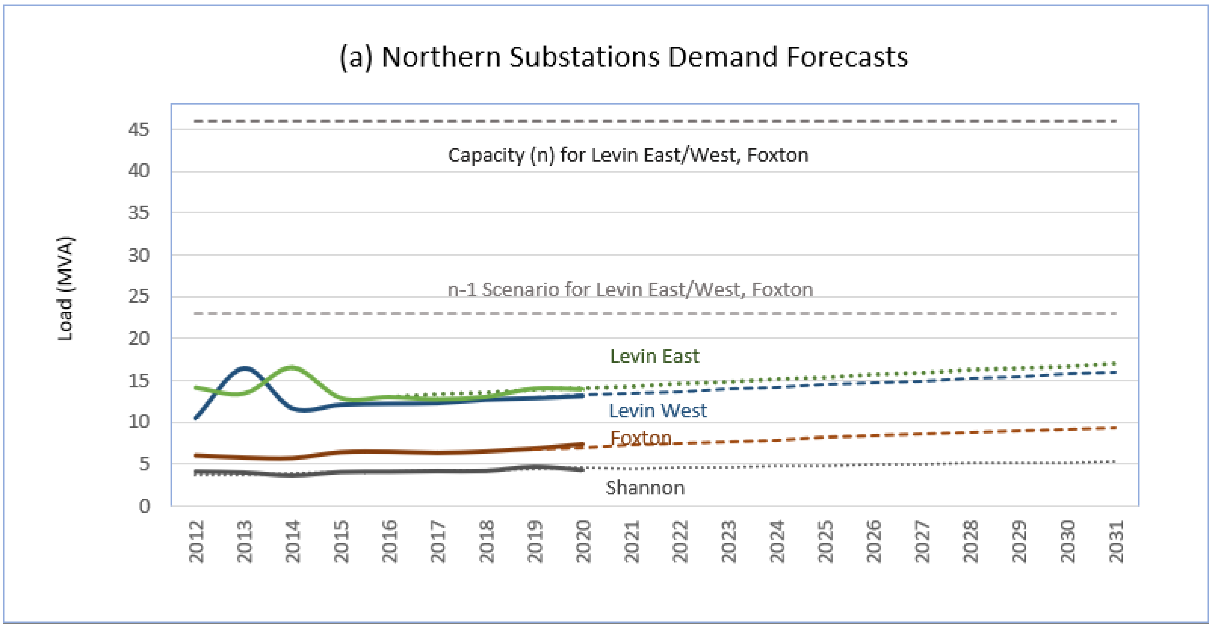
Furthermore, comparing the average annual load increase (averaged over ten years) as shown in Figure 4-4, there is a slight drop in the average annual growth rates for all zone substations with the exception of Foxton.

The northern substations' demand forecasts are shown in Figure 4-5a. The maximum demand growth rate is about 2% for Levin East, Levin West while Foxton is nearly 3% and these rates are well below their n-1 capacity, so no action is required. It should be noted that Foxton's maximum demand rose from 6.8MVA (2019) to 7.4 MVA (2020).

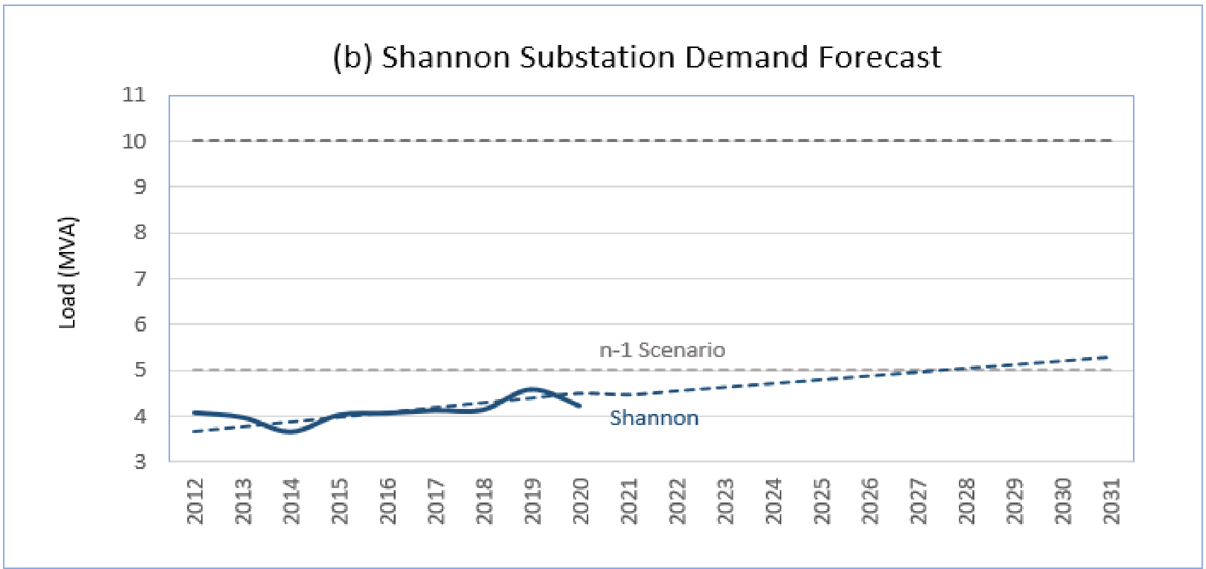
Concerning the Mangahao to Levin East supply, which was previously two parallel circuits as far as Waihou Road, then single circuit from Waihou Road to Levin East, the resilience of the supply was addressed in March 2020 when a second dedicated feeder between Mangahao and Levin East was commissioned enabling Electra to isolate either of the two feeds to Levin East for maintenance purposes.

With the additional circuit to Levin East, Electra will now be able to isolate one circuit each instance and carry out dedicated maintenance with lesser risk of supply interruption. The reconfiguration of both 110kV lines as a 33kV feed between Mangahao and Levin East will provide (n-1) security to Levin East whilst the Waihou Road – Levin East line is isolated.

In Figure 4-5b, the projected demand for Shannon substation suggests that the (n-1) rating will be exceeded after 2027 if the growth continue at 1.8% per annum. However, this can be managed by some load shifts at 11kV feeder level to Foxton substation.



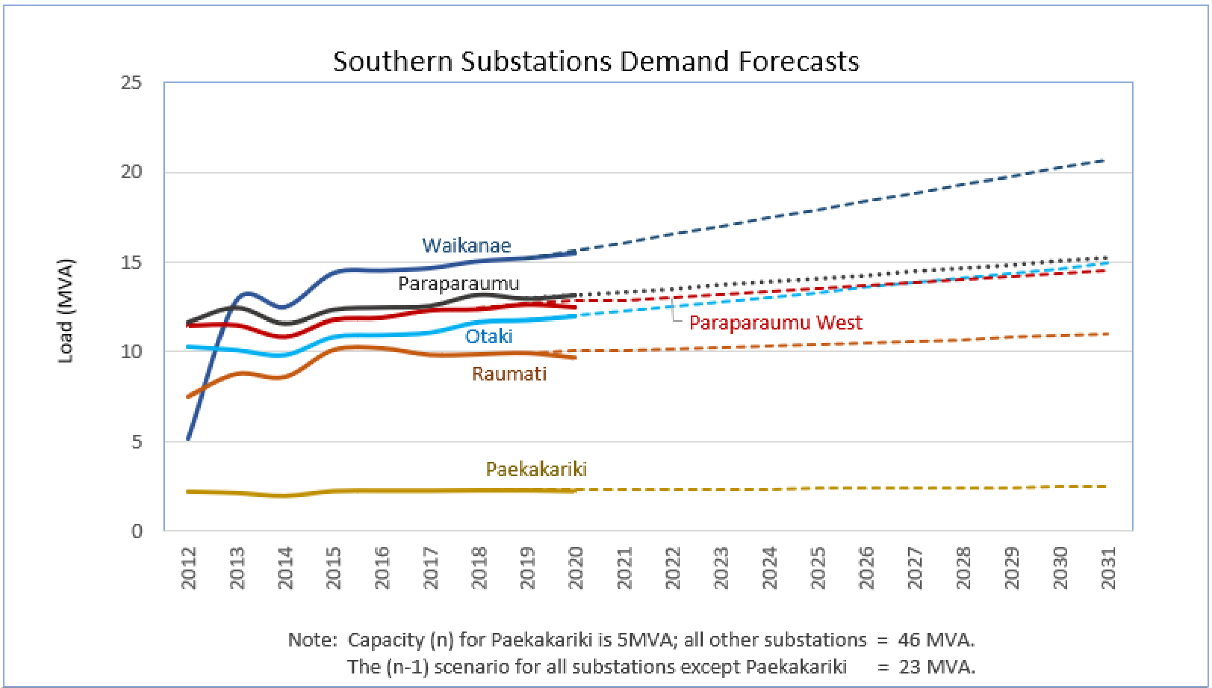
Zone Substation	Actual	Forecast Maximum Demand (MVA)											Annual
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Increase
Levin West	13.1	13.3	13.4	13.5	13.7	13.8	13.9	14.1	14.2	14.4	14.5	14.6	1.9%
Levin East	14.0	14.3	14.6	14.8	15.1	15.4	15.6	15.9	16.2	16.4	16.7	17.0	1.8%
Foxton	7.4	7.4	7.5	7.6	7.7	7.7	7.8	7.9	8.0	8.1	8.1	8.2	2.7%
Shannon	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.6	4.6	4.7	4.7	1.8%



Zone Substation	Actual	Forecast Maximum Demand (MVA)											Annual
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Increase %
Shannon	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.6	4.6	4.7	4.7	1.8%

Figure 4-5: (a) Northern substations demand forecasts, and (b) Shannon with scenarios

The southern substations demand forecasts are shown in Figure 4-6. The maximum demand growth rate is about 1% to 3% for the zone substations of Waikanae, Otaki, Paraparaumu, Paraparaumu West and Raumati and these rates are well below their n-1 capacity, so no action is required. Paekakariki growth rate is 0.8% only and at a maximum demand forecast of 2.5 MVA in 2031, the utilisation will still be below 50% of transformer capacity.



Zone Substation	Actual	Forecast Maximum Demand (MVA)											Annual
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Increase
Waikanae	15.5	16.1	16.6	17.0	17.5	17.9	18.4	18.9	19.3	19.8	20.3	20.7	2.9%
Otaki	11.9	12.2	12.5	12.8	13.0	13.3	13.6	13.9	14.1	14.4	14.7	14.9	2.2%
Paraparaumu	13.1	13.3	13.5	13.7	13.9	14.1	14.3	14.5	14.7	14.9	15.0	15.2	1.4%
Paraparaumu West	12.5	12.8	13.0	13.2	13.4	13.5	13.7	13.9	14.0	14.2	14.4	14.5	1.3%
Raumati	9.6	10.1	10.2	10.3	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	0.9%
Paekakariki	2.2	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5	0.8%

Figure 4-6: Southern substations demand forecasts

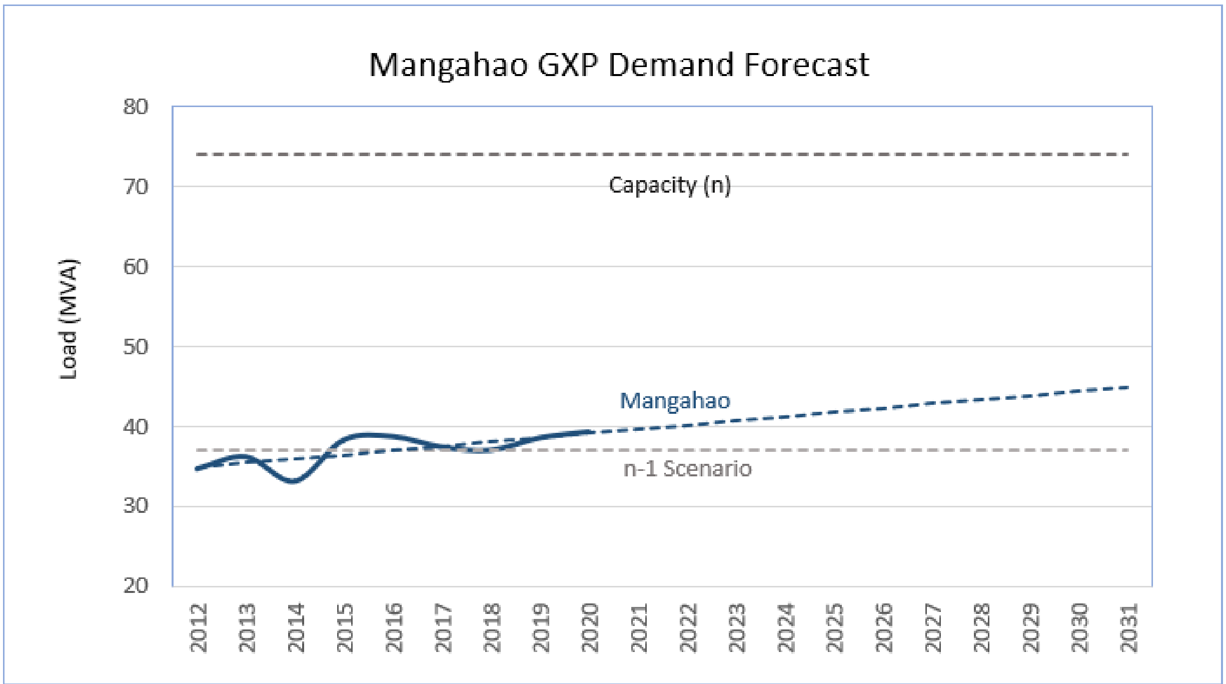
4.7.4 GXP demand forecasts

Major network constraints that Electra may face in the future will occur mainly at the Mangahao grid exit point on the network. As depicted in Figure 4-7, Mangahao GXP first exceeded the transformers (n-1) winter capacity of 37MVA by approximately 2.5MW in 2015 and for the winter demand this year, the (n-1) capacity was exceeded by 2.2MVA. The supply transformer overload is managed operationally by Mangahao generation which is usually available at peak load periods. If Mangahao continues to generate at 13MW or more, this issue could be delayed beyond the forecast period.

With the increased number of transportation projects, load growth is expected to increase more rapidly with the completion of Transmission Gully and Peka-Peka to Otaki Expressway projects by 2022. The upgrading of Paraparaumu GXP (as a result of the Transmission Gully highway project) has increased its capacity and removed any transmission constraints in the Kapiti area.

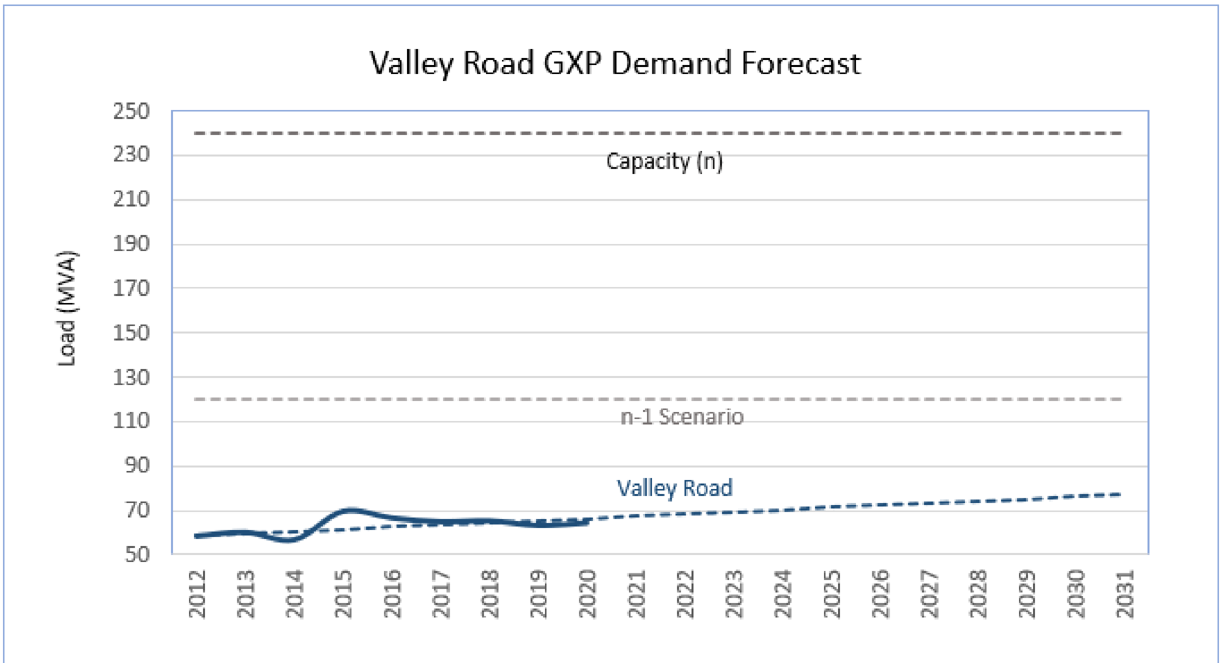
The zone substation demand forecasts have been aggregated to the following GXP demand forecasts:

GXP	Average annual demand growth		Provision for growth
	2019	2020	
Mangahao	1.3%	1.2%	No provision for capacity or security growth will be possible until about 2030 when it is expected that the existing transformers will be upgraded to approximately 60MVA
Paraparaumu	1.8%	1.6%	None required. This GXP has recently been reconfigured to obtain supply from Transpower's 220kV network to accommodate the proposed Transmission Gully highway. The result is that firm capacity has increased from 68 MVA to 120MVA. This means that any future growth can be met from the existing supply and the provisional measures outlined in previous AMP's to delay upgrade work are no longer needed



GXP	Actual	Forecast Maximum Demand (MVA)											Annual
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Increase %
Mangahau	39.2	39.7	40.2	40.7	41.2	41.8	42.3	42.8	43.4	43.9	44.4	44.9	1.2%

Figure 4-7: Mangahao GXP demand forecast

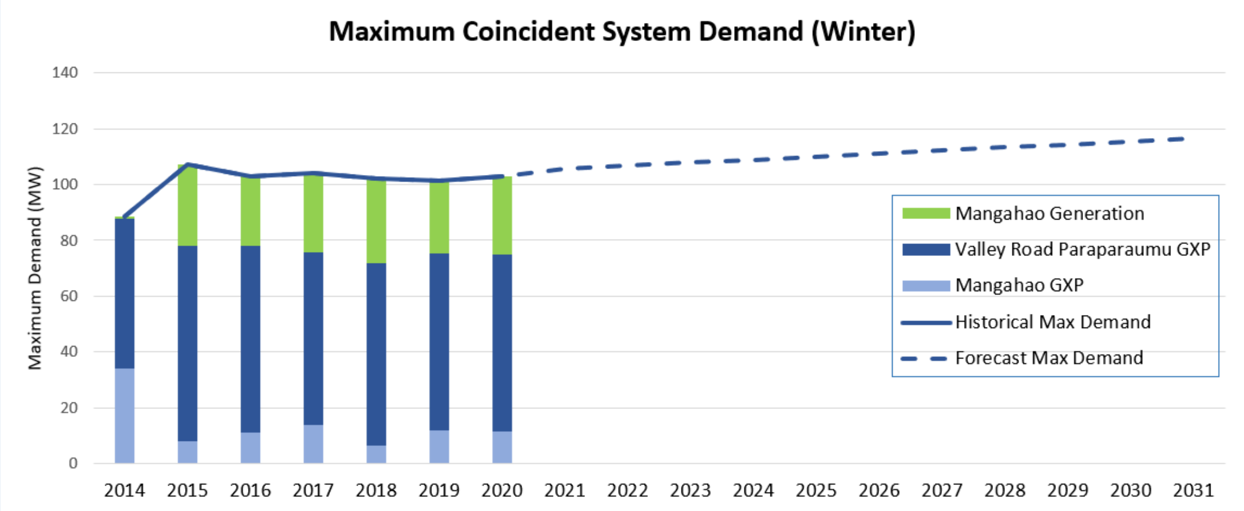


GXP	Actual	Forecast Maximum Demand (MVA)											Annual
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Increase %
Valley Road	64.5	67.4	68.3	69.3	70.3	71.3	72.3	73.3	74.2	75.2	76.2	77.2	1.6%

Figure 4-8: Valley Road GXP demand forecast

The maximum coincident system demand (winter) for calendar year 2020 rose from 101.4 to 102.9 MW and again, we see that the increasing trend had not been impacted much by the Covid-19 pandemic; the projected demand is shown in Figure 4-9 where the coincident maximum demand is projected to grow at 1% per year. Comparing the GXP winter maximum demands (MD) for calendar years 2019 and 2020, Mangahao's MD rose slightly from 38.5 MVA (2019) to 39.2 MVA (2020) and Valley Road's MD increased as well from 63.3 MVA to 64.5 MVA.

Since 2015, Mangahao generation (to the 33kV bus) has accounted for an average of 27% of coincident maximum demand with Valley Road and Mangahao GXPs contributing 63% and 10% respectively.



GXP	Actual 2020	Forecast Maximum Demand (MVA)										Annual
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030	Increase %
Max Coincident Demand	102.9	105.6	106.7	107.8	108.9	110.0	111.1	112.2	113.3	114.3	115.4	116.5	1.0%

Figure 4-9: Projected maximum coincident system demand

4.7.5 Improving demand forecasting

Electra plans to develop a suite of Low, Medium (Base) and High demand scenarios based on the following 5 factors which are expected to dominate demand growth or contraction:

- National and regional economic growth
- Aspects of transport policy that incentivise EV uptake
- Further decline in the cost of rooftop solar and residential batteries
- Housing policies that cause property prices to retreat from recent high levels, reducing the incentive to migrate from Wellington to Kapiti to Horowhenua
- Further penetration of domestic and retail premise air conditioning.

Electra expects these scenarios to look something like the following:

Driver	Low scenario	Mid (base) scenario	High scenario
National and regional economic growth	National GDP troughed at about 1.7% in Dec 2019 and expected to grow at a moderate pace into 2020	National GDP is expected to track at about 2.3% to 2.4% over the next couple of years [14, 15]	National GDP peaks at about 2.5% around mid-2020 and is expected to gradually improve.
Aspects of transport policy that incentivise EV uptake	Expect 400 EV's in Kapiti and 50 in Horowhenua by about 2021, again with an even mix of peak and off-peak charging	Expect 640 EV's in Kapiti and 160 in Horowhenua by about 2021, with an even mix of peak and off-peak recharging	Expect 1,000 EV's in Kapiti and 200 in Horowhenua by about 2021, with an even mix of peak and off-peak charging

[14] ANZ Research, Quarterly Economic Outlook "Through the looking glass", January 2020

[15]BNZ Markets Outlook, 16 December 2019

Driver	Low scenario	Mid (base) scenario	High scenario
Further decline in the costs of rooftop solar and batteries	The installed cost of a 2kW solar plus batteries supply will remain at about $14,000	The installed cost of a 2kW solar plus batteries supply that currently costs about $14,000 will decline to about $11,000 by 2022[16, 17] and then remain constant	The installed cost of a 2kW solar plus batteries supply will decline from the current $14,000 to about $9,000 by 2022 and then remain constant
Housing policies that cause property prices to retreat from recent high levels	House price growth in the lower North Island will drop sharply into a retreat	House price growth in the lower North Island will slow and eventually retreat into a decline in prices	House prices in the lower North Island will continue to grow, albeit at a slightly lower rate
Further penetration of domestic and retail premise air conditioning	Air conditioning penetration remains at about 45% for planning period	Air conditioning penetration will increase from about 45% in 2016 to about 50% by 2021 and then remain constant[18]	Air conditioning penetration increased to about 60% by 2021 and then remains constant

Electra also expects to have to consider component loading at an 11kV and LV feeder level as increasing penetration of batteries and solar panels may lead to localised demand growth that is not seen at a zone substation level.

[16] https://www.mysolarquotes.co.nz/about-solar-power/residential/how-much-does-a-solar-power-system-cost/

[17] https://www.greentechmedia.com/articles/read/solar-costs-are-hitting-jaw-dropping-lows-in-every-region-of-the-world#gs.XYIx1yw

[18] https://www.transpower.co.nz/sites/default/files/publications/resources/E528-use-forecasting-for-heat-pumps-jul-09.pdf

4.8 Development projects

The following sections contain the development projects planned for the ten-year period commencing from 1 April 2021 until 31 March 2031. Schedule 11a: Report on Forecasted Capital Expenditure in Appendix 2 reflects the costs incurred in these sections. Figure 4-10 displays the location and estimated budgeted costs of major network projects in the Kapiti and Horowhenua districts.

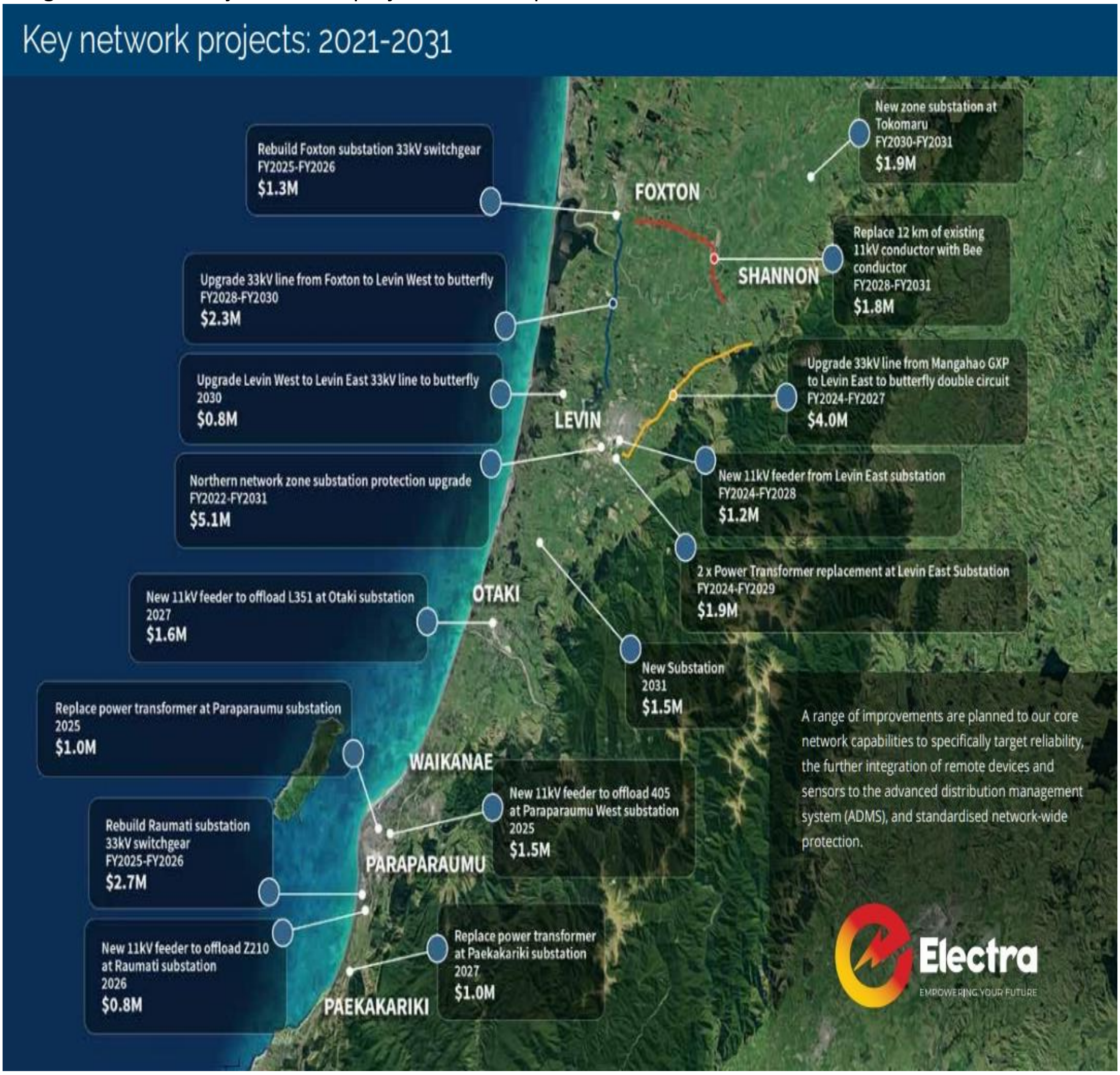


Figure 4-10: Key network projects

4.8.1 Development projects for FY2022 year

Development projects over $200,000 for FY2022 as well as their alternative options are shown on the following page.

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
1	Substation protection and communication work	Quality	$650,000	Risk of loss of supply due to slow fault clearance Risk of equipment damage Potential risk to people's safety Lack of ability to perform post-fault analysis		Upgrade to modern numerical relays (SEL)for the purpose of improved protection performance	• Upgrade to modern numerical relays (SEL) with required protection schemes and settings • Slow fault clearance is both an operational and a safety risk • New NER at Mangahao GXP • Address protection scheme non-conformance to reduce the risk of equipment damage • Reduce the risk of high impedance fault • Obsolete protection relays and insufficient relay functions • Mitigate the risk of arc flash hazards for indoor switchgears
2	Seismic strengthening of zone substation buildings	Legislative	$600,000	Continue with high risk buildings, which are prone to earthquake damage		Get buildings seismically assessed and carry out modifications to rate the building to IL4 of the code	• To carry out studies and carry out recommendations to get buildings compliant to the code to reduce the risk levels
3	Install pole-mounted sectionalisers on specified feeders to reduce number of customers affected by faults	Quality	$400,000	Continue with existing feeder sections		Install line sectionalisers on specific feeder locations	• Sectionalise feeders • As more customers are added to feeders, the number of customers effected by a fault will also increase, which is undesirable. Sectionalising will reduce the number of customers affected
4	Sub-division extensions	Customer Connection	$400,000	Continue with existing LV network configuration		Install links between LV circuits Increased capital contribution allowance as network extension policy being updated in FY 2021	• Install links between LV circuits • Allow faster restoration rather than repair time

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do-Nothing	Non-Network	Network	
5	Install LV -power quality monitors	Quality	$250,000	Continue with no visibility of LV power quality information	Install smart sensors on selected distribution transformers		• Install LV PQ monitors on selected transformers • This will provide valuable information to create a baseline of existing power quality, validate ADMD assumptions and additionally can feed information To ADMS to inform LV outages

* includes "low investment" options.

Non-material projects (<=$200,000) for the FY2022 as well as their alternative options follow:

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do Nothing	**Non-Network**	**Network**	
6	Install additional permanent fault locators to allow quicker location of faults	Quality	$200,000	Rely on existing telemetered devices to locate faults		Install fault locators	• Install fault locators • Quicker location of faulted section of feeder is consistent with strategy of improving reliability
7	Automation of ground mounted switchgear on specified feeders to reduce restoration times	Quality	$190,000	Continue with existing manual switching arrangements	Improve existing manual switching arrangements	Automate specific switches	• Automate specific switches • As more customers are added to feeders, the number of customers effected by a fault will also increase, which is undesirable. Automating specific switches will reduce supply restoration time • These devices will provide network data, which will help to improve network investment decisions of future
8	Automation of 11kV supply to Paekakariki ZS	Quality	$125,000	Continue with existing manual switching arrangements		Automate switches	• Paekakariki has only N connection and back feed is through non automated 11kV connections, which delays response • These devices will provide network data, which will help to improve network investment decisions of future
9	Link LV network where gaps exist to reduce fault restoration times	Quality	$100,000	Continue with existing LV network configuration		Install links between LV circuits	• Install links between LV circuits • Allow supply restoration in switching time rather than repair time
10	Levin East Power Transformer condition monitoring	Quality	$75,000	Continue with existing transformer inspections regime		Initiate transformer replacement	• Frequent transformer inspections to identify whether conditions are worsening at a faster than expected rate

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do Nothing	**Non-Network**	**Network**	
11	Install communications on specified fault locators to allow remote indication	Quality	$30,000	Continue with existing fault locaters that require manual observation		Install communications to allow remote indication of faults	• Install communications to allow remote indication of faults • Remote indication of faults allows quicker directing of fault men to faults, reducing restoration times
12	Replace P12 DDO with ABS	Quality	$25,553	Retain existing drop out fuses			• Replace DDO with an ABS or CB • ABS or CB allows load-breaking for greater switching options in outage events
13	Replace M93 Link with ABS	Quality	$11,124	Retain existing switching configuration		Maintain existing link	• Replace M216 with ABS • Greater reliability

* includes “low investment” options.

4.8.2 Development projects for FY2023 to FY2026

The development projects proposed for FY2023 to FY2026 with considerations made to alternative solutions include:

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do Nothing	Non-Network	Network	
1	Substation protection upgrade	Quality	$2,430,000	Risk of loss of supply due to slow fault clearance Risk of equipment damage Potential risk to people's safety Lack of ability to perform post-fault analysis		Upgrade to modern numerical relays (SEL)for the purpose of improved protection performance.	• Upgrade to modern numerical relays (SEL) with required protection schemes and settings • Slow fault clearance is both an operational and a safety risk • New NER at Mangahao GXP • Address protection scheme non-conformance to reduce the risk of equipment damage • Reduce the risk of high impedance fault • Obsolete protection relays and insufficient relay functions • Mitigate the risk of arc flash hazards for indoor switchgears
2	Subdivision extensions	Customer connection	$1,600,000	Continue with existing LV network configuration		Install links between LV circuits Increased capital contribution allowance as network extension policy being updated in FY 2021	• Continue with existing LV network configuration

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do Nothing	Non-Network	Network	
3	Install new feeder to offload 405	Growth	$1,500,000	Allow load and customer numbers on existing feeder to increase	Encourage customers to uptake solar and/or battery storage	Reconfiguration of feeders Add new feeder	• Add new feeder • Simply adding more customers will increase its asset utilisation and risk of in-service failure. This is inconsistent with Electra's policy on asset loading and increasing asset capacity • As more customers are added to the feeder, the number of customers effected by a fault will also increase which is undesirable. Offloading customers will reduce the number of customers affected • Customer uptake of solar and/or batteries are on an ad-hoc basis and cannot be predicted • Any connected solar or batteries may not be of reliable source due to intermittency of supply • All the nearby feeders also have significant number of customers connected to it and has high loading
4	Seismic strengthening of zone substation building	Legislative	$1,350,000	Continue with high risk buildings, which are prone to earthquake damage		Get buildings seismically assessed and carry out modifications to rate the building to L4 of the code	• To carry out studies and carry out recommendations to get buildings compliant to the code to reduce the risk levels
5	Automation of ground mounted switchgear	Quality	$1,280,000	Continue with existing manual switching arrangements		Automate specific switches	• Automate specific switches • As more customers are added to feeders, the number of customers effected by a fault will also increase, which is undesirable. Automating specific switches will reduce supply restoration time • These devices will provide network data, which will help to improve network investment decisions of future
6	Network sectionalisation using pole mounted switchgear	Quality	$1,100,000	Continue with existing feeder sections		Install line sectionalisers on specific feeder location	• Sectionalise feeders • As more customers are added to feeders, the number of customers effected by a fault will also increase, which is undesirable. Sectionalising will reduce the number of customers affected

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do Nothing	Non-Network	Network	
7	New feeder from Levin East Substation	Growth	$850,000	Allow load and customer numbers on existing feeder to increase	Encourage customers to uptake solar and/or battery storage	Reconfiguration of feeders Add new feeder	• Add new feeder • Simply adding more customers will increase its asset utilisation and risk of in-service failure. This is inconsistent with Electra's policy on asset loading and increasing asset capacity • As more customers are added to the feeder, the number of customers effected by a fault will also increase which is undesirable. Offloading customers will reduce the number of customers affected • Customer uptake of solar and/or batteries are on an ad-hoc basis and cannot be predicted • Any connected solar or batteries may not be of reliable source due to intermittency of supply
8	Install a new feeder to Matai Rd to offload Z210	Growth	$800,000	Allow load and customer numbers on existing feeder to increase	Encourage customers to uptake solar and/or battery storage	Reconfiguration of feeders Add new feeder	• Add new feeder • Simply adding more customers will increase its asset utilisation and risk of in-service failure. This is inconsistent with Electra's policy on asset loading and increasing asset capacity • As more customers are added to the feeder, the number of customers effected by a fault will also increase which is undesirable. Offloading customers will improve reliability • Customer uptake of solar and/or batteries are on an ad-hoc basis and cannot be predicted • Any connected solar or batteries may not be of reliable source due to intermittency of supply
9	Link between Waitarere and Hokio Beach.	Growth	$800,000	Continue with existing spur network arrangement	Install backup generators/battery for redundancy	Install a cable section to close the ring	• Install ring feed cable • Diesel generators and battery solutions are not cost effective • Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability
10	Install additional fault locators - permanent	Quality	$700,000	Rely on existing telemetered devices to locate faults		Install fault locators	• Install fault locators • Quicker location of faulted section of feeder is consistent with strategy of improving reliability

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do Nothing	Non-Network	Network	
11	Install alternative supply between W468 and Z50 to allow quicker restoration of faults	Quality	$540,000	Continue with existing unmeshed feeders		Install link between W468 and Z50	• Install link between W468 and Z50 • Being able to back-feed un-faulted sections of both feeders provides an opportunity to reduce restoration times
12	Northern network communication upgrade	Quality	$530,000	Retain existing communication systems		Upgrade communications network	• Upgrade communications network Upgrading communications network to provide greater resiliency and throughput for essential network control systems
13	Complete 11kV ring and replace LV OH with UG along Hokio Road	Quality	$500,000	Retain existing switching configuration and continue with existing heavily aged LV OH conductor		Replace OH LV reticulation	• UG LV reticulation and install 11kV ring • Renews aged asset, puts it out of public view. 11kV ring gives more switching options to keep customers online in outage events.
14	Ripple plant installation at Otaki to cover whole network if either of the existing plants are out of service	Quality	$500,000	No back up for the existing ripple plants		Ripple plant installed at Otaki to cover whole network if either of the existing plants are out of service	• Ripple plant installation at Otaki to cover whole network if either of the existing plants are out of service • Load can be managed efficiently
15	Install a new feeder through Te Moana Rd to offload Feeder 662	Growth	$460,000	Allow load and customer numbers on existing feeder to increase	Encourage customers to uptake solar and/or battery storage	Reconfiguration of feeders Add new feeder	• Add new feeder • Simply adding more customers will increase its asset utilisation and risk of in-service failure. This is inconsistent with Electra's policy on asset loading and increasing asset capacity • As more customers are added to the feeder, the number of customers effected by a fault will also increase which is undesirable. Offloading customers will improve the reliability • Customer uptake of solar and/or batteries are on an ad-hoc basis and cannot be predicted • Any connected solar or batteries may not be of reliable source due to intermittency of supply • All the nearby feeders also have significant number of customers connected to it and also has high loading

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do Nothing	Non-Network	Network	
16	Link LV network where gaps exist to reduce fault restoration times	Quality	$400,000	Continue with existing LV network configuration		Install links between LV circuits	• Install links between LV circuits • Allow supply restoration in switching time rather than repair time
17	Link between W42 and W293 -Paraparaumu Airport and install CFC	Quality	$385,000	Continue with existing spur network arrangement	Install backup generators/battery for redundancy	Install a cable section to close the ring	• Install ring feed cable • Diesel generators and battery solutions are not cost effective • Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability
18	Install ring feed cable to back up L470 to L332-Manakau Village	Quality	$375,000	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable • Meshing of circuits allows reduced restoration times
19	Install LV -power quality monitors	Quality	$250,000	Continue with no visibility of LV power quality information	Install smart sensors on selected distribution transformers		• Install LV PQ monitors on selected transformers • Provide power quality and loss of supply information • Validate ADMD assumptions
20	Cable installation between W494 and W502	Growth	$150,000	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable. Install ring feed cable • Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability
21	Relocate a 33/11kV transformer to act as a cold standby at Paekakariki	Quality	$130,000	Continue with existing single transformer configuration and relocate a transformer from another substation in the event of failure	Relocate a transformer from another substation and keep as a cold standby at Paekakariki that could be livened in 6 to 8 hours	Purchase second transformer and keep as a cold standby at Paekakariki that could be livened in 6 to 8 hours	• Relocate a transformer from another substation to keep as a cold standby at Paekakariki • Only some Paekakariki customers can be back fed on the 11kV from other substations, so a transformer failure would interrupt supply until the transformer was repaired (possibly months) or replaced
22	Install communications on specified fault locators to allow remote indication	Quality	$120,000	Continue with existing fault locaters that require manual observation		Install communications to allow remote indication of faults	• Install communications to allow remote indication of faults • Remote indication of faults allows quicker directing of fault men to faults, reducing restoration times
23	Waterfall Rd Alternative Supply	Quality	$105,000	Retain existing spur configuration		Install ring feed cable	• Install ring feed cable • Meshing of circuits allows reduced restoration times

Ref.	Description and purpose of project	Category	Cost	Options considered			Option chosen and reason
				Do Nothing	Non-Network	Network	
24	M216 Link Otaki, replace with ABS	Quality	$11,124	Retain existing switching configuration		Maintain existing link	• Replace M216 with ABS • Greater reliability

* includes "low investment" options.

4.8.3 Development projects for FY2027 to FY2031

Development projects proposed for FY2027 to FY2031 that have been considered are:

Ref.	Description	Category	Cost
1	Upgrade to bee to butterfly - Foxton to Levin West 33kV	Growth	$2,250,000
2	Sub-division extensions	Customer connection	$2,000,000
3	Northern network protection work	Quality	$2,000,000
4	New zone sub near Tokomaru to back up Foxton and Shannon and load growth and possible new grid exit point	Growth	$1,875,000
5	Automation of ground mounted switchgear	Quality	$1,870,000
6	New feeder at Otaki substation to offload L351	Growth	$1,560,000
8	New zone substation around Waikawa beach road, Manakau	Growth	$1,500,000
7	Close 11kV ring to improve reliability	Growth	$1,200,000
9	11kV cable upgrade	Quality	$1,100,000
10	Network sectionalisation using pole mounted switchgears	Quality	$1,100,000
11	Upgrade to bee to butterfly - Levin West to Levin East 33kV	Growth	$800,000
12	Raumati Esplanade 11kV Underground ring	Quality	$525,000
13	Link LV network where gaps exist	Quality	$500,000
14	Install switchgear in Otaki and reconfigure the network	Quality	$450,000
15	Close ring between Q91 to P271	Quality	$450,000
16	New feeder from Levin East	Growth	$350,000
17	Mill Rd, Otaki 11kV OH ring	Quality	$320,000
18	Install additional fault locators - permanent	Quality	$255,530
19	Cable replacement between W97 & W98	Growth	$250,000
20	Fault locator communications	Quality	$150,000

5 Lifecycle management

5.1 Asset lifecycle management

This section describes the robust and transparent processes in place for managing all phases of the network life cycle, from conception to disposal which is one of the objectives of the AMP. We manage our assets through the asset lifecycle according to the process illustrated in Figure 5-1. Asset lifecycle management means taking a long-term view to make informed and sound investment decisions to deliver our service levels at an appropriate cost. Benefits of a whole of life approach are:

- Minimising safety risks and future legacy issues through safety in design analysis conducted throughout the asset's lifecycle
- Establishing forecasts for operational and replacement expenditure, thus avoiding surprises
- Minimising the total cost of ownership while meeting accepted standards of performance.

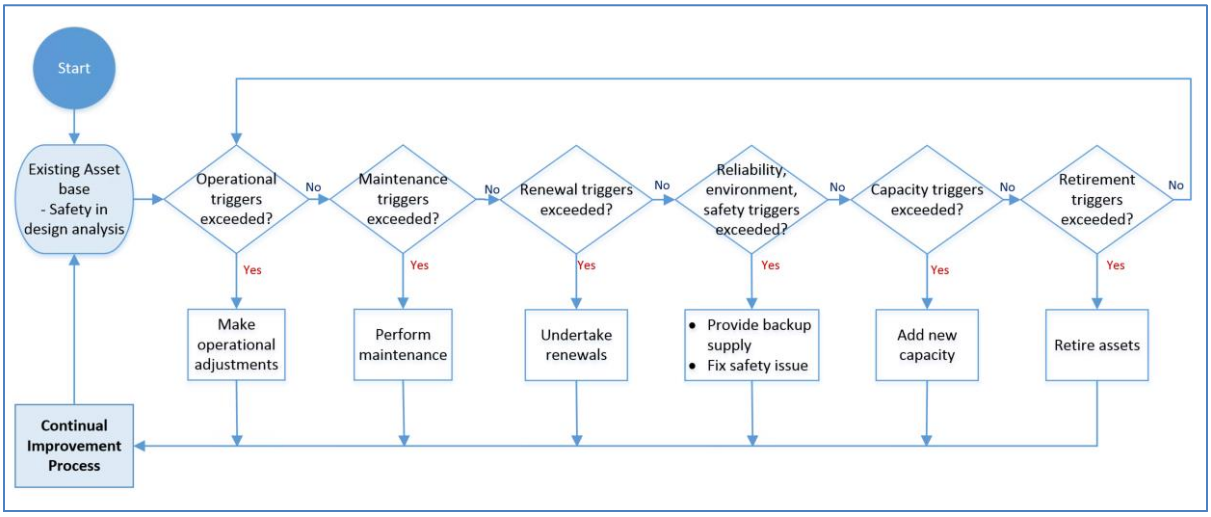


Figure 5-1: Management of the asset lifecycle

The key steps in the asset lifecycle are:

- **Operations**: altering the operating parameters of the asset (i.e. its configuration)
- **Inspection and maintenance**: predominantly associated with routine inspection, testing, vegetation management, and replacing or renewing items that are component parts of an asset (including both pre-planned and fault/emergency maintenance)
- **Renewal**: replacing non-consumable components with an identical item with similar functionality which may significantly extend the asset's life
- **Reliability, safety and environment**: associated with maintaining or improving the safety of the network for consumers, employees and the public, or with the improvement of reliability or service standards, or with meeting new or enhanced environmental requirements
- **System growth (add new capacity)**: replacing non-consumable components with a similar item with greater capacity
- **Retirement**: removing an asset from service and disposing of it.

5.1.1 Condition-based risk management

Electra uses a condition-based risk management method as the basis for most of its asset renewal and replacement decisions. The asset condition (or asset health indicator) is used to better predict the health of its network assets covering sub-transmission and 11kV distribution lines including poles and crossarms, LV cables, pillars and zone transformers.

We are currently developing the tool for other assets such as LV lines, crossarms and poles, HV cables, switches and distribution transformer and these models will be created within the next two years.

Asset criticality is one of the strategic themes that we have adopted as shown in our CBRM process shown in Figure 5-2 (a).

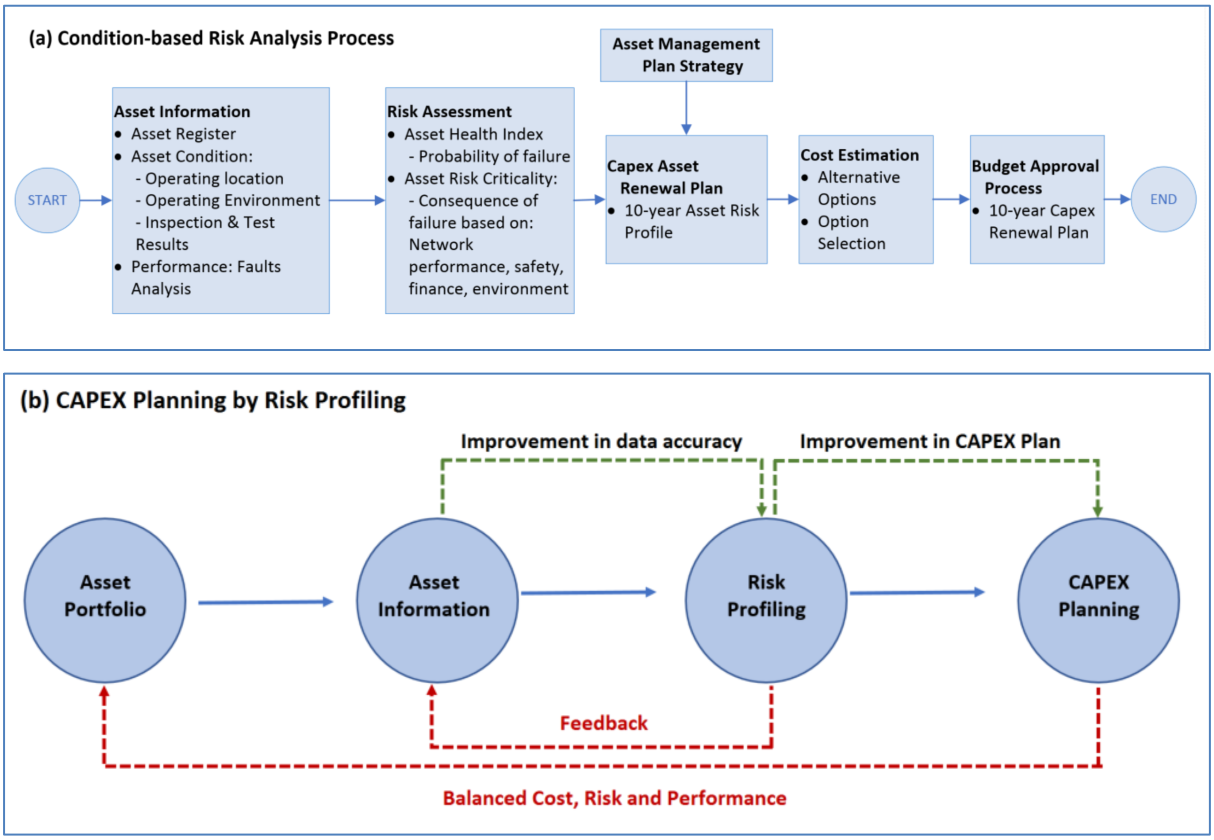


Figure 5-2: (a) Condition-based Risk Analysis Process; (b) CAPEX Planning by Risk Profiling of Assets

The criticality of an asset is a measure of its consequence of failure (CoF) based on network performance, safety, financial and environmental factors when compared with the average CoF for its asset type and age. The risk of failure for individual assets is based on the probability of failure (PoF) multiplied by the CoF. When an asset fails, there is an associated impact resulting from the failure.

The Health Index is the one of the key outcomes determined based on asset register information, observed condition data and measured/tested condition data. The index is a continuous scale between 0.5 and 10 where an index of 0.5 represents a new asset and 10 is for the worst condition asset in current time.

CAPEX planning templates have been developed for the asset classes where risk profile results are imported for CAPEX planning. The process is depicted in Figure 5-2 (b) where continual improvement in data accuracy and risk profiling via condition-monitoring are integrated into our CAPEX planning process.

5.1.2 Safety in design

Risk review activities involving project team members are conducted to achieve the safe and smooth delivery of our projects where safety in design (SiD) assessments are integrated into our processes as depicted in Figure 5-1. We are committed to safety being the paramount consideration in the work we do for our customers and records of SiD workshops provide traceability of Electra's application of this approach in support of Electra's commitment to the Health and Safety at Work Act 2015. Further SiD development and assurance stages continue to be included in the project delivery lifecycle.

5.1.3 Improvement in maintenance practices

Electra continues to improve its maintenance practices to meet reliability and cost efficiency measures. These improvements include:

- Upgrade of test equipment: Newly acquired test equipment for zone substations - CPC100, a primary injection test set as well as CMC356, a secondary injection test set
- Diagnostic testing of primary zone substation assets including partial discharge testing using ultrasonic, UHF, HFCT and TEV sensors for substation equipment
- Drone inspections of 33kV and 11kV overhead structures and assets
- Acoustic inspections of 33kV and 11kV overhead structures and assets
- Usage of hot-stick mounted with GoPro cameras.

5.1.4 Asset operations criteria and assumptions

Actively operating electricity distribution assets predominantly involves letting the electricity flow from the GXPs to consumers' premises. However, occasional intervention is required when a trigger point is exceeded. The following Figure 5-3 outlines the key operational triggers adopted by Electra for each class of assets.

Asset category	Voltage trigger	Demand trigger	Temperature trigger
400V lines and cables	Voltage routinely drops too low to maintain at least 94% of nominal voltage at the point of supply Voltage routinely rises too high to maintain no more than 106% of nominal voltage at the point of supply	Consumers' pole or pillar fuse blows repeatedly Transformer fuses blow repeatedly	Signs of overheating on fittings Infra-red survey reveals hot joint
Distribution substations	Voltage routinely drops too low to maintain at least 94% of nominal voltage at the point of supply Voltage routinely rises too high to maintain no more than 106% of nominal voltage at the point of supply	Load routinely exceeds rating where MDIs are fitted LV fuse blows repeatedly Short term loading exceeds guidelines in IEC 354	Infra-red survey reveals hot connections
Distribution lines and cables	Voltage falls below regulatory requirements and is not able to be adjusted with the distribution transformer tap changers	HV and or LV fusing routinely exceeds ratings HV and or LV fuse failures	Infra-red survey reveals hot joint
Zone substations	Voltage drops below level at which OLTC can automatically raise taps	Load exceeds guidelines in IEC 354	Top oil temperature exceeds manufacturers' recommendations Core hot-spot temperature exceeds manufacturers' recommendations

Asset category	Voltage trigger	Demand trigger	Temperature trigger
Sub-transmission lines and cables	Supply voltage at Zone outside of on-load tap changer requirements	SCADA reports over or under voltage alarms	Infra-red survey reveals hot joint

Figure 5-3: Key operational triggers

If any of the above operational triggers are reached, Electra's first efforts to relieve the problem are through one of the following operational activities:

- Operating a tap-changer to correct voltage excursions
- Opening and closing ABSs or RMUs to relieve an over-loaded asset
- Opening and closing ABSs or RMUs to shut down or restore power either planned or fault related
- Operating load control plant to reduce demand
- Activating fans or pumps on transformers to increase the cooling rate.

5.1.5 Asset maintenance planning criteria and assumptions

Maintenance is primarily about replacing consumable components. Continued operation of such components will eventually lead to failure. Failure of such components is usually based on physical characteristics. Exactly what leads to failure may be a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, ambient temperature, previous maintenance history and presence of contaminants. The need to avoid failure determines when maintenance is performed. The obvious trade-off with avoiding failure is the increased cost of labour and consumables over the asset lifecycle along with the cost of discarding unused component life.

Electricity networks are not only constrained electrically but also by the environment within which they are constructed. Electra's network is built within a coastal marine environment. This environment is hostile to most components used in an electricity network and is the principal driver of any accelerated maintenance programmes required to maintain service to consumers. Where possible, equipment designed for this environment is used.

Maintenance decisions are made on the basis of cost-benefit criteria with the principal benefits being avoiding supply interruption and minimising safety risks. Component condition is the key trigger for maintenance however the precise conditions that trigger maintenance are very broad, ranging from oil acidity to dry rot. The sub-sections from Sections 5.3 to 5.10 describes the maintenance triggers and drivers Electra has adopted for its lifecycle maintenance programme.

5.1.6 Reliability, safety and environment criteria and assumptions

If any of the following triggers are exceeded on a feeder Electra will consider adding a duplicate feeder to minimise the number of consumers impacted by an outage of a feeder:

- Maximum of 1,500 urban domestic consumer connections
- Maximum of 200 urban commercial consumer connections
- Maximum of approximately 20 or 30 urban light industrial consumer connections.

Details of the reliability, safety and environmental programmes and associated expenditures are provided in Section 4.8 on Development projects.

5.1.7 Asset renewal and refurbishment criteria and assumptions

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). A key criterion for renewing an asset is when its capitalised operating and maintenance costs exceed the renewal cost, and this can occur in the following ways:

- Operating costs become excessive for example: increasing level of inputs into a SCADA system requires an increased number of staff
- Maintenance costs begin to accelerate - for example, a transformer needs more frequent oil changes as the seals and gaskets perish
- Supply interruptions due to component failure become excessive as determined by the number and nature of consumers affected
- Renewal costs decline, particularly where life-time costs of new technologies decrease significantly.

Again, the sub-sections from Sections 5.3 to 5.10 describes the renewal triggers and drivers Electra has adopted for its lifecycle maintenance programme. With scheduled inspection cycles for all assets and condition monitoring technology, asset renewal is leveraged at an appropriate level to meet our operational requirements.

Details of the renewal or refurbishment programmes and associated expenditures are provided in Section 4.8.

5.1.8 System growth criteria and assumptions

If any of the triggers depicted in Figure 5-1 and described in Section 4.2 are exceeded, we will consider adding additional capacity to the network.

We use a range of technical and engineering standards to achieve an optimal mix of the following outcomes:

- Comply with environmental and public safety requirements
- Meet likely demand growth for a reasonable time horizon including consideration of modularity and scalability
- Minimise the risk of long-term stranding
- Maximise operational flexibility
- Maximise the fit with software capabilities such as engineering and operational expertise and vendor support.

Standard designs on our network are generally adopted for all asset classes with minor site-specific alterations. Work identified by Electra as needing to be done is almost solely carried out by Electra's Distribution Operations staff.

As part of the building and commissioning process, our information records are recorded through the "as-built" process and all testing of new assets is documented.

Details of the system growth programmes and associated expenditures are provided in Section 4.8 on Development projects.

5.1.9 Consumer connection criteria and assumptions

These projects are driven by consumers. Typically, these projects include assets to connect a consumer to the existing network. This category includes upstream assets that are changed to meet the load of a new consumer (or existing consumer requesting a larger capacity). Given the nature of the work, consumers may approach up to three contractors authorised to work on our network.

5.1.10 Retiring assets criteria and assumptions

The general criteria for retiring an asset includes:

- 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.

Our group policy on the "Disposal of Assets and Waste Material" identifies the following principles when disposing 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 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
- encourage re-purposing before disposal by re-cycling, with treatment as waste as a last resort.

Other criteria for retirement of each class of asset are included in the following sections.

5.2 Management of our assets

Electra manages network assets by asset class or type. The lifecycle plans for each asset class are set out in following Sections of 5.3 onwards, which describe the detailed approach adopted to inspect and maintain all asset classes covering:

- **Overhead structures**: poles, crossarms
- **Overhead conductors**: sub transmission, distribution and low voltage lines
- **Underground cables**: sub transmission, distribution and low voltage cables
- **Service connections**: low voltage link and service pillars, cabinets and service intakes
- **Zone substations**: power transformers, zone switchgear, buildings, protection relays, load control
- **Distribution transformers**: ground and pole-mounted transformers
- **Distribution switchgear**: reclosers, pole-mounted fuses and switches
- **Secondary systems**: SCADA and communications.

This includes a description of the primary features, inspections and condition-monitoring carried out, and the actions taken to address any systemic problems by asset category.

The inspections of various assets are planned and Figure 5-4 shows some of the inspection areas.

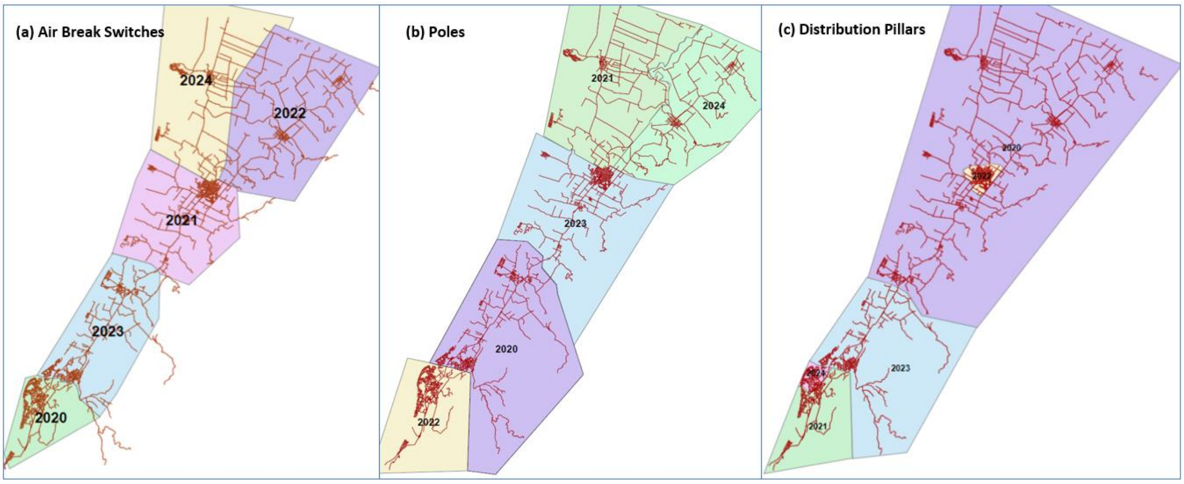


Figure 5-4: Five-year inspection cycle areas for (a) Air break switches, (b) Overhead line poles and (c) Distribution pillars

The condition of the asset is provided in Figure 5-5 which aligns the grades of asset condition with the grades set out in the Commerce Commission's Determination[19]:

Commerce Commission		Electra	
Grade	**Determination Definition**	**Code**	**Description**
H1	Replacement recommended	0	• Imminent risk of failure. • Schedule replacement for next working day unless repair or replacement required immediately
H2	End of life drivers for replacement present, high asset related risk	1	• End of serviceable life, immediate intervention required, within 3 months
H3	End of life drivers for replacement present, increasing asset related risk	2	• Material deterioration but asset condition still within serviceable life parameters. • Intervention likely within 3 years
H4	Asset serviceable – no drivers for replacement, normal in-service deterioration	3	• Normal deterioration requiring regular monitoring
H5	As new condition – no drivers for replacement	4	• Good or as new condition

Figure 5-5: Electra - grades of asset condition

Electra has inspectors who populate the inspections information of various assets into the ArcGIS Collector residing on hand-held tablets. The data input at the site is based on the condition of the asset and the data is synchronised into our database. The information is then analysed internally by asset engineers and based on the grading in Figure 5-5, the work is created and scheduled based on the assessed risk.

Data accuracy levels used in this section also refer to the said Commerce Commission's Determination and refers to the definition of the assessment of the accuracy of the data provided:

1. Means that good quality data is not available for any of the assets in the category and estimates are likely to contain significant error
2. Means that good quality data is available for some assets but not for others and the data provided includes estimates of uncounted assets within the category

[19] Commerce Commission, "Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018)"

3. Means that data is available for all assets but includes a level of estimation where there is understood to be some poor-quality data for some of the assets within the category
4. Means that good quality data is available for all the assets in the category.

We also follow the classification of conditional and non-conditional end-of-life or EOL drivers. Conditional EOL drivers relates to the physical condition serviceability while non-conditional EOL drivers relate to the external environment such as economic changes or changes in technology.

The following sections discuss the first two key steps of the asset life cycle (Operations; and Inspection and Maintenance) in detail including policies, programmes and actions. It also provides a summary of the renewal, reliability, system growth and retirement criteria. Electra's detailed plans for these steps are in Section 4.8 on Development projects.

5.3 Overhead structures

5.3.1 Concrete and steel poles

Electra has 20,459 concrete poles and 28 steel poles on its network. These range in age from new to 79 years and have been sourced from a range of suppliers including the HEPB's own pole factory. The pole population and age profile of wooden, concrete and steel poles follow:

Sub-class	Number	Unit	Percent	Key features of sub-class
Pre-stressed concrete	2,401	Each	11.7%	No known concerns but observed that heavily loaded poles are deteriorating faster
Solid concrete	17,883	Each	87.3%	No known concerns but observed that heavily loaded poles are deteriorating faster
Ex-Transpower concrete	173	Each	0.84%	Drone inspection conducted prior to energisation on March 2020
Spun concrete	2	Each	0.01%	
Steel	20	Each	0.1%	
Oclyte	8	Each	0.04%	
Total	**20,487**	**Each**	**100%**	

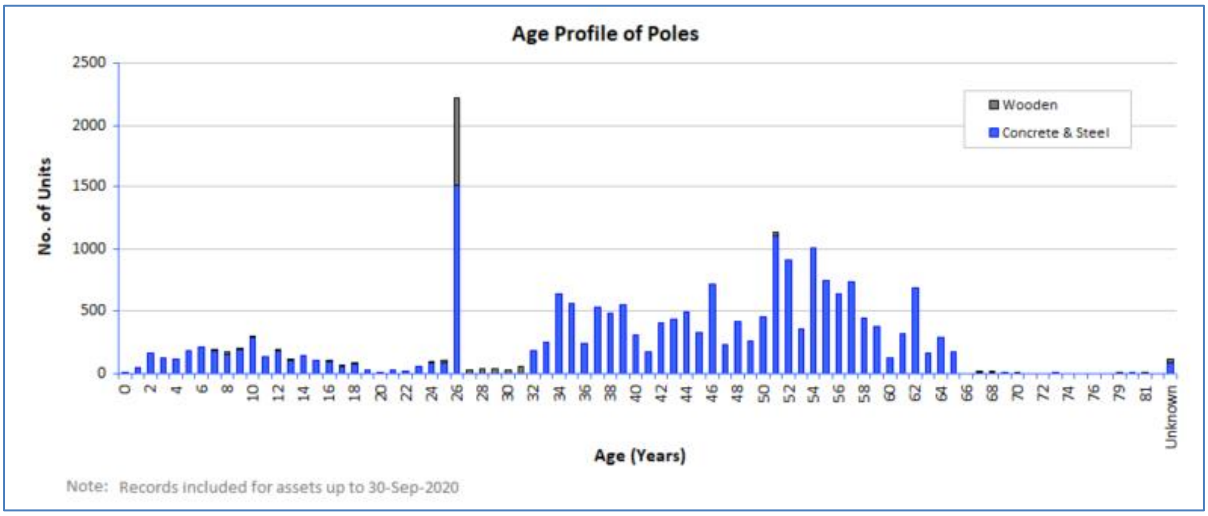


Figure 5-6: Age profile of poles

Key design parameters used are:

Parameter	Value
Durability	General design life of 60 years

Structural strength	Minimum strength embodied in Electra's Overhead Line Design Standard

5.3.1.1 Condition-monitoring

The condition of the poles is graded as shown in the following table:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Data accuracy	Percent forecast for replacement over next 5 years
		2%	94.34%	3.66%	3	2%

There are no known systemic issues with Electra's concrete or steel poles.

The key condition EOL drivers for maintenance are:

- Overall integrity of concrete
- Verticality of pole in all directions, including slumping or subsidence of surrounding ground
- Clearance of live conductors from both ground and surrounding structures
- Corrosion of steel poles, especially at ground level.

The overhead network is inspected on a five-yearly cyclic basis. Maintenance criteria include:

- Cracking or spalling of concrete becomes greater than hairline or more than 250mm long
- Reinforcing steel becomes exposed
- Supporting ground shows evidence of erosion or subsidence e.g. pole slumping
- Pole leans to the point where conductors are overly strained, or sag below minimum allowable height
- Steel pole corroded to more than surface deep, especially near ground level.

The assumptions for the above include:

- Spalling of concrete will lead to unsafe pole condition within 5 years in inland areas, and 3 years in coastal areas
- Erosion of ground will lead to unsafe condition within 2 years
- Surface corrosion of steel poles will continue to corrode deeper
- Deterioration at ground level is most critical due to greater bending moment.

Condition assessment techniques and methods are primarily visual and may include any one or more of accepted industry techniques for either structural (loading) testing or estimating remaining cross-section.

Non-condition EOL drivers include loading factors and line clearances.

Besides the poles being replaced in renewal projects, poles are also replaced or installed during key capital projects such as line upgrades, customer work or asset relocation projects which may be various requirements such as road widening works.

5.3.1.2 Inspections and maintenance

The grading of inspections together with refurbishment or renewals applied follow:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew within 3 months

Grade	Inspection	Refurbishment	Renewal
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years if repair or refurbish options are not cost effective	Will not be refurbished, may have minor repairs to lift from Grade 1	Renew within inspection cycle
3	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-
4	Continue to inspect, amend grade as required	-	-

Defect corrections are carried out within the following time frames:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within 1 week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Lifecycle decision criteria include:

- Electra will repair hairline cracks in concrete poles using commercially proven grout and treatments
- The criteria for replacement of the pole is whether the crack is bigger than hairline, more than 250mm long, or has exposed the reinforcing steel
- For poles with a planned replacement date, an optimised reduced maintenance programme may be developed if analysis concludes that the risks can be prudently managed. This may include different approaches for specific assets in sensitive areas such as parks or near schools.

Life extension and investment deferral techniques follow:

- Electra views poles as safety-critical and therefore weighs the risk of failure more heavily in its “refurbish-replace” decisions, which creates a bias for replacement (rather than squeezing a few remaining years out of pole).

5.3.1.3 Major projects and programmes

Projects and programmes FY2022:

Ref	Location	Description	Category	Cost
1	All	400V pole replacements (approx. 35 poles) - inspection driven	Renewal	$240,000
2	All	11kV pole replacements (approx. 30 poles) - inspection driven	Renewal	$250,000
3	All	33kV pole replacements (approx. 13 poles) - inspection driven	Renewal	$170,000
4	All	Fault/urgent defect replacement	Renewal	$75,000

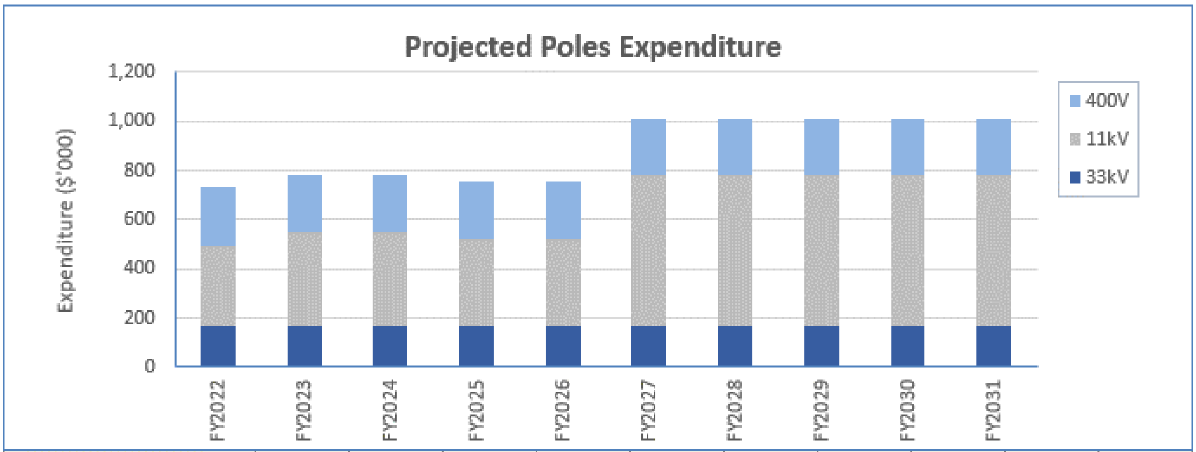
Projects and programmes FY2023 to FY2026:

Ref	Location	Description	Category	Cost
1	All	400V pole replacements (approx. 131 poles) - inspection driven	Renewal	$920,000
2	All	11kV pole replacements (approx. 122 poles) - inspection driven	Renewal	$1,220,000
3	All	33kV pole replacements (approx. 52 poles) - inspection driven	Renewal	$680,000
4	All	Fault/Urgent defect replacement	Renewal	$250,000

Projects and programmes FY2027 to FY2031:

Ref	Location	Description	Category	Cost
1	All	400V pole replacements (approx. 164 poles) - inspection driven	Renewal	$1,150,000
2	All	11kV pole replacements (approx. 255 poles) - inspection driven	Renewal	$2,810,810
3	All	33kV pole replacements (approx. 65 poles) - inspection driven	Renewal	$850,000
4	All	Fault/urgent defect replacement	Renewal	$250,000

The forecast budget for 33kV, 11kV and LV poles is shown in Figure 5-7.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
33kV	170	170	170	170	170	170	170	170	170	170
11kV	325	380	380	355	355	612	612	612	612	612
400V	240	230	230	230	230	230	230	230	230	230
Total:	735	780	780	755	755	1,012	1,012	1,012	1,012	1,012

Figure 5-7: Projected poles expenditure

5.3.2 Wooden poles

There are records of a further 1,118 service line poles whose ownership may include Chorus or customers', and is very unlikely to include Electra. There are 71 sub-transmission wooden poles. These range in age from new to 78 years old and is depicted in the age profile of Figure 5-6.

A renewal program was carried out in FY2021 to replace all 11kV hardwood poles.

Sub-class	Number	Unit	Percent
Soft wood	826	Each	69%
Hard wood	292	Each	25%
Ex Transpower hardwood	70	Each	5.92%
Ex Transpower softwood	1	Each	0.08%
Total	**1,189**		**100%**

5.3.2.1 Condition-monitoring

The condition of our hardwood poles is indicated in the following table and these will be replaced eventually by concrete poles.

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
Hardwood distribution	-	5.79%	93.25%	0.96	-	2	6%

There are no known systemic issues with Electra-owned wood poles.

Electra has been developing a customer-owned (wood) pole strategy during 2018 which will present a range of options for Electra to assist customers in maintaining their service lines and service mains in a safe condition.

5.3.2.2 Inspections and maintenance

Our maintenance drivers consist of:

- Overall integrity of timber, including absence of splits, warping or enlarging of knots
- Verticality of pole in all directions
- Evidence of rot or fungus, especially at ground level
- Clearance of live conductors from both ground and surrounding structures.

The criteria for maintenance include:

- Splitting of timber becomes greater than finger-width
- Warping or twisting of timber strains or slackens conductors
- Heart timber becomes exposed
- Supporting ground shows evidence of erosion or subsidence
- Pole leans to the point where conductors are overly strained, or sag below minimum allowable height
- Deterioration of timber becomes more than surface deep, especially at ground level.

Assumptions for the above maintenance criteria include:

- Splitting of timber will lead to unsafe pole condition within 5 years in inland areas, and 3 years in coastal areas
- Erosion of ground will lead to unsafe condition within 2 years
- Surface deterioration of timber will continue to deteriorate deeper
- Deterioration at ground level is most critical due to greater bending moment.

Condition assessment techniques and methods are primarily visual, noting that very few remain on Electra's network.

Results of our inspections are graded as shown in the following table with refurbishment or renewals applied.

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew within 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years	Minor repairs only	Renew within 3 years

Grade	Inspection	Refurbishment	Renewal
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Defect corrections are carried out within the same time frames as for concrete poles.

Lifecycle decision criteria includes:

- Electra will increase the frequency of inspection when a pole exceeds any of the maintenance criteria
- Electra will schedule replacement of wood poles when inspections reveal it to be structurally unsound or placing undue load on other components including straining or slackening conductors.

The programme and budget for the replacement of wood poles is included with concrete poles in Section 5.3.1.3.

5.3.3 Pole-top hardware

Electra has 38,033 wooden cross arms and 3,424 galvanised steel cross arms. Further details of the crossarms in the network are tabulated below:

Sub-class	Number	Unit	Percent
Hard wood	5,958	Each	14.34%
Soft wood	63	Each	0.15%
Tallow wood	31,928	Each	76.85%
Steel	304	Each	0.73%
Steel box section	2,740	Each	6.60%
Polymer	45	Each	0.11%
Ex Transpower hardwood	78	Each	0.19%
Ex Transpower softwood	6	Each	0.01%
Ex Transpower steel	380	Each	0.91%
Unknown	42	Each	0.10%
Total:	**41,544**	**Each**	**100%**

The age profile of these crossarms is shown in Figure 5-8a for wooden crossarms, and Figure 5-8b for steel crossarms. 60% of crossarm ages are unknown as the installation dates for pole-top hardware were not recorded prior to year 2000 in the previous mapping system.

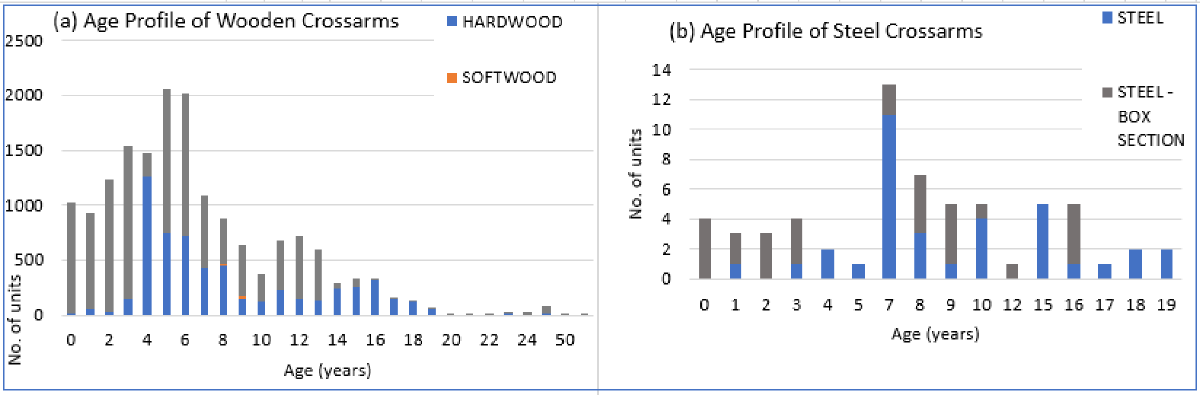


Figure 5-8: (a) Wooden and (b) Steel crossarms age profile

The key design parameters are tabulated below:

Parameter	Value
Weight	Minimise, to ease carrying to site and ease (safety) of installation
Durability	Expect to last 35 to 40 years
Insulation	May be designed to higher voltage for salty coastal areas (e.g. 22kV instead of 11 kV)
Structural strength	Embodied in Electra's overhead line design standards and includes consideration of static and wind loads

5.3.3.1 Condition-monitoring

The condition of our crossarms follow:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
		3.5%	77.6%	18.9%		-	4%

Systemic issues include pollutants on our insulators and mitigation measures follow:

Systemic issue	Mitigation	Magnitude of issue and impact on Electra
Wind-borne pollutants tracking on porcelain insulators	Electra has standardised on polymeric insulators from 2013	This issue is of minimal magnitude and doesn't significantly impact on Electra

5.3.3.2 Inspection and maintenance

The overhead network is inspected on a five-yearly cyclic basis. The drivers for pole-top maintenance include:

- Splitting, warping or bending of wooden arms
- Brown, white or soft rot of wooden cross arms, including sap staining as an early indicator of rot
- Mildew or lichen (as an indicator of moisture and as an early indicator of possible rot)
- Fungus, especially fruiting (indicative of significant decay)
- Burning or scorching possibly from tracking
- Rust on galvanised steel arms more than surface deep as observed from ground level
- Corrosion of stays significant enough to reduce physical strength
- Loose or fallen stays
- Corrosion of bolts
- Missing nuts, plate washers or spring washers
- Deterioration of air break switches, and associated actuators and linkages.

The criteria for maintenance include:

- Splitting of wooden arms more than 300mm long, risk of pin or bolt disengaging due to split width, or fungus beginning to form in split
- Brown rot (spotting or streaking) covering most of arm surface, shrinkage leading to cracking or risk of pin or bolt disengaging

- White rot (stripes) more than about 300mm long and 50mm wide, or emerging fungus (later stage)
- Soft rot (dark spots or streaks) more than about 100mm long and 15 mm thick
- Thickening mildew or lichen (possible early indicator of rot)
- Round fungus about the size of a golf ball or flat fungus more than about 100mm long
- Intermittent burn marks between pin and pole
- Visibly chipped or broken insulators
- Loose or missing nuts or washers
- Visibly loose binder
- Stay has become unfastened or is missing
- Air break switch becomes difficult to operate.

Assumptions include:

- Splitting of timber arms may lead to sudden failure
- Warping or bending or timber arms may unevenly strain conductors, leading to excessive binding tension
- Burning or scorching indicates electrical tracking
- Lichen or mildew indicates retained moisture which may lead to rot
- Visible fungus indicates likely internal decay
- Loose nuts or washers may be caused by timber arms shrinking or warping
- Tightening of air break switch operation indicates corrosion
- Visible cracking of insulators could result in water ingress and further cracking.

Condition assessment techniques and methods are primarily visual for cross-arms, looking specifically for splits, enlarged holes or fungal growth as well as visual inspections for stay straps, bolts, air-break switches with follow up on any switches reported to be stiff or not fully operating.

Inspection results are graded as follows with refurbishment or renewals applied:

Condition	Inspection	Refurbishment	Renewal/replacement
0	Scheduled for immediate replacement	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	Replace either immediately or next working day
1	No further inspections, schedule for replacement within next 3 months	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	Urgent repairs or replace with 3 months which depends on the condition and the asset type
2	No further inspection, replacement scope to be confirmed during first half of next inspection cycle	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	Renew within 1 year or within next inspection cycle which depends on the condition and the asset type
3	Will not meet replacement criteria during this inspection cycle, continue inspecting	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	Replace within first half of next inspection cycle

Condition	Inspection	Refurbishment	Renewal/replacement
4	No sign of deterioration, continue scheduled inspections	Pole top components are generally renewed rather than refurbished General servicing of air break switches on a 5-year cycle	No replacement required

Defect correction:

- **Public safety defects**: correction within one week of identification
- Significant defects that could lead to asset failure (e.g. arm breaking): correction within one week of identification
- **Minor defects**: repair by approved method within 3 months of identification.

Lifecycle decision criteria:

- Worn, damaged or broken components are generally renewed at the first convenient opportunity
- Loose cross arm bolts would generally be re-tightened unless there was evidence of excessive arm shrinkage, warping, mould, lichen, rot or fungus in which case the arm would be renewed.

Life extension and investment deferral techniques:

- Electra does apply any life extension techniques to pole top hardware.

5.3.3.3 Major projects and programmes

The projects and programmes for FY2022:

No.	Location	Description	Category	Cost
1	All	Inspection driven crossarm replacements - 11kV	Renewal	$560,000
2	All	Inspection driven crossarm replacements - 400V	Renewal	$450,000
3	All	Inspection driven crossarm replacements - 33kV	Renewal	$675,000
4	All	Fault/urgent defect replacement of cross arms	Renewal	$70,000

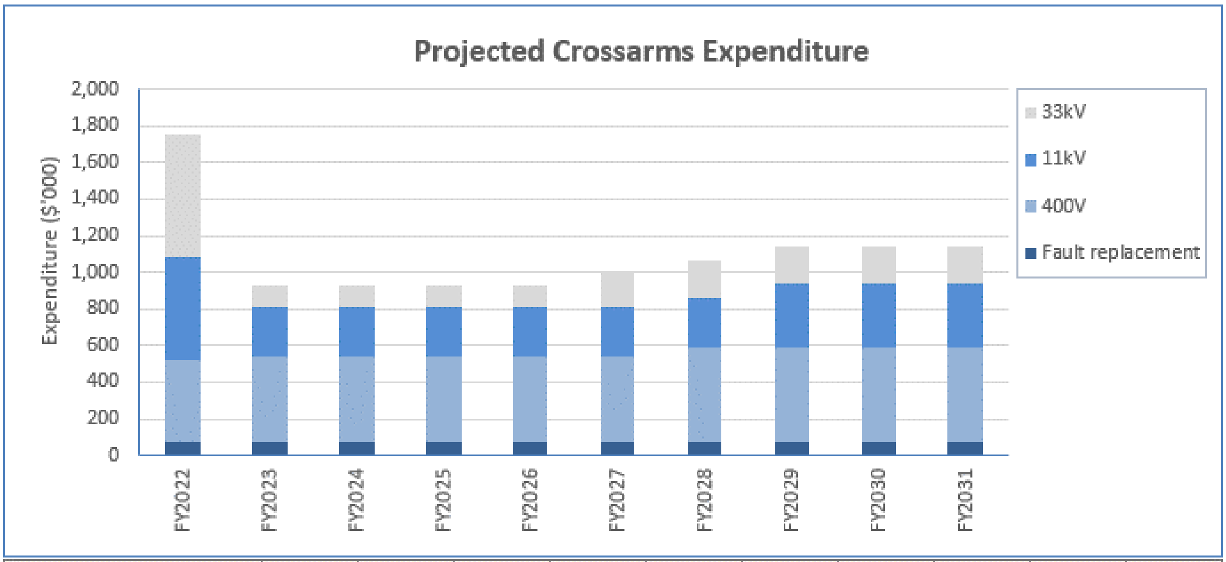
The projects and programmes for FY2023 to FY2026:

No.	Location	Description	Category	Cost
1	All	Inspection driven crossarm replacements – 11kV	Renewal	$1,100,000
2	All	Inspection driven crossarm replacements – 400V	Renewal	$1,862,516
3	All	Inspection driven crossarm replacements – 33kV	Renewal	$480,000
4	All	Fault/urgent defect replacement of cross arms	Renewal	$280,000

The projects and programmes for FY2027 to FY2031:

No.	Location	Description	Category	Cost
1	All	Inspection driven crossarm replacements – 11kV	Renewal	$1,600,000
2	All	Inspection driven crossarm replacements – 400V	Renewal	$2,545,629
3	All	Inspection driven crossarm replacements – 33kV	Renewal	$1,000, 000
4	All	Fault/urgent defect replacement of cross arms	Renewal	$350,000

The budget forecast is depicted in Figure 5-9.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
33kV	675	120	120	120	120	200	200	200	200	200
11kV	560	275	275	275	275	275	275	350	350	350
400V	450	466	466	466	466	466	520	520	520	520
Fault replacement	70	70	70	70	70	70	70	70	70	70
Total:	**1,755**	**931**	**931**	**931**	**931**	**1,011**	**1,065**	**1,140**	**1,140**	**1,140**

Figure 5-9: Projected crossarm expenditure

5.4 Overhead line conductors

5.4.1 Overhead sub-transmission lines

5.4.1.1 Inspection policies and programmes on overhead sub-transmission lines

Electra inspects the 33kV overhead circuits annually as one part of its life-cycle asset management process. Special inspections, including the use of thermal imaging every five years, are also used to enhance the maintenance planning process.

All line surveys are carried out by experienced linemen who inspect the line route and note any visual defects. Under certain conditions, these inspections may be undertaken using live line techniques. This is usually when a close-in inspection is required such as the five-yearly ABS inspections. All overhead circuits are visually inspected as follows:

Asset	Inspection guidelines
Poles	Type, leaning, spalling of concrete/or rot
Cross arms and insulators	Type, rot, lean, brackets, contamination
Conductor	Incorrect sag, damaged conductor
Trees	Growth around overhead lines, new planting, or potential fire sources
Slips or ground disturbances	Slips or other ground disturbances threatening poles, structures or underground cables
Buildings	Construction under/near lines or over cables
Telecommunication lines	Clearance from ground and Electra’s circuits
Thermography	Five-yearly – 33kV only

We record and store this information electronically. All inspection results are filtered by condition and purchase orders are raised for remedial or replacement works in the next financial year, urgent work is completed immediately.

Electra intends to complete the physical strength and remaining life tests on 33kV 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.

Electra also carries out five yearly live line condition assessments of all 33kV and 11kV ABSs on a rotating basis. These inspections examine operation, contacts, vegetation and contamination.

5.4.1.2 Maintenance policies and programmes on overhead sub-transmission lines

Circuit faults, in particular overhead lines, are the largest contributor to SAIDI. Therefore, maintenance of these circuits is essential to maintain the operating flexibility and capacity of the electricity network and minimise the risk of expensive failures and loss of supply to consumers.

The maintenance plan includes vegetation control and any works required as a result of the routine inspections and tests and is allowed for in the maintenance budget.

Cross-arms and insulators are replaced on overhead circuits as required after condition assessment inspection. This expenditure is treated as maintenance. Electra has, through its routine inspections, identified poles, cross-arms and insulators for replacement, these have been included as renewals in the budget.

5.4.1.3 Key features

Electra has 10 sub-transmission feeders as follows:

GXP	Feeder	Rating (A)	Typical loading (%)		Performance and risk concerns
			2019	2020	
Mangahao	Mangahao – Shannon 1	600	7%	6%	Nil
	Mangahao – Shannon 2	600	10%	11%	Nil
	Mangahao – Levin East 1	390	29%	29%	Mangahao CB 332 will be replaced before its rating of 390A is likely to be constrained by N-1 rating when feeding Otaki
	Mangahao – Levin East 2	390	32%	31%	Mangahao CB 312 will be replaced before its rating of 390A is likely to be constrained by n-1 rating when feeding Otaki
Valley Road	Valley Road – Waikanae 1	530	19%	20%	Nil
	Valley Road – Waikanae 2	600	22%	23%	Nil
	Valley Road – Para West	530	21%	22%	Nil
	Valley Road – Paraparaumu 1	600	18%	18%	Nil
	Valley Road – Paraparaumu 2	600	14%	14%	Nil
	Valley Road – Paekakariki	600	3%	3%	Nil

Electra has 185 km of 33kV overhead conductor, and its age profile is shown in Figure 5-10. The circuit lengths of its overhead and underground sub-transmission network can be found in Section Figure 2-5.

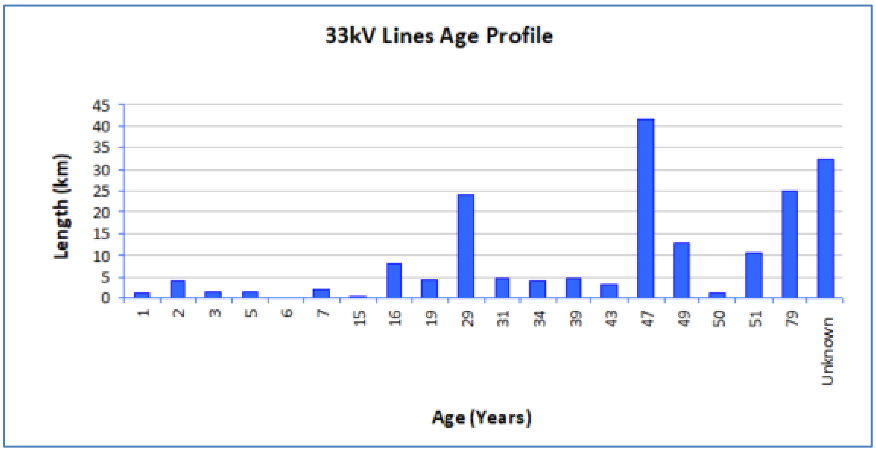


Figure 5-10: 33kV line age profile

5.4.1.4 Condition-monitoring

The condition of these lines is tabulated below where 10% is forecasted to be replaced in the next 5 years.

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
33kV conductor		14%	81.47%	4.62%		3	15.0%

5.4.1.5 Reliability analysis

Figure 5-11a shows our sub-transmission fault rate compared to other electrical distribution businesses or EDBs over the last two years (FY2019 to FY2020). At a fault rate per 100km of 3.4, we are slightly above the median of 2.7. Figure 5-11b graph will be discussed in Section 5.4.2.1.

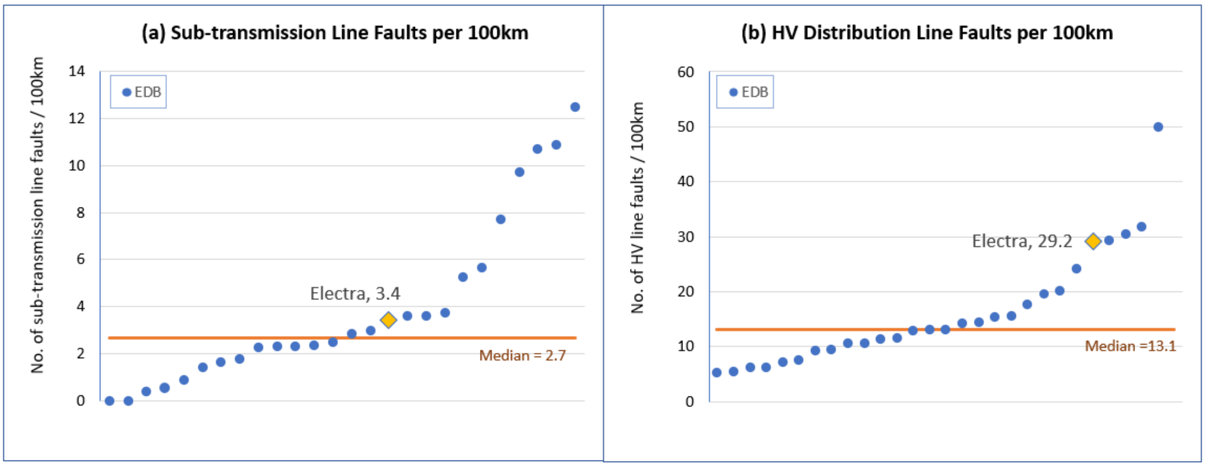


Figure 5-11: FY2019-20 number of faults per 100km of line for (a) Sub-transmission lines, and (b) HV distribution lines

The details of its inspection and maintenance criteria, programmes and budget are included in Sections 5.4.2.3 to 5.4.2.5.

The projected sub-transmission overhead lines expenditure is shown in Figure 5-14.

5.4.2 Overhead distribution conductors

Electra has 849 km of 11kV overhead conductor, and 524 km of LV overhead. These conductors are a mix of Gopher, Bee, Butterfly, 7/0.083 Copper, 19/0.064 Copper and 19/0.092 Copper.

The age profile for these distribution lines is shown in Figure 5-12 for 11kV line and Figure 5-13 for low voltage lines.

The key design parameters are:

Parameter	Value
Capacity	Nominal load of 70% of manufacturer's rating
Mechanical strength	Embodied in Electra's overhead line design standard, which in turn are referenced to span lengths and tension

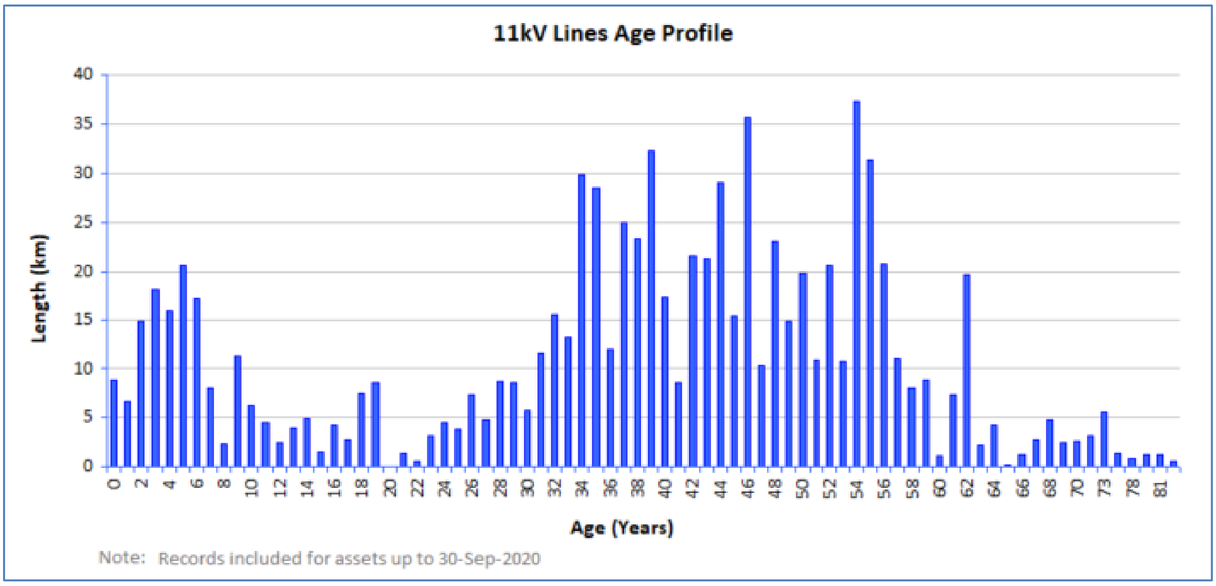


Figure 5-12: 11kV line age profile

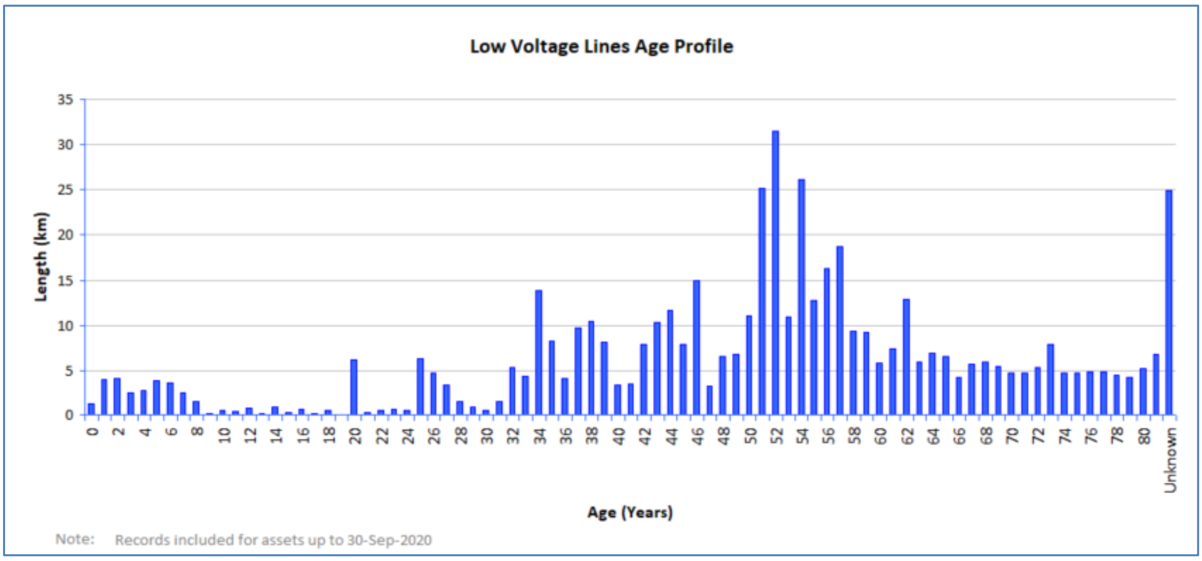


Figure 5-13: Low voltage line age profile

5.4.2.1 Condition-monitoring

The condition of our 11kV and low voltage lines are graded as shown in the following table with the forecasted replacement over the next five years:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
11kV conductor		7.00%	72%	21%		3	7%
LV conductor		5.0%		5%	90%	2	5.0%

Capacity, security and reliability constraints have been identified in Section 4.4.

A systemic issue involving ACSR conductors in coastal areas and mitigation measures are identified below:

Systemic issue	Mitigation	Magnitude of issue and impact on Electra
ACSR conductors in coastal area have had problems with corrosion	Electra's standards have been changed so that ACSR conductors have aluminium coated rather than grease coated steel reinforced	This issue is of minimal magnitude and does not significantly impact on Electra

5.4.2.2 Reliability analysis

Figure 5-11b shows our HV distribution line fault rate (11kV) compared to other EDBs over FY2019 to FY2020. The fault rate per 100km of 29.2 includes dropout fuses and third-party faults such as vehicle versus pole incidents. Broken lines, line clashes and defects due to poles, crossarms, insulators and connectors only contribute to a fault rate of 4.25 per 100km. For FY2021, we are reclassifying third party causes and equipment faults to the "Others" category within the Commerce Commission's Schedule 10(v) Fault rate and these procedures have been established.

5.4.2.3 Inspection and maintenance

The 11kV conductors and major 400V feeders are inspected on a five-year basis as compared to 33kV lines which are inspected annually.

The drivers for the maintenance of overhead conductors follow:

- Breakage, fraying or splaying of individual strands
- Stretching, elongation or necking consistent with annealing
- Bird-caging of complete conductor
- Clearance of live conductors from ground, trees, other parties' wires and surrounding structures
- Excessive surface corrosion, or
- Overall integrity of complete conductor.

The criteria for maintenance or replacement are:

- Cross-section area reduced to less than 85% of as-new conductor
- One or more strands of a 7-strand conductor visibly broken or close to breaking
- Three or more strands of a 19-strand conductor visibly broken or close to breaking

- Corrosion (especially black or green) appears more than surface deep for significant fractions of individual spans
- Individual strands visibly bird-caging
- Evidence of overheating
- Excess tension (usually a pole leaning issue)
- Sag below minimum allowable distance (usually a pole leaning issue).

Assumptions for our maintenance criteria include:

- Fraying of individual strands will place more strain on remaining strands and lead to accelerated failure
- Corrosion that is deeper than surface will place more strain on remaining strands and lead to accelerated failure
- Heavy loading for prolonged periods may anneal the conductor, reducing its tensile strength.

Condition assessment techniques and methods are primarily visual with a focus on looking specifically for cracked or corroded strands or splaying of strands.

5.4.2.4 Lifecycle policies, criteria and activities

Inspections are graded as follows and refurbishment or renewals applied as follows:

Condition	Inspection	Refurbishment	Renewal/replacement
0	Scheduled for immediate replacement	Will not be refurbished	Replace either immediately or next working day
1	No further inspections, schedule for replacement within next 3 months	Will not be refurbished	Replace with 3 months
2	No further inspection, replacement scope to be confirmed during first half of next inspection cycle	Minor repairs only	Renew within 3 years
3	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	Replace within first half of next inspection cycle
4	No sign of deterioration, continue scheduled inspections	Repair to extend life as considered appropriate by Planning & Development Manager	No replacement required

Defect corrections are made as follows:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Upgrading activities are carried out based on the following criteria:

- **Renewal/replacement**: progressive replacement of all copper conductor with a thicker conductor to allow 11kV back feeding and eliminate safety hazard (breakage and whipping), starting with 7/0.064 where possible

- **Lifecycle decision criteria**: up-size if conductor is loaded beyond 70% of nominal rating for more than about 3,000 hours per year; replace if more than 1 strand of a 7-strand conductor or 3 strands of a 19-strand conductor are visibly broken or splayed
- **Life extension and investment deferral techniques**: use of aluminium-coated steel-reinforced ACSR rather than grease coated steel reinforcing.

5.4.2.5 Major projects and programmes

The projects and programmes for FY2022 follow:

Ref	Location	Description	Category	Cost
1	All	400V Reconductor	Renewal	$525,000
2	All	Carryover budget	Renewal	$500,000
3	Mangahao Rd, Shannon	Replace 16mm Cu with Gopher (4km in 2 years)	Renewal	$290,000
4	Takapu Road, Otaki	Replace aged Gopher with Gopher (1.64km)	Renewal	$247,000
5	Waitohu Valley Rd, Otaki	Replace Rango with BEE conductor (1.5km)	Renewal	$235,000
6	SH57 near Shannon	Replace 35mm Cu with BEE (3.9km in 3 years)	Renewal	$205,000
7	Te Manuao Rd, Otaki	Replace 16mm Cu with BEE (1km)	Renewal	$150,000
8	Hokio Beach Rd, Levin	Replace Cu with Bee conductor (0.9km)	Renewal	$140,000
9	Wi Tako St, Manakau	Replace 14mm Cu with BEE (0.7km)	Renewal	$110,000
10	Tui Crescent, Waikanae	Replace 16mm Cu with Gopher (0.68km)	Renewal	$102,000
11	Domain Rd, Otaki	Replace 16mm Cu with Gopher (0.5km)	Renewal	$75,000
12	Wilton St, Levin	Replace Cu with BEE (0.4km)	Renewal	$65,000
13	Rahui Rd, Otaki	Replace Cu with BEE (0.2km)	Renewal	$40,000

Projects and programmes for FY2023 to FY2026 are:

Ref	Location	Description	Category	Cost
1	Mangahao to Levin East	Upgrade 33kV to Butterfly double circuit	Renewal	$3,000,000
2	All	400V Reconductor	Renewal	$2,100,000
3	All	Inspection driven conductor replacements	Renewal	$1,259,914
4	SH57 near Shannon	Replace 35mm Cu with BEE (3.9km in 3 years)	Renewal	$420,000
5	Tiro and Mako Rd, Levin	Replace 35mm Cu with BEE (2.5km in 2 years)	Renewal	$340,000
6	Mangahao Rd, Shannon	Replace 16mm Cu with Gopher (total 4km in 2 years)	Renewal	$300,000
7	SH1, Manakau L4 to H86	Replace 35mm Cu with BEE (2km)	Renewal	$272,000
8	Engles Rd, Shannon	Replace 16mm Cu with Gopher (2km)	Renewal	$272,000
9	SH1, Manakau L224 to L4	Replace 35mm Cu with BEE (1.86kms)	Renewal	$252,960
10	Bryce St, Shannon	Replace 16mm Cu with Gopher (1.8kms)	Renewal	$244,800
11	SH1, Levin H166 to H102	Replace 35mm Cu with BEE (1.8kms)	Renewal	$244,800
12	Tasman Road, Otaki	Replace 35mm Cu with BEE (1.45kms)	Renewal	$197,200
13	Makora Road, Paraparaumu	Replace 16mm Cu with BEE (1.3kms)	Renewal	$176,800
14	SH1, Levin H86 to H166	Replace 35mm Cu with BEE (1.2kms)	Renewal	$163,200
15	Ngarara Rd, Waikanae	Replace 16mm Cu with BEE (1.2km)	Renewal	$163,200
16	Whakahoro Rd, Otaki	Replace 16mm Cu with Gopher (1.1km)	Renewal	$150,000
17	Valley Rd, Paraparaumu	Replace 16mm Cu with Gopher (0.75km)	Renewal	$102,000
18	Tame Porati St, Otaki	Replace existing 16mm Cu with Gopher (0.46kms)	Renewal	$62,560
19	Wilton St, Levin	Replace 16mm Cu with Gopher (0.4km)	Renewal	$54,000

Ref	Location	Description	Category	Cost
20	Alexander Rd, Raumati	Replace 16mm Cu with Gopher (0.28km)	Renewal	$38,080
21	Whyte St, Paraparaumu	Replace 16mm Cu with Gopher (0.26km)	Renewal	$32,640
22	Armagh St, Levin	Replace 16mm Cu with Gopher (0.22km)	Renewal	$29,920
23	Bledisloe St, Levin	Replace 16mm Cu with Gopher (0.21km)	Renewal	$28,560
24	Read St, Levin	Replace existing 16mm Cu with Gopher (0.21kms)	Renewal	$28,560
25	Titoki St, Otaki	Replace existing 16mm Cu with Gopher (0.2kms)	Renewal	$27,200

Projects and programmes FY2027 to FY2031 follow:

Ref	Location	Description	Category	Cost
1	All	Inspection driven conductor replacements	Renewal	$7,218,480
2	All	400V Reconductoring	Renewal	$3,125,000
3	Shannon Rd, Foxton	Replace 35mm Cu with BEE (12.08kms in 4 years)	Renewal	$1,800,000
4	Mangahao to Levin East 33kV	Upgrade to Butterfly double circuit	Renewal	$1,000,000
5	SH1 Waitarere Beach Rd to Koputaroa Rd	Replace Mink with Bee (2.5km)	Renewal	$340,000
6	Levin	Replace 35mm Cu with Bee (0.82km)	Renewal	$111,520

The projected distribution overhead lines expenditure is shown in Figure 5-14.

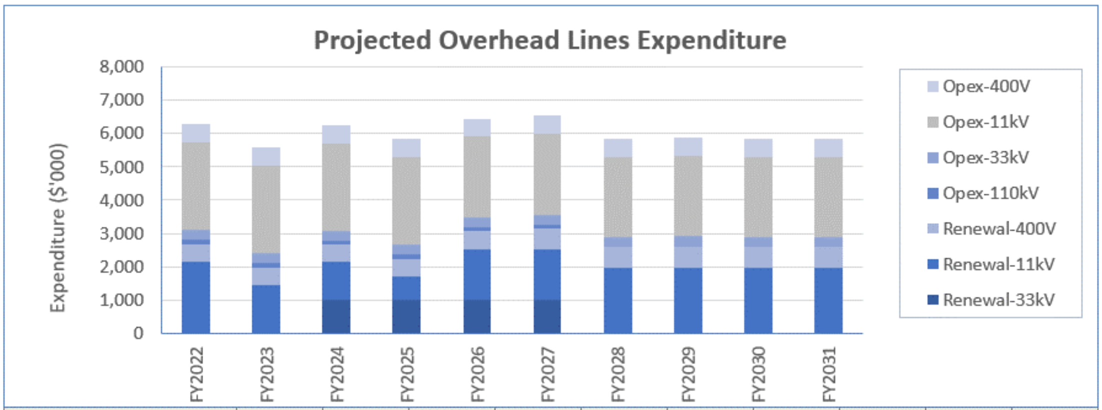
5.4.3 Customer-owned lines

Whilst customer-owned lines (broadly defined as any line on the customer's side of the property boundary) are not owned by Electra, these lines form an integral part of the electricity supply chain.

Electra has commenced a programme to inform customers about risks associated with customer-owned power lines and offer a service to assist them in reducing any identified issues.

5.4.4 Overhead lines forecast

The projected sub-transmission, 11kV and low voltage overhead lines expenditure is shown in Figure 5-14.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
Renewal-33kV	0	0	1,000	1,000	1,000	1,000	0	0	0	0
Renewal-11kV	2,159	1,456	1,149	721	1,534	1,534	1,984	1,984	1,984	1,984
Renewal-400V	525	525	525	525	525	625	625	625	625	625
Total (Capex):	**2,684**	**1,981**	**2,674**	**2,246**	**3,059**	**3,159**	**2,609**	**2,609**	**2,609**	**2,609**
Operational Expenditure ($'000)										
Opex-110kV	120	120	120	120	120	120	0	0	0	0
Opex-33kV	295	320	295	295	320	295	295	320	295	295
Opex-11kV	2,637	2,622	2,622	2,622	2,403	2,403	2,403	2,383	2,383	2,383
Opex-400V	552	552	552	552	552	552	552	552	552	552
Total (Opex):	**3,603**	**3,613**	**3,588**	**3,588**	**3,394**	**3,369**	**3,249**	**3,254**	**3,229**	**3,229**

Figure 5-14: Projected overhead lines expenditure

5.5 Underground cables

5.5.1 Sub-transmission cables

5.5.1.1 Inspection policies and programmes on underground sub-transmission assets

Underground cables are generally not inspected except at terminations in zone substations, ground based transformers or switchgear. The sole exceptions are 33kV underground cables where the route is visually inspected annually on a similar basis as to overhead lines. Further, partial discharge testing of these single core XLPE insulated cables is carried out every three years.

5.5.1.2 Maintenance policies and programmes on underground sub-transmission assets

33kV cables are subject to annual visual inspections of all above ground terminations including annual thermograph scans of all terminations including annual visual inspections of all above ground terminations and triennial thermal tests. Partial discharge testing of these single core XLPE insulated cables is carried out every three years.

Electra has eight 33kV underground circuits; these are mainly in the Kapiti Coast except for one laid from Mangahao to Shannon, each being single core XLPE cables laid in trefoil formation.

5.5.1.3 Key features

Electra has 31 km of 33kV cable and associated terminations. The composition of these cables follows:

Sub-class	Length	Unit	Percentage
500 mm^2 aluminium XLPE	6.1	km	19%
630 mm^2 aluminium XLPE	19.1	km	62%
800 mm^2 aluminium XLPE	6	km	19%
Total	**31**	**km**	**100%**

The key design parameters include:

Parameter	Value
Load rating	Load to about 70% of manufacturer's rating before application of any other de-rating factors (such as proximity, soil thermal conductivity, ambient temperature)
Durability	Expect XLPE cable to last 50 to 60 years

Figure 5-15 shows the age profile of the 33kV cable class.

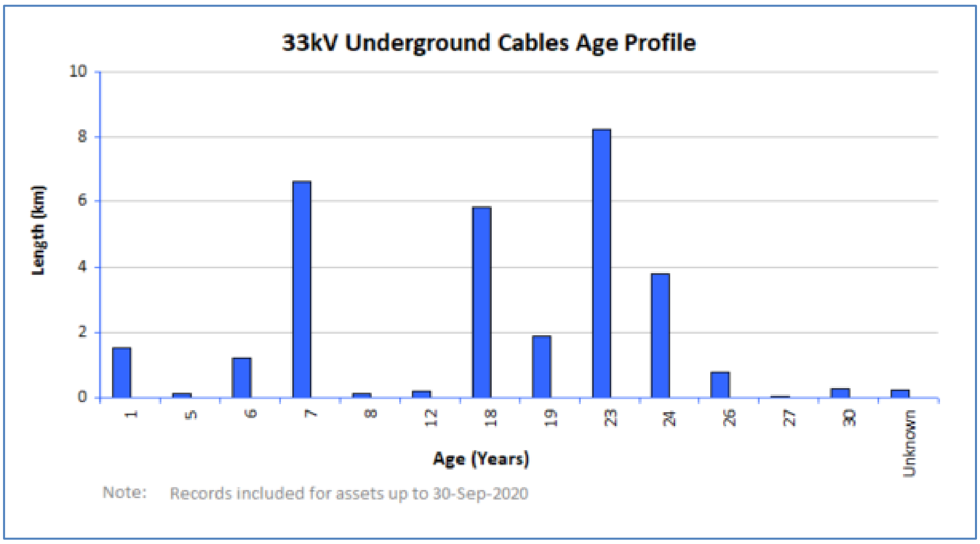


Figure 5-15: 33kV cable age profile

5.5.1.4 Condition-monitoring

The condition of these cables is tabulated in the following table and 4% are forecasted to be replaced over the next five years.

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
			69%	31%		4	0%

There are no known systemic issues with Electra's 33kV cables, and neither are there capacity nor reliability constraints.

5.5.1.5 Inspection and maintenance

The conditional EOL drivers for maintenance are:

- Visible deterioration of pot heads or terminations
- Visible deterioration of cable sheathing

- Deterioration of cable insulation
- Visible shifting of the cable within the mountings or ground that may be straining internal components.

To verify the condition of our 33kV cables, we carry out Tan Delta, also called Loss Angle or Dissipation Factor testing, which is a diagnostic method of testing cables to determine the quality of the cable insulation. One of the criteria for maintenance is when Tan Delta as well as partial discharge test results exceeds limits. Other maintenance criteria include:

- Thermography of cable terminations reveals excessive temperatures
- Splitting or cracking of PVC cable sheath such that armour wire or insulation is visible
- Excessive UV deterioration of PVC sheaths
- Movement of anchor points relative to supports or ground that may be straining internal components.

Assumptions made for the above maintenance criteria include:

- Unacceptable Tan Delta readings will continue to deteriorate rather than plateau
- Deterioration of PVC sheaths will lead to cracking, exposure of armour wires and eventual failures
- Straining of internal components due to movement is likely to damage insulation.

Condition assessment techniques and methods include the visual inspection of exposed components, surveying of cable routes to check for excavation or penetrations, regular Tan Delta and similar insulation checks.

Non-conditional EOL drivers include the availability of maintenance parts and specialist tools, orphan assets, repeated failures and workmanship.

Inspections are graded as follows and refurbishment or renewals applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew within 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years	Minor repairs only	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Correction of defects are carried out as follows:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

The criteria for lifecycle decisions include:

- Consider up-sizing if loading beyond 70% of manufacturer’s rating occurs for more than 3,000 hours per year
- Consider up-sizing if fault level exceeds cable fault rating.

Cable life is designed to achieve the correct rating at the design stage by understanding the cable loading and thermal characteristics of the soil, and by careful handling at the installation stage including adherence to minimum bending radii.

5.5.2 High voltage 11kV distribution cable

Electra has 246 km of 11kV cable and the composition of the cables follows:

Sub-class	Number	Unit	Percent
PILC	118	km	48%
XLPE, PVC or HDPE	128	km	52%
Total	**246**	**km**	**100%**

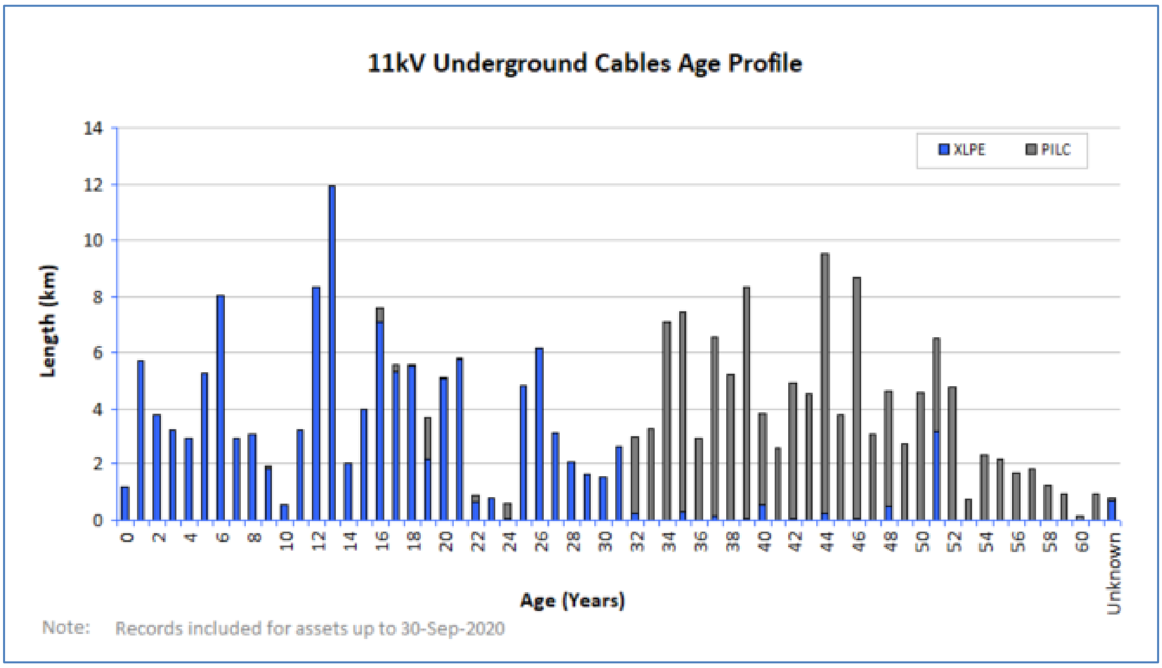


Figure 5-16: 11kV XLPE and PILC underground cables age profile

Key design parameters include:

Parameter	Value
Load rating	Nominally loaded to about 70% of manufacturer’s rating
Durability	Expect XLPE cable to last 50 to 60 years

5.5.2.1 Condition-monitoring

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
XLPE, PVC or HDPE	-	-	83.38%	16.62%	-	3	-
PILC	-	2.0%	98%	-	-	2	2.00%

There are no known systemic issues with Electra’s 11kV cable, and neither are there capacity, security nor reliability constraints.

5.5.2.2 Reliability analysis

Figure 5-17 depicts the HV distribution cable fault rate per 100km amongst EDBs from FY2019 to FY2020. Electra’s average fault rate of 10.7 faults per 100km is above the median of 2.9. Similar to that for overhead lines (Section 5.4.2.2), this rate includes equipment faults such as ground-mounted switchgear and transformers and such faults will be reclassified under "Others" in Commerce Commission's Schedule 10(v). The relevant cable faults due to cable joints and terminations only contribute to a fault rate of 4.9 per 100km.

Our annual review of these faults has not identified a systemic issue and each fault is considered uniquely, and remedial action taken where appropriate. The following sections identify our inspection and maintenance activities.

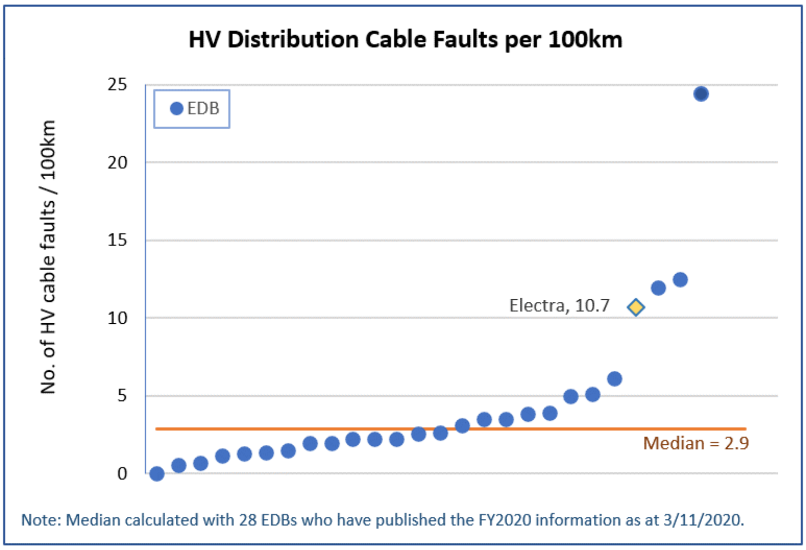


Figure 5-17: FY2019 to FY2020 HV underground cable faults per 100km for all EDBs

5.5.2.3 Inspection and maintenance

The conditional EOL drivers for maintenance are visible deterioration of cable sheathing, pot heads or terminations, the deterioration of cable insulation as well as visible shifting of the cable within the mountings or ground that may be straining internal components.

The maintenance criteria include:

- Splitting or cracking of PVC cable sheath such that armour wire or insulation is visible
- Excessive UV deterioration of PVC sheaths
- Movement of anchor points relative to ground that may be straining internal components.

The assumptions for maintenance are:

- The deterioration of PVC sheaths will lead to cracking, exposure of armour wires and eventual failures
- Straining of internal components due to movement is likely to damage insulation.

Condition assessment techniques and methods used are primarily visual inspection of exposed components only, mainly for chipped or broken bushings or perishing insulation.

Non-conditional EOL drivers include the availability of cable accessories, repeated failures, loading history and workmanship.

Inspections are graded as follows with refurbishment or renewals applied:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew within 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years	Minor repairs only	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Correction of defects are made as follows:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

The following activities are considered as follows:

- Lifecycle decision criteria
- Consider up-sizing if loading beyond 70% of manufacturer's rating occurs for more than 3,000 hours per year
- Consider up-sizing if fault level exceeds cable fault rating
- Life extension and investment deferral techniques: design cable life is achieved by correct rating at the design stage, understanding the cable loading and thermal characteristics of the soil, and by careful handling at the installation stage including adherence to minimum bending radii.

5.5.2.4 Major projects and programmes

The projects and programmes for FY2022 are:

Ref	Location	Type of work	Category	Cost
1	All	Design line/cable jobs	Renewal	$125,000
2	All	Replace pitch filled potheads with Raychem terminations	Safety	$60,000
3	All	Fault/urgent defect replacement of 11kV cables	Renewal	$60,000

Projects and programmes for FY2023 to FY2026 follow:

Ref	Location	Type of work	Category	Cost
1	All	Design line/cable jobs	Renewal	$300,000
2	All	Fault/urgent defect replacement of 11kV cables	Renewal	$240,000
3	Tui Rd, Raumati	Replace cable between Z92 and Z103 – 11kV	Renewal	$163,538
4	All	Replace pitch filled potheads with Raychem terminations	Safety	$160,000
5	Bath Street, Levin	Replace 11kV cable E313-E83	Renewal	$130,000

The projects and programmes for FY2027 to FY2031 follow:

Ref	Location	Type of work	Category	Cost
1	All	Fault/urgent defect replacement of 11kV cables	Renewal	$750,000
2	All	Design line/cable jobs	Renewal	$375,000

Ref	Location	Type of work	Category	Cost
3	All	Replace pitch filled potheads with Raychem terminations	Safety	$200,000
4	Tui Rd, Raumati	Replace cable between Z92 and Z103 – 11kV	Renewal	$81,769

The projected underground HV cables expenditure is shown in Figure 5-19.

5.5.3 LV cable

Electra has 497 km of LV cable and associated distribution pillars and fittings. The LV cable profile is shown in Figure 5-18.

The key design parameters are:

Parameter	Value
Load rating	Load to about 70% of manufacturer's rating before application of any other de-rating factors (such as proximity, soil thermal conductivity, ambient temperature)
Durability	Expect XLPE cable to last 50 to 60 years

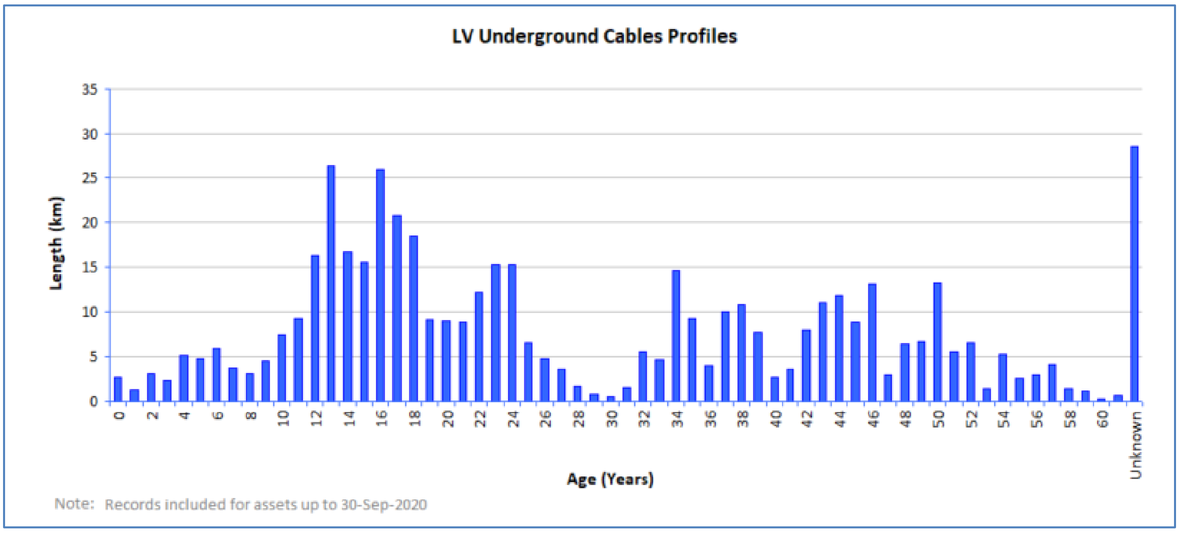


Figure 5-18: Low Voltage (LV) underground cable age profile

5.5.3.1 Condition-monitoring

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
			35.00%	9.00%	56.00%	2	2.00%

There are no known systemic LV cable issues. The following problems have been encountered in the past, but have been corrected:

- Failures of tee joints on pre-1970 cables.

Inspection and maintenance for LV cables are similar to that for 11kV cables listed in Section 5.5.2.3 and the operational expenses forecasted are shown in Figure 5-19.

5.5.3.2 Major projects and programmes

The projects and programmes FY2022 for underground cables follow:

Ref	Location	Type of work	Category	Cost
1	All	Fault/urgent defect replacement of 400V /streetlight cables	Renewal	$40,000

Projects and programmes 2023 to 2026:

Ref	Location	Type of work	Category	Cost
1	All	Fault/urgent defect replacement of 400V /streetlight cables	Renewal	$160,000

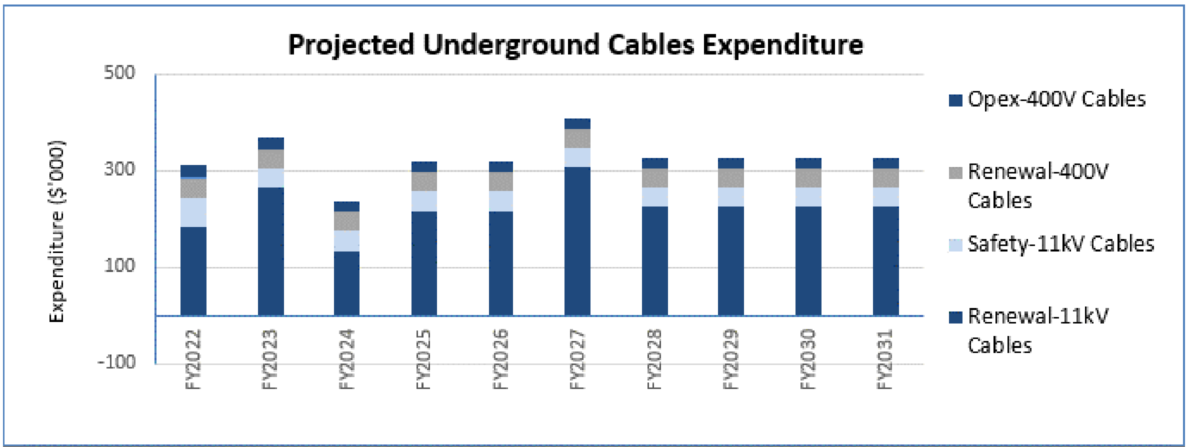
Projects and programmes 2027 to 2031:

Ref	Location	Type of work	Category	Cost
1	All	Fault/urgent defect replacement of 400V /streetlight cables	Renewal	$200,000

The projected underground LV cables and pillars expenditure is shown in Figure 5-19.

5.5.4 Underground cables forecast

The projected underground HV and LV cables expenditure is shown in Figure 5-19.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
Renewal-11kV Cables	185	265	135	217	217	307	225	225	225	225
Safety-11kV Cables	60	40	40	40	40	40	40	40	40	40
Renewal-400V Cables	40	40	40	40	40	40	40	40	40	40
Total (Capex):	**285**	**345**	**215**	**297**	**297**	**387**	**305**	**305**	**305**	**305**
Operational Expenditure ($'000)										
Opex-400V Cables	23	23	23	23	23	23	23	23	23	23
Total (Opex):	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**

Figure 5-19: Projected underground cables expenditure

5.6 Service connections

Connection assets connect Electra's 46,438 consumers (as of September 2020) to the 11kV and 400V distribution networks. These connection assets include simple pole fuses, suburban distribution pillars, and dedicated lines and transformer installations supplying single large consumers.

In most cases the fuse holder forms the demarcation point between Electra's network and the consumers' assets (the "service main"). This is usually located at or near the physical boundary of the consumers' property. These assets form the point of delivery for Electra's distribution services. About 50% of these connections are located on overhead lines and the other 50% on underground networks. These are made up of three phase and single-phase connections.

The 400V network connects the transformers to the consumers through fuses located at service poles and pillars. Also included within this network are the street and community lighting circuits. Electra owns and maintains all service fuses on the 400V network. Most fuses are HRC construction but rewireable types are still present on older overhead lines and load control circuits. Electra replaces fuses as they fail or when the equipment they are attached to is replaced.

There are 10,048 services pillars and cabinets.

The LV pillar population within our network comprise of service, footway and link pillars and the details follow:

Sub-class	Number	Unit	Percent
Service pillar	10,048	Each	93.9%
Link pillar	276	Each	2.6%
Footway pillar	381	Each	3.5%
Total	**10,705**	**Each**	**100%**

The pillars need to be unobtrusive, have low initial costs and low maintenance costs. Generally installed as part of new subdivisions, most pillars are steel if installed prior to 1990 and PVC if installed after 1990. The age profile of 400V pillars is shown in Figure 5-20.

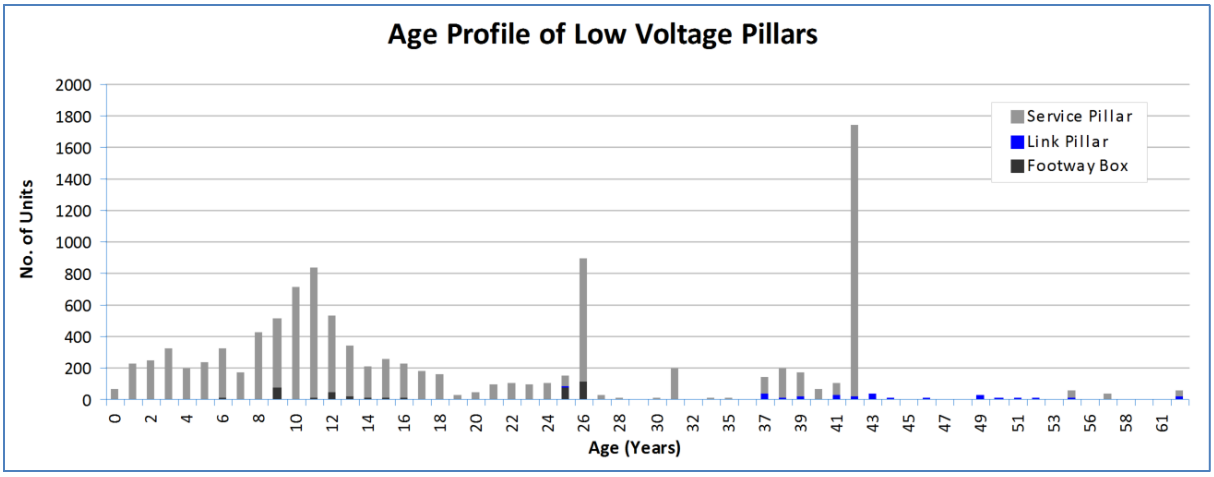


Figure 5-20: Age Profile of Pillars

5.6.1 Condition-monitoring

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
		5%	90%	5%		2	5%

The condition of pillars is monitored using the ARMM system.

The key systemic issue with service pillars has been the corrosion of some earlier thin steel pillars and the degradation of non-UV stabilised polymer pillars. The affected pillars are replaced progressively based on risk they pose to network and public safety.

The following problems have been encountered in the past, but have been corrected:

- Ground level corrosion of pre-1980 steel pillars.

Inspection and maintenance

Maintenance conditional EOL drivers include:

- Rusting of enclosures
- Stability of mounting, including slumping or subsidence of surrounding ground.

Maintenance criteria include:

- Rust more than surface deep
- Slumping or movement of ground, particularly tilting that may expose live components.

Conditional assessment methods include:

- Visual, including public safety checks and checking of copper earthing.

All 400V pillars are inspected on a five year cycle and any damaged units replaced and the schedule for various areas is shown in Figure 5-4. Inspections are graded as follows with refurbishment or renewals applied:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew within 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years	Minor repairs only	Renew within 3 years
3 & 4	Continue to inspect, check grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	

Correction of defects are carried out based on the following:

- **Public safety defects**: correction within 1 week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Criteria for lifecycle decisions and techniques include:

- Pillars that are considered to have an unacceptably high public safety risk will be specifically marked for accelerated replacement. The precise order of replacement will include consideration of actual condition, known defects, and proximity to sensitive locations like parks and schools
- Decision to renew rather than refurbish made on a case-by-case basis.

The FY2022 projects and programmes for pillars were included in the previous section 5.5.3.2 and the projected pillars expenditure is discussed in Section 5.5.4 and displayed in Figure 5-19.

5.6.1.1 Major projects and programmes

The projects and programmes FY2022 for pillars follow:

Ref	Location	Type of work	Category	Cost
1	All	Steel Link Pillar Removal	Safety	$250,000
2	All	Inspection driven –pillar replacement	Renewal	$198,085
3	All	Unplanned pillar replacement	Renewal	$30,000

Projects and programmes 2023 to 2026:

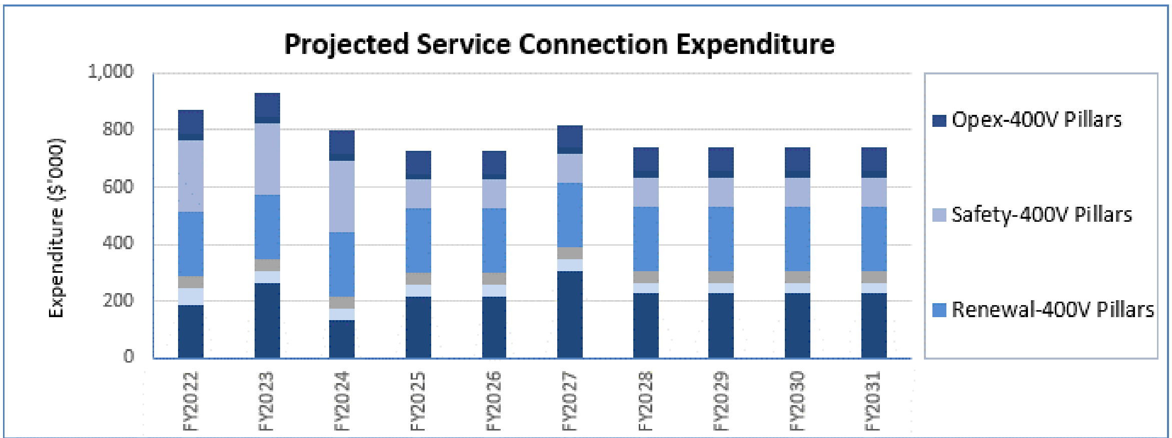
Ref	Location	Type of work	Category	Cost
1	All	Inspection driven –pillar replacement	Renewal	$792,340
2	All	Steel Link Pillar Removal	Safety	$700,000
3	All	Unplanned pillar replacement	Renewal	$120,000

Projects and programmes 2027 to 2031:

Ref	Location	Type of work	Category	Cost
1	All	Inspection driven pillar replacement	Renewal	$990,425
2	All	Steel Link Pillar Removal	Safety	$500,000
4	All	Unplanned - pillars	Renewal	$150,000

5.6.2 Service Connection Forecast

The projected service connection expenditure is shown in Figure 5-21.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
Renewal-400V Pillars	228	228	228	228	228	228	228	228	228	228
Safety-400V Pillars	250	250	250	100	100	100	100	100	100	100
Total (Capex):	**478**	**478**	**478**	**328**	**328**	**328**	**328**	**328**	**328**	**328**
Operational Expenditure ($'000)										
Opex-400V Pillars	83	83	83	83	83	83	83	83	83	83
Total (Opex):	**83**	**83**	**83**	**83**	**83**	**83**	**83**	**83**	**83**	**83**

Figure 5-21: Projected customer connection expenditure

5.7 Zone substations

Electra has ten zone substations which transform energy from the 33kV sub-transmission network to the 11kV distribution network. All but the Paekakariki substation are dual transformer substations. Therefore, all substations have (n-1) security as shown in the following table except for Paekakariki where the 33 kV circuit is backed by an 11 kV feeder from Raumati substation; the KiwiRail traction substation is backed by other KiwiRail feeders from Pukerua Bay.

Zone substation	Description	Security	ICPs	Nature of load	Performance and risk concerns
Shannon	• Dual transformer • Indoor switchgear • Built in 2010	(n-1)	2021	Mix of urban load in Shannon and rural load toward Tokomaru and Opiki	No known issues Performing within specification

Zone substation	Description	Security	ICPs	Nature of load	Performance and risk concerns
Foxton	• Dual transformer • High-level steel structure outdoor • Significantly rebuilt in 2004	(n-1)	3702	Predominantly urban load in Foxton with some rural load in all directions	No known issues Performing within specification
Levin East	• Dual transformer • High-level steel structure • Built in 1990	(n-1)	6342	Predominantly urban, although with some rural load to the south and east of Levin	No known issues Performing within specification
Levin West	• Dual transformer • High-level steel structure • Built in 1974	(n-1)	5796	Predominantly the rural areas to the north and west of Levin, Waitarere Beach, some urban load in the western parts of Levin	No known issues Performing within specification
Otaki	• Dual transformer • Indoor substation • Built in 1994	(n-1)	6387	Predominantly urban load in Otaki with some rural load in Otaki Gorge, Manakau, Te Horo and Waikawa Beach	No known issues Performing within specification
Waikanae	• Dual transformer • Indoor substation • Built in 1996	(n-1)	7416	Dense urban load in and around Waikanae, some rural load to the north in Pekapeka and to the east in Reikorangi	No known issues Performing within specification
Paraparaumu	• Dual transformer • High-level concrete pole outdoor • Built in 1970, rebuilt in 2015	(n-1)	4500	Dense urban load in the eastern and central parts of Paraparaumu, some rural load on the immediate outskirts of Paraparaumu	Performing within specification Increased inspection frequency for 1 transformer
Paraparaumu West	• Dual transformer • Indoor substation • Built in 2002	(n-1)	5417	Dense urban load in central and western parts of Paraparaumu	No known issues Performing within specification
Raumati	• Dual transformer • High-level steel structure outdoor substation • Built in 1988	(n-1)	4119	Dense urban load in and around Raumati	No known issues Performing within specification
Paekakariki	• Single transformer • High-level outdoor substation • Built in 1982 • 33 kV circuit backed up by 11 kV feeder from Raumati; KiwiRail traction substation is on ‘n’ security but backed up by other KiwiRail feeders to the north and south.	(n-1)*	925	Mix of light urban and semi-rural load around Paekakariki	No known issues Performing within specification

5.7.1 Improvement in maintenance standards

Zone substation maintenance standards are controlled by Electra’s “Zone Substation Sites and Buildings – Maintenance” Standard which defines maintenance intervals and service work for all zone substation sites and buildings in the electricity network. Routine maintenance tasks are carried out bi-monthly while major inspections are carried out annually.

Electra has acquired a new secondary injection test set CMC356 and this equipment is being used to test 33kV and 11kV protection settings. This new test set has brought an opportunity to standardise the test procedure and improve efficiency by creating OCC test files. Test reports can be generated in a standard format.

The new primary injection test set (CPC100) has allowed well-organised pre and post maintenance tests to be carried out on all substation transformers and contractors are engaged to maintain the tap-changers where required. These results are recorded in the Asset Health Index datasheet to reflect the current health status of the assets concerned.

Appendix 5 contains the Commerce Commission's Schedule 12b, the report on forecast capacity which shows the security of supply and capacity of the zone transformers.

5.7.2 Zone transformers

Electra has 19 zone substation transformers, all 33/11kV. These range from 5 MVA to 11.5/18/23 MVA and have a variation of cooling methods - ONAN, ONAF and OFAF.

There are three 5 MVA transformers and sixteen 11.5 / 23 MVA transformers and details of these transformers follow:

Zone substation	Number and rating	Cooling	Year of manufacture		Utilisation of installed firm capacity	
			T1	T2	FY2020	FY2021
Shannon	Two 5 MVA	ONAN	1977	1974	93%	85%
Foxton	Two 11.5/23 MVA	ONAN, ONAF	2004	2004	30%	32%
Levin East	Two 11.5/23 MVA	ONAN, ONAF	1979	1973	56%	61%
Levin West	Two 11.5/23 MVA	ONAN, ONAF	2011	2000	61%	57%
Otaki	Two 11.5/23 MVA	ONAN, ONAF	1976	1976	51%	52%
Waikanae	Two 11.5/23 MVA	ONAN, ONAF	1996	1996	66%	67%
Paraparaumu	Two 11.5/18/23 MVA	ONAN, ONAF, OFAF	1970	1970	56%	57%
Paraparaumu West	Two 11.5/23 MVA	ONAN, ONAF	2001	2001	55%	54%
Raumati	Two 11.5/23 MVA	ONAN, ONAF	2011	1987	43%	42%
Paekakariki	One 5 MVA	ONAN	1960	-		

Shannon is the only substation close to being loaded to near its firm (n-1) capacity, in that case the 11kV load can be shifted to Foxton or Levin East if the constraint emerges.

The key design parameters are:

Parameter	Value
Durability	Expect a minimum life of 60 years
Rating	Design load to no more than 70% to enable load of faulted substation to be supplied by two neighbouring substations

Since adopting the ARMM (or Asset Risk Management Model) to align with ISO 50001 requirements, Electra has been carrying out condition-monitoring for its power transformers systematically. The yearly inspection for all 19 power transformers has been completed in September 2020 for the three 5MVA and sixteen 20MVA in-service transformers. The Industry average life expectancy of a transformer is 60 years; depending on load factor, operational temperature and location of the transformer, the life expectancy may differ.

Paekakariki transformer is approaching the end of its asset life of 60 years. Regular electrical tests and maintenance confirm its continued performance and efficiency and Furan in oil analysis has confirmed healthy paper insulation.

The existing 11kV backup from Raumati substation have served Electra well over the previous decade and an upgrade of the protection system from a manual changeover to an automated changeover will increase the security of supply to Paekakariki.

Electra also owns two spare 5MVA transformers located at Shannon substation within a secure oil bund.

The age profiles of these zone transformers are shown in Figure 5-22.

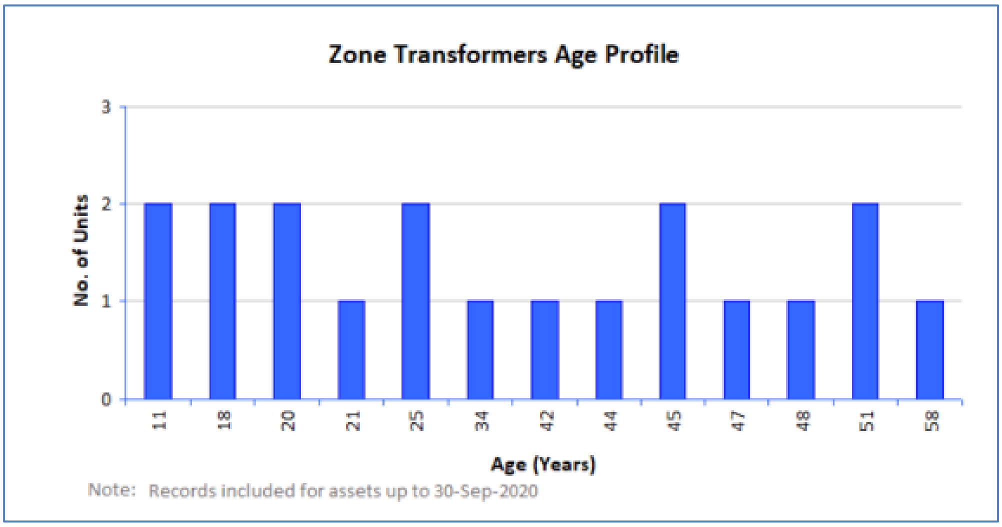


Figure 5-22: Zone transformers age profile

5.7.2.1 Condition-monitoring and assessment

The condition of our power transformers is either at Grade 3 or Grade 4:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
		10.52%	78.98%	10.5%		4	10.52%

There are no known systemic issues with Electra's zone substation transformers and no known capacity, security nor reliability constraints too

Conditional EOL drivers include:

- Oil purity
- Integrity of gaskets and flexible seals on tank and fittings
- Condition of bushings (chipping, cracking or low insulation level)
- Oil leaks or staining on tank.

Non-conditional EOL drivers include availability of spares, skilled manpower, safety issues and noise.

5.7.2.2 Inspection and maintenance

The criteria for maintenance cover the following:

- Key oil parameters such as acidity, gas content and moisture content exceed manufacturers' recommendations for main tank and tap changer compartment
- Poor results for tests such as partial discharge, Furan analysis, paper sampling
- Cabinets show evidence that gaskets and seals are failing
- Bushings are chipped, cracked or deteriorating to the point of imminent failure

- Oil leaks or staining suggests on-going leakage.

Assumptions made include:

- Declining oil condition will continue to decline rather than plateau
- Chipped or cracked bushings could result in sudden failure
- Corona discharge signals deteriorating component condition
- Oil rising into conservator tank suggests excessive heating, suggesting a localised hot spot in the absence of overloading.

Condition assessment techniques and methods include:

- Visual inspection of tank, bushings, gaskets, seals and instruments
- Regular testing of oil for dissolved gases and metals
- Regular impedance and insulation testing
- Lifecycle policies, criteria and activities.

Inspections are graded as follows and refurbishment or renewals applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	Bi-monthly inspections but no further detailed monitoring, as it will be replaced within 12 to 18 months	Will not be refurbished	Renew with 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years if repair or refurbish options are not cost effective	Minor repairs only	Renew within 3 years if repair and refurb options are not cost effective
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Defect corrections are carried out within the following period:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Lifecycle decisions include:

- Oil filtration will be triggered by unacceptable acidity, gas or moisture levels
- Re-packing and re-bolting of core will be triggered by excessive vibration
- Major refurbishment of windings will typically occur after 35 years operation
- Consideration of lifetime loading
- Consideration of number and intensity of faults.

Life extension and investment deferral techniques include:

- Paint or galvanising will be applied if the transformer develops rust
- Capacity margin may be deliberately planned to ensure light loading
- Major interventions such as oil filtration and re-packing the core may occur.

5.7.2.3 Major projects and programmes

The major projects, programmes and budget forecast follow:

No projects or programmes scheduled FY2022.

Projects and programmes FY2023-2026 follows:

Ref	Location	Type of work	Category	Cost
1	Levin East substation	Power transformer T1 replacement	Renewal	$950,000
2	Paraparaumu substation	Power transformer replacement	Renewal	$900,000

Projects and programmes FY2027-2031 follows:

Ref	Location	Type of work	Category	Cost
1	Levin East substation	Power transformer T2 replacement	Renewal	$950,000
2	Paekakariki substation	Power transformer replacement	Renewal	$950,000

The budget forecast for zone transformers is shown in Figure 5-24.

5.7.3 Zone switchgear

Electra has 57 separate 33kV circuit breakers and 79 separate 11kV circuit breakers in its zone substations, including associated protection:

Circuit breaker class	Number	Unit	Percent
33kV SF6 (indoor)	35	Each	26.1%
33kV SF6 (outdoor)	22	Each	15.7%
11kV oil	3	Each	2.2%
11kV vacuum	68	Each	50.0%
11kV SF6	8	Each	6.0%
Total	**136**		**100%**

Details of the incoming (33kV) switchgear follow:

Zone substation	Description and number	Year of manufacture	Typical loading	
			2019	2020
Shannon	10 indoor SF6 circuit breakers	2008 – all	3%	3%
Foxton	4 outdoor SF6 circuit breakers	2007: one circuit breaker 2003: three circuit breakers	10%	11%
Levin East	7 outdoor SF6 circuit breakers	2019: one circuit breaker 2015: one circuit breaker 2009: two circuit breakers 2007: one circuit breaker 2003: one circuit breaker 1987: one circuit breaker	20%	21%
Levin West	5 outdoor SF6 circuit breakers	2012: two circuit breakers 2009: one circuit breaker 2007: one circuit breaker 2000 – one circuit breaker	19%	19%
Otaki	5 indoor SF6 circuit breakers	2003: one circuit breaker 1995: four circuit breakers	8%	9%
Waikanae	6 indoor SF6 circuit breakers	1996: all	11%	11%

Zone substation	Description and number	Year of manufacture	Typical loading	
Paraparaumu	8 indoor SF6 circuit breakers	2015: eight circuit breakers 2007: one circuit breaker	9%	9%
Paraparaumu West	5 indoor SF6 circuit breakers	2001: all	9%	9%
Raumati	5 outdoor SF6 circuit breakers	2009: one circuit breaker 2007: one circuit breaker 2005: one circuit breaker 1989: one circuit breaker 1988: one circuit breaker	7%	7%
Paekakariki	1 outdoor SF6 circuit breaker	2009: one circuit breaker	3%	3%

Some information and loadings of outgoing 11kV switchgear follow. Of note this year is the reduction of the greatest peak load for Waikanae due to the addition of our new Waikanae Beach 11kV feeder:

Zone substation	Description and number	Year of manufacture	Typical loading for feeder with highest load	
			2019	**2020**
Shannon	7 Reyrolle LMVP	2007	20%	20%
Foxton	7 Reyrolle LMVP	2004	23%	27%
Levin East	8 South Wales SF6 1 Reyrolle LMVP	2006: one circuit breaker 1989: eight circuit breakers	25%	25%
Levin West	9 Reyrolle LMVP	2012: one circuit breaker 2011: two circuit breakers 2000: six circuit breakers	35%	34%
Otaki	8 Reyrolle LMVP	1996: three circuit breakers 1995: five circuit breakers	26%	27%
Waikanae	10 Reyrolle LMVP	2020: one circuit breaker 2010: one circuit breaker 1996: eight circuit breakers	39%	27%
Paraparaumu	10 Reyrolle LMVP	2015: all	33%	33%
Paraparaumu West	8 Reyrolle LMVP	2007: one circuit breaker 2002: seven circuit breakers	35%	37%
Raumati	7 Reyrolle LMVP	2018: four circuit breakers 2005: two circuit breakers 1997: one circuit breaker	31%	31%
Paekakariki	3 Reyrolle LMT oil 1 Reyrolle LMVP	2013: one circuit breaker 1982: three circuit breakers	15%	15%

The typical loading for the switchgear (630A capacity rating) is calculated based on the feeder with the highest load. We examine feeder loads regularly and actively carry out load transfers between feeders to balance loads.

The age profiles for the 33kV and 11kV zone switchgear are shown in Figure 5-23.

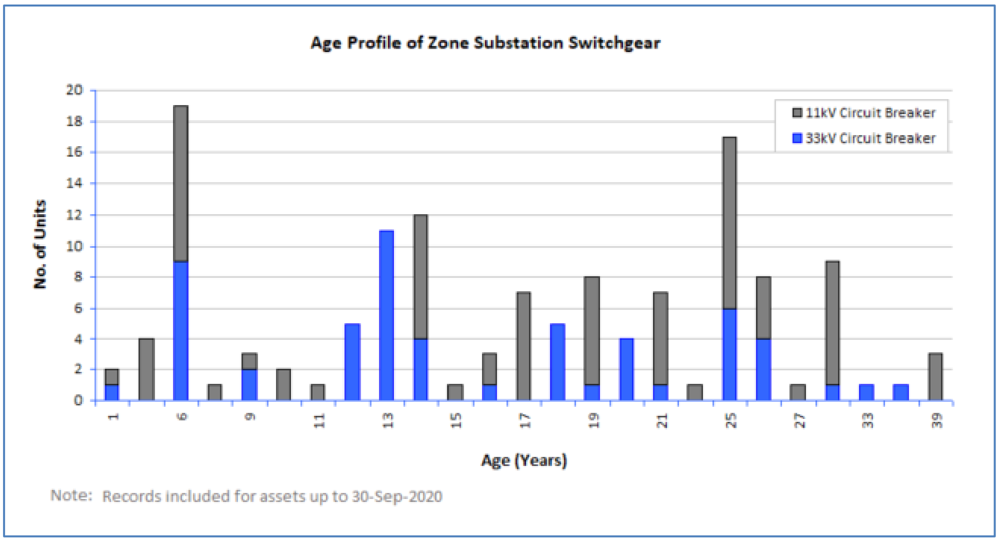


Figure 5-23: 11kV and 33kV zone switchgear age profile

The key design parameters are:

Parameter	Value
Durability	Expected life of 40 to 45 years
Load rating	Generally standard 630 A, which is often far in excess of likely load

5.7.3.1 Condition-monitoring and assessment

The condition of zone switchgear follows:

Condition	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
Indoor CB 22kV or 33kV			50%	50%		4	
Outdoor CB 22kv or 33kV		41%	49%	10%		4	41%
33kV Switch (Pole Mounted)		38%	52%	9.5%		3	38%
3.3kV, 6.6kV, 11kV or 22kV (GM)		5%	75%	20%		3	5%

Conditional EOL drivers cover the external condition, insulation dielectric properties, bus/bushing partial discharge, gas/oil leaks, known design issues as well as interrupter life and operation count measured by either the square of interrupted fault current or the number of operations.

Non-conditional EOL drivers include the availability of maintenance parts and specialist tools, orphan assets, uncertified modifications, workforce skills, failure containment, operator clearance and safety.

There are no known systemic issues and no capacity, security nor reliability constraints with Electra’s zone substation switchgear.

5.7.3.2 Inspection and maintenance

Maintenance drivers include:

- The correct operation of mechanism, including remote functionality
- The correct pressure or level of arc-quenching medium
- The correct alignment of contacts, and timing of contact separation

- The integrity of interrupting chambers
- Surface rust on cabinets.

The criteria for maintenance include:

- The number of operations exceeds manufacturers maintenance recommendations
- Operating mechanism requires excessive force
- Remote functionality fails to operate correctly
- Pressure or level of arc-quenching medium below manufacturers recommendations
- Rust becomes more than surface deep
- Evidence that arc is not being correctly quenched.

The assumptions made for maintenance are the continuing decline in pressure or level of the arc-quenching medium and that surface rust will continue to deepen. Also, operating mechanisms which are stiff and require excessive force will require repairs.

Condition assessment techniques utilise a combination of visual inspections and regular checking of fluid levels and gas pressures as per OEM specifications.

Inspections, refurbishment or renewals are graded and applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished	Renew with 1 year
2	Bi-monthly inspections and close monitoring, and is likely to be replaced within 3 years if repair or refurbish options are not cost effective	Minor repairs only	Renew within 3 years if repair and refurb options are not cost effective
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Public safety defects and significant structural defects are corrected within one week of identification while minor structural defects are repaired within three months of identification.

Electra is more likely to renew or replace assets rather than refurbish them due to safety reasons, increased fault levels or obsolescence of key components. If the sole issue is the fault rating, replacement of the interrupter heads with higher rated heads is undertaken to avoid replacing the whole switchboard.

5.7.3.3 Major projects and programmes

The projects and programmes as well as budget forecast follow:

Projects and programmes FY2022:

Ref	Location	Type of work	Category	Cost
1	All	Unplanned capital	Renewal	$135,000

Projects and programmes FY2023-2026:

Ref	Location	Type of work	Category	Cost
1	Raumati	Rebuild substation	Renewal	$2,700,000
2	Foxton	Rebuild substation	Renewal	$1,300,000

Ref	Location	Type of work	Category	Cost
1	Raumati	Rebuild substation	Renewal	$2,700,000
3	All	Unplanned capital	Renewal	$540,000
4	Paekakariki	Circuit breaker replacement	Renewal	$350,000

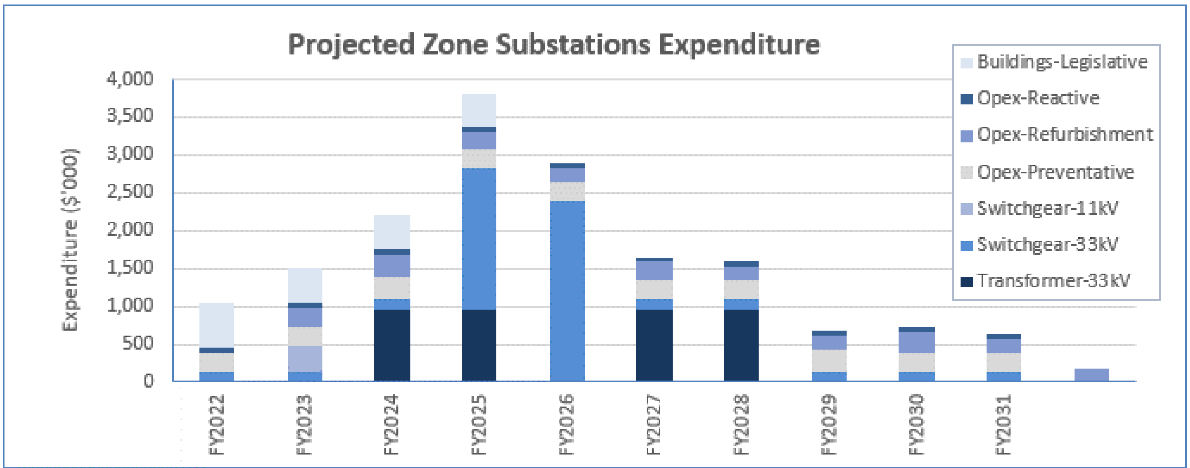
Projects and programmes FY2027-2031:

Ref	Location	Type of work	Category	Cost
1	All	Unplanned capital	Renewal	$675,000

The budget forecast for zone switchgear is shown in Figure 5-24.

5.7.4 Zone substations forecast

The projected zone substations expenditure for zone transformers and switchgear is shown in Figure 5-24.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
Buildings-Legislative	600	450	450	450	0	0	0	0	0	0
Transformer-33kV	0	0	950	950	0	950	950	0	0	0
Switchgear-33kV	135	135	135	1,885	2,385	135	135	135	135	135
Switchgear-11kV	0	350	0	0	0	0	0	0	0	0
Total (Capex):	**735**	**935**	**1535**	**3285**	**2385**	**1085**	**1085**	**135**	**135**	**135**
Operational Expenditure ($'000)										
Opex-Preventative	251	251	301	251	248	248	248	298	248	248
Opex-Refurbishment	250	310	215	190	255	190	190	275	190	170
Opex-Reactive	61	61	61	61	61	61	61	61	61	61
Total (Opex):	**562**	**622**	**577**	**502**	**564**	**499**	**499**	**634**	**499**	**479**

Figure 5-24: Projected zone substations expenditure

5.7.5 Load control plant

Electra owns and operates the following load control plant:

- One Zellweger SFU-K/203 injection plant at Shannon rated at 80kVA and signalling to the northern area. This was installed in 2011 as part of the substation rebuild.
- One Landis + Gyr SFU-K/403 injection plant rated at 200kVA located at Paraparaumu zone substation and signalling to the southern area. This was installed in 2016.
- Two Zellweger SFU-K/203 injection plant controllers rated at 80kVA in storage as spares at Paraparaumu West and Shannon.

Both the Shannon and the Valley Road plants inject into the 33kV at 283Hz.

Most customer load control relays are owned by the energy retailer. Electra, does however, 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.

5.7.5.1 Condition-monitoring and assessment

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
Centralised plant			50.0%	50.0%		4	
Relays					100.0%	2	10.0%

There are no known systemic issues with Electra's load control plant as well as no known capacity, security nor reliability constraints with Electra's load control plant.

Key design parameters include the following:

Parameter	Value
Durability	Expected life of 20 years
Load rating	About 50kVA to 100kVA
Frequency	283 Hz

5.7.5.2 Inspection and maintenance

The drivers for maintenance include the correct injection of required signals when instructed, the correct operation of relays as well as the integrity and isolation of coupling cells.

Maintenance is also required when injection fails, the relay fails to operate, or the coupling cell shows evidence of failure or insulation breakdown. The signal generator needs to be replaced as additional load is connected.

Condition assessment methods include visual inspections and regular testing to confirm signal frequency and strength as well as a five-year rolling inspection and maintenance contract with Landis+Gyr to ensure plant reliability.

Inspections, refurbishment and/or renewals are graded and applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, as will be replaced within 1 year	Will not be refurbished	Renew with 1 year
2	No further inspections, as will be replaced within 3 years	Minor repairs only	Renew within 3 years if repair and refurb options are not cost effective

Grade	Inspection	Refurbishment	Renewal
3 & 4	Continue to inspect, amend grade as required	Refurbish major components Functionality and signal penetration considered, as this may make replacement more feasible	

Defect correction is carried out based on the following timeline:

- **Public safety defects**: correction within one week of identification
- **Injection failure**: immediate correction in order to manage demand
- **Minor control defects**: repairs carried out within one month of identification.

Load control may be replaced rather than renewed if analysis reveals that improved functionality can be obtained by replacement. Insufficient signal penetration may require replacement with a more powerful signal generator.

There are no major load control or relay programmes nor forecast for the planning period.

5.7.6 Buildings

The general structure of zone substation buildings follows:

Zone substation	General description	Year built	Condition grade
Shannon	Timber framed	2008	Normal deterioration monitored in normal inspection cycle
Foxton	Masonry shear walls	1970	Normal deterioration monitored in normal inspection cycle
Levin East	Masonry shear walls	1973	Normal deterioration monitored in normal inspection cycle
Levin West	Masonry shear walls	1976	Normal deterioration monitored in normal inspection cycle
Otaki	Timber framed	1995	Normal deterioration monitored in normal inspection cycle
Waikanae	Timber framed	1982	Normal deterioration monitored in normal inspection cycle
Paraparaumu old	Masonry shear walls	1973	Normal deterioration monitored in normal inspection cycle
Paraparaumu new	Masonry shear walls	2016	Good or as new condition
Paraparaumu West	Timber framed	2002	Normal deterioration monitored in normal inspection cycle
Raumati	Masonry shear walls	1987	Normal deterioration monitored in normal inspection cycle
Paekakariki	Masonry shear walls	1982	Normal deterioration monitored in normal inspection cycle

Detailed seismic assessments were done for all zone substations in 2018. A further detailed seismic design was undertaken for Paraparaumu West substation in 2019 and a structural upgrade will be carried out this financial year in compliance with the Building Code, Section C5 of the Engineering Assessment Guidelines regarding the seismic assessment of existing buildings.

An asbestos survey was carried out on all zone substations in 2020. Three substations were tested clean and the remaining sixteen varied between presumed to low and very low traces of asbestos. Electra has activated the asbestos management plan and is actively managing the risk through mitigation and elimination to ensure compliance with the Health and Safety (Asbestos) Regulations 2016.

5.8 Distribution transformers

Electra’s distribution transformers range from rural 1-phase 5kVA pole-mounted transformers with minimal fuse protection, to 3-phase 1,000kVA ground-mounted transformers with ring main unit and circuit breaker protection. Transformers may provide electricity to single large consumers, several large consumers or many small consumers.

Electra has 1,610 overhead distribution transformers and 962 ground-mounted distribution transformers of various kVA ratings as follows:

Substation rating	Pole mounted (quantity)	Ground mounted (quantity)	Total (quantity)
1-phase 5kVA	1	0	1
1-phase 7kVA	1	0	1
1-phase 10kVA	8	0	8
1-phase 15kVA	22	0	22
1-phase 30kVA	7	1	8
1-phase 100kVA	1	0	1
3-phase 5kVA	0	1	1
3-phase 7kVA	1	0	1
3-phase 10kVA	2	0	2
3-phase 15kVA	75	0	75
3-phase 25kVA	6	0	6
3-phase 30kVA	864	31	895
3-phase 50kVA	365	64	429
3-phase 75kVA	2	0	2
3-phase 100kVA	220	105	325
3-phase 150kVA	2	1	3
3-phase 200kVA	30	217	247
3-phase 250kVA	0	18	18
3-phase 300kVA	3	415	418
3-phase 500kVA	0	87	87
3-phase 750kVA	0	14	14
3-phase 1000kVA	0	8	8
Total:	1,610	962	2,572

The population and age profile of these transformers are shown in Figure 5-25.

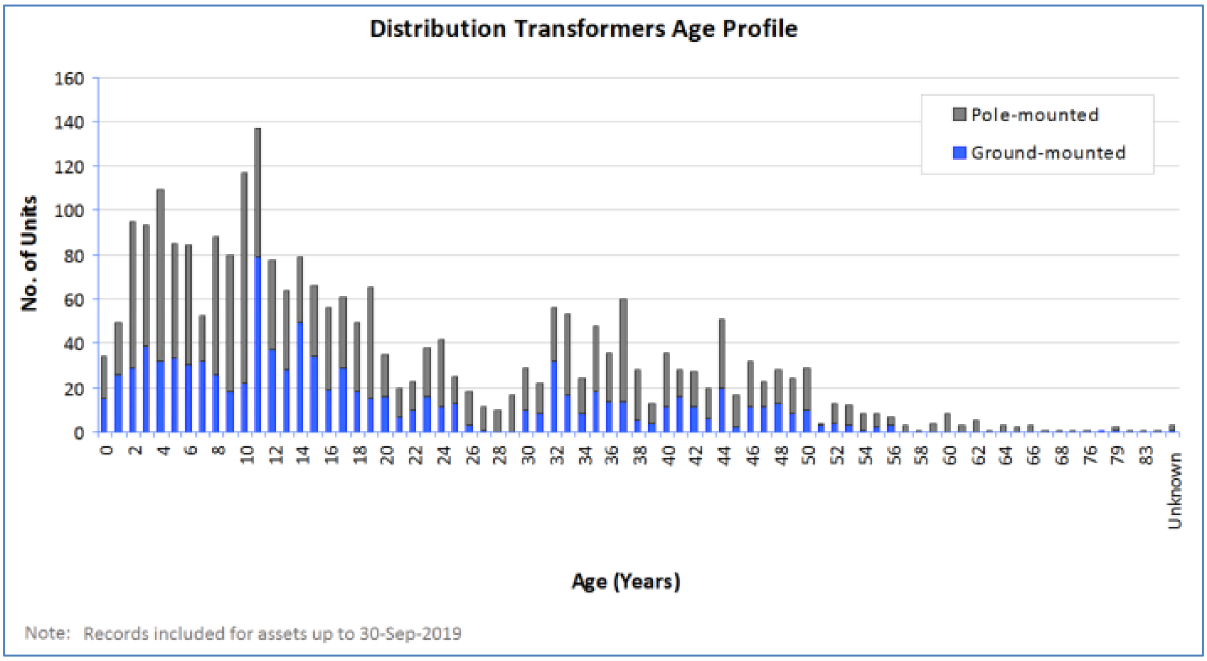


Figure 5-25: Distribution transformers age profile

Key design parameters are:

Parameter	Value
Rating	Design loading to 80% of manufacturer's rating subject to design ambient temperature and airflow
Durability	Expect to last 45 years

5.8.1 Condition-monitoring

The condition of these transformers is as tabulated below:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
Pole mounted	-	5%	72%	23%	-	4	5%
Ground mounted	-	5%	53%	42%	-	4	5%

Identified systemic issues include:

- Corrosion of ground mounted transformer enclosures closer to coastal areas, these typically require replacement after 30-40 years of service
- Deck mounted transformers (on poles) requiring replacement due to declining structural integrity of the deck.

5.8.2 Reliability analysis

The failure rate for distribution transformers is indicated in Figure 5-26 for faults from FY2015 to FY2020 including the SAIDI-SAIFI impact. There were 13 faults reported in FY2020, where only 7 were attributed to transformer related and the other 6 were due to blown DDO fuses only. Such faults (DDO fuses) will be removed from the transformer fault in FY2021 classification. Furthermore, our improvement measures include the removal of vegetation around ground-mounted transformers as well as painting to prevent rust and moisture ingress. Besides inspections and mitigation measures identified, we are applying ARMM (Asset Risk Management Model) described in Section 8.4.1 into our process.

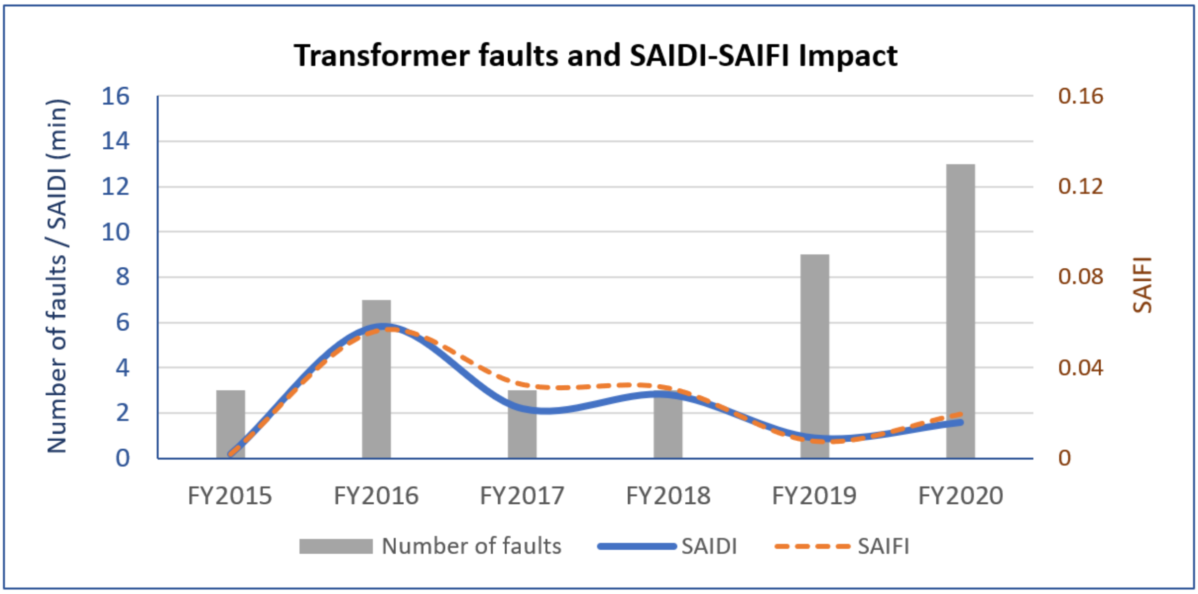


Figure 5-26: FY2015 to FY2020 - Distribution transformer faults with SAIDI-SAIFI impact

The mitigation measures for these issues follow:

Systemic issue	Mitigation	Magnitude of issue and impact
Corrosion of ground mount steel transformer enclosures	Replace corroded enclosure with more suitable type	Minimal, no significant impact
Safety concerns around structural integrity of deck mounted transformers	Replace with light weight overhead or ground mounted transformers	Minimal

There are no known distribution substation capacity, security nor reliability constraints.

5.8.3 Inspection and maintenance

Conditional EOL drivers for maintenance include the rusting or oil-staining of the tank, the colour of the silica gel breather where fitted, as well as excessive graffiti or evidence of interference or tampering including copper earthing.

Maintenance criteria include:

- Rusting of tank becomes more than surface deep
- Oil staining on tank suggests repeated internal overheating
- Silica gel breather remains blue
- Level of graffiti shows repeated attempts
- Evidence of attempts to force entry into cabinets.

The assumptions for maintenance are:

- Oil staining of tank suggests boiling of oil to the point of expulsion from around lid seal
- Once tank rust appears more than surface deep from ground level, tank perforations are likely.

Condition assessment techniques and methods are:

- Primarily visual, especially for oil leaks, breather colour, tank rust, chipped or broken bushings and perished seals or gaskets as well as including public safety checks and checking of copper earthing;

- Oil sample tests only on 750kVA and above.

Non-conditional EOL drivers include safety issues and noise.

Inspections are graded as follows with refurbishment or renewals applied:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished (generally scrapped as too expensive to refurbish	Renew within 1 year
2	No further inspections, will be replaced within 3 years	Will not be refurbished (generally scrapped as too expensive to refurbish	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Minor repair to extend life as considered appropriate by Planning & Development Manager	-

Electra procedures ensure that transformers are maintained, transported and disposed in compliance with our environmental policy. Oil-related leaks are captured as an incident in our Health & Safety system and such events are monitored and audited.

Defect correction is carried out based on the following timeline:

- **Public safety defects**: correction within one week of identification
- **Significant structural integrity defects**: correction within one week of identification
- **Minor structural integrity defects**: repair by approved method within three months of identification.

Lifecycle decision criteria include:

- Replace when necessary repairs become more than minor
- Replace when MDI readings reveal regulator loading to more than 100% of design rating
- Life extension and investment deferral techniques
- Additional galvanising or paint for coastal areas.

5.8.4 Major projects and programmes

Projects and programmes for FY2022:

Ref	Location	Constraint description	Category	Cost
1	All	Ground transformer replacements	Renewal	$600,000
3	All	Pole transformer replacements	Renewal	$160,000
4	All	Ground transformer faults	Renewal	$100,000
5	All	Pole transformer faults	Renewal	$55,000

Projects and programmes for FY2023 to FY2026:

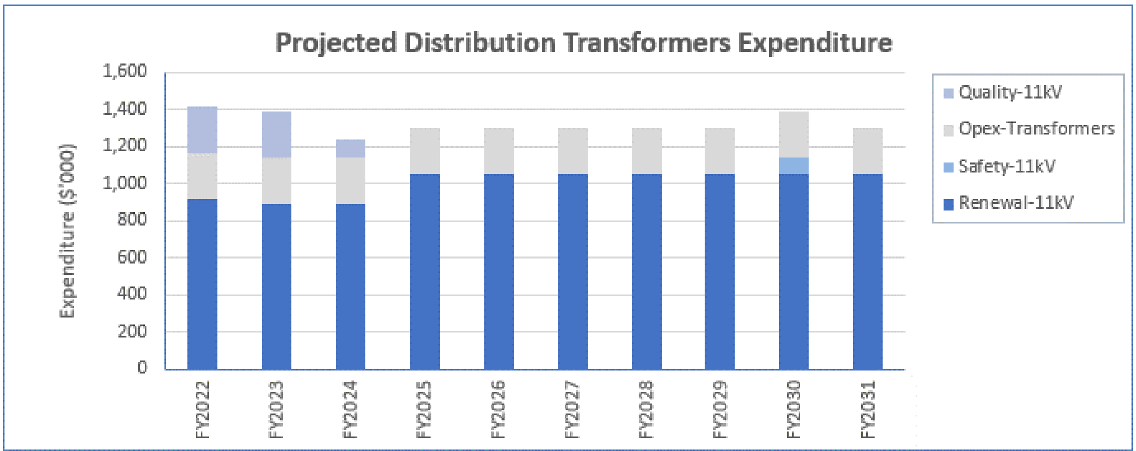
Ref	Location	Constraint description	Category	Cost
1	All	Ground transformer replacements	Renewal	$2,200,000
2	All	Pole transformer replacements	Renewal	$728,000
3	All	Ground transformer faults	Renewal	$400,000
4	All	Indoor substations	Renewal	$327,076
5	All	Pole transformer faults	Renewal	$220,000

Projects and programmes for FY2027 to FY2031:

Ref	Location	Constraint description	Category	Cost
1	All	Ground transformer replacements	Renewal	$2,750,000
2	All	Pole transformer replacements	Renewal	$910,000
3	All	Indoor substations	Renewal	$817,690
4	All	Ground transformer faults	Renewal	$500,000
5	All	Pole transformer faults	Renewal	$275,000

5.8.5 Distribution transformers forecast

The projected distribution transformers expenditure is shown in Figure 5-27.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
Renewal-11kV	915	887	887	1,051	1,051	1,051	1,051	1,051	1,051	1,051
Safety-11kV	0	0	0	0	0	0	0	0	90	0
Quality-11kV	250	250	102	0	0	0	0	0	0	0
Total (Capex):	**915**	**887**	**887**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**	**1,141**	**1,051**
Operational Expenditure ($'000)										
Opex-Transformers	252	252	252	252	252	252	252	252	252	252

Figure 5-27: Projected distribution transformers expenditure

5.9 Distribution switchgear

Electra has 2,614 individual items that are broadly classified as distribution switches are these are as tabulated below:

Sub-class	Number	Percent
Ground mount switches	153	6%
Auto reclosers	63	2%
Air break switches	346	13%
In-line drop-out fuses	2,052	79%
Total	**2,614**	**100%**

The age profiles of these switches are shown in Figure 5-28.

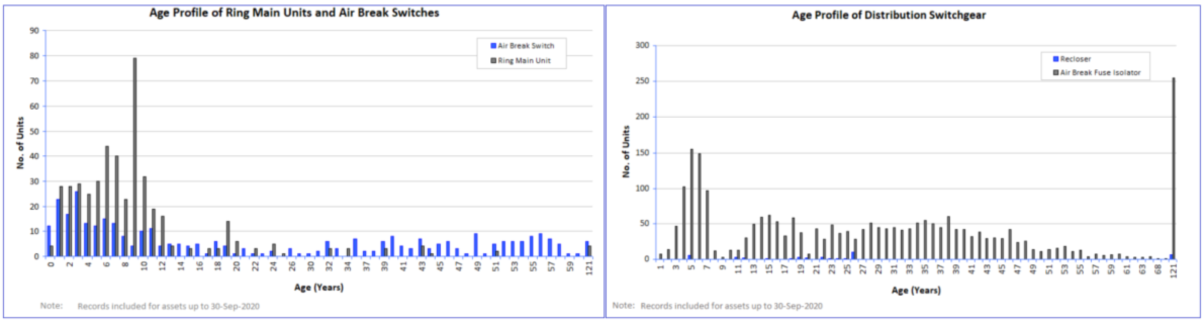


Figure 5-28: Distribution switchgear age profile

The key design parameters for the switchgear are tabulated below:

Parameter	Value
Durability	Expected life of 45 years
Load rating	Generally, the rating is based on minimum commercially available rating of 630A

SF_6 ring-main units and reclosers are deployed in the network and complies with our environmental policy. Our procurement policy includes considering alternatives such as vacuum -break switches which are being deployed where appropriate.

5.9.1 Condition-monitoring

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Data accuracy	Percent forecast for replacement over next 5 years
Pole mounted circuit breakers (reclosers and sectionalisers)		2.50%	62.50%	35.00%	4	2.50%
Pole mounted switches and fuses		8%	77.69%	14.31%	3	8.32%
Ring main units		7.0%	61.63%	31.37%	3	7%

Conditional EOL drivers include the enclosure condition, cable box or bus chamber partial discharge for ring-main units, oil/gas leaks, operating history and known type or design issues.

Non-conditional EOL drivers cover the availability of maintenance parts and/or specialist tools, orphan assets, uncertified modifications, workforce skills, operator and public safety, operator clearances for outdoor equipment and foundation or site issues.

We have identified a systematic issue with porcelain insulators on a particular brand for ABSs manufactured between 1996 to 2015.The total number affected is 104 units.

We have undertaken various operational and tactical measures to manage the risks involved with these ABSs including:

- Operational restrictions are placed on ABSs with additional Go-Pro inspections which are made mandatory before operation
- Drone inspections to be undertaken every year on the identified ABSs to determine any further deterioration
- Capex allocation have been increased to replace ABSs with integrated load break switches; these replacements will be risk ranked (such as presence of underbuilt LV and proximity to public places)
- Synergy with smart grid application will involve automation and replacing identified ABSs.

5.9.2 Inspection and maintenance

Maintenance conditional EOL drivers include:

- Interrupting medium levels or pressures
- Continued correct operation of mechanisms without excessive force
- Continue correct operation of remote capability
- Rusting of enclosures
- Stability of mounting, including slumping or subsidence of surrounding ground
- Manufacturers recommended overhaul intervals.

Maintenance criteria include:

- Number of operations exceeds manufacturers recommendations
- Oil levels drop below indicated minimum
- Gas or vacuum pressure varies outside of prescribed levels
- Failure to operate correctly, or with accepted level of force
- Timing test reveals contact separation times are outside of specification
- Testing reveals that trip coil is not operating within specified voltages
- Rust more than surface deep
- Slumping or movement of ground, particularly tilting that may expose live components above oil level.

Assumptions are:

- Stiff operating mechanism will eventually fail, rather than plateau
- Decline in insulating medium level or pressure will continue, rather than plateau.

Conditional assessment methods include:

- Visual, including public safety checks and checking of copper earthing;
- Regular checking of fluid levels, gas pressures and other parameters as per OEM specifications.

Inspections are graded as follows with refurbishment or renewals applied:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, will be replaced within 1 year	Will not be refurbished (generally scrapped as too expensive to refurbish)	Renew within 1 year
2	No further inspections, will be replaced within 3 years	Will not be refurbished (generally scrapped as too expensive to refurbish)	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Repair to extend life as considered appropriate by Planning & Development Manager	-

Correction of defects are carried out based on the following:

- **Public safety defects**: correction within 1 week of identification
- **Significant structural integrity defects**: correction within one week of identification

- **Minor structural integrity defects**: repair by approved method within three months of identification.

Criteria for lifecycle decisions and techniques include:

- Ground-mounted switches that are considered to have an unacceptably high public safety risk will be specifically marked for accelerated replacement. The precise order of replacement will include consideration of actual condition, known defects from industry experience, and proximity to sensitive locations like parks and schools
- Decision to renew rather than refurbish made on a case-by-case basis for ground-mounted distribution switches
- Decision to up-size or to replace single phase with three-phase based on load and fault level studies
- Electra may apply extra paint, galvanising or grease to individual switches near coastal areas.

5.9.3 Major projects and programmes

Projects and programmes FY2022:

Ref	Location	Description	Category	Cost
1	All	ABS new and renewals	Safety	$325,000
2	All	Replace ring main units	Renewal	$130,000
3	All	Urgent DDO/ABS replacement	Renewal	$30,000

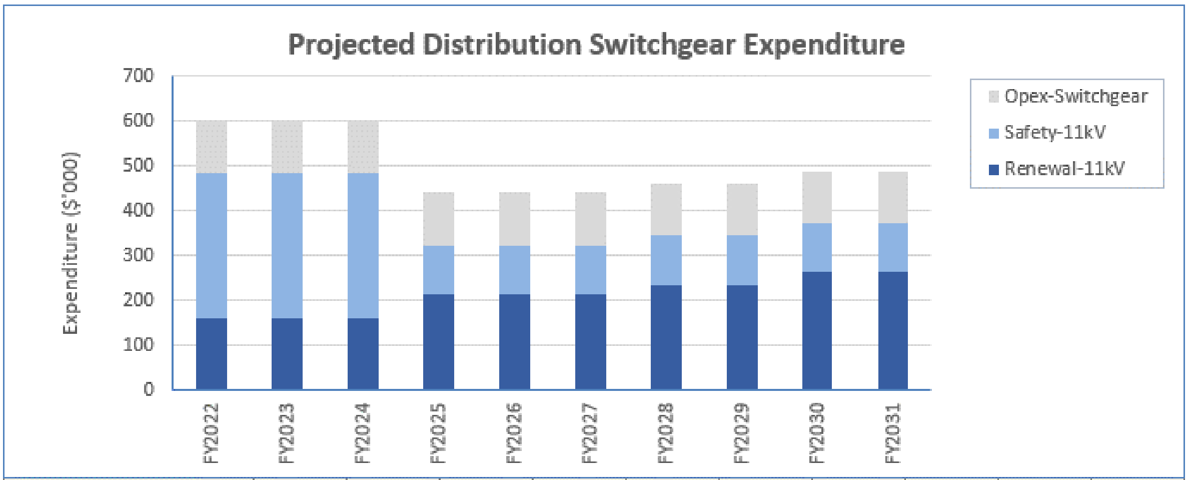
Projects and programmes FY2023 to FY2026:

Ref	Location	Description	Category	Cost
1	All	ABS new and renewals	Safety	$870,000
2	All	Replace ring main units	Renewal	$627,960
3	All	Urgent DDO/ABS replacement	Renewal	$120,000

Projects and programmes FY2027 to FY2031:

Ref	Location	Description	Category	Cost
1	All	Replace ring main units	Renewal	$919,900
2	All	ABS new and renewals	Safety	$550,000
3	All	Urgent DDO/ABS replacement	Renewal	$290,000

The budget forecast for distribution switchgear is depicted in Figure 5-29.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
Renewal-11kV	160	160	160	214	214	214	234	234	264	264
Safety-11kV	325	325	325	110	110	110	110	110	110	110
Total (Capex):	**485**	**485**	**485**	**324**	**324**	**324**	**344**	**344**	**374**	**374**
Operational Expenditure ($'000)										
Opex-Switchgear	116	116	116	116	116	116	116	116	116	116

Figure 5-29: Projected distribution switchgear expenditure

5.10 Secondary systems

5.10.1 Protection and control

Electra's network includes the following broad classes of protection and control equipment:

- Legacy protection relays (overcurrent (OC), earth fault (EF), restricted earth fault (REF), auto reclose functions)
- More recent digital protection (voltage, frequency, directional, distance, differential, bus zone and failure functionality)
- Transformer and tap changer temperature sensors including surge arrestors, explosion vents and oil level sensors such as Buchholz and pressure relief valves (PRV)
- Electra's main class of control assets are tap changer controls, for which Electra has standardised on the Eberle range.

Key features of Electra's protection and control include:

Area	33kV Subtransmission	Zone Substation Transformer	33kV Busbar	11kV Feeder	Distribution Feeder
Northern	Directional Over Current	• Electrical protection: Differential/ REF/ OC/ EF • Mechanical protection: Buchholz/ PRV	Not applicable	OC/ EF/ Auto-Reclose	Fuse
Southern	Line Differential/ Distance/ OC/ EF/ Inter-tripping	• Electrical protection: Differential/ REF/ OC/ EF/ CB Fail • Mechanical protection: Buchholz/ PRV	Paraparaumu East & Raumati: Busbar Differential/ CB Fail	OC/EF	Fuse

Electra also owns several battery chargers, batteries and power supplies rated for a minimum of 6 hours continuous supply. All these assets are in good serviceable condition.

There are 170 protection relays, with ages as shown in Figure 5-30.

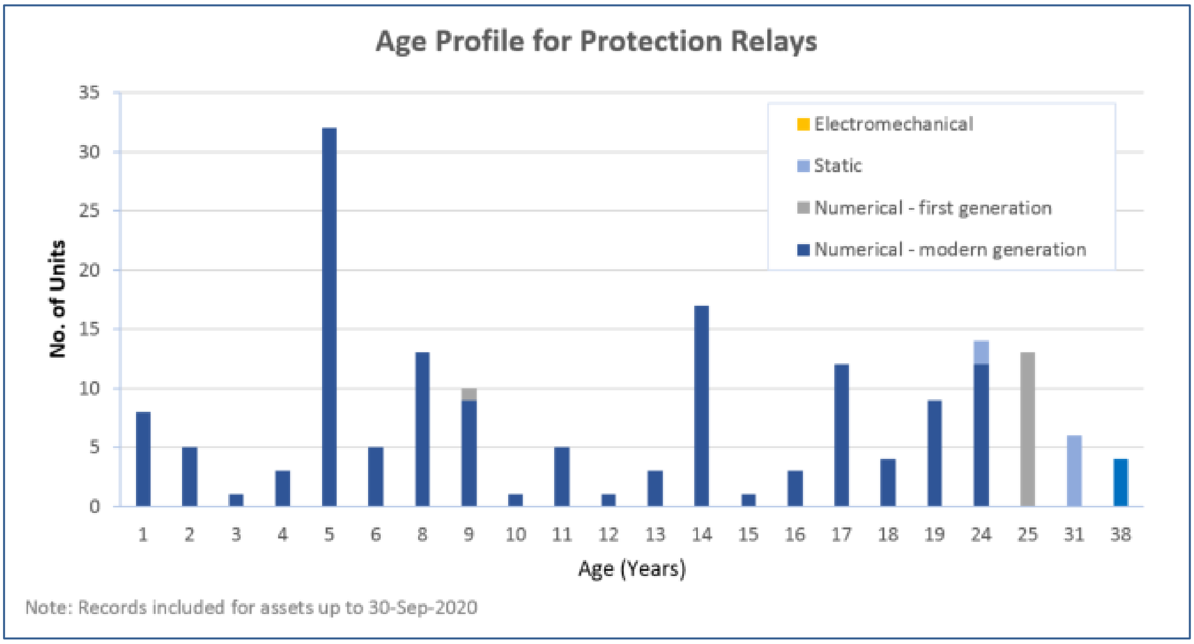


Figure 5-30: Protection relays age profile

5.10.1.1 Condition-monitoring

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Data accuracy	Percent forecast for replacement over next 5 years
		20.5%	44.5%	35.0%	4	20.5%

There are no known systemic issues with Electra's protection and control plants.

Due to several spurious 33kV trippings, a review of the protection settings at zone substations has been undertaken and the development of a strategy based on the following design parameters:

Parameter	Value
Functionality	Minimum as specified by Electra
Durability (relays)	Expected life of 15 to 20 years
Durability (batteries)	Expected life of 8 to 15 years
Capacity (batteries, UPS)	Minimum 6 hours full load

5.10.1.2 Inspection and maintenance

The maintenance conditional EOL drivers are:

- The correct operation of relays
- Battery chargers continue to charge at rated capacity
- Batteries' ability to hold the required charge.

Assumptions made include the failure to hold a charge indicates imminent failure, and a relay that has failed to correctly operate once will continue to fail.

The criteria for maintenance include:

- Relay fails to operate correctly
- Battery charger fails to maintain battery charge or voltage

- Battery fails to hold charge
- Battery age reaches design life
- Blown fuse.

Condition assessment methods include:

- Primarily visual for batteries, with fluid level checks for non-sealed batteries
- Regular testing of relay functionality and sensitivity where necessary
- Lifecycle policies, criteria and activities, including inspections.

Inspections are graded as follows and refurbishment or renewals applied as follows:

Grade	Inspection	Refurbishment	Renewal
1	No further inspections, as will be replaced within 1 year	Protection and control plant are normally replaced rather than refurbished	Renew with 1 year
2	No further inspections, as will be replaced within 3 years	Protection and control plant are normally replaced rather than refurbished	Renew within 3 years
3 & 4	Continue to inspect, amend grade as required	Protection and control plant are normally replaced rather than refurbished	

The correction of defects is carried out as follows:

- **Public safety defects**: correction within one week of identification
- **Relay fails to operate correctly**: investigate within one week, remedy within one month
- **Failure of battery charger**: replace within one month to reduce dependence on duplicate charger
- **Failure of battery to hold charge**: replace within one week.

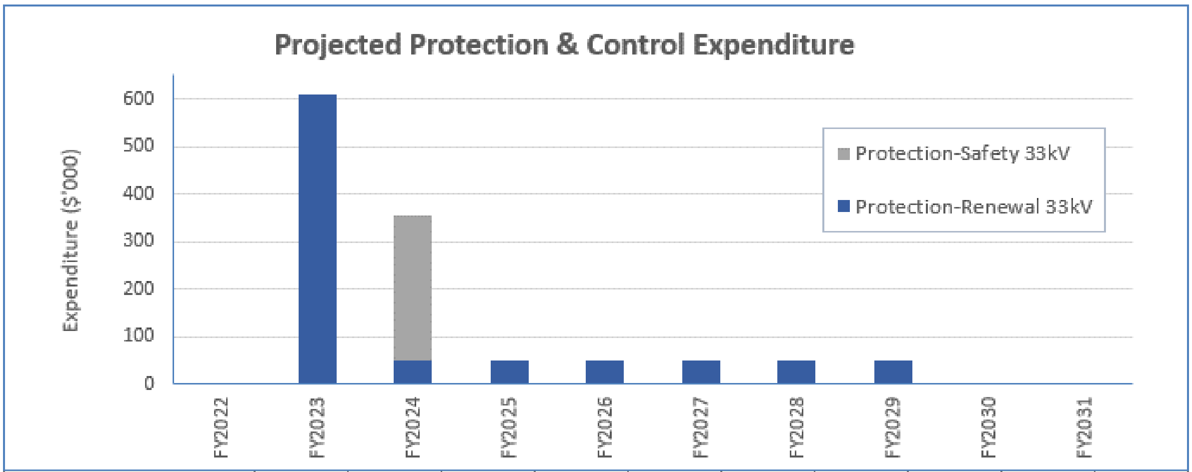
Due to the criticality and low value of individual protection and control plant, components are usually replaced rather than refurbished.

5.10.1.3 Major projects and programmes

The projects and programmes as well as budget forecast follow:

Year	Ref	Location	Description	Category	Cost
FY2023 to FY2026	1	All	Substation breaker /VT/CT upgrade to enable protection	Renewal	$610,000
	2	Zone substations	Arc flash protection	Safety	$305,000
	3	All	33kV protection	Renewal	$150,000
FY2027 to FY2031	1	All	33kV protection	Renewal	$150,000

The projected protection and control expenditure are depicted in Figure 5-31.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
Protection-Renewal 33kV	0	610	50	50	50	50	50	50	0	0
Protection-Safety 33kV	0	0	305	0	0	0	0	0	0	0
Total:	**0**	**610**	**355**	**50**	**50**	**50**	**50**	**50**	**0**	**0**

Figure 5-31: Projected protection and control expenditure

5.10.2 SCADA and communications

Electra uses iSCADA for general control and monitoring. This was installed during 2010. The master station has had progressive upgrades of software and hardware and is located at Levin West Substation, with a second instance on “hot” standby at Levin, Head Office. This relays information via a point-to-point link to the network control centre at Electra’s offices in Levin. A replica emergency control centre is also located at Levin West.

Microwave radio and voice connect all sites with a self-healing topology that includes the following repeater sites as shown in Figure 5-32:

- Forest Heights, Waikanae
- Mataihuka south of Paraparaumu Moutere Hill west of Levin
- Levin West substation
- Tunapo at Paekakariki.

The ages of remote terminal units or RTUs range from one to ten years.

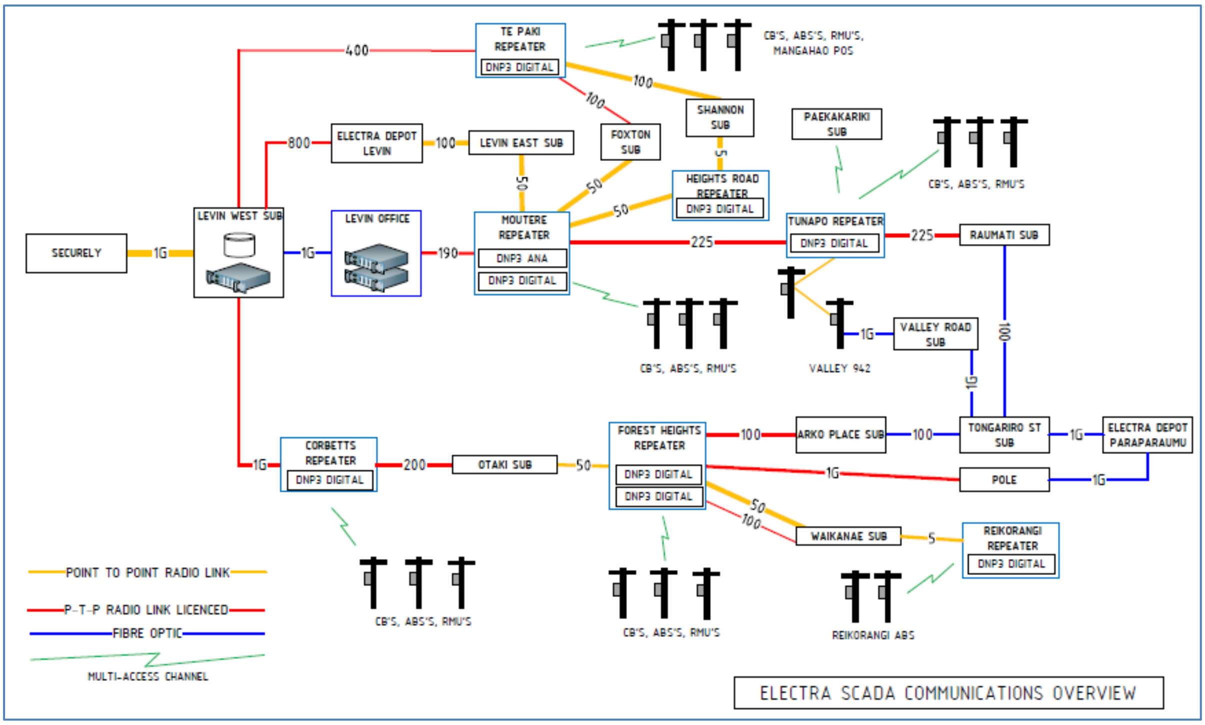


Figure 5-32: SCADA communications overview

5.10.2.1 Condition-monitoring

The condition of the RTUs follow:

Condition:	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy	Percent forecast for replacement over next 5 years
		10%	70%	20%		3	15%

There are no known systemic issues nor known constraints with Electra's SCADA. Functionality is a key design parameter and within minimum specifications for network operation.

5.10.2.2 Inspection and maintenance

The conditional EOL drivers for maintenance requirements are:

- The failure of core functionality
- The failure of RTUs during operation.

Assumptions made include:

- Faulty operation indicates imminent failure
- Replacement is preferred rather than refurbishment for new functionalities.

Condition assessment tends to be based on failure events.

Inspections, refurbishment or renewals are applied as follows:

Inspection	Refurbishment	Renewal
Review of system errors and alarm logs to identify faults	More likely to be replaced than refurbished	Tends to be driven by obsolescence or declining functionality rather than condition Lifecycle decision criteria

Defect correction is carried out as follows:

- **Immediate action**: for major loss of functionality or processing capacity, major input defects, or major RTU defects
- **Within three days**: minor input defect or minor RTU defects.

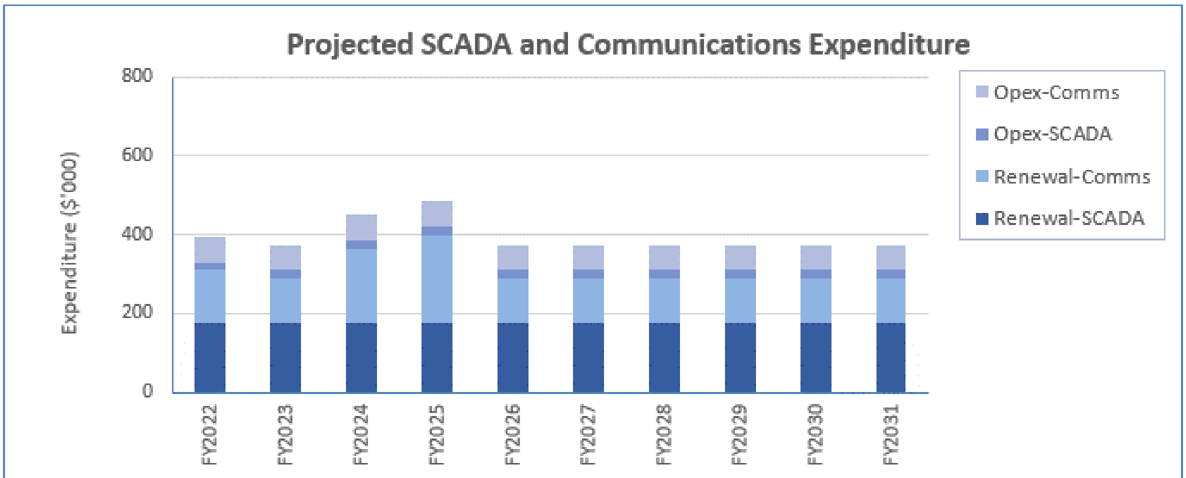
5.10.2.3 Major projects and programmes

The projects, programmes and budget forecast follow:

Year	Ref	Location	Description	Category	Cost
FY2022	1	Control Centre	SCADA upgrade	Renewal	$175,000
	2	All	Comms general - FMS	Renewal	$135,000
FY2023 to FY2026	1	Control Centre	SCADA upgrade	Renewal	$700,000
	2	All	Comms general - FMS	Renewal	$645,000
FY2027 to FY2031	1	Control Centre	SCADA upgrade	Renewal	$875,000
	2	All	Comms general - FMS	Renewal	$575,000

5.10.3 SCADA and communications forecast

The projected SCADA and communications expenditure are shown in Figure 5-33.



Description	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Capital Expenditure ($'000)										
Renewal-SCADA	175	175	175	175	175	175	175	175	175	175
Renewal-Comms	135	115	190	225	115	115	115	115	115	115
Total (Capex):	**310**	**290**	**365**	**400**	**290**	**290**	**290**	**290**	**290**	**290**
Operational Expenditure ($'000)										
Opex-SCADA	20	20	20	20	20	20	20	20	20	20
Opex-Comms	64	64	64	64	64	64	64	64	64	64
Total (Opex):	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**	**84**

Figure 5-33: Projected SCADA and communications expenditure

5.10.4 IoT communications and deployment

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.

There are fifteen LoRaWAN gateways deployed in the Electra region at key locations including substation and repeater sites:

- Foxton
- Levin
- Moutere
- Paekakariki
- Shannon
- Tunapo
- Te Paki
- Waikanae.

The Electra IoT Communications framework is shown in Figure 4-2.

5.10.4.1 Condition-monitoring

The LoRa gateways are recent additions to the Electra communications network. Only installed in the last two years, their condition is Class 1 (new).

Gateways have an expected lifespan of 7 to 10 years; however, technology changes are more likely to drive upgrades prior to failure.

There are no known systemic issues nor known constraints with Electra's IoT platform. Resilience, reliability and cyber security are key design parameters in deployment.

5.10.4.2 Inspection and maintenance

The conditional EOL drivers for IoT Gateway maintenance requirements are:

- Failure of core functionality
- RF coverage
- Change in functional requirements.

Assumptions made include:

1. Faulty operation indicates imminent failure as reliability is critical.
2. Replacement is preferred over refurbishment due to unit cost.

Condition assessment tends to be based on the nature and frequency of failure events.

Inspections, refurbishment or renewals are applied as follows:

Inspection	Refurbishment	Renewal
Review of system errors and alarm logs to identify faults	Due to unit cost devices are likely to be replaced rather than refurbished though units are inspected to understand the cause of failure	Driven by failure, obsolescence and changing functionality requirements rather than condition Lifecycle decision criteria

Defect correction is carried out as follows:

- For major loss of functionality or processing capacity: immediate action
- Minor defects or signalling issues: within three days.

The details of the installation plan for IoT sensors as well as major programs and budget are detailed in Section 6.2.4.

5.10.5 ADMS

Historically Electra has operated a range of network ICT systems that have delivered basic functions well but have lacked interconnectivity and had few specific analysis capabilities. In 2015 Electra identified a range of barriers to improving its reliability / cost mix and implemented a number of isolated technology solutions. Those solutions provided some quick gains in fault restoration times, cost reductions and overall staff appreciation of technology, but still did not provide a unified ICT platform with advanced functionality.

Following an RFP process, Electra purchased the Milsoft ADMS, which was considered to provide the best functionality, scalability and cost for an EDB of up to 100,000 connections. Milsoft provides modules to integrate the previously separate functions of distribution management, SCADA, outage management, fault dispatching and various network engineering analysis functions. There are streams of work identified to improve the data quality to further enhance the Milsoft functions and improve customer experience overall through a combination of improved network reliability and lower costs.

Benefits have included:

- Quicker restoration of faults, including through quicker dispatch of fault crews
- Estimation of technical losses
- Improved demand and load flow analysis that is likely to allow deferral of asset upgrades
- Improved information available to customers
- Automated telephone and website updates during major events
- Reduced call volumes due to customers accessing the web outage viewer
- Enhanced data capture.

Current initiatives include:

- Re-engineering Electra’s as-built processes to a pre-build process enabling the ADMS model to reflect the real time network state
- Implementing a switching scheduler application
- Building an LV data model to reflect the customer phase connections and provide a building block to improved LV network management.

5.10.6 Mobile generator

Electra has owned a 500kVA mobile diesel generator since 2008. It is primarily used to maintain supply during planned and unplanned outages.

5.11 Strategic spares

In line with our strategy to achieve excellence in our operations, Electra has commenced the development of a critical spares database in September 2020. This database will cover the inventory and details of critical spares stored in substations and stores including switchgear, circuit breakers, transformers, bushings, drives and motors. This project is expected to complete by 2021 and will include dashboards, pivot tables and charts for various equipment including their location.

In the event of network emergencies and high impact low probability events, it is important to keep adequate quantities of spares as well as to promptly access the equipment to enable the fast restoration of defects.

Some of the equipment located at various depots and substations include:

Critical equipment type	Critical spare	Quantity	Location
Zone Transformer	5MVA 3 phase	1	Shannon Substation
Pole Mount Transformer	15kVA 1 phase	1	Levin East Substation
	30kVA 1 phase	1	Levin East Substation
	30kVA 3 phase	8	5 Levin East Substation, 3 Paraparaumu West Substation
	50kVA 3 phase	4	2 Levin East Substation, 2 Paraparaumu West Substation
	100kVA 3 phase	2	1 Levin East Substation, 1 Paraparaumu West Substation
	200kVA 3 phase	1	Levin East Substation
	500kVA 3 phase	1	Levin East Substation
Ground Mount Transformer	50kVA micro sub	2	1 Levin East Substation, 1 Paraparaumu West Substation
	100kVA 3 phase	1	Levin East Substation
	200kVA 3 phase	1	Paraparaumu West Substation
	200kVA 3 phase	1	Levin East Substation
	300kVA 3 phase	1	Levin East Substation
	300kVA 3 phase	1	Levin East Substation
	500kVA 3 phase	1	Paraparaumu West Substation
	500kVA 3 phase	1	Paraparaumu West Substation
	1000kVA	1	Levin East Substation
	Transformer pad	1 of each	Levin East Substation: 75kVA-100kVA, 100kVA–300kVA, 500kVA–1000kVA
Switchgear/Fuses	Schneider RN62c	1	Levin Depot
	ABB	1 of each	Levin Depot: ccc, cfcc, cfc, cccc
	ABS (load break)	4	2 Levin depot, 2 Paraparaumu depots
	33kV Polymer solid links	6	Paraparaumu depot
	DO Fuse sets	10	Connectics: 3-phase sets
	Solid Link	19	Connectics

5.12 Trees

Electra does not own any trees, but it does 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. Electra, through the ENA, has submitted suggested changes to the Electricity (Hazards from trees) Regulations to reduce the current high cost of vegetation management.

Electra also adheres to the ENA/EEA's risk-based methods as recommended by the Risk Based Vegetation Management Guide[20] that provides direction on how to proactively manage vegetation risk, to improve supply reliability, security, performance and the safety of our network.

[20] Electricity Networks Association and Electricity Engineers Association, "Risk Based Vegetation Management Guide", July 2016

5.12.1 Condition-monitoring

Electra's overhead lines are surrounded by trees of varying heights, foliage types, growth rates and ownership classes. Section 8.4.6 contains our vegetation strategy which has moved to integrate a planned program where cyclic trimming is undertaken based on a risk-based assessment strategy.

Figure 5-34a shows a gradual increase in vegetation OPEX since FY2016 to FY2020 and a resulting decrease in vegetation SAIDI from 7.8 minutes in FY2018, to 4.1 minutes (FY2019) and to 0.67 minutes in FY2020. Our average vegetation SAIDI is 2.4 minutes over FY2019 to FY2020, which is 88% below the industry median of 20.1 minutes when compared with other ELBs (Figure 5-34b); the SAIDI performance versus vegetation OPEX is discussed further in Section 8.3.4.2.

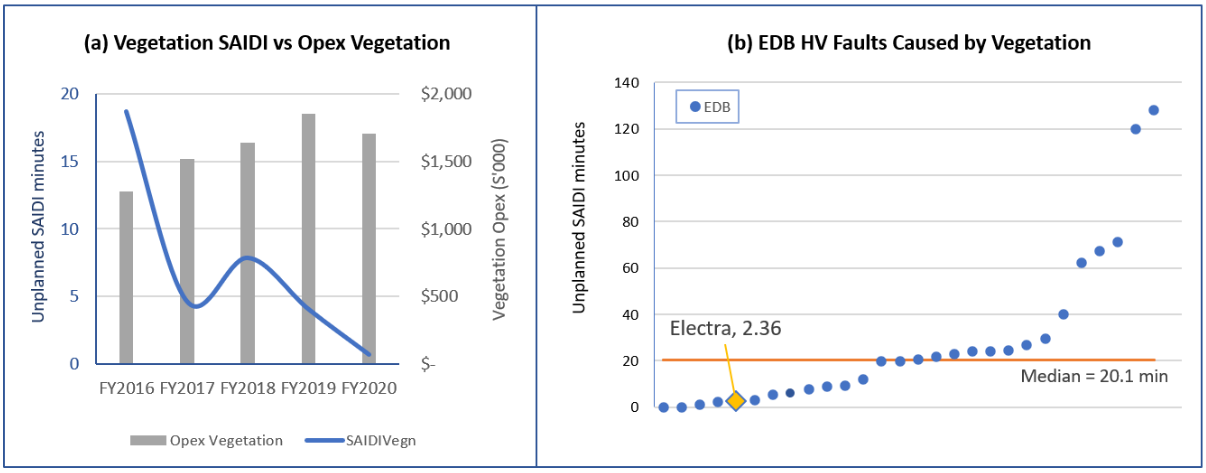


Figure 5-34: (a) Electra HV faults caused by vegetation, and (b) FY2018 -FY2019 EDB faults caused by vegetation

5.12.2 Inspection and maintenance

The maintenance drivers for tree management are the safety to the public, to customers, and to Electra personnel. Other drivers include the mitigation of risk of supply interruption, maintenance of minimum clearances specified in the Regulations, the fall zone for trees, and tree roots interfering with cables or ground level 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
- Roots observed to interfere with ground level assets
- Roots believed to interfere with cables
- Obviously unsafe tree within fall zone.

The assumptions made for these maintenance tactics are that most tree owners will accept the first cut at Electra's expense, but will prefer the tree to be removed rather than pay for second and subsequent cuts themselves. People usually give little thought to power lines when choosing the location or species of tree.

Our method for determining maintenance requirements is primarily visual, with a focus on major trunk splits or defects that could cause the tree to fall across a line.

Inspections are graded as follows and refurbishment or renewals applied as follows:

Inspection	Refurbishment	Renewal
Graded by encroachment and estimated time to reach encroachment zone; one year, three years	Not applicable	Customers are encouraged to replace fast growing species with slow growing natives Low-growing species such as toitoi and flax that encroach on ground mounted assets will be removed

Defect corrections are carried out based on the following assessments:

- **Public safety defects**: mitigations established, and corrective action scheduled within one week of identification
- **Early engagement with customers**: early engagement during surveys encouraging proactive management prior to encroachment
- **Within notice zones**: these targets follow the timelines set out in Electricity (Hazards from Trees) Regulations 2013.

5.12.3 Major projects and programmes

Since 2018, we have investigated methods and specific technologies for migrating tree trimming from a responsive based approach to a risk-based approach, to systematically reduce tree-related SAIFI and SAIDI. Initial goals focus on vegetation on feeder sections closest to zone substations and out to the first automated switch. Feeder sections have been prioritised by the greatest improvement in vegetation-based risk. This programme has been enabled by insights developed from historical inspection data and Electra's geospatial network model.

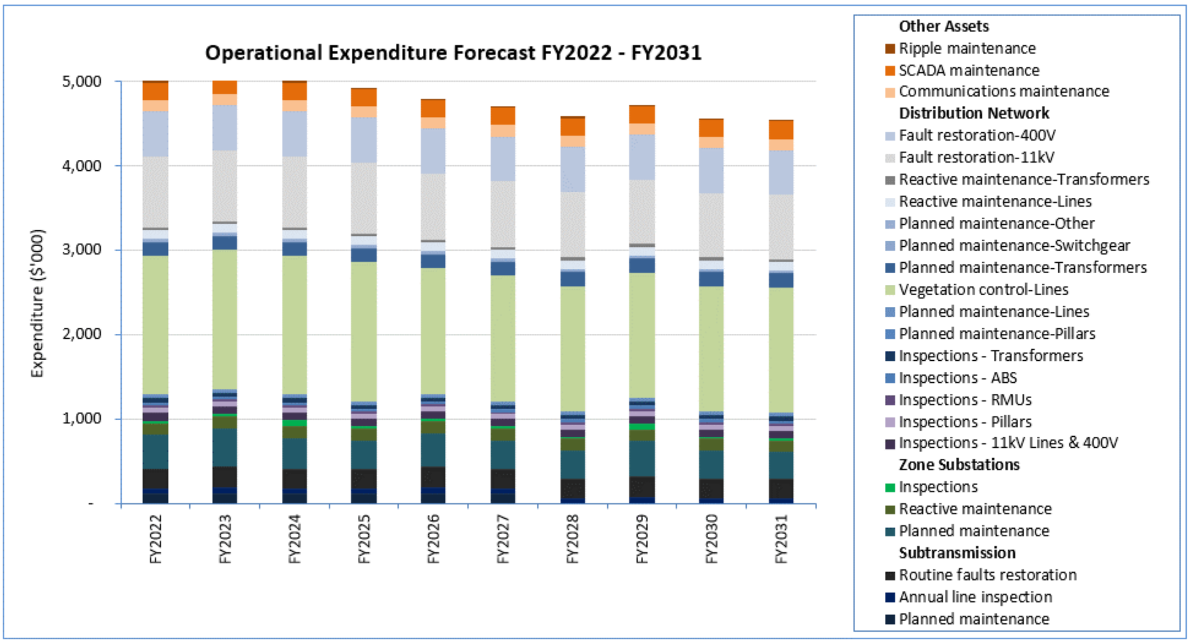
The programmes for the indicated financial years follow and the tree or vegetation control operational budget is included in the following table as well as in Figure 5-35.

Year	Ref	Location	Type of work	Category	Cost
FY2022	1	All	Vegetation control (not faults)	Vegetation	$1,645,000
FY2022 to FY2025	2	All	Vegetation control (not faults)	Vegetation	$6,422,578
FY2026 to FY2030	3	All	Vegetation control (not faults)	Vegetation	$7,437,890

5.13 Summary of inspections and maintenance

Inspections and maintenance for all asset classes described in the above sections are summarised in the following chart and graph of Figure 5-35: Projected operational expenditure (OPEX) for FY2022 to o FY 2031.

These costs for OPEX are also reflected in Schedule 11b Report of Forecast Operational Expenditure in Appendix 3.



Operations & Maintenance (Current $'000)	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Subtransmission										
Planned maintenance	120	120	120	120	120	120	-	-	-	-
Annual line inspection	55	80	55	55	80	55	55	80	55	55
Routine faults restoration	240	240	240	240	240	240	240	240	240	240
Zone Substations										
Planned maintenance	396	456	361	336	398	333	333	418	333	313
Reactive maintenance	141	141	141	141	141	141	141	141	141	141
Inspections	25	25	75	25	25	25	25	75	25	25
Distribution Network										
Inspections - 11kV Lines & 400V	100	85	85	85	85	85	85	85	85	85
Inspections - Pillars	60	60	60	60	60	60	60	60	60	60
Inspections - RMUs	25	25	25	25	25	25	25	25	25	25
Inspections - ABS	35	35	35	35	35	35	35	35	35	35
Inspections - Transformers	50	50	50	50	50	50	50	50	50	50
Planned maintenance-Pillars	15	15	15	15	15	15	15	15	15	15
Planned maintenance-Lines	28	28	28	28	28	28	28	28	28	28
Vegetation control-Lines	1,645	1,645	1,645	1,645	1,488	1,488	1,488	1,488	1,488	1,488
Planned maintenance-Transformers	168	168	168	168	168	168	168	168	168	168
Planned maintenance-Switchgear	27	27	27	27	27	27	27	27	27	27
Planned maintenance-Other	8	8	8	8	8	8	8	8	8	8
Reactive maintenance-Lines	102	102	102	102	102	102	102	102	102	102
Reactive maintenance-Transformers	34	34	34	34	34	34	34	34	34	34
Fault restoration-11kV	841	841	841	841	780	780	780	760	760	760
Fault restoration-400V	531	531	531	531	531	531	531	531	531	531
Other Assets										
Communications maintenance	133	133	133	133	133	133	133	133	133	133
SCADA maintenance	206	206	206	206	206	206	206	206	206	206
Ripple maintenance	20	20	20	20	20	20	20	20	20	20
Total Operational Expenditure	**5,007**	**5,077**	**5,007**	**4,932**	**4,800**	**4,710**	**4,590**	**4,730**	**4,570**	**4,550**

Figure 5-35: Projected operational expenditure (OPEX) for FY2022 to FY2031

The next sections cover our employees and the resourcing strategy to implement our development and maintenance plans.

5.14 Our employees

Electra's employees are the most valuable asset to our business. Their safety, working environment, well-being and job satisfaction are paramount to Electra. All Employees contribute to the success of our business.

In line with our strategic objectives, to "Develop our people and keep safe", and "Excellence in Operation", Electra invests in our people's safety, wellbeing, and job satisfaction. Key initiatives include increased focus on employee wellbeing through promotion of EAP Services, fully funded Medical Insurance through Southern Cross and associated member benefits, Drug and Alcohol education, and an upcoming focus on resilience. Performance management, talent matrix and succession planning initiatives are being linked together to identify future people leaders.

Electra is proud of our diverse and inclusive workplace. Our team demographic is varied, and we recognise and value our employee's individuality and authenticity. As a continuous improvement initiative, our entire team will be attending training sessions on unconscious bias with the objective of ensuring we as individuals understand and identify barriers to embracing others that are different from us.

5.14.1 Training and development

Electra has invested in a comprehensive training and development programme to develop our workforce with increased competencies and career pathways. A performance management framework has been established to enable all employees to receive formal feedback on their individual performance and individual development plans has been established. Regular feedback and discussions with line managers around their performance against key performance indicators and their behaviours which reflect our values: Safe, Professional, Accountable, Integrity, and Respect, are being promoted and expected.

A four-session series has been run for people leaders to ensure professional and consistent approaches to HR related topics, and newly appointed Leading Hands participated in a development programme. The EWRB Competence Programme is run over two days annually, achieving a 100% success rate (Figure 5-36). A 100% competency success rate was also achieved during our Aborists' refresher day. This now includes a session from the Group Health, Safety and Wellbeing Manager about learning from incidents in the industry and our workplace. Four field crew members are currently cross training in other roles and four more are waiting for approval to enroll.

Electra achieved 3,700 training hours in FY2020, and we expect to continue our commitment to training in the following years. In FY2020, team members who work on Electra's Distribution assets have attained 22 National Certificates an increase from 11 certificates in FY2019 showing our commitment to continue to "develop our people and keep safe". The certifications include:

- 14 x National Certificate in Electricity Supply (Distribution Line Mechanic) (Level 4)
- 3 x National Certificate in Electricity Supply (Electrical) (Level 4) with strands in Electricity Supply Electrician, Electrical Fitter and Electrical Technician
- 1 x National Certificate in Horticulture (Arboriculture) (Level 3)
- 1 x National Certificate in Horticulture (Arboriculture Advanced) (Level 4)
- 3 x National Certificate in Electricity Supply (Fault Response) (Level 4).

Figure 5-36: EWRB competence programme of August 2020 with 100% success rate

To ensure effective communication of our asset management policies and objectives, key managers such as the GM of the Lines Business, the Health, Safety and Wellbeing Manager, the Training and Development Coordinator, attend monthly depot meetings to provide updates, and to respond to questions, achievements and concerns.

5.14.2 Effects of the pandemic

Throughout the Covid-19 alert levels, the safety of our employees remains our key objective.

Our workers continue to operate in their own bubbles either at home or work, or a mixture of both.

We have been guided throughout the crisis by good information and daily updates from the Ministry of Health, and the information received has formed the basis of almost all our safe working processes. In addition, we collaborated with our peers in the industry, regional emergency management and other essential organisations to ensure that Electra is adopting best (and safe) practices.

The requirements for our lines crews to maintain social distancing was a challenge but our teamwork and collective efforts allowed Electra to ensure that excellence in operations were maintained.

5.15 Resourcing policy and strategy

Our resourcing policy supports our corporate strategy and our asset management objectives to develop our people and keep everyone safe as well as to maintain operational excellence. The following sections cover our resourcing approach to support our capital and maintenance programs.

5.15.1 Resourcing approach

Key features of Electra's resourcing strategy include:

- Forecasting the annual hours required for the three key occupational classes of electrician/jointer, line mechanic, and arborist
- Identify the annual available man-hours for each of the three occupational classes, including new hires, apprentices, resignations and retirements.

Any shortfall of annual man-hours within each occupational class is identified and plans to meet those shortfalls are developed. Those plans can include multi-skilling of existing staff, improving productivity of existing work practices, training of apprentices, recruitment from the open market, or using contractors.

The competency requirements of staff and contractors deployed adhere to our SMS on competency requirements to ensure the safety of approved contractors' employees, staff and the public through effective training and the development of a highly competent work force.

5.15.2 Resourcing guidelines

Electra's resourcing is guided by the following principles:

- Most of the network construction, operation and maintenance will be performed by internal staff
- Contractors will be engaged for well-defined tasks such as trenching, directional drilling or concreting where their rates are cost competitive
- Infrequently required specialist skills will similarly be contracted when required.

Any transition from the use of contractors to in-house staff will include consideration of competency, likely work volumes, presence of contractors and the expected difference between wages and contract rates.

5.15.3 Strategic workforce issues

Electra recognises a range of strategic workforce issues that include:

- An increasing ICT content for its field work that includes programming and device interconnection
- Adjusting field crew makeup, leveraging the skills and experience of older people for works inspection and scoping while enabling younger workers to step up to work team leadership
- Forecast AMP spends by other EDB's is putting upward pressure on field services wages
- Retention of workers upon completion of training.

5.15.4 Specific resourcing plans

Current service delivery utilisation is about 79%, rising in each of the last two years. Utilisation and productivity are areas of continued focus. Reporting, feedback and process developments aim to lift this to 85%.

Electra has a programme of annually recruiting new apprentices as part of its long-term succession planning, and it expects to continue this practice year-on-year over the next 10 years.

Part of the capability matrix is to upskill 30% of the workforce to be multi-skilled in different disciplines to accommodate for peak periods.

5.15.5 Required resources to deliver works

Looking ahead Electra must recruit 18 replacement FTE's over the next 10 years due to 20% of the workforce approaching the age of National Superannuation entitlement. Capability and succession planning are in place to minimise that impact. Skillset capacity is analysed to identify current FTE's and vacancies in the process of being filled.

The expected resources, the surplus and shortfalls for works delivery is depicted in Figure 5-37.

The forecast shortfall of electrician/jointers can be offset by re-deploying multi-skilled line mechanics who can perform jointing work, and potentially also re-deploying the six FTE’s allocated to third-party work to Electra jobs and projects.

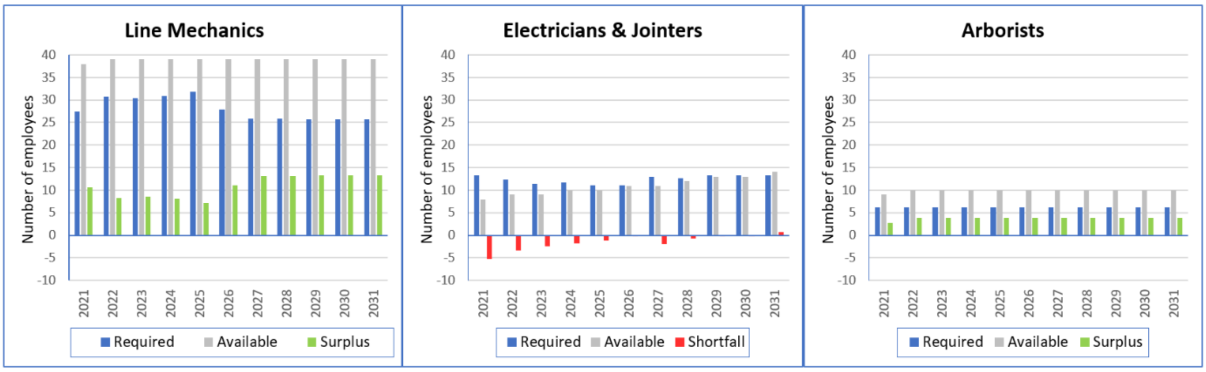
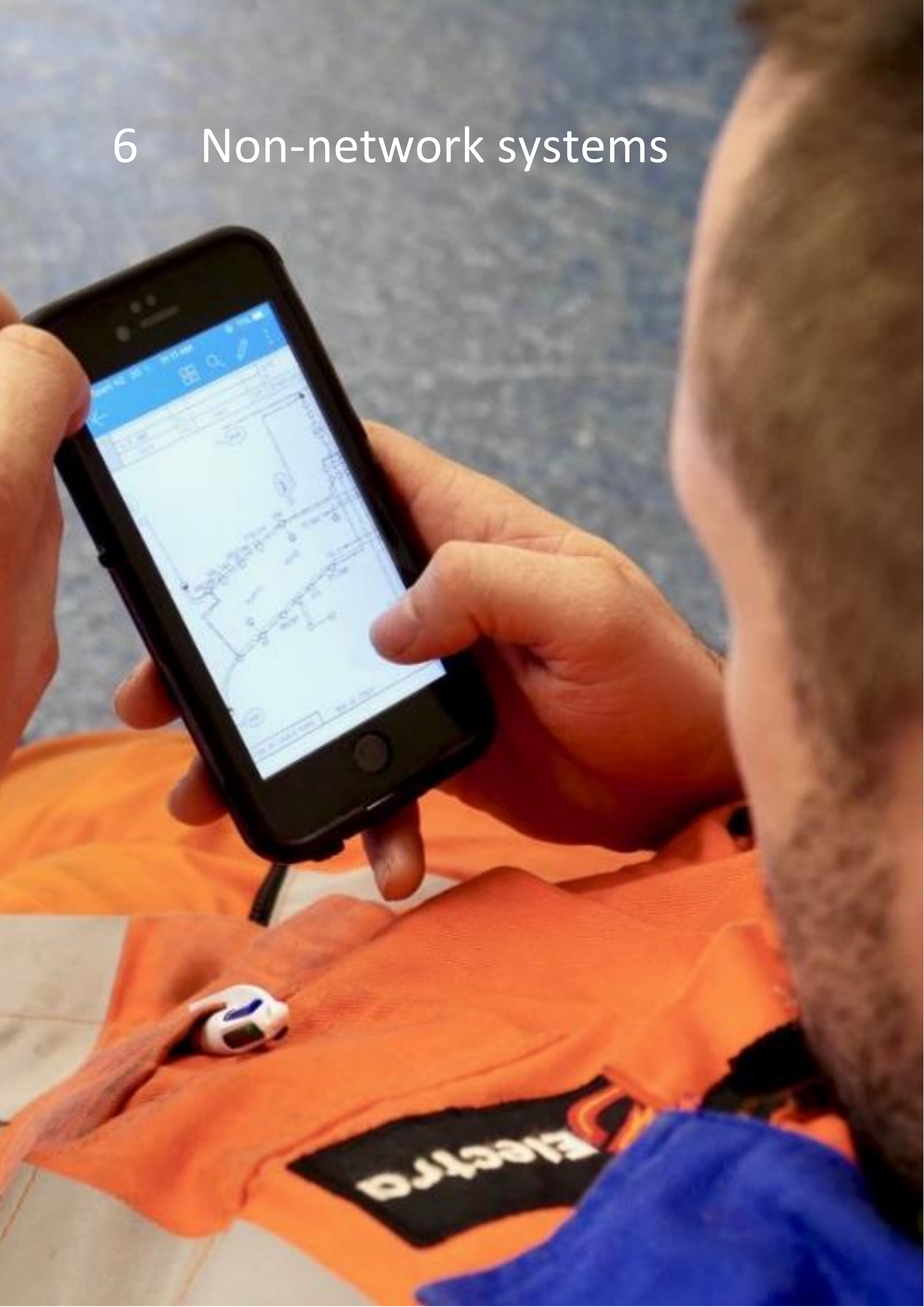


Figure 5-37: Works delivery projected resources

6 Non-network systems

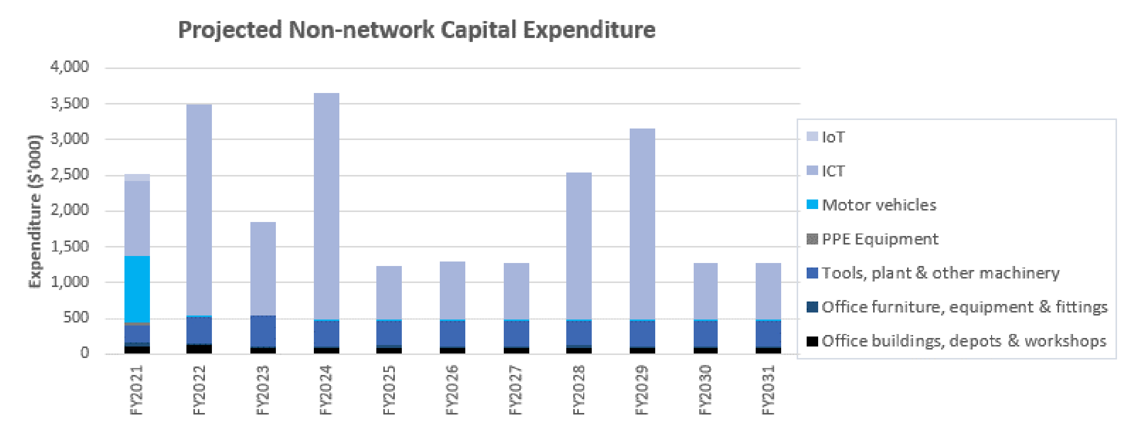


6.1 Summary of non-network assets

Electra's non-network assets include:

Asset class	Description	Approximate value	Criticality to asset management
Non-network ICT and AMIS	Financial system - Microsoft Nav-Dynamics	About $0.5m total replacement cost Fully depreciated	Financial reporting and purchasing would be disrupted. Criticality would be about 1 month unless a specific data extraction job was necessary
	Other corporate software	$188,000 (NBV)	
	In-house outage management and job dispatch system	$60,000 (NBV)	Fault dispatch work would be disrupted. Criticality is about 12 hours
	Customer Resource Management System (CRM)	$93,000 (NBV)	Existing work would continue, customer history for new jobs would need manual lookup. Criticality is about 30 days
	SCADA – iFix (Catapult, marketed by GE)	$1,288,000 (NBV)	Real-time operations would require manual HV switching. Criticality is minutes
AM systems	NIMS – based on ESRI GIS, but largely in-house	$1,600,000 (NBV)	Existing work could continue, but new jobs couldn't be created. Criticality is about 30 days
	Milsoft ADMS suite	$0 (NBV) Fully depreciated	Outage resolution would be delayed increasing SAIDI
Buildings	Head office (Levin)	$1,040,000 (NBV) Includes electric car chargers	Head office critical over the long-term, but short-term alternatives for control room and other critical work have been established
Photovoltaic (PV) and battery storage system	Head office (Levin)	$27,000 (NBV)	Not critical
Office furniture	Desks and workstations Chairs	$390,000 (NBV) Includes PCs and related IT equipment	Not critical as easily replaced
Vehicles	Cars Vans 2WD Utes 4WD Utes Bucket Trucks	$4,250,000 (NBV)	Not critical as alternatives can be arranged
Tools, plant and machinery	Hand tools Test Equipment Power tools	$633,000 (NBV)	Not critical as easily replaced through local retailers or specialised suppliers

The overall projected non-network expenditure is shown in Figure 6-1.



Non-Network CAPEX	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Office buildings, depots & workshops	100	125	90	90	95	90	90	95	90	90	90
Office furniture, equipment & fittings	60	25	25	25	25	25	25	25	25	25	25
Tools, plant & other machinery	250	380	420	350	350	350	350	350	350	350	350
PPE Equipment	38	-	-	-	-	-	-	-	-	-	-
Motor vehicles	925	15	10	10	10	10	10	10	10	10	10
ICT	1,060	2,953	1,300	3,175	765	825	800	2,070	2,691	800	800
IoT	100	-	-	-	-	-	-	-	-	-	-
Total CAPEX	**2,533**	**3,498**	**1,845**	**3,650**	**1,245**	**1,300**	**1,275**	**2,550**	**3,166**	**1,275**	**1,275**

Figure 6-1: Projected non-network expenditure

6.2 Non-network ICT strategy

Electra's principles, approach and overall investment priorities for the business align with the other strategic and operational plans of the company including this Asset Management Plan, the departmental business plans and associated budgets.

This section of the AMP refers to all technology centric operations and the development of systems to support the electricity distribution business, particularly, non-network ICT will support investment and operation via the following:

- Efficient works delivery
- Improved customer experience
- Improved supplier relationships
- Improved real-time operation
- Optimised network investment
- Integration of increasing data into Electra's wider businesses
- One and only one data item that is reliable ("Single Source of Truth").

6.2.1 Strategic context

Electra's Statement of Corporate Intent (SCI) identifies five focus areas for the company. These are

- Excellence in Operation
- Focus on Customers
- Develop the New
- Prepare for Change, and
- Develop our People and Keep Safe.

These focus areas feature in Electra Group Business Plan and budgets.

	Focus	Threat	ICT Initiatives in response
External Factors	Opportunities	Customers seek accurate and timely info. Reduce procurement and operational costs Growth potential in subsidiaries New business in technology centric business	CRM, Integrations and correct data Collaborate with CIO's in other ELB's Support and develop acquisitions Search and bring to the table
	Threats	Cyber and physical threats to operation Disruption of significant regional disasters Data Breach/Disclosure Pandemic	Collaborate, strength, educate and test Plan and prepare and practice Controls, classification and education Improved support of distribution or remote workforce
Internal Factors	Strengths	ICT operation and management expertise Modern business information systems Progressive company strategy Strategic partners	Document and teach for succession Leverage and develop tools Research, innovate and learn Develop and maintain strong relationship
	Weaknesses	Limited business intelligence and analytics Phased ADMS implementation ICT staff lacking expertise in various systems	Investigate, select and develop Develop and extend Education and mentoring

Figure 6-2: Needs Analysis Survey.

Electra desires to serve its customers with better quality information by leveraging the ADMS. The business expects the highest levels of service availability while being cognisant of the threats to our operation.

6.2.2 Electra's ICT assets

The operations and functions of each capability are integrated, and any business service often relies on one or more of these to operate at effective service levels.

The following model outlines Electra's approach to categorising our ICT assets and capabilities:

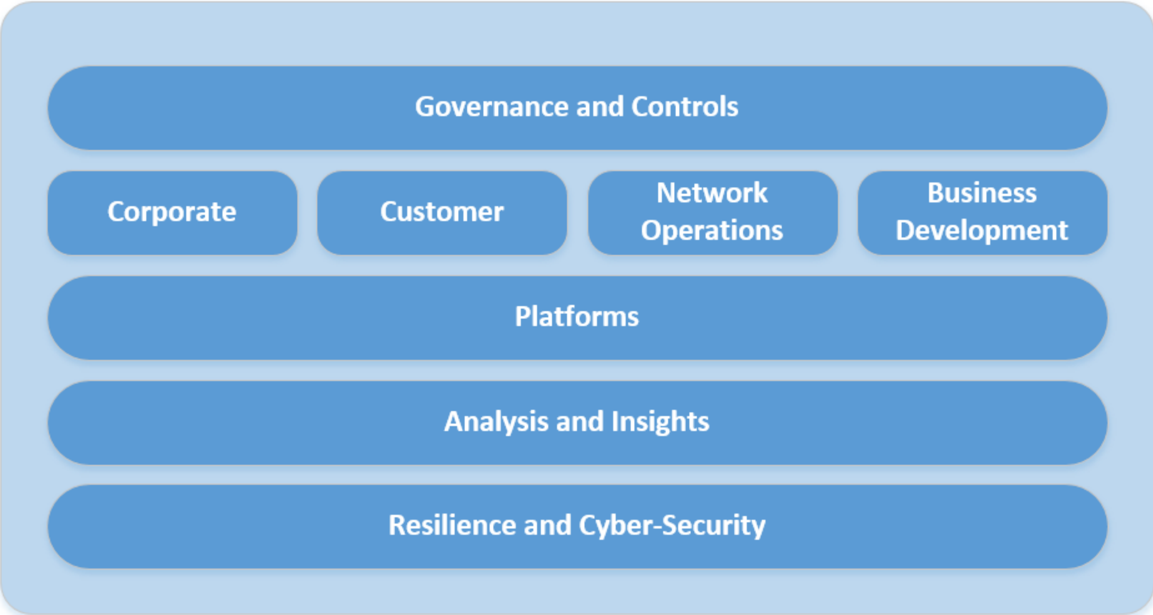


Figure 6-3: Electra ICT asset and capability framework

Each asset class provides business services, being:

ICT asset class	Business services
Governance and controls	Contributes to the overarching strategic direction of Electra. Aligns business decision making and ICT investment. Provides frameworks, planning and controls
Corporate	Supports the effective operation of business support functions, including finance, human resources and payroll, health & safety and knowledge management
Customer	Enables customers to interact with Electra – to understand outages, advise of concerns/incidents and to request new connections
Network operations	Supports the safe and effective operation of our electricity distribution network. Contributes to an integrated information sharing and efficient use of resources. ICT provides guidance on best practice
Business development	Support the operation and growth of existing businesses. Identify and drive creation of new businesses
Platforms	Underpins delivery and management of Electra's ICT services – both our Cloud and on-premises operating environments including hardware, software and services
Analysis and insights	Provide platform, expertise and training to enable the analysis of datasets and creation of performance graphs
Cyber security and resilience	Ensure our ICT services availability and enables response to threats and risks through establishing and maintaining internal controls

6.2.3 Smart grid strategy - ADMS platform

In 2018, Electra implemented the Advanced Distribution System (ADMS) from Milsoft Utility Solutions. This provided a suite of products for the design, analysis, operation and performance reporting of the distribution business.

Three key components are:

- Outage Management System that despatches jobs to field devices and provides visibility to electricity outages through a webpage and mobile application
- Design and Engineering analysis maintains the single-source-of-truth for the network design and provides the ability to edit and extend the network. This also provides load flow analysis
- Management of planned and unplanned outages including regulatory reporting.

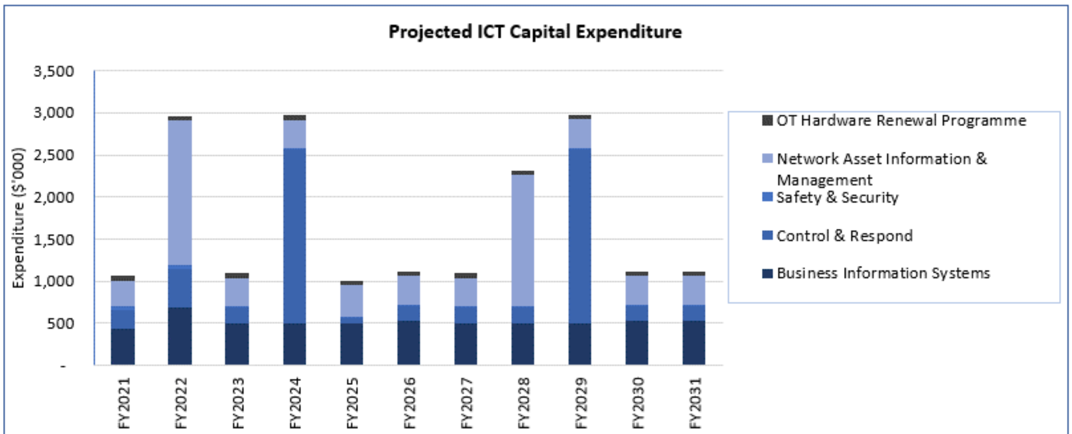
We are already realising the benefits of improved communication with our customers, greater visibility of processes that span the company and more accurate reporting of reliability metrics. A data quality improvement programme continues to improve the completeness of the underlying information.

Electra also implemented the Milsoft-aligned Clevest Field Service Management platform which provides field crews with greater visibility and the ability to update and restore customer outages easily at the site.

Over the past twelve months, Electra has deployed an IoT platform (LoRaWAN) to leverage long range low bandwidth communication to collect real-time information on voltage, current and network status. The advantages of these platforms are that they are low cost, long range and easily deployed. The information collected feeds into a central “data lake” for post-event analysis and is also presented to the control room operators for event notification and verification. This information improves network reliability, asset management, decision making and communication with the customer. This initiative involves deployment of a range of approved technologies within our electricity network with the support of vendors and customers.

6.2.4 ICT CAPEX forecast

The following Figure 6-4 has been produced by analysing our historic costs, then forecasting likely changes to the major systems. The costs have been estimated through consultation with solution providers.



Capital Expenditure	FY2021	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
Business Information Systems	435	685	500	500	500	525	500	500	500	525	525
Control & Respond	225	458	183	2,058	58	183	183	183	2,058	183	183
Safety & Security	50	50	20	20	20	20	20	20	20	20	20
Network Asset Information & Management	300	1,710	340	340	380	340	340	1,560	348	340	340
OT Hardware Renewal Programme	50	50	50	50	50	50	50	50	50	50	50
Total (CAPEX):	**1,060**	**2,953**	**1,093**	**2,968**	**1,008**	**1,118**	**1,093**	**2,313**	**2,976**	**1,118**	**1,118**

Figure 6-4: ICT CAPEX forecast

Capital Expenditure is spread across 5 major categories. These are:

Category	Initiatives
OT Hardware Renewal Programme	• Provision for the procurement and/or replacement of OT related assets
Network Asset Information & Management	• Implementation of an Enterprise Asset Management System (EAMS) • Upgrade and integration of Navision (ERP) • Upgrade of GIS/Spatial solution (ESRI) • Network Asset Information Improvement project • Network Asset Condition Monitoring improvement project
Safety & Security	• Replacement/Upgrade of security and surveillance systems for Network Zone Substations and other critical locations • Replacement/Upgrade of security and surveillance systems for Server Rooms • Lone worker solution
Control & Respond	• Development and enhancement of SCADA platform (iFIX) • Development and enhancement of ADMS (Milsoft) • Establish secondary control room • Strategic and continual improvement programme for secure network communications
Business Information Systems	• HRIS Solution • Replace/Upgrade security and surveillance systems for corporate offices • Business Information Systems (BIS) core architecture upgrade • Corporate Website Update • CRM Development • Business Information Systems (BIS) Service Delivery Solution replacement

The investment in FY2022 reflects the anticipated implementation of a new Enterprise Asset Management system in conjunction with the upgrade and integration of Microsoft Dynamics Navision to Microsoft Dynamics Business Central. The focus is also going to be improving the quality and accuracy of LV information through a formalised and agreed data improvement strategy over the next 5 years. In the same financial year, we will continue to improve the resilience and capability of our private Microwave WAN and public network connectivity solutions.

In FY2022/23 we will be reviewing our requirements relating to our ADMS and SCADA solutions with the expectation being the replacement or upgrade. The desire is to implement a secure, consolidated solution which will simplify planned or unplanned outages and customer communications.

6.2.5 Cyber security plan

Electra has a mature Risk Management Framework that identifies the threat from regional natural disasters and cyber threats, amongst others. In 2018 the company undertook an extensive assessment and improvement programme with a New Zealand leading provider. This improved Electra's existing ICT controls to staff and customers. Initiatives carried out in 2019 included the use of Multi-Factor Authentication (MFA) when logging into one of our remote servers from anywhere except offices of the Electra Group. The product used is called ESET Secure Authentication which uses an application installed on your mobile phone which will prompt you to approve any attempt to log in to the Remote Access server using your username and password.

In 2020, Electra adopted the Crowdstrike Falcon X Automated Threat Intelligence. This solution combines automated analysis with human intelligence and is widely used throughout the industry in New Zealand.

We continue to use leading hardware and software vendors when it comes to securing our infrastructure. This includes scheduled update and replacement of key architecture to support growth and resilience.

6.3 Buildings and property

Asset class	Key policies	Strategies and initiatives
Buildings	Head office (Levin) Depot (Levin) Depot (Paraparaumu)	Plans to create additional meeting rooms at Head Office and to alter the layout at the Levin Depot to allow for more meeting space. To be completed before end of 20/21 FY.

Buildings and property will support investment and operations by the deployment of:

- Safe, comfortable working environment
- Disaster resilience
- Ability to accommodate additional office and field staff
- Flexibility to rearrange staff as org structure evolves
- Specific plans for system control, especially back-up (cuts across ICT).

6.3.1 Photovoltaic (PV) and battery storage systems

A single-phase system was installed at Electra's Head office in 2019 and used to learn about domestic energy trading (Energy Arbitrage), how hybrid PV systems operate, and how users interact with these systems. This PV configuration is typical of a domestic dwelling with battery storage. A Sonnen 8kWh Lithium Iron Phosphate (LFP) Battery has been installed with ten 315-watt solar panels on the northern facing roof with room for another 89 panels. The black mono N-type solar panels each have an S230 micro inverter. N-type solar panels do not suffer from light-induced degradation (LID) which causes a decrease in efficiency over their lifetime.

6.4 Office furniture and fittings

Asset class	Key policies	Strategies and initiatives
Office furniture	Desks and workstations Chairs Cabinets and storage	No specific strategy, typically low value items that simply follow the need for staff work patterns and duties. Plans to replace the office furniture at Head Office to allow more employee numbers to work there.

Office furniture and fittings will support investment and operations through:

- Safe, comfortable working environment
- Disaster resilience
- Ability to accommodate additional office and field staff
- Flexibility to rearrange staff as organisation structure evolves.

6.5 Vehicles

Electra has two electric vehicles comprising of a Hyundai Ioniq and an LDV van, plus a hybrid Mitsubishi Outlander Plug-in Hybrid Electric Vehicle (PHEV), in our pool of vehicles.

The asset strategy for Electra's vehicles is tabulated below and our policy is based on the most fuel-efficient vehicle that meets the requirements of its use, and whether this meets fuel and emission requirements.

Asset class	Key policies	Strategies and initiatives
Electric vehicles and hybrids	Cars – electric vehicles and hybrids: EV batteries replacement as per manufacturer's recommendations	Evaluation on "fit for purpose" is undertaken by the team manager or supervisor, based on the distance the EV can be driven between recharging. If a fully Electric Vehicle is not fit for purpose, a Plug-in Hybrid Electric Vehicle (PHEV) is evaluated as such vehicles have no range limitation and have substantially lower emissions than a typical hybrid or fuel vehicle and will cost the same over its lifetime
Other Vehicles	Cars (petrol): replace after 130,000km or 4 years Cars (diesel): replace after 160,000km or 4 years Vans and Utes: replace after 160,000km or 6 years Trucks: determined by GM – Lines Business, but typically 10 years.	Key strategy is that the load capacity, terrain capability and range need to align with key network features as well as aspects of passenger or cargo or towing capacity or other requirement so that a fuel vehicle is justified e.g. extent of network footprint, length and weight of poles

Our vehicles contribute to our investment and operation by their ability to perform all required investment and operational activities including transport, lifting and digging.

6.6 Tools, plant and machinery

Electra's key policies for renewal and replacement of non-network assets include:

Asset class	Key policies	Strategies and initiatives
Tools, plant and machinery	Hand tools – replace when unsafe or insufficient functionality Power tools Generator - serviced every 250 hours including replacement of oil and filter. Electrical connections tested annually, COF for the trailer is renewed every 6 months	A replacement strategy based on the safe and efficient operation of our tools and equipment

The replacement policies aim to match the depreciation of the assets.

7 Risk management

Electra recognises it is exposed to a wide range of risks, not just those risks inherent in operating an electrical network but also those from external influences such as legislation, environmental changes, stakeholder satisfaction, plus our subsidiary businesses and joint ownership enterprises. Aside from the obvious physical risks such as cars hitting poles, vandalism, public safety and storm damage, the network business is exposed to a wider range of risks that need to be considered. As a Lifeline utility, Electra recognises our responsibility to ensure a safe network, one that is both secure and as a company has long term resiliency.

Electra has a well-established Risk and Audit committee, with a company appointed Risk Manager to provide oversight. Electra also participates in and leads the industry EDB Risk Managers forum.

7.1 Risk analysis and methods

Electra has a comprehensive risk management framework as shown in Figure 7-1; this is regularly reviewed by the Board Risk and Audit committee and Management, in line with the requirements of the Health and Safety at Work Act 2015.

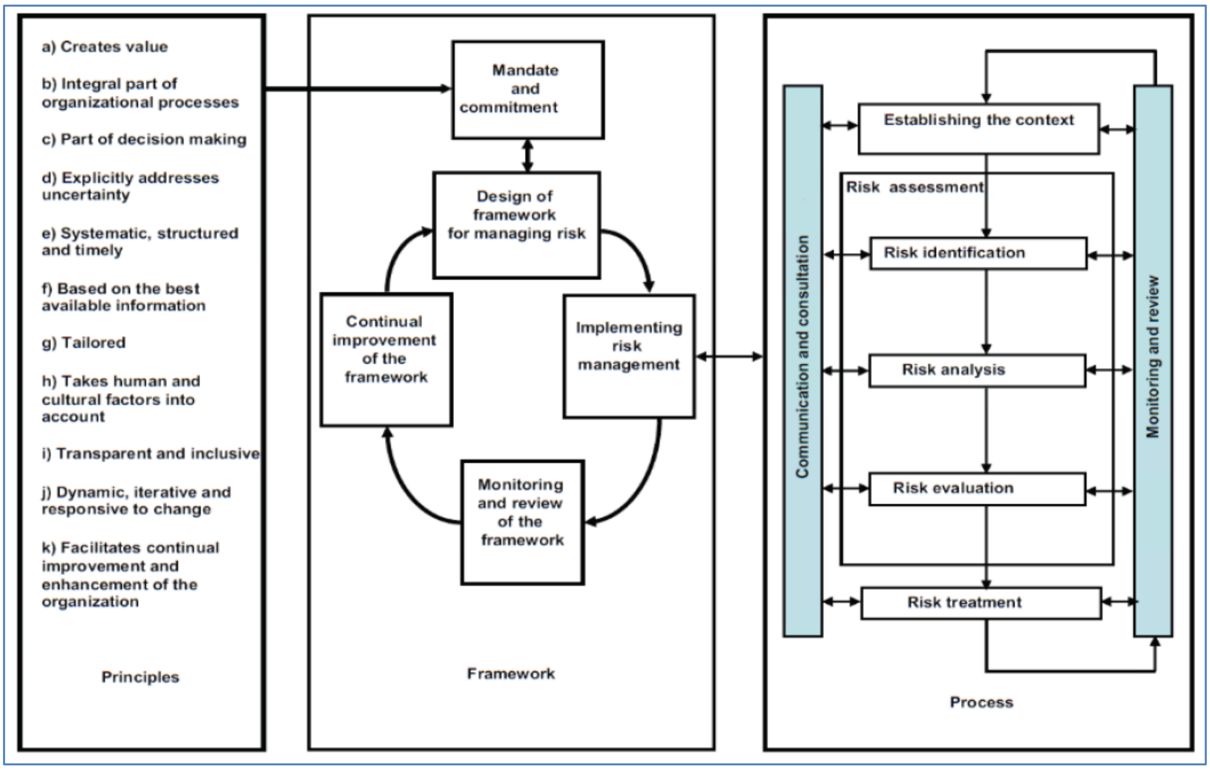


Figure 7-1: Risk management framework based on AS/NZS ISO 31000:2009

This framework uses an established process based on AS/NZS ISO 31000:2009 to:

- Identify risks that affect the business
- Assess the impact and likelihood of the risk occurring
- Identify existing controls that will mitigate the risk
- Identify the top five residual risks once the controls have been applied
- Produce and implement risk treatment plans to further minimise risks
- Assessments and plans will be fully documented to assist with the following year's review.

An essential part of this process is the identification of workplace hazards and the requirement to keep a register of accidents.

7.1.1 Risk management system

Electra uses the Vault risk management system to record and manage all risks for the company. Vault is a stand-alone cloud-based risk management and incident reporting tool. Our Health Safety and Welfare, and organisational risks are recorded on this platform, with all events including incidents, injury, illness and near misses reported (either via desktop or a mobile application). Incident investigations are also recorded here.

The primary benefit is a common and consistent risk evaluation and scoring system. This enables the business to readily identify the greatest risks to the Electra Group.

7.1.2 Risk register

The Group maintains a Risk Register which is reviewed no less than quarterly by the Senior Leadership Team. Key risks are reported to the Risk and Audit Committee and the Board. Changes to the previously reported state are identified to support increased understanding of changing risk profiles and effectiveness of planned mitigation. Shifts of risk scores also reflects our greater understanding of risks and risk controls.

Senior management are required to complete Legal and Statutory Compliance certificates on a quarterly basis and actively support any ongoing compliance surveys such as ComplyWith.

The Group's Risk Register records identified risks, the methods of control, and the resultant residual risk (exposure to loss remaining after other known risks have been countered, factored in, or eliminated. Electra staff and management regularly complete a comprehensive risk analysis on the network and the supporting management structures. These risk analyses are reviewed by and agreed by the Risk and Audit committee comprised of Electra Directors. From this analysis, Electra identifies critical elements and plans required to manage these risks.

The Electra Group Risk and Control Environment is updated to reflect the progress of agreed actions.

The only current major project risk identified is major digital projects, with this being classified as low risk.

7.2 Specific risks

The following risks are listed as subset of the risk maintained in the Vault Risk Management System.

7.2.1 Operating safety risks

Operating and maintaining an electrical network involves hazardous situations with risks that cannot be entirely eliminated. Electra is committed to providing a safe reliable network that does not place our staff, other workers, the community, or the environment at risk. This has been underpinned with the implementation and incorporation of the Public Safety Management System (PSMS) into the business. The PSMS system is a regulatory requirement and is independently audited by Telarc annually. A certificate verifying compliance with the standard has been issued.

External parties are required to provide us with internal controls assurance before their formal engagement.

Electra's strategies to mitigate risks relating to personal and public safety are:

- Development and maintenance of safety policies and manuals
- Giving the highest priorities to safety related network improvements

- Design, operate and develop a network in compliance with regulations and accepted industry practice
- Operation of a Public Safety Management System (PSMS): This is a regulatory requirement focusing on public safety and certified to NZS7901:2008 in 2012 and renewed in 2020. Documents contributing to PSMS are being reviewed to ensure they comply with NZS7901:2008, the standard we currently operate to. Outside contractors are engaged to provide support to.

Some of the key aspects of the health safety and wellbeing policy 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 & safety issue must be reported to the Company using the procedure explained in our PSMS manual
- 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.

7.2.2 Natural disaster risks

Electra's distribution network is exposed to a range of natural disaster risks. These are described more fully along with Electra's disaster response in the Vault, Business Continuity Plan (BCMP) and Major Network Event Guidelines (MNE).

The Major Network Event Guidelines document is available to ensure major events are managed appropriately. To be classified as a major event identified thresholds need to be met, and outlines the management required for such an event.

These BCMP and MNE documents are updated no less than annually and exercises conducted every two years

7.2.3 Asset failure risk

The greatest probability of failure to any infrastructure utility is at any point where there is a concentration of assets, such as at a zone substation for an electricity distribution network. At zone substations, the highest risk equipment is the indoor 33kV and 11kV switchboards. A failure of these assets tends to be explosive and may cause subsequent damage to adjacent assets. This will increase the extent of any outage and the restoration time.

Assets are more likely to fail towards the end of their useful life. As discussed in Section 5.2, Electra inspects all its assets on a cyclical basis. Any assets that are of poor condition and are assessed to have a high likelihood of failure either have maintenance tasks performed to extend its asset life or are replaced with a new asset. Replacements are shown as renewals in the network development plan discussed in Section 4.

7.2.4 Network records risks

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 Group IT Security Policy

Access controls include the use of Microsoft Active Directory and expected antimalware and behaviour monitoring software.

7.2.5 Regulatory risk

The following regulatory risks are noted:

- Uncertainty associated with the implementation of government-initiated electricity pricing review
- Uncertainty of how regulators may influence adoption of emerging energy technologies and electrification of transport network
- Uncertainty about the replacement of the Transmission Pricing Methodology.

Electra is proactively collaborating and growing capabilities to adapt to the opportunities and risks presented by the above. By gaining experience in these new technologies and developing new products and services for our customers, Electra is acting rather than waiting for change to be imposed.

The results of the Group Legislation Compliance Survey 2020, completed by 41 managers and key employees, were reviewed by the Risk and Audit Committee in September 2020. The survey covered 81 pieces of legislation and this survey ensures that we are monitoring our legal obligations as well as educating our staff on these requirements. There is an information function for each survey question which enables staff to check what compliance means for that particular requirement. The survey is run on cloud-based software provided by ComplyWith and Figure 7-2 depicts the process.

Figure 7-2: Legal risk management process

7.2.6 Pandemic response

As an essential business, Electra kept the lights on and our communities and business safe and connected during Covid-19 restrictions.

Field staff were provided with appropriate personal protection equipment and well briefed on the correct processes and protocols. Teams worked in dedicated bubbles of four for the entire duration of the lockdown levels three and four; staff were restricted to one person to a vehicle until level three when sharing of vehicles with work bubble colleagues commenced.

Increased use of working from home and video calls was encouraged for office-based staff.

The Group pandemic plan has been updated, and is regularly reviewed, to reflect the steps required to maintain business during a pandemic.

7.2.7 Distributed Energy Resource (Solar and Electric Vehicles)

Consumer expectations change over time, with both sustainability and new initiatives such as electric vehicles (EV) (transport and domestic fleet) and Distributed Energy Resource (DER) receiving increased attention and market penetration.

Electra is moving from tactical decision making for new initiatives to guiding strategy for future networks. Unless planned for, increases in these initiatives may cause disruption to existing infrastructure. An increased interest in solar farms is already occurring.

Electra intends to support DER adoption by

- Developing a strategy to inform decision making
- Facilitating discussion with those considering DER
- Performing a high-level technical feasibility
- Refresh of Network Connection Policy
- Designing the Network to support different future use

Our response to the increased expectations of our connected customers and the industry in which we operate is to be involved in industry initiatives and working groups such as EV Connect with Wellington Electricity.

There is an increased appetite for the decarbonisation of New Zealand. With the risk of regulatory change to facilitate this, a positive impact there may be an incentive to encourage use of DER and further renewables, along with the risk our network will not be ready for it.

Electra is not at considerable risk to the introduction of incentives that might encourage greater adoption of residential solar +/- battery storage and electric vehicles as Electra starts with a low base. Requests to connect larger scale installations require an application and approval process which applies a user-pay approach for any upgrade of distribution equipment. Electra is in the process of creating a strategy that considers the Network impact of changes. This will guide decision making and investment decisions

7.2.8 Decarbonisation

Electra is committed to support the governments low-carbon initiatives delivered through EECA and other government agencies. Converting process heat from coal and gas to clean energy, and the decarbonisation of NZ transport sector by moving operators from petroleum products are major opportunities for Electra.

To support these government initiatives Electra is

- Regularly meeting local government 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
- Participation in relevant national workgroups and events

Decarbonisation will be included in Electra's strategy for management of DER and PV demands

7.2.9 Climate change

The Ministry for the Environment has identified the top 42 climate risks for New Zealand in their 2020 National Climate Change Risk Assessment report. They have prioritised those that require the most action.

Climate change is expected to cause a change in sea levels. Changing weather patterns may lead to more severe and frequent storms than previously experienced. Average temperatures, wind and rainfall may be impacted, and these changing weather effects may potentially affect assets and network operations. Continual improvement and efforts will be undertaken to monitor these changes to manage network reliability and improve network resilience.

Electra recognises New Zealand is dependent on lake levels for hydro electricity generation and any rainfall variations may impact electricity supply or transmission.

Increased rainfall may also result in interruption to supply due to flooding as a result of reduced infrastructure maintenance by local authorities, where water is unable to be carried away rapidly by stormwater systems.

Electra participates in relevant national workgroups and events and maintains a watching brief on the market.

7.2.10 Economic Downturn

New Zealand moved early against the Covid-19 threat with a range of subsides and stimulus incentives provided to maintain the economy. However, many countries, including our major business partners are facing difficult times that are impacting their people and production.

There are uncertainties how global economies will fair and the impact of businesses. The two key risks to the Electra Group are delayed supply of long-lead-time equipment and regional slowdown reducing connection and consumption growth.

On the assumption that the economy would recover in several years, the ten-year Asset Management Plan would not significantly change from what has been presented. Electra continues to maintain a capable workforce, strategic spares for urgent repairs and planning windows can factor in delays for specialist equipment.

7.3 Mitigating network vulnerabilities

Electra manages risk through a combination of measures. These can include both physical and operational measures and will be focused on management and minimization of them.

Specific plans include both physical and operational mitigation measures ranging from replacing assets to insurance and access to financial reserves.

Physical risk management is part of Electra's overall legislative compliance programme. Electra, using the relevant electricity industry and building seismic codes, has a robust network.

Aspect of work	How risks are managed
Data integrity	As-built plans are required for all new extensions Asset data is required for all new extensions and all replacement or maintenance programmes
Easements	All new assets on private property are suitably protected by registered easements
Control of work	All work on the electricity assets – regardless of voltage – must be co-ordinated through the Control Centre Work must comply, as a minimum, with the Electricity Industry Safety Rules
Strength of works	As a minimum, all new extensions and all replacement or maintenance work must comply with relevant Electrical Codes of Practice and Electra's Network Construction standards

The following table summarises asset specific risk mitigation and management features of the network assets.

Activity	How risks are managed
Transformers and switchgear	Oil containment where located outside All zone transformers have individual oil containment with 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 VESDA sniffer 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
Buildings and zone substations	All major projects, such as a new zone substation, are specifically designed for their location – electrically and structurally All buildings are built to the relevant building code Electra has seismically engineered bracing on all power transformers at zone substations, with seismic bracing for switchgear and other components as required Electra replaced all zone substation access locks with a tiered key system in 2002, distribution transformers completed in 2003 and all other 11kV equipment in 2004. Access keys are only provided to employees and contractors on a "need to have" basis – the need determined by Electra and not the contractor Electra completed security fences at the remaining zone substations in 2004 Electra undertakes bi-monthly visual inspections of all zone substations. Any necessary repairs are scheduled immediately
Network design	As a minimum, Electra uses the Electricity Act and associated Regulations as the basis for construction and maintenance of the network. Safety in design is a key requirement. Electra, through the design process, ensures that, as the network develops, further interconnection is provided at 11kV.
Reticulation	Electra requires pole strength calculations for all new pole transformers and overhead extensions Underground cables are specified to withstand through short-circuit faults along with capacity requirements The annual network inspections identify any deterioration affecting physical strength, and safety clearances to ensure public safety
Network operation	Electra generally operates the 33kV network in two meshed networks to provide a high level of support for the zone substations Foxton, Otaki and Paekakariki are not on the closed 33kV rings; these substations are backed up by the 33kV and 11kV network through automatic changeover schemes Although the 11kV network is operated in a radial manner, all backbone feeders are interconnected with other feeders from the same zone substation and adjacent zone substations
Spares	Electra holds modern equivalent spares for all electrical assets on the network at their Paraparaumu and Levin depots Individual zone substations have site-specific spares stored at each site as appropriate Details are included in Section 5.11.

Electra also uses insurance as the basis for financial risk management, covering professional and director's indemnity, public liability, buildings and plant, loss of profit and vehicles. Except for zone substations, it is not possible for Electra to insure the electricity network for catastrophic damage. Electra requires insurance of its contractors to cover contract works, all project assets, public liability and liquidated damages.

7.4 Resilience framework

As per our asset management strategies, Electra has put in place a resilience framework to manage and mitigate events beyond normal circumstances and under emergency situations. The framework covers High Impact Low Probability Events, Climate Change, Emergency Response and contingency planning and Resilience Planning for Risk Preparedness.

7.4.1 High Impact Low Probability (HILP) Events

HILP Events are events that have a higher impact than that is allowed in normal system planning criteria. These include extended contingency events (greater than n-1) and domino-effect or cascading events causing the system to fail.

It is difficult to predict these events because there are multiple failure modes and some New Zealand examples of HILP events include:

- Sep 2010: Christchurch earthquake where electricity to 75% of the city was cut
- Oct 2014: Penrose cable trench fire causing blackouts to 85,000 Auckland customers.

HILP events can cause prolonged periods without power supply and customers have a low tolerance for prolonged outages. Our customers, the community and other lifelines utilities depend on electricity every day - during and after HILP events. To meet our responsibilities, we have set up an HILP and crisis risk management team. The Civil Defence Emergency Management Act 2002 (CDEM) also requires us to function to the fullest possible extent during and after these HILP events.

7.4.2 Emergency response and contingency planning

Electra has an active Business Continuity Management Plan (BCMP), which is reviewed and updated regularly. Recent inclusions and updates include pandemic threats, climate change and seismic threat. Biennial simulation exercises are undertaken to ensure the BCMP remains relevant.

The following strategies are applied to mitigate the impact of potential HILP events:

- **Identification**: understand the type and impact of the events the network could potentially experience
- **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 the use of contingency plans to invoke a staged and controlled restoration of the network.

7.4.3 Emergency response plans

Electra regularly responds to emergencies. Generally, these are outages on the network and are used as the basis for planning and training for large-scale emergencies. All emergency response is based at Electra's Control Centre (supported by a UPS) through the toll-free fault service 0800 LOST POWER, web outage page and phone app.

7.4.3.1 General network faults

Electra Distribution Operation's staff are available 24/7 in case of outages – with various levels of response to different fault types and widespread events such as storms. Electra's Network staff are also available to help with contract and network operational issues.

Most faults are restored in less than three hours. As a guide, equipment failure, and the associated response can be summarised as follows:

Level of response	Means of response	Work required
Immediate (30 minutes to 3 hours)	SCADA or field switching Field repairs	No major work required (e.g. clearing tree branch off a line) Time depends on cause, available personnel, and extent of switching
Medium (3 hours to 12 hours)	SCADA or field switching (most consumers are restored by switching) Field repairs	Equipment damaged (e.g. pole hit by car, transformer needs changing, overhead line needs repairs or replacing) Time depends on cause, available personnel, and extent of switching
Long (12 hours to 48 hours)	SCADA or field switching (most consumers restored by switching) Field repairs	Major equipment damaged e.g. loss of a zone substation, replacing part or all of a damaged 33kV bus Time depends on cause, available personnel, and spares

7.4.3.2 Restoration of key component failures

Electra has considered the following network failure scenarios in order to assess its ability to promptly restore (n) security of supply:

- Busbar faults at each zone substation
- Loss of each sub-transmission circuit
- Loss of each zone substation transformer
- Loss of each communication hub
- Inability to access the Electra Head Office and associated systems.

The likely outcomes of each scenario have been considered, along with the tasks required to restore (n) security of supply and the resources required for each task. The list of major strategic spares including storage location is included in Section 5.11.

7.4.3.3 Reinstating the network after a disaster or HILP event

Electra has developed a Major Network Event Guideline which outlines the broad tasks that Electra would need to undertake in HILP events of Section 7.4.1, to restore electricity supply to (n) security under the following publicly credible disaster scenarios:

- An earthquake of Richter magnitude 7.5 or greater on a major Wellington fault
- Volcanic activity at Ruapehu resulting in ash coverage of about 10mm throughout the Northern part of Electra's area
- A one in 100-year flood of the Otaki, Waikanae or Manawatu rivers, or
- A tsunami impacting on the West Coast that could inundate up to 2km inland.

Preparation of the guideline has revealed that Electra has already put many recovery initiatives in place and has coordinated its likely responses with other agencies in both the Kapiti and Horowhenua districts.

7.4.3.4 Continuity of key business processes

Electra has used an external advisor to identify its key business processes and assess the vulnerability of those processes to a range of natural disasters, man-made events and deliberate interference. Mission critical processes are:

- Invoicing retailers for use of the network
- Receipting payments from retailers
- Maintaining sufficient business records of invoicing and receipting activities to compile compliant accounts and regulatory disclosures.

The key risks identified to these processes are:

- Unauthorised access to data
- Accidental fire or arson at Electra's offices or adjoining premises
- An earthquake of Richter magnitude 7.5.

Mitigating actions taken include:

- Maintaining a backup Control Centre off-site from the head office that contains all the necessary software and templates to perform critical tasks discussed above
- Review of the physical security of the principal server regarding unauthorised physical interference, fire damage or earthquake damage
- Regular review of Electra's level of cyber security maturity and level of preparedness.

7.4.4 Resilience planning for risk preparedness

The procedures that relate to our network resilience cover the following:

No.	Documents	Description
1	Asset Management Policy and Strategies	Our asset management policy underpins out asset management plan, strategies and imperatives contained in our Asset Management Plan. Ensuring sustainability, network reliability as well as resilience is an important objective, and this theme is being repeated throughout this AMP
2	Asset Risk Management Plan	Our asset risk plan for major incidents and/or emergencies which include risk treatment, prioritisation of risks, main contingency measures and location of emergency spares
3	Participant Rolling Outage Plan	This plan was written to comply with Part 9 Security of Supply of the Electricity Industry Participant Code 2010. The procedures outlined are in response to major generation shortages and/or significant transmission constraints. Typical scenarios include unusually low inflows into hydro-generation facilities, loss of multiple thermal generating stations or multiple transmission failures. The main energy saving measure deployed in response to such a scenario is the use of rolling outages. Our plan identifies how we will shed load when requested by Transpower (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
4	SMS Major Network Event (SMS Standard 47664), Escalation of a Major Risk Event (SMS Standard 57552)	The Major Network Event standard provides guidance around what needs to occur in the lead up to an event, at announcement of an event and during the event. It assists the team to ensure that they are aware of their responsibilities during such circumstances. The Escalation guidelines document is to assist the Electra Control Centre to identify when to escalate Electra's response to outages

No.	Documents	Description
5	Environmental Risks Policy and Plan	Environmental risks including sustainability requirements are included in the Electra Group's Environmental and Sustainability Policies, and our plans and activities are guided by these policies in environmental-related work
6	Business Unit Continuity Plans	Identifies the responsibilities of key roles and designations to ensure business continuity
7	Contingency Plans	Contingency plans are included in our standard documents concerning minimum critical spares; a double contingency risk analysis of Electra's Sub transmission Network has been carried out to evaluate the likelihood of a second contingency occurring while an existing event is occurring
8	Risk and Hazard Management (Standard 57517)	This plan details processes that are required and the actions undertaken in the identification, assessment, review and management of the risks that the Company is exposed
9	Minimum Critical Spares	This Safety Operating Procedure provides guidelines for the management of minimum critical spares necessary to ensure unplanned outages can be repaired in a timely manner; main strategic spares are listed in Section 5.11.

Figure 7-3: Key network resilience procedures

The Gladstone Road initiative is one project that demonstrated risk management and quick action taken to mitigate risks as well as the commitment of our employees (see Figure 7-4). During a preventative line inspection, a "hanger" (a tree being held up by contact with other trees) was discovered and the linesman quickly organised emergency help to have the 11kV lines isolated and dropped; the road was closed and tree crews cleared the vegetation with a digger to assist with directional felling and clearing the debris off the road. This prevented not only a costly repair but mitigated the risk of a broken line and public safety.

Fault staff are quick to respond in all weather conditions and customers are grateful for the quick response and professional manner of our dedicated employees - restoring power and making the site safe by felling at-risk trees.

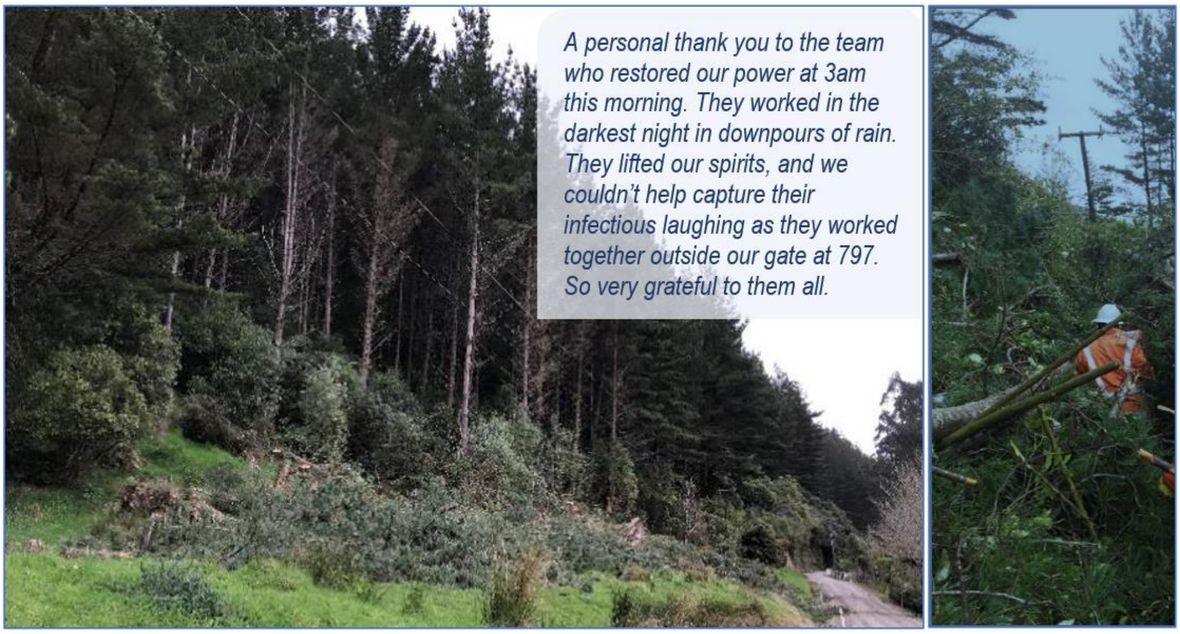


Figure 7-4: Gladstone Road Initiative and Insert: A Customer's Thank You Note

8 Performance evaluation

8.1 Works delivery performance

This section outlines Electra's progress against budgeted targets FY2020.

8.1.1 Maintenance plan delivery

The following table presents a summary of actual spend against budgeted spend as well as the reasons for the variances of the key operational maintenance categories:

Category	FY2020 Target ($'000)	FY2020 Actual ($'000)	Variance ($000)	Variance (%)	Reasons for variances
Service interruptions and emergencies	1,858	1,715	-143	-8%	• Less than forecast due to more faults resulting in capital expenditure. • The expenditure for 2020 included significant time and effort to replace stolen earth wires around the network
Vegetation management	1,538	1,707	+169	+11%	• An additional analytical tool, over and above the requirements of the Electricity (Hazards from Trees) Regulations, to systematically identify the greatest risk to customer service and safety from trees close to network. This has led to a higher than forecast spend to improve customer experience.
Routine and corrective maintenance and inspection	911	1,060	+149	+16%	• Additional inspections were carried out in response to safety concerns relating to specific types of Air Break Switches and 33kV insulators
Asset replacement and renewal	372	1,038	+666	+179%	• Zone Substation transformer maintenance was more involved than initially identified, and was not included in forecast, 33kV insulator replacements as result of additional inspections completed
System operations and network support	3,050	2,926	-124	-4%	• This expenditure was less than forecast predominantly due to vacancies in the Network • Support team
Business support	5,430	4,573	-857	-16%	• This expenditure was less than forecast predominantly due to less corporate salaries • attributed to the regulated business due to vacancies/deferral in hiring
Total	**13,159**	**13,019**	**-140**	**-1%**	• No material variation

Overall, our operational expenditure was $140K under forecast or 1% below the forecast and the variances within the main categories are depicted in Figure 8-1a.

Electra applies a materiality threshold of $100K to identify material projects.

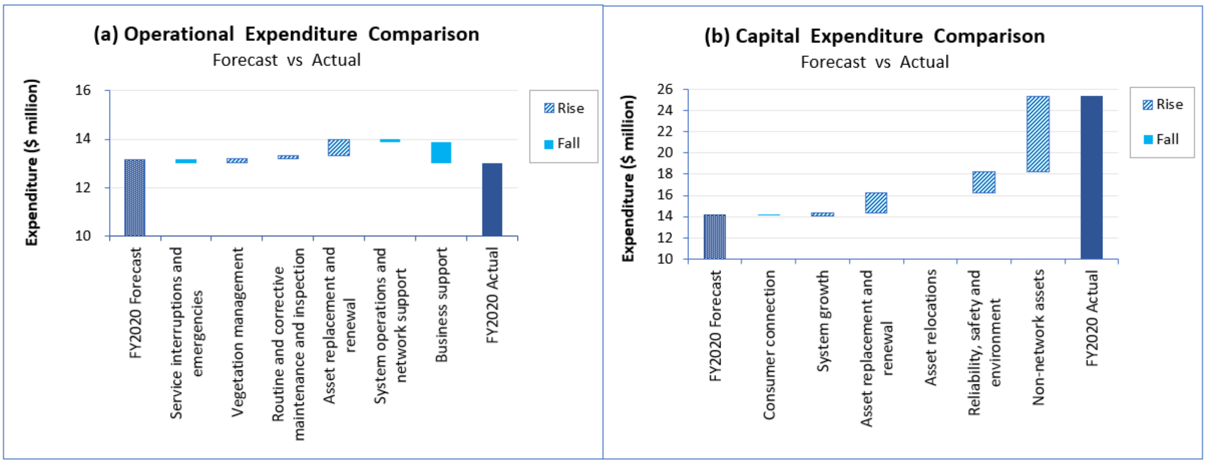


Figure 8-1: Variations between forecast and actual expenditures for: (a) Operational expenditure (OPEX), and (b) Capital expenditure (CAPEX)

8.1.2 Network development plan delivery

Overall expenditure on assets was $11.2M above forecast. The following table summarises the actual against budgeted spend for the key development categories as well as the main reasons for the variances.

Category	FY2020 Budget ($'000)	FY2020 Actual ($'000)	Variance ($000)	Variance (%)	Reasons for variances
Consumer connection	95	0	-95	-100%	• Only customer connections were for third party and they are all vested assets. Forecast customer connections in the AMP is based on a contribution formula relating to the size and type of developments. This expenditure classification is for any network design improvements due to synergies.
System growth	950	1,180	+230	+24%	• Commissioning of a new feeder (682) to Waikanae Beach due to the existing feeder (672) being close to capacity. • A remotely operable switchgear was also installed to enhance network operational flexibility and resilience.
Asset replacement and renewal	7,276	9,263	+1,987	+27%	• Exceeded forecast due to overhead line replacement projects and two large projects carried over from the previous disclosure year. • Carryover renewal expenditure from the previous year included 11kV line replacement and switchgear installation in Waikanae and 11kV line replacement in Waitohu Valley. • Renewal expenditure included 11kV line replacements in Manakau South Road, Otaki, Winchester St Levin and SH1 Foxton.

Category	FY2020 Budget ($'000)	FY2020 Actual ($'000)	Variance ($000)	Variance (%)	Reasons for variances
Reliability, safety and environment	3,325	5,264	+1,939	+58%	• Installation of a new cable in Raumati contributed to the overspend as a result of complexities encountered with the project including difficult ground conditions, resulting in additional expenditure to de-water and stabilise the trenches. • The site location of the cable also incurred State Highway 1 traffic management expenses. • An additional 33kV overhead line was commissioned in the disclosure year from Mangahao GXP to Levin East substation. This additional circuit provides further resilience to the northern network and will improve Electra's ability to maintain/renew other northern 33kV circuits at lower cost
Asset relocation	0	19	+19	0%	• No variance
Non-network assets	2,515	9,652	+7,137	+284%	• Addition to the RAB of $6.2m of assets related to Electra's internal Service Delivery team; 'one-off' adjustment related to Service Delivery assets ($4.9m) and Right of Use Assets • Other expenditure includes implementation of a Customer Relationship Management system and deployment of Internet of Things (IoT) Sensors to monitor the LV Network
Total (ii)	**14,161**	**25,358**	**+11,197**	**+79%**	• Variation mainly due to renewals and non-network assets expenditure as explained above.

Figure 8-1b shows the forecast, actual spend as well as variances for main categories.

8.2 Network reliability performance

8.2.1 Customer service performance (reliability)

Electra's actual performance against target performance for the FY2020 year for the key customer service attributes is shown in the following table and discussed in Section 3.2.

Attribute	Measure	FY2020 target	FY2020 actual	Comment
Network reliability: planned outages	SAIDI B	15	19.5	Non-compliant due to prolonged planned shutdowns impacted during the Covid-19 period such as Waikanae 682 capital works where two outages contributed 2.6 SAIDI minutes and 0.0057 SAIFI.
	SAIFI B	0.06	0.062	
	CAIDI B	250	313	
Network reliability: unplanned outages	SAIDI C	68	75.4	Non-compliant due to vehicle versus cable/pole incidents impacting SAIDI by 5.5 minutes (SAIFI 0.11) and an extreme weather event where 3,818 customers were affected, contributing to 3.9 SAIDI minutes and 0.083 SAIFI.
	SAIFI C	1.6	1.81	

Attribute	Measure	FY2020 target	FY2020 actual	Comment
	CAIDI C	42.5	41.8	Compliant
Public safety	Electricity (Safety) Regulations 2011	Compliant	Compliant	Continued compliance to NZS 7901

Electra's performance for planned and unplanned outages is shown in Figure 8-2 for SAIDI and Figure 8-3 for CAIDI. The data is averaged for a two-year period (FY2019 to FY2020) and Electra is ranked 5th for SAIDI (planned and unplanned) and ranked the best amongst 28 EDBs[21] for CAIDI.

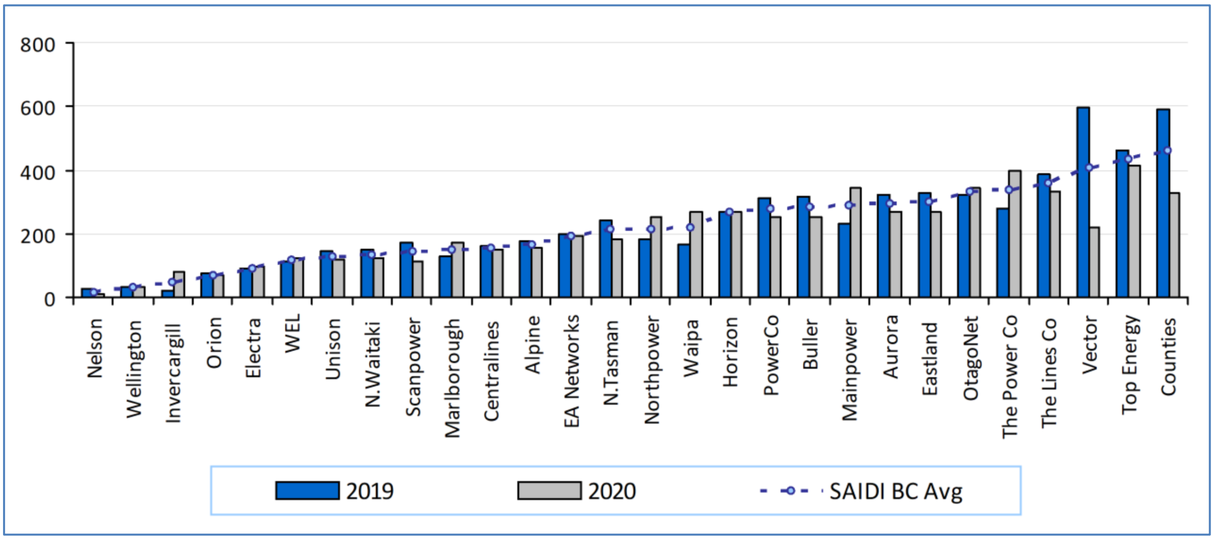


Figure 8-2: FY2018 to FY2019 SAIDI for planned B and unplanned C outages for electricity line businesses

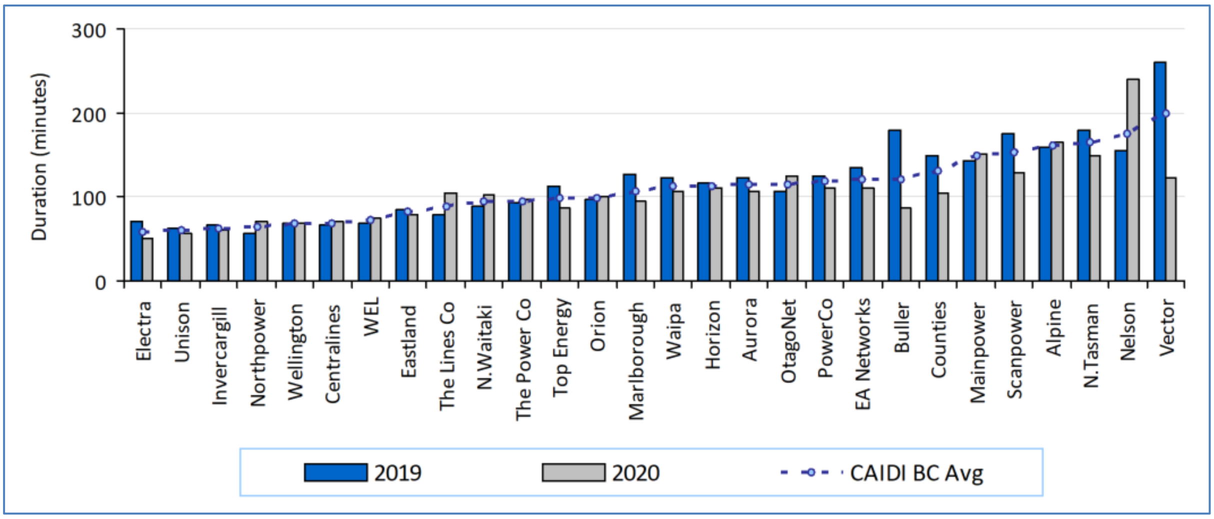


Figure 8-3: FY2018 to FY2019 CAIDI for planned B and unplanned C outages for electricity line businesses

8.2.2 Causes of faults

A cause analysis into our network reliability performance is depicted in Figure 8-4. The highest cause of faults impacting SAIDI in FY2020 (Figure 8-4a) is foreign interference (31%) followed by defective equipment (20%), wildlife (7%) and adverse weather (7%). A further investigation based on the number of faults (Figure 8-4b) gave the highest fault contributors as defective equipment (20%), foreign interference (15%), wildlife (14%) and lightning (10%). Other than unknown faults, other causes of faults include human error and vegetation.

[21] As at 3/11/2020, out of 29 EDBs, only 28 had disclosed the FY2020 Information Disclosures.

Other than faults on DDOs or fuses (20%), most defective equipment are attributed to conductors (25%), transformers (20%), underground cables (14%) and poles/crossarms (10%); renewal programs and maintenance activities are undertaken to address and resolve such faults. Faults caused by trees or vegetation are discussed in Section 5.12.

Out of a total of 52 faults caused by foreign interference, 36 are due to vehicle accidents, 13 by contractors/others, two by vandals and another one due to tree trimming.

The SAIDI impact and the number of HV faults between FY2016 to FY2020 are also shown in Figure 8-4a. SAIDI has decreased from 95 minutes (FY2018) to 57 minutes (FY2019) and 75 minutes (FY2020). Since the commissioning of the ADMS in 2019, we have detected that a single outage has been recorded multiple times in the system sometimes as many as five different outages due to multiple restoration sequences. We have since corrected this anomaly and the actual number of unplanned outages in FY2020 is 304 rather than 354. For FY2021 reporting, this issue has been resolved where Control Room operators analyse repeated outages and assess occurrence times.

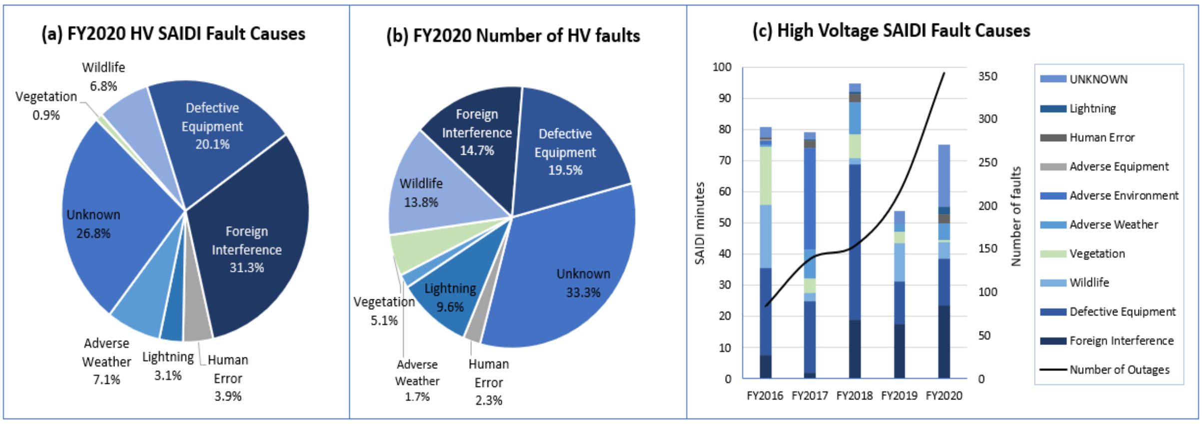


Figure 8-4: (a) FY2020 causes of HV faults by SAIDI, (b) Number of FY2020 HV faults by causes, (c) Number of HV faults from FY2016-FY2020

8.2.3 Restoration of faults

The information disclosure includes the performance indicator for faults restoration within a period of three hours. Figure 8-5b compares the performance of Electra against other EDBs from FY2019-FY2020 where our average performance of 81% is higher than the industry's median of 69%. Our performance between FY2016 to FY2020 is shown in Figure 8-5b where our performance peaked in FY2019 when we have restored 85% of faults within three hours followed by FY2020 where 270 faults or 76% of faults were restored within the three-hour period.

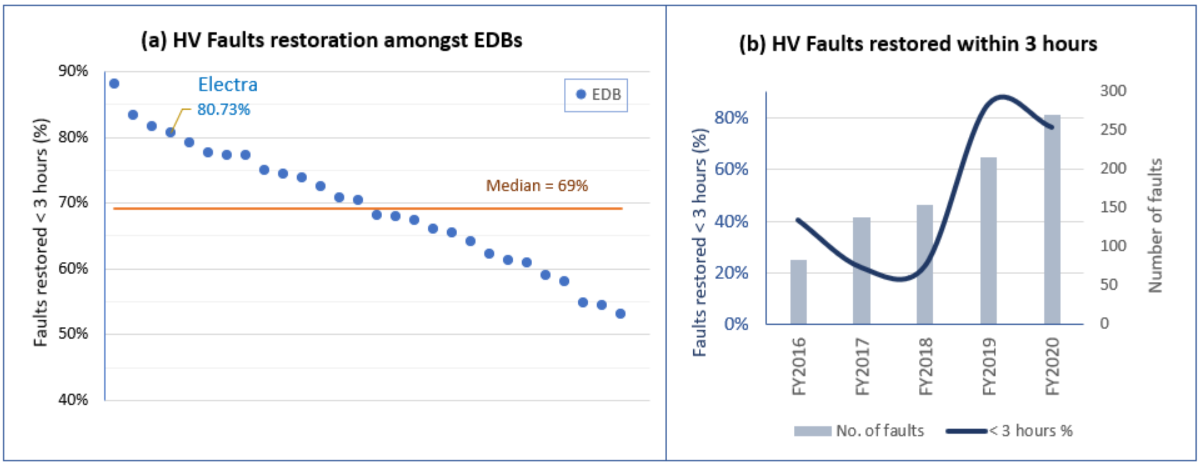


Figure 8-5: Faults restored within 3 hours: (a) EDB benchmarking from FY2019-FY2020, and (b) Electra FY2016-FY2020

8.2.4 Live line works and temporary generation

To avoid outages and inconvenience to customers, Electra carries out live-line operations annually on the 11kV and 33kV networks based on risk assessment. Live-line work practices are stringently carried out according to safety operating procedures where the risks are first assessed including safety in design analysis, consideration of the ease of maintenance, operations and accessibility of the assets. These procedures are carried out in compliance with the New Zealand Code of Practice for High Voltage Live Line Work NZECP 46:2003 covering work practices, communications and safety equipment such as live-line gloves, insulating barriers and hot sticks.

Other SAIDI mitigation and customer-focus activities include the provision of temporary generation during planned outages. The use of a generator is evaluated using a SAIDI-Generator Cost Impact calculator.

8.3 Asset performance

Electra's actual performance against target performance for the FY2020 year for the key asset and financial indicators follow:

Attribute	Measure	FY2020 target	FY2020 actual	Comment
Industry performance	Electricity Distribution Information Disclosure Determination 2012 and subsequent amendments	Compliant	Compliant except in minor Risk preparedness[22] sectors	AMP assessed as generally compliant as per Appendix 1: Reconciliation of Asset Management Plan to Electricity Distribution Information Disclosure Determination 2012.
Energy delivery efficiency	Load factor (units entering network/maximum demand * hours in year)	50%	51%	Target achieved.
	Loss ratio (units lost / units entering network)	6.9%	7.7%	Non-technical loss identification programme underway to address the issue.
	Capacity utilisation (maximum demand/installed transformer capacity)	30%	30%	Target achieved.
Financial efficiency	Capital expenditure on assets (CAPEX) per: total circuit length (km) connection point	 $5,170 $270	 $10,914 $561	CAPEX/km and CAPEX/ICP for the 2020 year has increased due to a one-off adjustment required to include Network Service Delivery assets and Right of Use assets into our Regulatory Asset Base (RAB). This adjustment comprised $7.4m.
	Operational expenditure (OPEX) per: total circuit length (km) connection point	 $5,420 $280	 $5,603 $288	OPEX slight increase against targets with OPEX/km at $5,603 and OPEX/ICP at $288. Electra is committed to arrest increasing costs.

[22] Commerce Commission (2019). AMP Review of EDB Risk Preparedness

8.3.1 Load factor trends

Figure 8-6 illustrates the historical trends for our load factor, derived from the energy (GWh) entering our network and maximum demand (MW). Our load factor in FY2020 is 51% a slight increase of 0.7% from FY2019 - the low load factor is attributed to a historical legacy to over-design for system growth. The load factor is expected to rise by less than 1% yearly in the coming years aligned with the forecasted annual increase of 1.3% and 1.0% of our consumption levels and maximum demand respectively. However, the load factor may be affected by a fall in energy (GWh) usage in FY2021, an effect from the Covid-19 pandemic.

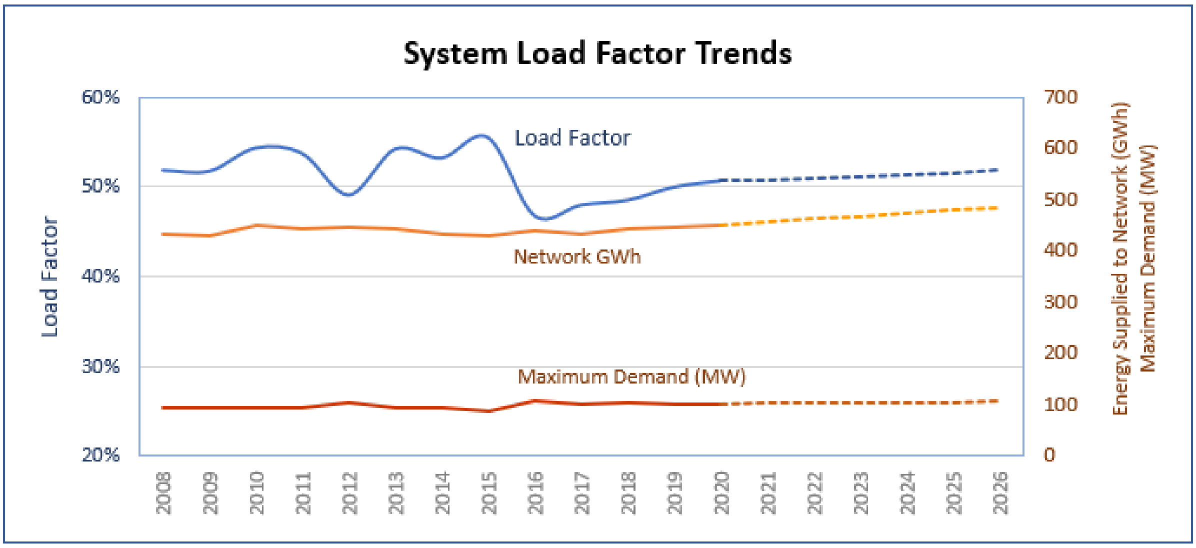


Figure 8-6: System load factor historical trends and forecast

8.3.2 Capacity utilisation trends

Figure 8-7 shows the industry's distribution transformer capacity utilisation against network load density. Electra sits well above the line of best fit at 30% utilisation and we use this relationship to set our utilisation target above 30%.

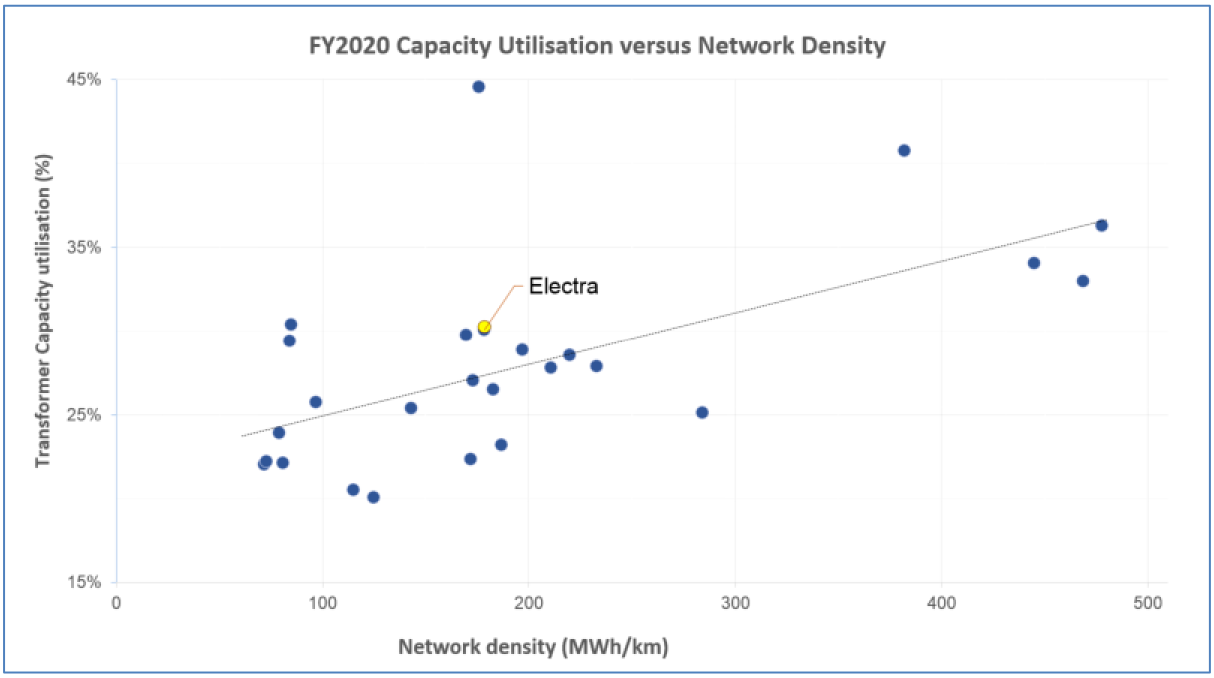


Figure 8-7: FY2020 transformer capacity utilisation versus network density

8.3.3 Loss ratio

We use the loss ratio for the purposes of information disclosure which is calculated based on electricity losses divided by the electricity (GWh) entering the system for supply to our customers. Figure 8-8 shows the historical trends for our losses and system GWh from FY2008 to FY2020 as well as our forecasts until FY2026.

Network losses in FY2020 (7.7%) were greater than the forecast by 0.8%. With the rise in the energy (GWh) supplied, our losses in the coming years are forecasted to less than 7.7%. Technical loss investigations and monitoring are being conducted with the installation of PQ meters at strategic intake points on the network. Further research is currently undertaken into “normal open point” optimisation of our 11kV distribution network to potentially reduce power losses. These losses will be analysed with various network reconfigurations, power factor compensation and phase unbalance management.

Non-technical losses arise from theft, metering and reconciliation errors and with our new AXOS billing system, there is now added data validations to improve billing accuracy and we are conducting billing analyses with incoming data from substation metering, PQ meters and comparing these with billing information to evaluate these losses.

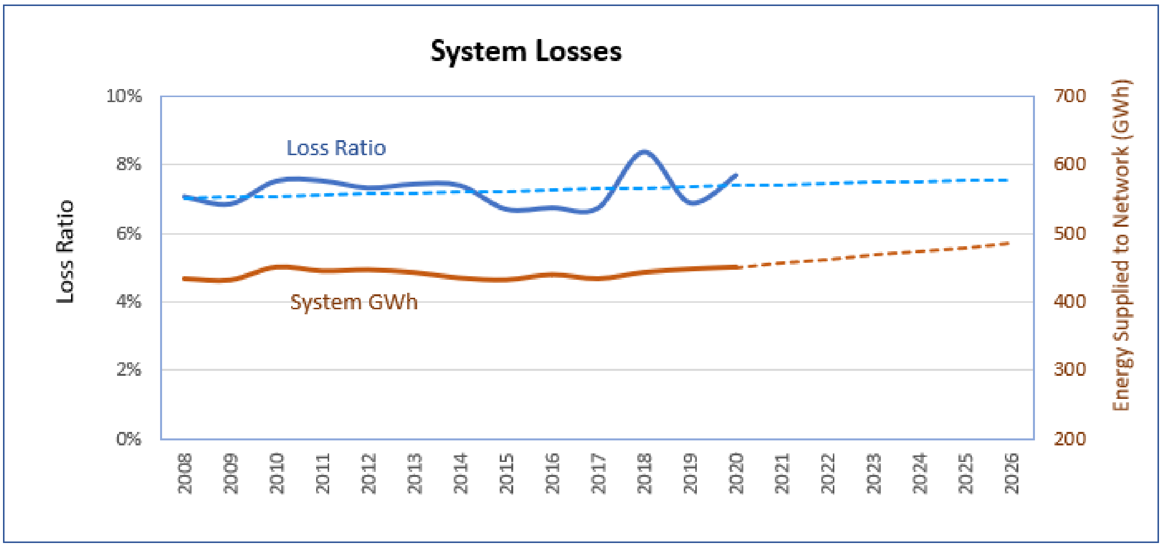


Figure 8-8: System losses historical trends and forecasts

8.3.4 Financial effectiveness

To examine our OPEX and CAPEX, Electra is compared with its peer group[23] of eight networks based on network characteristics, network density and customer size; these networks include Alpine, Aurora, Counties Power, Horizon, Network Tasman, The Lines Co and Top Energy.

Within the peer group, our financial performance was:

- OPEX/ICP at $288 is the second lowest and within the first quartile compared with the industry average of $424 and the peer median of $467 (Figure 8-9a)
- Asset CAPEX/ICP at $561 is the second lowest and within the first quartile compared with the industry average of $616 and the peer median at $620 (Figure 8-9b)
- Asset CAPEX/km at $10,914 is the highest above the peer median of $6,577 and industry average of $7,450 (Figure 8-10a). CAPEX/km (and CAPEX/ICP) has increased in FY2020 due

[23] FY2020 data is extracted from Information Disclosure schedules from the relevant EDB’s website; as at 3/11/2020, out of 29 EDBs, 28 EDBs had disclosed their FY2020 Information Disclosures.

to a one-off adjustment required to include Network Service Delivery assets and Right of Use assets into our Regulatory Asset Base (RAB)

- Line charge revenue/ICP (Figure 8-10b), at $792 is the lowest compared with the peer median and industry average of $1,253 and $1,412 respectively.

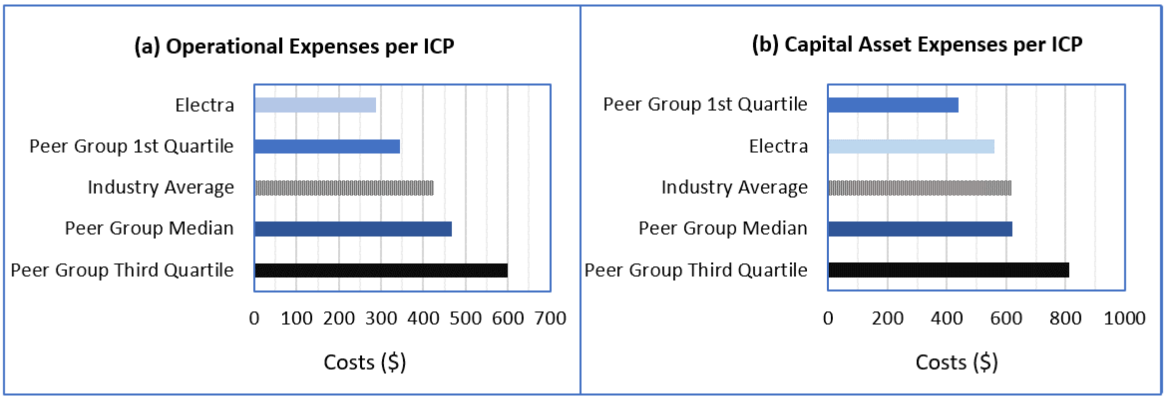


Figure 8-9: Peer group FY2020 OPEX and Asset CAPEX per ICP

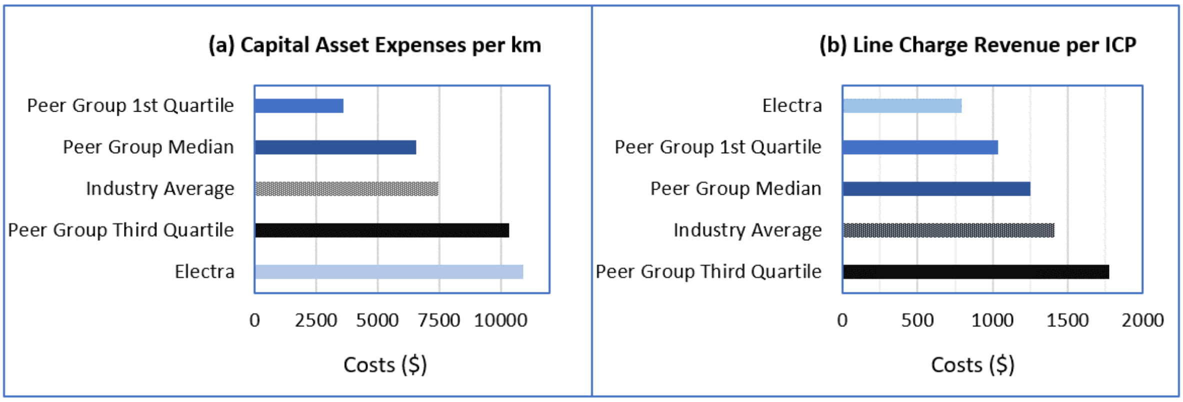


Figure 8-10: Peer group FY2020: (a) Asset expenditure per km, and (b) Line charge revenue per ICP

To study the operational expenses further, the OPEX per km of total circuit length is compared to reliability indicator SAIDI (unplanned) as shown in Figure 8-11 and compared with similar electricity distribution businesses (EDBs) in New Zealand. The input parameters are extracted from the 2020 Information Disclosures for the relevant EDBs[24]. Electra is within a group of ten EDBs who's average OPEX/km is over the industry average of $4,471 but below the unplanned SAIDI average of 129 minutes.

Figure 8-12 compares the FY2020 OPEX per ICP versus unplanned SAIDI for all EDBs. Electra is one of nine EDBs whose OPEX/ICP and unplanned SAIDI are below the industry averages of $408 and 142 minutes respectively. Our OPEX/ICP at $271 is 34% below the industry average while unplanned SAIDI (57 minutes) is 60% below the said SAIDI average.

[24] As at 3/11/2020, 28 EDBs have published their FY2020 Information Disclosures on their website.

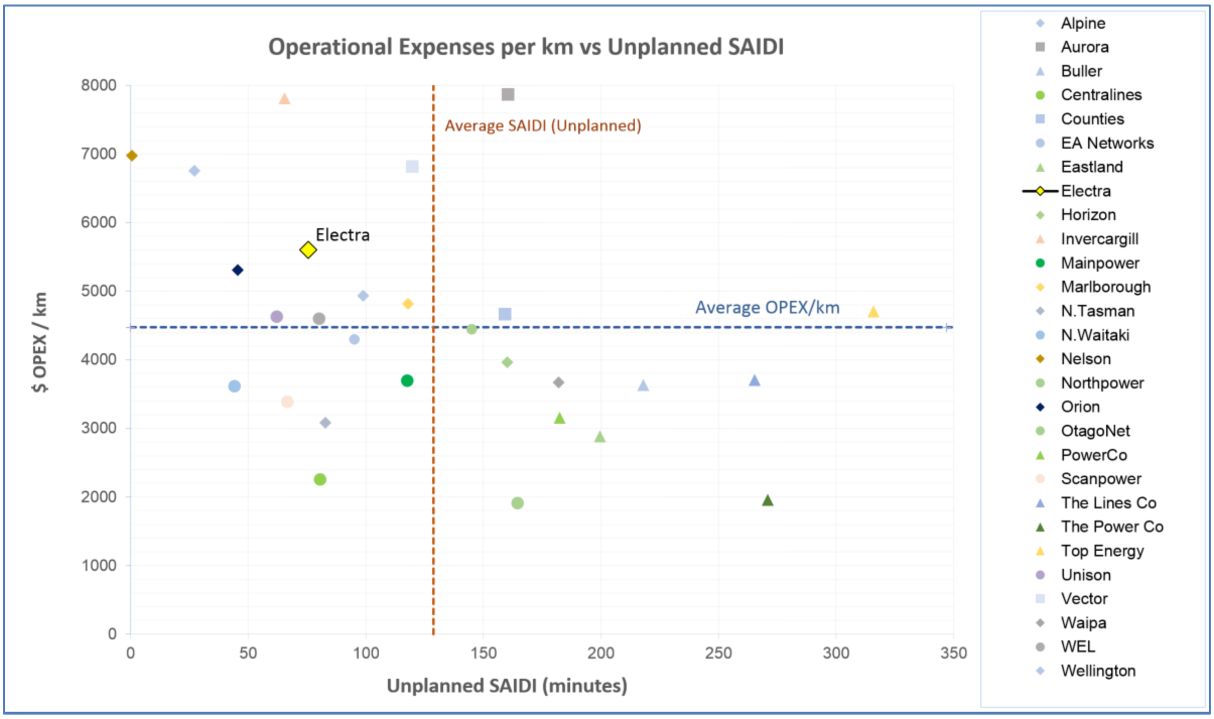


Figure 8-11: Operational expenses per circuit length (km) versus unplanned SAIDI for FY2020

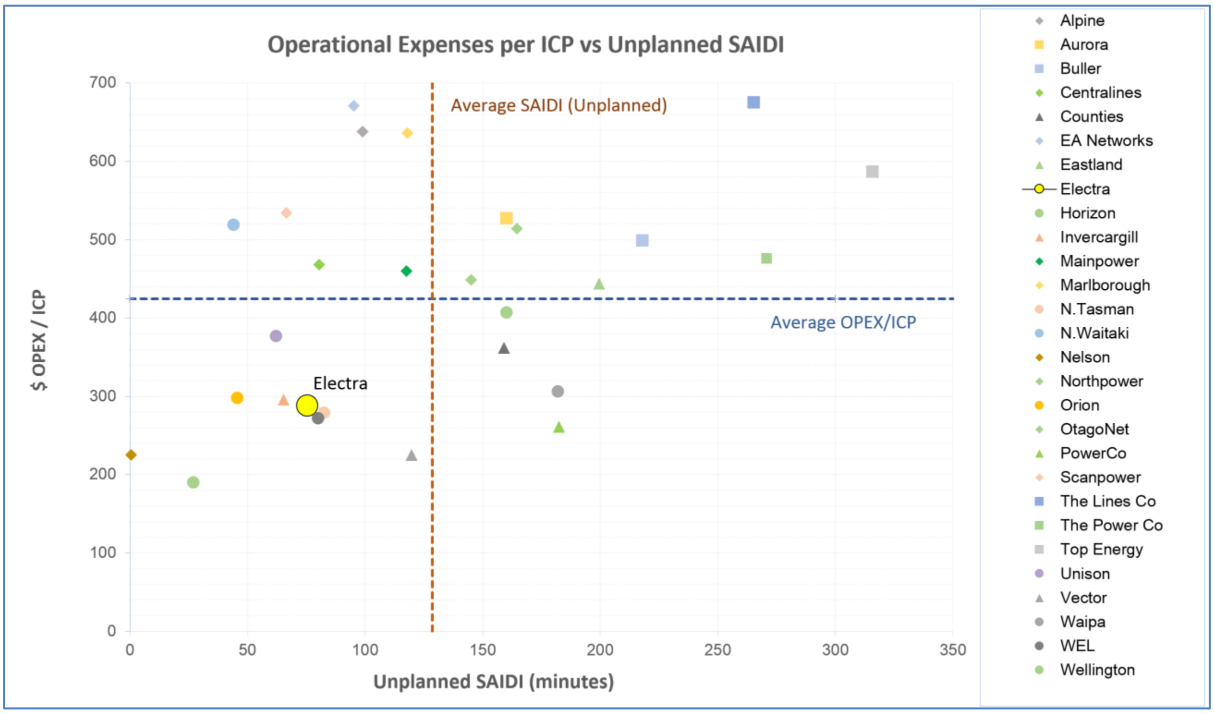


Figure 8-12: Operational expenses per ICP versus unplanned SAIDI for FY2020

8.3.4.1 System operations, network and business support expenditure

From FY2018 to FY2019, system operations and network support (SONS) costs increased by 13% while there was only a 1% increase in business support costs. In comparison with our peers in FY2020, we are below the SONS median by 14% and well below (57%) the industry average as shown in Figure 8-13a. For business support costs (Figure 8-13b), these are also below the peer group median and industry average by 24% and 45% respectively.

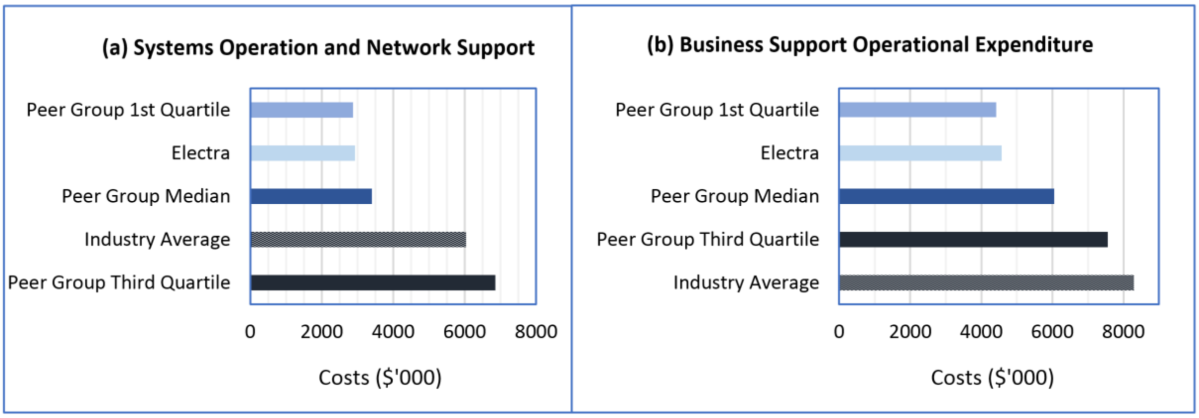


Figure 8-13: Peer group FY2020: (a) System operations and network support, and (b) Business support operating expenditure

8.3.4.2 Vegetation management performance

Our vegetation management operational expenditure decreased from $1.85M in FY2019 to $1.71M in FY2020 with the reduction in tree-trimming works as we moved from a responsive based approach to a risk-based/proactive approach to systematically reduce tree-related faults (Section 5.12).

Figure 8-14 portrays the industry's vegetation management operational expenditure per km-circuit requiring vegetation clearing versus SAIDI caused by vegetation faults for FY2020. Our expenditure of $1,098 per km is only 1% above the industry average of $1,084 and the expenditure on vegetation management has resulted in the reduction of SAIDI due to vegetation faults to only 0.668 minutes (from 4.05 minutes previously). The SAIDI value is also 97% below the industry average of 20.2 minutes.

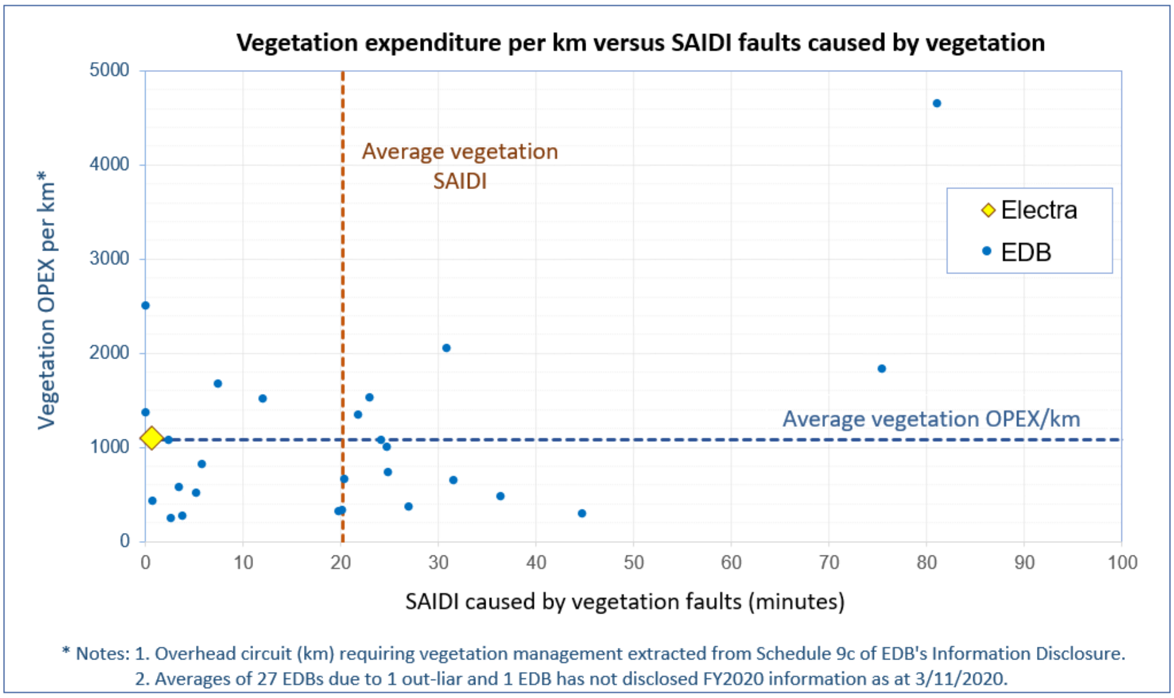


Figure 8-14: FY2020 vegetation management expenditure per km versus SAIDI caused by vegetation faults for EDBs

8.4 Asset management practice performance improvement

ISO 55001 is the successor of BSI PAS 55:2008, which is the basis for the Asset Management Maturity Assessment Tool (AMMAT) developed by the Commerce Commission to assess to develop the maturity if EDB asset management. The Report on Asset Management Maturity (Schedule 13) is in Appendix 8.

As part of our ongoing improvement for aligning ourselves with international best asset management practices and operational excellence, Electra commissioned an external consultancy to conduct an ISO 55000 (cum AMMAT) audit in February 2020. Covaris, a leading-edge engineering consultancy in asset management was engaged to conduct an independent, accurate and unbiased assessment on the maturity of its asset management practices, processes and capabilities. The in-depth process included the identification of gaps, the target and alignment of improvement opportunities with current and future initiatives.

The summary of performance for the main clauses of ISO 55001 rankings is depicted in Figure 8-15. Each of the spokes in the figure can be tied back to the ISO standard; two series were plotted - the average of all criteria for each clause and the minimum performance of any criteria associated with a clause. The variance was only of significance in elements associated with asset information, reflecting the spread of capability found in Electra.

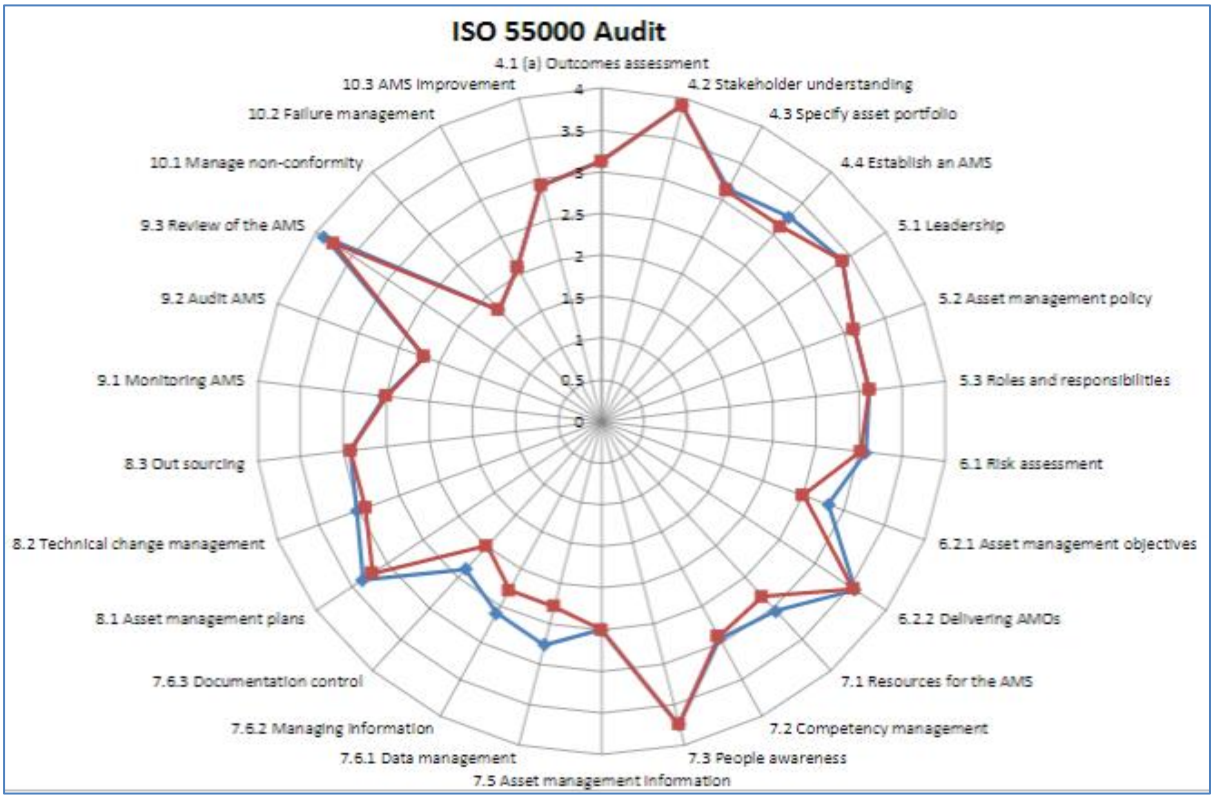


Figure 8-15: Electra ISO 55000 audit and ISO 55001 rankings

Covaris also conducted an independent AMMAT report and the scores below were extracted from the raw audit results and compared to an Electra internal AMMAT assessment carried out in FY2020 (Figure 8-16). The alignment of the AMMAT scores with the ISO scores considered the different ranking system under AMMAT as compared to the IAM[25]-endorsed ranking system applied by Covaris.

[25] The Institute of Asset Management (IAM) is the international professional body for asset management professionals based in the UK.

The ISO-based review scored our approach to asset management *higher* because the evidence documented suggests that Electra's approach is appropriate for the network considering its topology, social alignment and services delivery. Covaris stated that: "*While it could be argued that with its lean team, Electra does not have the same depth in some aspects of asset management as larger EDBs, what it has in place is competent.*"

Further, the main concern the ISO-based review had compared to Electra's self-assessment is with the use of systems and data to make informed decisions. While current performance is seen as exemplary in terms of cost and SAIDI measures, this situation could turn around without detailed information about the condition of the network and tracking work done.

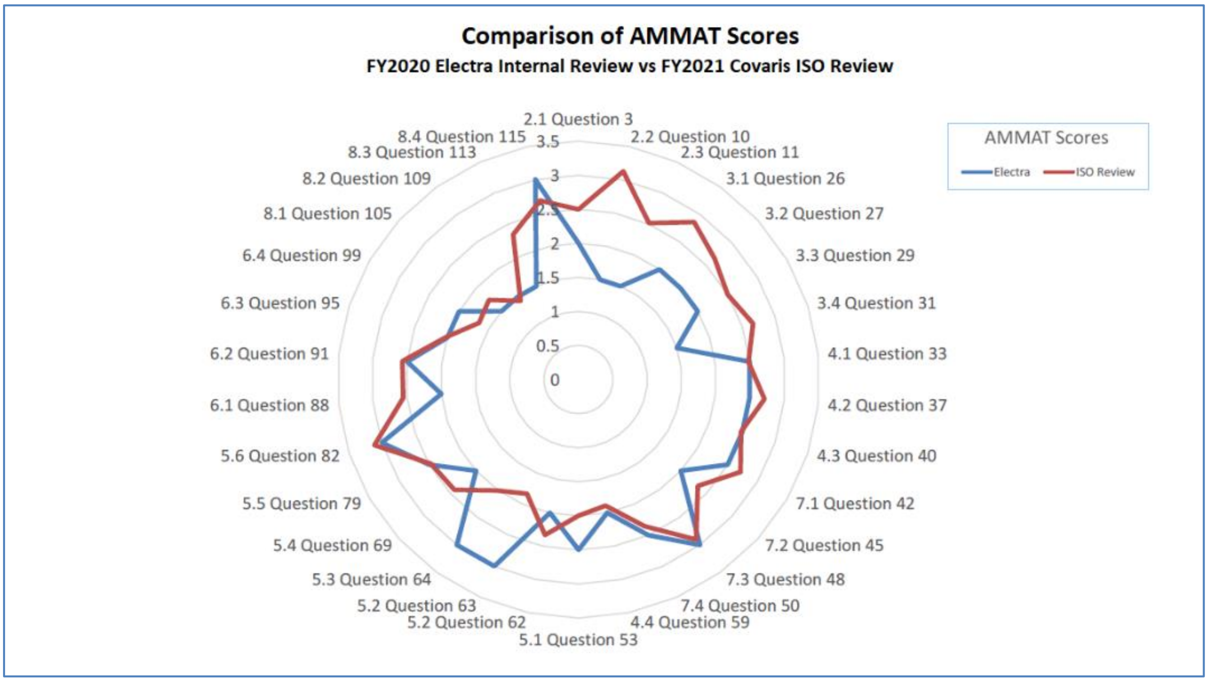


Figure 8-16: AMMAT scores for FY2020 and FY2021

Significant aspects that Electra wishes to improve in the short term are:

Practice cluster	Proposed improvements
Asset management policy	Revision of policy to align with asset management objectives, and communication across the teams.
Asset management strategy	Development of standards for the accurate estimation and then planning of work considering all overheads.
Asset management plan	Work management being managed by a comprehensive asset management information system (AMIS) which covers asset configuration, work management, standard procedures, materials management and interface to the permit system.
Asset management system documentation	Improvement of work pack details to include standard procedures, technical standards and quality requirements.
Training, awareness and competence	Building on the concepts and models being developed to improve the long-term work force plans, particularly for service delivery staff
Communication, participation and consultation	Improvement of team communications with the use of selected performance reports and management feedback on improvement targets.

A road map is being drawn up to sequence the above improvements.

8.4.1 Asset Risk Management Model

Electra uses asset condition as the basis for most of our asset renewal and replacement decisions.

To improve our asset management practices using ISO 55000 principles and concepts, Electra applies a risk-based, information-driven approach in our asset investment planning and decision-making processes. The Asset Risk Management Model (ARMM) has been developed for key network asset classes and used as decision-making tools to enable us to improve our asset investment planning with consideration to costs, risks, opportunities and performance.

As per section 5.1.1, ARMM models are being used for the following asset classes: 33/11kV overhead conductors, poles, crossarms, underground cables as well as zone substation transformers and circuit breakers.

The objective of this work-stream is to have all network investment decisions driven by the asset health and criticality framework.

8.4.2 Drone inspections of 33/11kV structures and assets

Drone inspections have been commissioned to expedite the inspection and condition-monitoring of our overhead assets in our efforts to meet our objectives for operational excellence. Since December 2019, the following inspections have been undertaken:

- 16 km of 110kV transmission line acquired from Transpower from Mangahao Road to Tararua Road, Levin energised at 33kV
- 20 km of 33kV circuits from Mangahao to Levin East
- 115 km of 33kV circuits and ABIs extending from Mangahao to Levin, Foxton, Shannon and Paekakariki involving over 2,000 assets.

Defects identified were assessed and rectifications undertaken based on our condition-risk based assessment of asset health indicators and classification explained in Section 5.2; the details are entered into the relevant ARMM model and the asset condition updated.

The dashboard for the October 2020 drone inspection is shown in Figure 8-17.

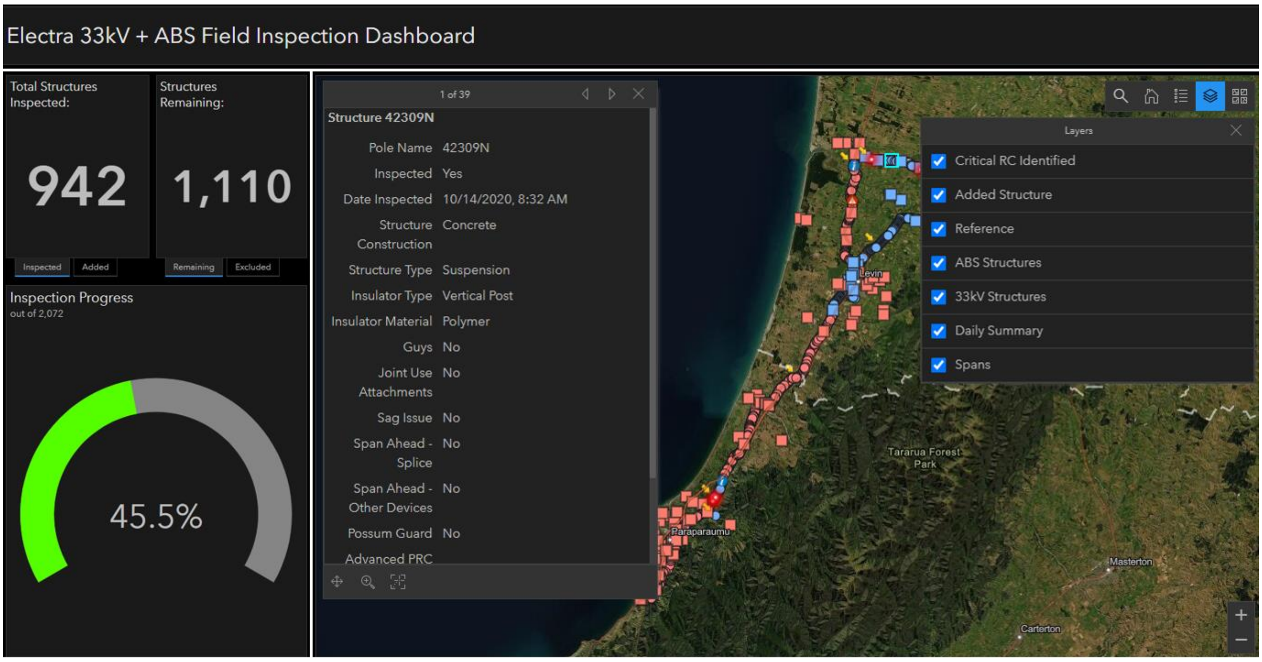


Figure 8-17: Dashboard on Drone Inspection undertaken as of 24 October 2020

8.4.3 Advanced distribution management system

The on-going adoption of the Milsoft Advanced Distribution Management System (ADMS) has provided Electra with leading grid management capabilities to improve outage response, optimise grid operations and better track the resolution of customer enquiries.

Figure 8-18 shows the as-built update process improvement where reticulation plans are keyed into the ADMS prior to the commencement of project works including a ten-day requirement for the submission of as-builts after project completion.

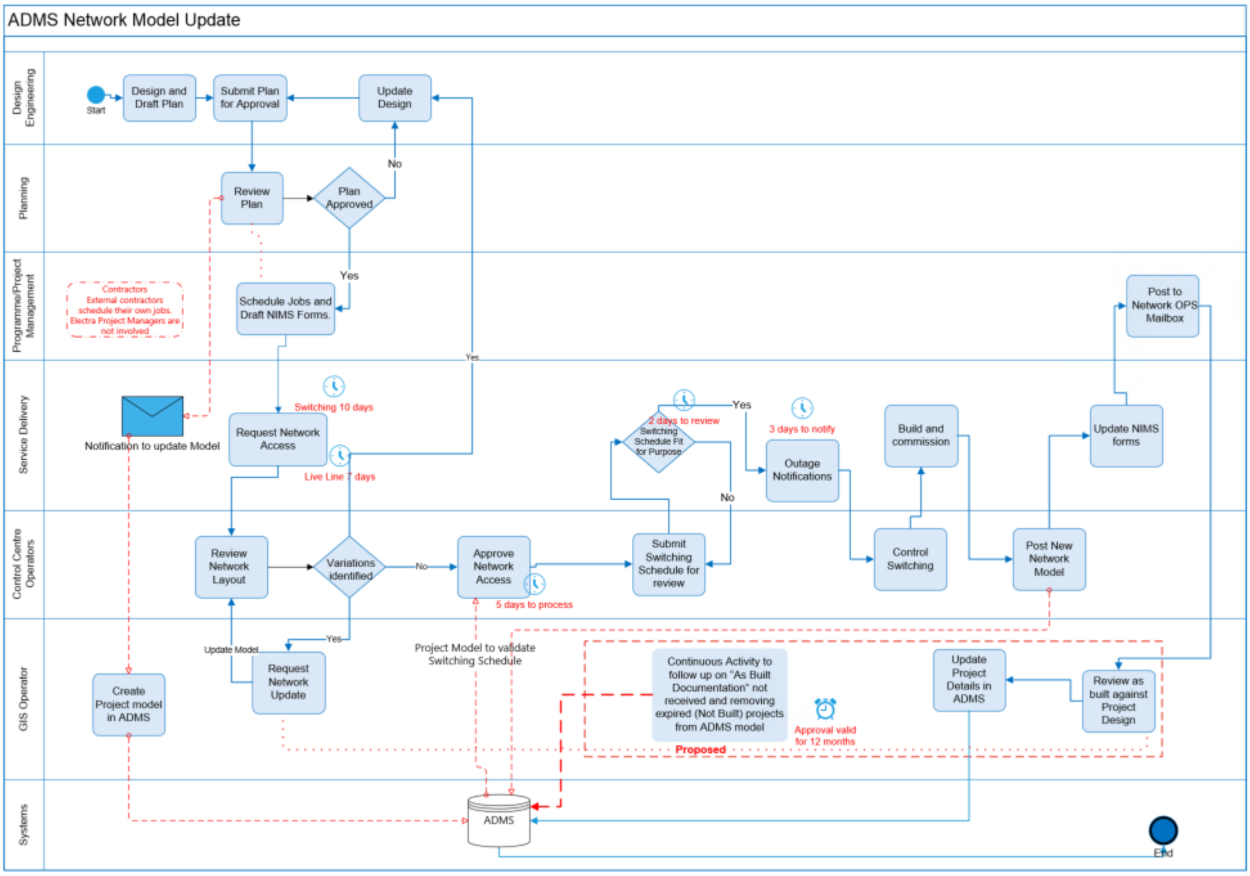


Figure 8-18: ADMS network process improvement

8.4.4 Improvements to Axos billing system

Electra switched to the Axos billing system as the previous bespoke system had minimal support availability and limited features and Axos was an off-the-shelf product, which was well supported with a development roadmap.

The enhancements observed since the system went live were:

- Support of current and future billing requirements, retailers and major consumers with standard or complex tariffs for time-of-use, smart meter, non-half hour and profiled sites
- Implementation of Axos Insights which is a dashboard to assist with Revenue Assurance
- Ability to export bulk files.

The road map for improvement includes improved reporting and exception checking headed by a Financial Analyst who will focus on change management, system improvement and revenue assurance.

8.4.5 Information disclosure compilation tool

Our information disclosure and asset management compilation processes are aided by the Information Disclosure Compilation Tool. The tool is a Microsoft Access program which links asset information, analyses the information via macros and filters the relevant asset data in accordance with asset classes set out in the Determination[26]. In line with our drive for continuous improvement and excellence in our operations, the tool assists us to ensure information consistency and accuracy for compliance. It also assists us in process efficiency as the tool also provides the age profiles and asset tables for the Asset Management Plan as depicted in Figure 8-19: (a) Information Disclosure Compilation Tool (IDT), and (b) Sample reports from IDT.

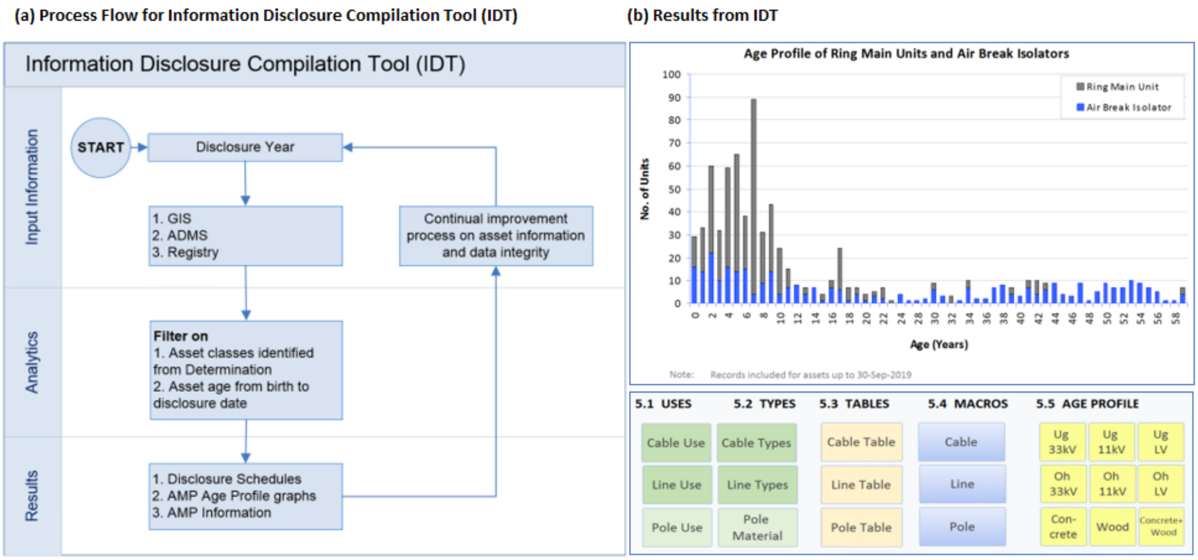


Figure 8-19: (a) Information Disclosure Compilation Tool (IDT), and (b) Sample reports from IDT

8.4.6 Strategic vegetation management improvement process

Another asset improvement process is within our vegetation management. As discussed in Section 3.10.5, we have moved from a responsive to a proactive planned tree-trimming risk-based process depicted in Figure 8-20. In order to improve our performance, we are using location and date information to forecast risk and develop trimming and removal plans by feeder section. For this work feeder sections are bounded by reclosers and remotely operable switches. Work is undertaken section by section and is prioritised based on the reduction of safety and SAIDI risk. Forecasts indicate a reducing OPEX from lower first cut and trim volumes, removal of trees on subsequent cuts and lower costs by proactive removal before trees reach the proximity requiring a safety observer.

[26] Commerce Commission, Electricity Distribution Information Disclosure Determination 2012

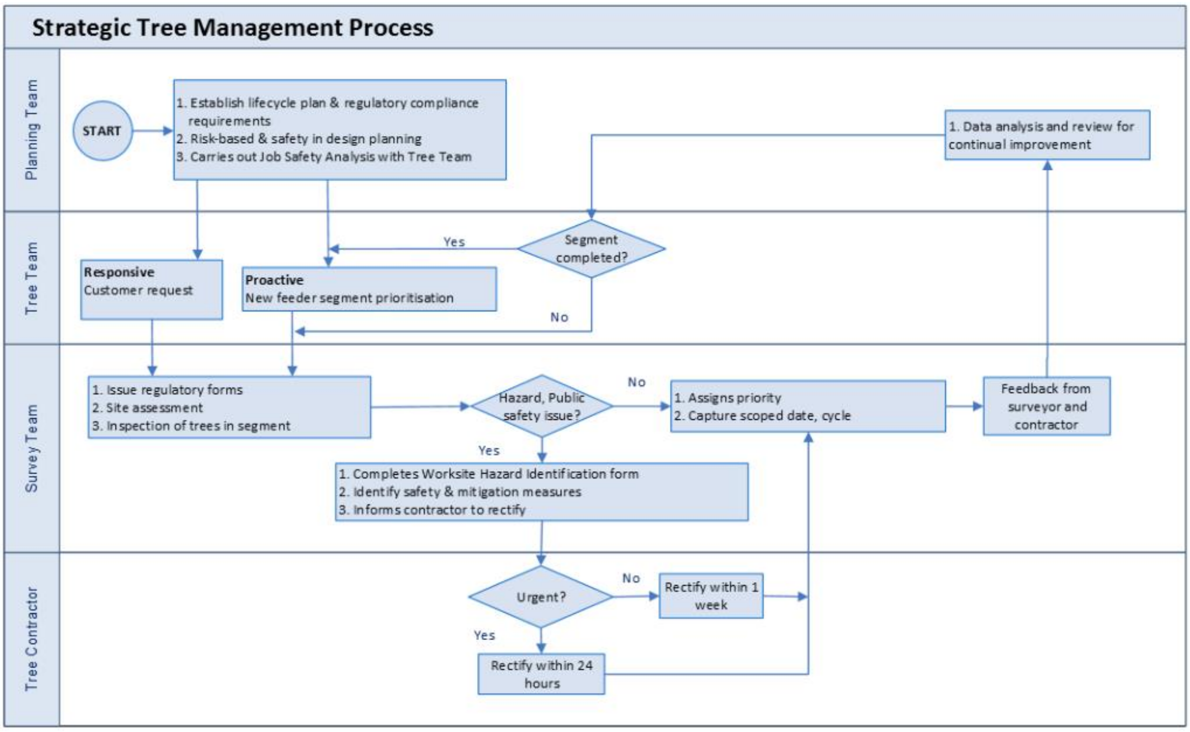
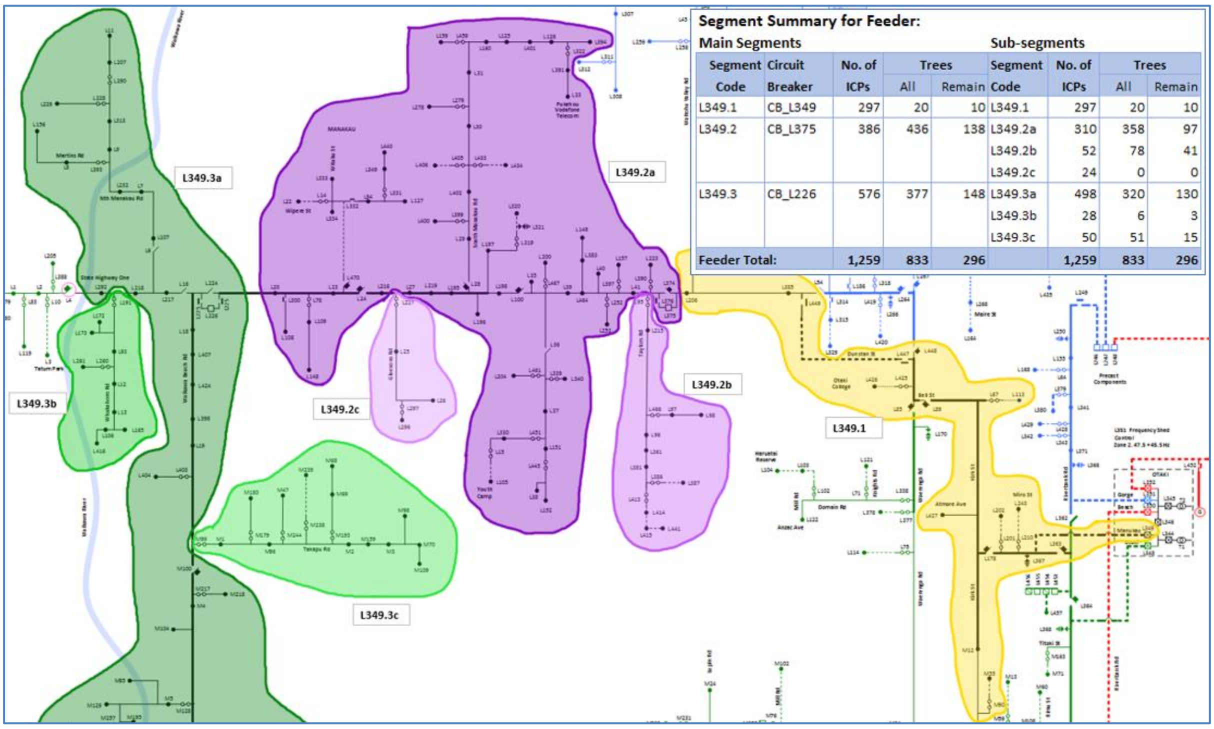


Figure 8-20: Tree-trimming planned process integration

Up to 150 segments were identified and analysed and the first hundred were prioritised for inspection and follow-up tree-trimming work in FY2020; a sample of the Otaki segment is shown in Figure 8-21. As of September 2019, 95% of these segments have been surveyed, and looking at the vegetation fault and cost management statistics in Section 8.3.4.2, we have made considerable progress in reducing our vegetation SAIDI as well as controlling vegetation costs.



Segment Summary for Feeder:

Main Segments					Sub-segments			
Segment Code	Circuit Breaker	No. of ICPs	Trees All	Trees Remain	Segment Code	No. of ICPs	Trees All	Trees Remain
L349.1	CB_L349	297	20	10	L349.1	297	20	10
L349.2	CB_L375	386	436	138	L349.2a	310	358	97
					L349.2b	52	78	41
					L349.2c	24	0	0
L349.3	CB_L226	576	377	148	L349.3a	498	320	130
					L349.3b	28	6	3
					L349.3c	50	51	15
Feeder Total:		1,259	833	296		1,259	833	296

Figure 8-21: Sample of an Otaki feeder segment analysis

8.4.7 Identification of worst 11kV feeders

The number of failures of 11kV feeders has been added into the computation of our worst performing feeders; this initiative has previously been referred to in Section 3.10.6. The prioritisation for reliability-improvement projects for the worst feeders identified are based on factors such as the condition-based risk assessment, asset criticality factors, number of customers affected and capacity constraints shown in Figure 8-22. The trade-off between cost and reliability are evaluated carefully where network analysis, circuit reconfiguration, automation and alternative methods are assessed while considering the SAIDI and cost impact. This process will reduce the number of repeated failures and improve the quality of supply and reliability for our customers.

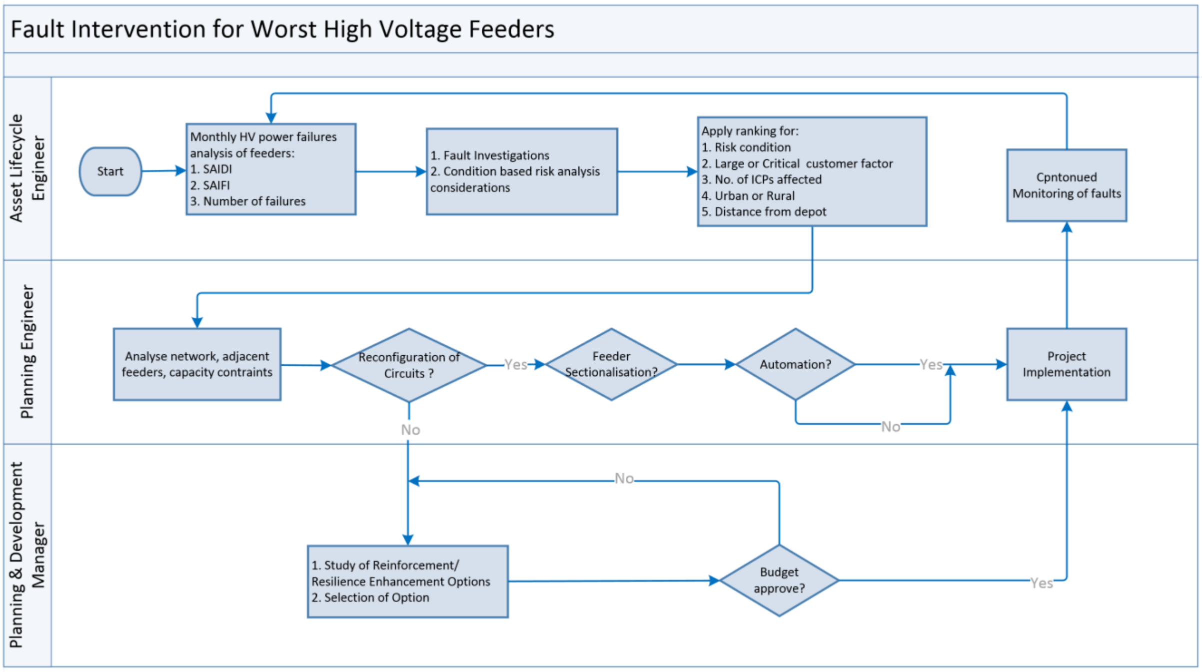


Figure 8-22: Fault intervention process for worst 11kV distribution feeders

8.4.8 Health and safety management system

Vault is a health, safety and risk management software tool commissioned in mid-2017. Public safety incidents recording started in Vault from September 2019, replacing a Microsoft Access database; legacy public safety data is being retrospectively included into Vault.

Vault is a stand-alone risk management and incident reporting tool administered by our Health & Safety Section. Our health and safety, and organisations risks are recorded on this platform. All events including incidents, injury, illness and near misses are reported (either via desktop or a mobile application) and recorded in this tool. Incident investigations are also recorded.

The system automatically notifies the senior management of critical events.

9 Appendices

9.1 **List of** Appendices

Appendix 1: Reconciliation of Asset Management Plan to Electricity Distribution Information Disclosure Determination 2012

The following table cross references the sections of this AMP to Attachment A of the Electricity Distribution Information Disclosure Determination 2012 (consolidated to 3 April 2018)*.

Determination Clause (Attachment A of Determination*)	AMP Section(s)
3. The AMP must include the following-	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	Executive summary, 1 Introduction
3.2 Details of the background and objectives of the EDB's asset management and planning processes;	1 Introduction, 1.1 Company strategy, 1.1.1 Mission and vision, 1.1.2 Key strategies, 1.2 Asset management system, 1.3 Asset management framework
3.3 A purpose statement which-	1 Introduction
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;	1 Introduction, 1.11 Overview of documentation and controls
3.3.2 states the corporate mission or vision as it relates to asset management;	1.1.1 Mission and vision
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	1.3.1 Key plans and documents
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	1.3.2 Relationship between plans and documents
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	1.3.3 Linkages between planning goals
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;	1.4 Planning period
3.5 The date that it was approved by the directors;	1.5 Board approval
3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	1.6 Stakeholder interests
3.6.1 how the interests of stakeholders are identified	1.6.1 Stakeholder interests and how they are identified
3.6.2 what these interests are;	1.6.2 Linking stakeholder interests to asset management practices
3.6.3 how these interests are accommodated in asset management practices; and	1.6.2 Linking stakeholder interests to asset management practices
3.6.4 how conflicting interests are managed;	1.6.3 Managing conflicting stakeholder interests
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	1.8 Accountabilities for asset management
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;	1.8.1 Summary of roles, delegated authorities and reporting
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and	1.8.1 Summary of roles, delegated authorities and reporting
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;	1.8.2 Use of external contractors and advisers

Determination Clause (Attachment A of Determination*)	AMP Section(s)
3.8 All significant assumptions-	1.13 Significant assumptions, 1.13.1 Causes of possible material differences, 1.13.2 Financial forecasts, 1.13.3 Limitations of this AMP
3.8.1 quantified where possible;	1.13 Significant assumptions
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including-	1.13 Significant assumptions
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business;	N/A Not applicable
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	1.13 Significant assumptions
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;	1.13.2 Financial forecasts
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;	1.13.1 Causes of possible material differences
3.10 An overview of asset management strategy and delivery;	1.2.1 Asset management policy, 1.2.2 Asset management strategy, 1.7 Sustainability and climate change, 4.5 Innovation and emerging technologies
3.11 An overview of systems and information management data;	1.9 Asset management systems and information management, 4.5 Innovation and emerging technologies
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;	1.9.1 Data Integrity
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance;	1.10.1 Routine inspections, 1.10.2 Maintenance drivers
3.13.2 planning and implementing network development projects; and	1.10.3 Development project drivers
3.13.3 measuring network performance;	1.10.4 Measuring performance
3.14 An overview of asset management documentation, controls and review processes.	1.11 Overview of documentation and controls
3.15 An overview of communication and participation processes;	1.12 Overview of communication processes
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	1.13.2 Financial forecasts
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.	Table of contents, 1 Introduction
4. The AMP must provide details of the assets covered, including-	5 Lifecycle management
4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	2 Network overview
4.1.1 the region(s) covered;	2.1.1 Regions covered

Determination Clause (Attachment A of Determination*)	AMP Section(s)
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities;	2.1.2 Large consumers
4.1.3 description of the load characteristics for different parts of the network;	2.1.3 Network load characteristics, 2.2 Network configuration
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	2.1.4 Demand and energy, 2.2 Network configuration
4.2 a description of the network configuration, including-	2.2 Network configuration
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;	2.1.3 Network load characteristics, 2.2 Network configuration
4.2.2 a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	2.1 Network area, 2.2 Network configuration
4.2.3 a description of the distribution system, including the extent to which it is underground;	2.2 Network configuration
4.2.4 a brief description of the network's distribution substation arrangements;	2.2 Network configuration, 5.8 Distribution transformers
4.2.5 a description of the low voltage network including the extent to which it is underground; and	2.2 Network configuration, 5.1.9 Consumer connection criteria and assumptions, 5.6 Service connections
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	5.10 Secondary systems
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 Not applicable
4.4 The AMP must describe the network assets by providing the following information for each asset category-	5 Lifecycle management
4.4.1 voltage levels;	5 Lifecycle management
4.4.2 description and quantity of assets;	5 Lifecycle management
4.4.3 age profiles; and	5 Lifecycle management
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.	5 Lifecycle management
4.5 The asset categories discussed in clause 4.4 should include at least the following-	5 Lifecycle management
4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	5 Lifecycle management
4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others;	5 Lifecycle management
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	5.10.6 Mobile generator
4.5.4 other generation plant owned by the EDB.	N/A Not applicable
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.	3 Service levels

Determination Clause (Attachment A of Determination*)	AMP Section(s)
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.	3.2 Primary customer service levels
7. Performance indicators for which targets have been defined in clause 5 should also include-	
7.1 Consumer oriented indicators that preferably differentiate between different consumer types; and	3.2 Primary customer service levels, 3.3 Secondary customer service levels
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.	3.4 Asset performance levels
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.	3.2.2 Justification for reliability targets, 3.8 Justification for service levels
9. Targets should be compared to historic values where available to provide context and scale to the reader.	3 Service levels
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.	1.13.1 Causes of possible material differences, 1.13.2 Financial forecasts, 1.13.3 Limitations of this AMP, 3.4.4 Financial efficiency
11. AMPs must provide a detailed description of network development plans, including—	4 Network development
11.1 A description of the planning criteria and assumptions for network development;	4.2 Development criteria
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;	4.2 Development criteria
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;	3.10 Tactical programmes, 4.3 Development policies, standards and methods, 8.4 Asset management practice performance and improvement processes
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	
11.4.1 the categories of assets and designs that are standardised; and	4.3.1 Methods and approaches used to standardise activities
11.4.2 the approach used to identify standard designs;	4.3.1 Methods and approaches used to standardise activities
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	4.3.2 Consideration of energy efficiency
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;	4.3.5 Options for meeting or managing demand
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;	4.3 Development policies, standards and methods, 4.6 Development prioritisation
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;	4.4 Known constraints, 4.7 Demand forecasts

Determination Clause (Attachment A of Determination*)	AMP Section(s)
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	4.7 Demand forecasts
11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	4.7.3 Zone substation demand forecasts, 4.7.4 GXP demand forecasts
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	4.4 Known constraints
11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	4.3.4 Impact of distributed generation
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-	4.3.5 Options for meeting or managing demand, 4.8 Development projects
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	4.3.5 Options for meeting or managing demand
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	4.3.5 Options for meeting or managing demand
11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	5 Lifecycle management, 5.1 Asset lifecycle management
11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	4.3 Development policies, standards and methods
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;	4.8.1 Development projects for FY2022 year
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	4.8.2 Development projects for FY2023 to FY2026
11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period;	4.8.3 Development projects for FY2027 to FY2031
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	4.3.3 Policies on embedded generation, 4.3.4 Impact of distributed generation
11.12 A description of the EDB's policies on non-network solutions, including-	4.3.5 Options for meeting or managing demand, 4.5 Innovation and emerging technologies, 6 Non-network systems
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	4.3.5 Options for meeting or managing demand, 4.5 Innovation and emerging technologies
11.12.2 the potential for non-network solutions to address network problems or constraints.	4.3.5 Options for meeting or managing demand, 4.5 Innovation and emerging technologies
12. The AMP must provide a detailed description of the lifecycle asset management processes, including—	5 Lifecycle management
12.1 The key drivers for maintenance planning and assumptions;	5.1 Asset lifecycle management

Determination Clause (Attachment A of Determination*)	AMP Section(s)
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-	5 Lifecycle management, 5.1 Asset lifecycle management
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;	5 Lifecycle management
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	5 Lifecycle management
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	5 Lifecycle management, 5.14 Summary of inspections and maintenance
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-	5 Lifecycle management
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;	5 Lifecycle management
12.3.2 a description of innovations that have deferred asset replacements;	3.10 Tactical programmes, 4.5 Innovation and emerging technologies
12.3.3 a description of the projects currently underway or planned for the next 12 months;	5 Lifecycle management, 5.14 Summary of inspections and maintenance
12.3.4 a summary of the projects planned for the following four years (where known); and	5 Lifecycle management, 5.14 Summary of inspections and maintenance
12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	5 Lifecycle management, 5.14 Summary of inspections and maintenance
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	5 Lifecycle management, 5.14 Summary of inspections and maintenance
13. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	6 Non-network systems
13.1 a description of non-network assets;	6.1 Summary of non-network assets
13.2 development, maintenance and renewal policies that cover them;	6.2 Non-network ICT strategy
13.3 a description of material capital expenditure projects (where known) planned for the next five years; and	6.2.5 ICT CAPEX forecast
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	6.2.5 ICT CAPEX forecast
14. AMPs must provide details of risk policies, assessment, and mitigation, including—	7 Risk management
14.1 Methods, details and conclusions of risk analysis;	7.1 Risk analysis and methods
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;	7.1 Risk analysis and methods, 7.2 Specific risks, 7.2.2 Natural disaster risks, 7.4 Resilience framework, 7.4.1 High Impact Low Probability (HILP) Events

Determination Clause (Attachment A of Determination*)	AMP Section(s)
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	7.3 Mitigating network vulnerabilities, 7.4.3 Emergency response and contingency planning, 7.4.4 Emergency response plans, 7.4.5 Resilience planning for risk preparedness
14.4 Details of emergency response and contingency plans.	7.3 Mitigating network vulnerabilities, 7.4.3 Emergency response and contingency planning, 7.4.4 Emergency response plans, 7.4.5 Resilience planning for risk preparedness
15. AMPs must provide details of performance measurement, evaluation, and improvement, including—	8 Performance evaluation
15.1 A review of progress against plan, both physical and financial;	8.1 Works delivery performance, 8.2 Network reliability performance, 8.3 Asset performance, 8.3.4 Financial effectiveness
15.2 An evaluation and comparison of actual service level performance against targeted performance;	8.1 Works delivery performance, 8.2 Network reliability performance, 8.3 Asset performance
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.	8.4 Asset management practice performance and improvement processes
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.	3.10 Tactical programmes, 8.4 Asset management practice performance and improvement processes
16. AMPs must describe the processes used by the EDB to ensure that-	
16.1 The AMP is realistic and the objectives set out in the plan can be achieved; and	1.11 Overview of documentation and controls, 5.15 Our Employees, 5.16 Resourcing policy and strategy, Appendix 1 Reconciliation of Asset Management Plan to Electricity Distribution Information Disclosure Determination 2012
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	1.11 Overview of documentation and controls, 1.8 Accountabilities for asset management, 1.8.1 Summary of roles, delegated authorities and reporting, 1.8.2 Use of external contractors and advisers, 5.15 Our Employees, 5.16 Resourcing policy and strategy

Appendix 2: Schedule 11a - Report on Forecast Capital Expenditure

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031

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).

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	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	95	400	406	412	418	425	431	437	444	451	457
11	System growth	1,450	-	-	1,700	1,569	1,497	1,950	1,148	1,554	2,788	3,487
12	Asset replacement and renewal	6,217	7,147	6,757	7,557	9,375	9,785	9,099	8,626	7,784	7,878	7,997
13	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:											
15	Quality of supply	2,002	3,057	3,396	3,910	3,440	3,104	3,691	3,172	3,309	2,626	2,380
16	Legislative and regulatory	450	600	457	464	471	-	-	-	-	-	-
17	Other reliability, safety and environment	895	635	934	634	261	265	269	273	277	383	286
18	**Total reliability, safety and environment**	3,347	4,292	4,787	5,007	4,172	3,370	3,960	3,446	3,586	3,009	2,665
19	**Expenditure on network assets**	11,109	11,839	11,950	14,676	15,534	15,076	15,440	13,657	13,368	14,126	14,607
20	Expenditure on non-network assets	4,773	3,498	1,873	3,760	1,302	1,380	1,374	2,788	3,514	1,436	1,458
21	**Expenditure on assets**	15,882	15,337	13,822	18,436	16,836	16,455	16,813	16,445	16,882	15,562	16,064
22												
23	*plus* Cost of financing	100	90	90	90	90	90	90	90	90	90	90
24	*less* Value of capital contributions	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
25	*plus* Value of vested assets	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
26												
27	**Capital expenditure forecast**	16,102	15,547	14,032	18,646	17,046	16,665	17,023	16,655	17,092	15,772	16,274
28												
29	Assets commissioned											

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	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
32		**$000 (in constant prices)**										
33	Consumer connection	95	400	400	400	400	400	400	400	400	400	400
34	System growth	1,450	-	-	1,650	1,500	1,410	1,810	1,050	1,400	2,475	3,050
35	Asset replacement and renewal	6,217	7,147	6,657	7,335	8,966	9,219	8,446	7,889	7,014	6,994	6,994
36	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
37	Reliability, safety and environment:											
38	Quality of supply	2,002	3,057	3,241	3,795	3,290	2,925	3,426	2,901	2,981	2,331	2,081
39	Legislative and regulatory	550	600	450	450	450	-	-	-	-	-	-
40	Other reliability, safety and environment	895	635	920	615	250	250	250	250	250	340	250
41	**Total reliability, safety and environment**	3,447	4,292	4,611	4,860	3,990	3,175	3,676	3,151	3,231	2,671	2,331
42	**Expenditure on network assets**	11,209	11,839	11,668	14,245	14,856	14,204	14,332	12,490	12,045	12,540	12,775
43	Expenditure on non-network assets	4,773	3,498	1,845	3,650	1,245	1,300	1,275	2,550	3,166	1,275	1,275
44	**Expenditure on assets**	15,982	15,337	13,513	17,895	16,101	15,504	15,607	15,040	15,211	13,815	14,050
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											
50												

	for year ended	Current Year CY 31 Mar 21	CY+1 31 Mar 22	CY+2 31 Mar 23	CY+3 31 Mar 24	CY+4 31 Mar 25	CY+5 31 Mar 26	CY+6 31 Mar 27	CY+7 31 Mar 28	CY+8 31 Mar 29	CY+9 31 Mar 30	CY+10 31 Mar 31
Difference between nominal and constant price forecasts		$000										
Consumer connection		-	-	6	12	18	25	31	37	44	51	57
System growth		-	-	-	50	69	87	140	98	154	313	437
Asset replacement and renewal		-	-	100	222	410	566	653	737	770	885	1,003
Asset relocations		-	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:												
Quality of supply		-	-	155	115	150	179	265	271	327	295	298
Legislative and regulatory		(100)	-	7	14	21	-	-	-	-	-	-
Other reliability, safety and environment		-	-	14	19	11	15	19	23	27	43	36
Total reliability, safety and environment		(100)	-	176	147	182	195	284	294	355	338	334
Expenditure on network assets		(100)	-	282	431	679	872	1,108	1,167	1,323	1,586	1,832
Expenditure on non-network assets		-	-	28	110	57	80	99	238	348	161	183
Expenditure on assets		(100)	-	309	541	735	951	1,206	1,405	1,671	1,747	2,015

11a(ii): Consumer Connection

	for year ended	Current Year CY 31 Mar 21	CY+1 31 Mar 22	CY+2 31 Mar 23	CY+3 31 Mar 24	CY+4 31 Mar 25	CY+5 31 Mar 26
*Consumer types defined by EDB**		$000 (in constant prices)					
All		95	400	400	400	400	400
[EDB consumer type]							
[EDB consumer type]							
[EDB consumer type]							
[EDB consumer type]							
**include additional rows if needed*							
Consumer connection expenditure		95	400	400	400	400	400
less Capital contributions funding consumer connection							
Consumer connection less capital contributions		95	400	400	400	400	400

11a(iii): System Growth

	Current Year CY 31 Mar 21	CY+1 31 Mar 22	CY+2 31 Mar 23	CY+3 31 Mar 24	CY+4 31 Mar 25	CY+5 31 Mar 26
Subtransmission	-	-	-	-	-	-
Zone substations	-	-	-	-	-	-
Distribution and LV lines	-	-	-	-	-	-
Distribution and LV cables	1,450	-	-	1,650	1,500	1,410
Distribution substations and transformers	-	-	-	-	-	-
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	1,450	-	-	1,650	1,500	1,410
less Capital contributions funding system growth						
System growth less capital contributions	1,450	-	-	1,650	1,500	1,410

11a(iv): Asset Replacement and Renewal

	for year ended	Current Year CY 31 Mar 21	CY+1 31 Mar 22	CY+2 31 Mar 23	CY+3 31 Mar 24	CY+4 31 Mar 25	CY+5 31 Mar 26
		$000 (in constant prices)					
Subtransmission		360	915	360	1,360	1,360	1,360
Zone substations		131	135	1,095	1,135	2,885	2,435
Distribution and LV lines		4,027	4,259	3,332	3,025	2,571	3,385
Distribution and LV cables		378	453	533	403	485	485
Distribution substations and transformers		887	915	887	887	1,051	1,051
Distribution switchgear		160	160	160	160	214	214
Other network assets		275	310	290	365	400	290
Asset replacement and renewal expenditure		6,217	7,147	6,657	7,335	8,966	9,219
less Capital contributions funding asset replacement and renewal							
Asset replacement and renewal less capital contributions		6,217	7,147	6,657	7,335	8,966	9,219

11a(v): Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**		$000 (in constant prices)					
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other project or programmes - asset relocations							
Asset relocations expenditure		-	-	-	-	-	-
less Capital contributions funding asset relocations							
Asset relocations less capital contributions		-	-	-	-	-	-

11a(vi): Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**		$000 (in constant prices)					
Protection Work		850	650	580	1,280	500	600
Improving Network Interconnectivity		341	1,100	1,100	1,615	2,015	1,100
Network Automation and Sectionalisation		683	1,002	1,331	620	620	1,070
Fault Locator		128	230	230	280	155	155
Condition Monitoring		-	75	-	-	-	-
**include additional rows if needed*							
All other projects or programmes - quality of supply							
Quality of supply expenditure		2,002	3,057	3,241	3,795	3,290	2,925
less Capital contributions funding quality of supply							
Quality of supply less capital contributions		2,002	3,057	3,241	3,795	3,290	2,925

11a(vii): Legislative and Regulatory

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**		$000 (in constant prices)					
Seismic Strengthening		550	600	450	450	450	-
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
**include additional rows if needed*							
All other projects or programmes - legislative and regulatory							
Legislative and regulatory expenditure		550	600	450	450	450	-
less Capital contributions funding legislative and regulatory							
Legislative and regulatory less capital contributions		550	600	450	450	450	-

Row		Current Year CY 31 Mar 21	CY+1 31 Mar 22	CY+2 31 Mar 23	CY+3 31 Mar 24	CY+4 31 Mar 25	CY+5 31 Mar 26
150	for year ended						
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	Arc Flash Protection	-	-	305	-	-	-
154	New ABS and renewals	325	325	325	325	110	110
155	Replacement of Deck Transformers	160	-	-	-	-	-
156	Replacement of Pitchfilled Potheads	60	60	40	40	40	40
157	Steel Link Pillar Removal	250	250	250	250	100	100
	Replacement of Room transformers	100	-	-	-	-	-
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	895	635	920	615	250	250
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety and environment less capital contributions**	895	635	920	615	250	250
163							

Row		Current Year CY 31 Mar 21	CY+1 31 Mar 22	CY+2 31 Mar 23	CY+3 31 Mar 24	CY+4 31 Mar 25	CY+5 31 Mar 26
164 / 165	for year ended						
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	Office buildings, depots & workshops	100	125	90	90	95	90
170	Office furniture, fittings and equipment incl. PPE	98	25	25	25	25	25
171	Motor vehicles	1,525	15	10	10	10	10
172	Tools, plant & other machinery	250	380	420	350	350	350
173	ICT	725	1,453	1,155	1,155	745	680
174	IoT	25					
175	**include additional rows if needed*						
176	All other projects or programmes - routine expenditure						
177	**Routine expenditure**	2,723	1,998	1,700	1,630	1,225	1,155
178	**Atypical expenditure**						
179	*Project or programme**						
180	Retailer Billing	-	-	-	-	-	-
181	ADMS and SCADA Development	100	250	125	2,000	-	125
183	HRIS Software	1,000	50	-	-	-	-
184	ADMS and SCADA Development	500	1,200	20	20	20	20
185	Replacement of mobiles, tablets and organic growth	250	-	-	-	-	-
	Network Asset Communications	100	-	-	-	-	-
	IoT - Low Voltage Network Status Monitoring	100	-	-	-	-	-
186	**include additional rows if needed*						
187	All other projects or programmes - atypical expenditure						
188	**Atypical expenditure**	2,050	1,500	145	2,020	20	145
189							
190	**Expenditure on non-network assets**	4,773	3,498	1,845	3,650	1,245	1,300

Appendix 3: Schedule 11b - Report on Forecast Operational Expenditure

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031

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.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory 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	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,859	1,894	1,922	1,951	1,980	1,945	1,974	2,004	2,011	2,042	2,072
11	Vegetation management	1,608	1,645	1,670	1,695	1,720	1,579	1,603	1,627	1,651	1,676	1,701
12	Routine and corrective maintenance and inspection	999	1,050	1,076	1,118	1,082	1,122	1,112	997	1,095	1,027	1,043
13	Asset replacement and renewal	312	418	485	395	374	449	386	391	492	403	386
14	**Network Opex**	4,778	5,007	5,153	5,158	5,157	5,094	5,074	5,019	5,249	5,148	5,202
15	System operations and network support	3,111	4,841	5,090	5,289	5,369	5,449	5,531	5,614	5,698	5,783	5,870
16	Business support	4,625	4,131	4,269	4,454	4,520	4,588	4,657	4,727	4,798	4,870	4,943
17	**Non-network opex**	7,736	8,972	9,359	9,743	9,889	10,037	10,188	10,341	10,496	10,653	10,813
18	**Operational expenditure**	12,514	13,979	14,512	14,901	15,046	15,132	15,262	15,359	15,745	15,801	16,015
19		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,859	1,894	1,894	1,894	1,894	1,832	1,832	1,832	1,812	1,812	1,812
23	Vegetation management	1,608	1,645	1,645	1,645	1,645	1,488	1,488	1,488	1,488	1,488	1,488
24	Routine and corrective maintenance and inspection	999	1,050	1,060	1,085	1,035	1,057	1,032	912	987	912	912
25	Asset replacement and renewal	312	418	478	383	358	423	358	358	443	358	338
26	**Network Opex**	4,778	5,007	5,077	5,007	4,932	4,800	4,710	4,590	4,730	4,570	4,550
27	System operations and network support	3,111	4,841	5,015	5,134	5,134	5,134	5,134	5,134	5,134	5,134	5,134
28	Business support	4,625	4,131	4,206	4,323	4,323	4,323	4,323	4,323	4,323	4,323	4,323
29	**Non-network opex**	7,736	8,972	9,221	9,457	9,457	9,457	9,457	9,457	9,457	9,457	9,457
30	**Operational expenditure**	12,514	13,979	14,298	14,464	14,389	14,257	14,167	14,047	14,187	14,027	14,007
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
40	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	28	57	87	112	142	171	199	229	260
43	Vegetation management	-	-	25	50	75	91	115	139	163	188	213
44	Routine and corrective maintenance and inspection	-	-	16	33	47	65	80	85	108	115	131
45	Asset replacement and renewal	-	-	7	12	16	26	28	33	49	45	48
46	**Network Opex**	-	-	76	151	225	295	364	429	520	578	652
47	System operations and network support	-	-	75	155	235	315	397	480	564	649	736
48	Business support	-	-	63	131	197	265	334	404	475	547	620
49	**Non-network opex**	-	-	138	286	432	580	731	884	1,039	1,196	1,356
50	**Operational expenditure**	-	-	214	437	657	875	1,095	1,313	1,558	1,774	2,008

Appendix 4: Schedule 12a – Report on Asset Condition

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031

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

sch ref	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
7					Asset condition at start of planning period (percentage of units by grade)							
10	All	Overhead Line	Concrete poles / steel structure	No.	-	-	2.00%	94.34%	3.66%	-	3	2.00%
11	All	Overhead Line	Wood poles	No.	-	-	5.79%	93.25%	0.96%	-	2	6.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	14.00%	81.47%	4.62%	-	3	15.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	69.00%	31.00%	-	4	-
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.	-	-	50.00%	30.00%	20.00%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-		50.00%	50.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	41.00%	49.00%	10.00%	-	4	41.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	38.00%	52.50%	9.50%	-	3	38.00%
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.	-	-	5.00%	75.00%	20.00%	-	3	5.00%
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.	-	-	10.52%	78.98%	10.50%	-	4	10.52%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	7.00%	72.00%	21.00%	-	3	7.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	83.38%	16.62%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	2.00%	98.00%	-	-	2	2.00%
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.	-	-	2.50%	62.50%	35.00%	-	4	2.50%
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.	-	-	8.00%	77.69%	14.31%	-	3	8.32%
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.	-	-	7.00%	61.63%	31.37%	-	3	7.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	-	5.00%	72.00%	23.00%	-	4	5.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	5.00%	53.00%	42.00%	-	4	5.00%
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	-	-	5.00%	-	5.00%	90.00%	2	5.00%
56	LV	LV Cable	LV UG Cable	km	-	-	-	35.00%	9.00%	56.00%	2	2.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	-	-	-	100.00%	2	1.00%
58	LV	Connections	OH/UG consumer service connections	No.	-	-	5.00%	90.00%	5.00%	-	2	5.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	20.50%	44.50%	35.00%	-	4	20.50%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	10.00%	70.00%	20.00%	-	3	15.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	-	-	50.00%	50.00%	-	4	-
63	All	Load Control	Relays	No.	-	-	-	-	-	100.00%	2	10.00%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Appendix 5: Schedule 12b – Report on Forecast Capacity

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. 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)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Shannon	4.2	5	N-1	6	84%	5	89%	No constraint within +5 years	
10	Foxton	7.4	23	N-1	4	32%	23	34%	No constraint within +5 years	
11	Levin West	13.1	23	N-1	12	57%	23	60%	No constraint within +5 years	
12	Levin East	14.0	23	N-1	12	61%	23	64%	No constraint within +5 years	
13	Otaki	11.9	23	N-1	4	52%	23	56%	No constraint within +5 years	
14	Waikanae	15.5	23	N-1	12	67%	23	72%	No constraint within +5 years	
15	Paraparaumu	13.1	23	N-1	16	57%	23	61%	No constraint within +5 years	
16	Paraparaumu West	12.5	23	N-1	8	54%	23	59%	No constraint within +5 years	
17	Raumati	9.6	23	N-1	12	42%	23	45%	No constraint within +5 years	
18	Paekakariki	2.2	-	N-1 (Switched)	6	-	-	-	No constraint within +5 years	Automatic changeover to Raumati using fault monitors and motorised switches
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Appendix 6: Schedule 12c – Report on Forecast Network Demand

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031

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							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
11	*Consumer types defined by EDB**						
12	All	400	425	450	475	500	525
13	[EDB consumer type]						
14	[EDB consumer type]						
15	[EDB consumer type]						
16	[EDB consumer type]						
17	**Connections total**	400	425	450	475	500	525
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	125	135	145	155	165	175
21	Capacity of distributed generation installed in year (MVA)	0.5	0.5	0.5	0.5	0.6	0.6
22	**12c(ii) System Demand**						
23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** — for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
25	GXP demand	77	77	78	79	79	80
26	*plus* Distributed generation output at HV and above	26	27	27	27	27	27
27	**Maximum coincident system demand**	103	104	105	106	106	107
28	*less* Net transfers to (from) other EDBs at HV and above						
29	**Demand on system for supply to consumers' connection points**	103	104	105	106	106	107
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	396	401	406	412	416	422
32	*less* Electricity exports to GXPs						
33	*plus* Electricity supplied from distributed generation	61	62	62	62	63	63
34	*less* Net electricity supplied to (from) other EDBs						
35	**Electricity entering system for supply to ICPs**	457	463	468	474	479	485
36	*less* Total energy delivered to ICPs	423	428	433	438	443	448
37	**Losses**	34	34	35	36	36	37
38							
39	**Load factor**	51%	51%	51%	51%	51%	52%
40	**Loss ratio**	7.4%	7.4%	7.5%	7.5%	7.5%	7.6%

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Network / Sub-network Name	Electra Ltd

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*
9	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	15.0	15.0	15.0	15.0	15.0	15.0
12	Class C (unplanned interruptions on the network)	68.0	68.0	68.0	68.0	68.0	68.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.06	0.06	0.06	0.06	0.06	0.06
15	Class C (unplanned interruptions on the network)	1.60	1.60	1.60	1.60	1.60	1.60

Appendix 8: Schedule 13 – Report on Asset Management Maturity

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO 55001

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	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2.5	• An asset management policy has been developed and authorised. Its principles were competent for an electricity distribution company. • Presentations are made to the teams on asset management direction as set out in the RAMP. • The asset management policy is not circulated, and senior management have not seen the document.		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?	3.1	• All policies go through the Risk and Audit Committee of the Board and this is a detailed process. It ensures consistency of documentation. The Board has an experienced engineer who reviews the RAMP in addition to the third-party experts. • There is a quarterly review to align policies undertaken by the Risk and Audit Committee, which tests where risk levels are rising. A risk situation may trigger a deep dive into a policy to test improvement. Asset managers have visibility of this process. • Senior executives discuss their policies and risk management every 2 weeks since Electra is a small organisation and they are familiar with immediate risks. For example, H&S are now involved in some asset-related risks affecting H&S with people held accountable.	Moving towards strategies and updating databases and information, developing the ARMM database for overhead lines, zone transformers, circuit breakers. Documentation needs to be formalised.	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?	2.5	• Within the RAMP Electra define asset management strategies for different asset classes and type issues. The RAMP also considers population numbers and age profiles. • The RAMP covers different stakeholder requirements and regional issues. • Over the last two years Electra have improved their asset information systems, recovering history as linked pdf documents so that old reports are now useful leading to mid-life refurbishments. • Information is sorted by substations in which specific circuit breakers can be identified with photographs and scanned documents. Some of this information is transferred directly into AHIs.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2.9	• Planning seeks to ensure that risk is returned to original condition and that the work is safe, good quality and there is a replacement strategy to cope with ageing assets. • Electra cope with assets installed in the 1960/70s. • Planning also ensures Electra has the resources necessary to deliver the proposed work. • There are several drivers of work in the AMP including system growth, reliability performance, safety and condition-based asset renewals. • Annual load forecasts update the known network growth. • Planning considers seasonal access issues and network access.		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?	2.7	• Business cases identify options and work to be done for major work >200K. (1M needs a Board paper.) Then detailed design is undertaken, and work delivered. Workflow standards cover many processes covering design, approvals, materials management and commissioning. • Work is prioritised using multiple criteria. Risk prioritisation is reported in the RAMP. • Asset age is reported in AHI bands with a band ranked low being replaced. • RAMP is updated every year and is more focused for the next 3 years on specific projects. After this horizon, budget estimates are more based on planning targets depending on asset condition.	There is a need to communicate to other stakeholders in the organization such as their customer services and construction teams	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.

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2.5	• The RAMP is the focal point of delivering the AMS. For example, IT check that their systems are in place to allow delivering the works programme. • The AMP is one of the most critical documents in the organisation and it is essential that people support the objectives of the AMS. • 2.5 years ago, Electra released that they did not manage change well or communicate the requirements. Electra needed to document their processes and selected the person most relevant to the change and engaged them to document the requirement. Now Electra is a lot better at communications, making products fit for purpose and communicating with people and understanding their frustrations.		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)	2.7	• Planning seeks to ensure that risk is returned to original condition and that the work is safe, good quality and there is a replacement strategy to cope with ageing assets. • Electra cope with assets installed in the 1960/70s. • Planning also ensures Electra has the resources necessary to deliver the proposed work. • There are several drivers of work in the AMP including system growth, reliability performance, safety and condition-based asset renewals. • Annual load forecasts update the known network growth.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2.5	• Major incident plans are established along with contingency planning for recovery from major events. These include buildings not available, loss of SCADA and operation of the grid. • Operators can work remotely, and operations communications are not reliant on major carriers and are backed up. • Back up site at Levin West substation including control room desk. • Scenario testing included an event modelled at Coventry depot and paper-based simulated an event. • Electra participate in civic emergency scenarios with local organisations. A head office staff member attends civil defence meetings.	Events need to be reviewed and monitored for improvement.	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)?	2.7	• The CEO plays a leading role in establishing and leading the AMS which then gets delegated to the GM for the Lines business. There is a strong alignment between the CEO and the priorities of work within the AMP. • The CEO confirms that the KPIs are relevant such as progressing work from the AMP, safety and reliability. He takes accountability for these trends.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2.5	• The AMP recognises the skills needed and Electra is informed by HR on work in recruitment and staff retention which is needed. • Electra look at the resources required for the AMP to be delivered and request senior people to ensure the right people are available to deliver the work. • GM Lines is currently reviewing the skills needed to deliver the AMP including shared services and IT support. • The last couple of years has seen greater investment in cross skilling of core people allowing greater flexibility. • The business is investing in leadership development and a talent matrix plus succession planning. This will better equip people leaders down to the level of Team Leaders. • There is greater clarity on the responsibilities of people leaders. • The CEO speaks at Training Days and Directors attend fieldworks.		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.

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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	• Electra are satisfied that continual improvement is occurring since they have overspent all improvement projects covering people, safety, technical and the parent company. • The business is receptive to change based on what it needs to deliver asset management such as managing critical functions like safety. The teams are supplemented with special skills when needed. • Electra have progressed to work more effectively: 10 years ago, the Annual Works Plan was never achieved; now the teams get the plan delivered. • Number of people in leadership roles has lifted with a commitment to leadership and engagement of teams. There is more investment in the people. • Department meetings consider new AMP opportunities as well as progress to deliver the current AMP. This demonstrates senior management focus on delivery of the AMP.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2.3	• Noted that there is legal review of contracts before signing as part of the risk controls. • Electra employs long-term contractors where necessary who know the network and its assets. • Contracts are reviewed for commercial terms and have Supply complied with legal and warranty conditions. This covers how Electra has purchased assets or services, consistent use of Electra standard for procurement and supplier performance. • The process for new equipment acquisition covers technical specification, network approval procedures and engineering standards such as purchased from Powerco.		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)?	2.9	• Role specifications are across the organisation and reach up to the Senior Leadership Team. • The Performance Management System covers individual development plans, e.g. some financial people have responsibilities associated with the AMP. • Position descriptions are provided for every role across the Group, e.g. line mechanics have a position description which includes key responsibilities and purpose of the role. • When recruiting for senior managers, Electra assess if the person has close experience with the specific function associated with the role. The business is capability focused. • Secondly when considering a person, Electra assess how they would fit into the team and work with others. Hence there are priorities on experience and ability to work in the Electra 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.
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?	2.4	• A dedicated training coordinator covers requirements for certification of competence. This is based on the NZ government system of qualifications. Skills are assessed every 6 months such as at mandatory attendance at Safety Days. • Annual assessment of pole top risk, joining and crimping of conductors • Mandatory tests and training records are recorded in VAULT. • Multi-skilling such as electrician and cable jointer is a formal process of qualification with training tracked. The training is competency based including record and verification. • Individual KPIs and performance reviews are in place along with the EEA asset management competency framework. • The EWRB competency framework ensures that people are trained and competent to work on the assets.		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.

2

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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?	1.9	• People working on the network all have national qualifications or are working towards them. This is backed by annual refresher training. • Training is undertaken in several facilities and Electra is well supported by RTOs. o The Horowhenua Training Centre provides courses to improve literacy o Line mechanics train in Auckland or Napier o Cable jointers train in Auckland o Electricians train in Wellington • There is no self-paced learning, but Electra are getting into video training. • The current training budget of 280K can be compared to a previous budget of 110K, and ensures people are right-skilled. • 100% apprentice retention rates achieved since Electra will recruit local people.		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	• ESRI system pushes all asset data on to a web page. This is available internally and to contractors. It is a good interface which is better than Windmill. o An inspection app collects data into o Inspection sheets are updated annually and use standard forms. Every 5 years a new form is created to avoid over writing the data. o All measurement data is held in ESRI and indexed to a plant number available to the inspector. o NP&D Manager is driving improvement to these forms to collect more data. • Not too much WIP is carried past end of March. Projects which extend across March and into the new financial year are a problem. Large projects which hold up WIP every year get a lot of attention. Need to ensure Project Managers are conscious of the March deadline for capitalisation.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	1.9	• Outage management system displays information on the web for customers. • ADMS is hooked into SCADA so that ADMS can show the trip with the trip stored as an outage. • Customer calls can be picked up as a fault in ADMS. • The level of asset information in the ADMS is minimal. It mainly covers shared connectivity on the 400V network. • ADMS was never designed to be an asset information system but it has some tables which are useful. • Asset tactics are kept in the documents managed by electricians and held on SharePoint. They are supposed to keep all this information here, but it has spread around several file servers and Electra have not pulled all this together. • There is no central store of the OEM manuals.		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?	2.3	• The ADMS covers the following: o Dispatch – outage management and fault response with dispatch of teams to a fault o IVR – voltage response o Calls Manager – the Call Centre enters transactions in the system. The customer database has the ICP data. • Windmill is used for system connectivity. Changes in systems are made here and engineering analysis of voltage drops uses the connectivity module. • GIS can enter Windmill drawings which are updated nightly with a link between Windmill and ESRI. • ESRI system pushes all asset data on to a web page. This is available internally and to contractors. It is a good interface which is better than Windmill. • Navision is an expenditure tracking system for work on the network. Historically assets were managed in blocks and the work was booked to blocks. Now work is booked to assets. This means costs can be captured to assets now, but the history is poor with assets treated as blocks.		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.

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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?	1.8	• Systems make it hard to track WIP and update the RAB. It is a manual process to take work out of WIP and update the RAB, which must be achieved by the end of March each year to enable capitalisation. • There is no library of drawings or construction drawings and what is held is poor quality. • Design drawings are managed using a spreadsheet.		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	• Navision is an expenditure tracking system for work on the network. Historically assets were managed in blocks and the work was booked to blocks. Now work is booked to assets. This means costs can be captured to assets now, but the history is poor with assets treated as blocks. • The schedule of inspections is held in the RAMP, which means it is not a schedule at all and it is hard to locate the information being referred to. • RAP Note: Electra need a works management system which also manages inspection data and an asset configuration aligned with the GIS asset portfolio. • Assets are not well covered. For example, substation assets are in a spreadsheet. • Comms asset management is by a contractor. • Vegetation is a spreadsheet.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2.4	• The RAMP was checked, and Section 7 refers to the Electra risk management framework. It references a risk assessment tool and risk mitigation strategies. It does not discuss how investment plans are prioritised based on risk. • Electra promotes proactive behaviour including the use of documentation.		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, 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	• There are two Safety Days a year to identify issues people are keen to see resolved or seek training. These share industry lessons to the team. • Supervisors are proactive in their surveillance of their teams. • There is now a lot more focus on walkdowns and on-site surveillance. These cover safety observations and assessment of what people are doing. • Workplace observations are recorded in VAULT. VAULT Checks are detailed and thorough reviews of a worksite. (VAULT Incident is used to record observations and incidents.) • VAULT results are reported to the Board. • Non-compliance is followed up by improvement of procedures, training etc. Note non-compliance can result in a formal warning.		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?	3.1	Safety • All lines teams meet monthly, attended by training coordinator and safety officer and supported by the GM. Outcomes are reinforced in the newsletter. • Depots manage safety plans and are more aware of risks, including: o Workshop – lifting plans for heavy loads, moving vehicles, high visibility and clean workshop o Audit of trucks – technical safety and lot of focus on crews – Safety Days cover their view on what needs to be on the trucks o Trainer will audit that equipment is safe • Board/ELT come out for safety observations Legal Compliance – some material included under external stakeholder notes in Section 2.1 • Annual survey undertaken of legal compliance requirements. • Non-compliance is registered in VAULT. • CARs are tracked and surveys go to the Board. • Electra legal team become involved with partial or non-compliance issues. Corrective actions are registered in VAULT.		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

Company Name	Electra Ltd	
AMP Planning Period	1 April 2021 – 31 March 2031	
Asset Management Standard Applied	ISO 55001	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2.6	• When equipment is acquired it is considered for the following: o Standards for approval of selection of equipment. o Appropriate supplier for the equipment. o There is no limit on source of supply 9e.g. country of manufacture). o Quality control is dependent on the size of equipment. • Commissioning involves recording the test results from the network team as a scanned pdf which is then stored against the job in Navision. • Electra will test equipment before it taken out to the field. Testing may determine issues such as switchgear damaged in delivery which will lead to its rejection before installation commences. • The testing and QA are undertaken by experienced people.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2.6	• Third party designs are checked in-house with local knowledge of what is being put into the ground. • It is understood that every job is different. Hence there is a process to get a shutdown notice and enough time to assess the job. • Prior to receiving the design, the scope of the job is assessed to see if Electra can install it. This involves the project management and the contract supervisor. They review if the design is feasible for the local situation. This covers sizing and appropriate specifications, access to the work site (e.g. weight of poles being carried) and so forth. • With network changes paper copies are held and as-built drawings are scanned electronically, and the model updated. • Quality has been good in commissioning. If new equipment arrives and does not meet specifications, then it does not leave the depot.		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	• Inspectors are trained and talk to network engineers: they implement a pre-audit of work they have specified every week to get a balanced view. Inspectors are benchmarked and mentored based on their performance. Note that there are only two inspectors, so they have to simply align the interpretation and feedback of these people. • Drone inspections of the 33 kV lines found some asset health issues. These are being correlated with the results from the inspectors and where the differences are showing up. They are saving a lot of time and everyone can see the photographs. • There is continual improvement to assess effectiveness of inspections, e.g. cross check when cross arms are taken down and should they have been replaced? • Substations have regular inspections every 2 months and 5-yearly refurbishments. (Seismic strengthening of subs now being implemented across the business.) Note that there is only one outdoor substation. The indoor subs are pressurised with no evidence of corrosion (RAP Note: excellent performance close to the ocean).		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 non-conformities	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?	1.7	• Possible Fault reports can be raised in a document chain when maintenance observe a fault. The reports are emailed to network engineers and an SME will investigate the issue. • Network team meetings every week consider possible faults and future risks. • Improvement recommendations consider improved products and suppliers as well as how to improve designs. • Post fault assessments also consider where improvement is needed (e.g. network design, type of insulator, improved earthing standards, etc.) in a combined Services and Network approach. • ICAMS are undertaken after major events.		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.

Company Name	Electra Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	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))?	1.8	• In response to improvement assessments, Electra now create jobs earlier and map them to the GIS. The Project Manager is then enabled to package them better. • Champions of systems and initiatives talk to the teams and the teams then get involved with UAT of the new initiatives. They need to be assured that appropriate training material is available at the time of testing.	Electra appreciates that under PAS 55, there is a requirement to further lift the auditing process to drive continual improvement in asset management audit activities.	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?	1.4	• Internal stakeholder requirements are actively assessed with standard monthly forums and feedback strategies such as newsletters. • The Public Safety Management System is routinely audited and provides input from a risk perspective and influence the AMP to ensure replacement priorities for at-risk equipment (e.g. oil-filled switchgear). • Drivers of the AMOs include response times for services, which means Electra works to reduce the response times. • Management have monthly KPIs including reliability, e.g. SAIDI, Costs/km and Costs/ICP. Every month the CEO receives a report on SAIDI and there are fortnightly meetings of the leadership team to discuss reliability. Monday meetings in the control room review the effect of current plans on planned SAIDI. All work is planned with consideration of SAIDI impact. • Fortnightly project status reports advise how work is tracking. If SAIDI is an issue, then a project may be deferred.		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	• Technically focused people in the service provider team advise the network on opportunities. An example is investment in electrical testing which was recommended by Services and then supported with new testing equipment. • Lot of recommendations are made to the H&S committee. • An improvement initiative was undertaken across the business to assess if the teams are operating at an optimal level with the right people in the right roles. This led to strengthening of the design team.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2.7	• Benefits realisation is undertaken for a potential project for a new AMIS: e.g. mobility offers 20% greater productivity. There is a need for capable resources to be able to use a new AMIS. An existing project is coming to an end to free up resources to focus work on this new opportunity. • Concerning improved practices, Electra balance their focus on budget versus continual improvement in asset management and assess if their resourcing of initiatives is right. • For example, a good resource was identified associated with new information technology who represents an additional FTE. Investment in this resource will be based on people's preferences for specific initiatives and where this resource should work.		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.

Company Name	Electra Limited
For Year Ended	31 March 2021

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
10-year planning period – Annual CPI allowance for increased cost, based on 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
Current disclosure year – nil, no impact. 10-year planning period – Annual CPI allowance for increased cost, based on construction and compliance costs.

Appendix 10: Certification for Asset Management Plan

CERTIFICATION FOR YEAR-BEGINNING DISCLOSURE - ASSET MANAGEMENT PLAN CLAUSE 2.9.1

We, Shelly Anne Mitchell-Jenkins and Michael Charles Underhill, directors of Electra Limited certify that, having made all reasonable enquiries, to the best of our knowledge that:

a) The following attached information of Electra prepared for the purposes of clause 2.6.1 and clauses 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) in all material respect complies with that determination.

b) The forecasts in Schedules 11a, 11b, 12a, 12b 12c and 12d of the attached information are based on objective and reasonable assumptions which both align with Electra's corporate vision and strategy and are documented in retained records.

c) 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

Shelly Anne Mitchell-Jenkins – Director	26/2/21 **Date**
Michael Charles Underhill - Director	26/2/21 **Date**

Appendix 11: Glossary

Term	Description
ABS	Air Break Switch
ADMS	Advanced Distribution Management System
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
ARMM	Asset Risk Management Model
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
CBD	Central Business District
CBRM	Condition-based risk management
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.
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
DER	Distributed Energy Resource
DG	Distributed Generation
Distribution Substation	A kiosk, outdoor ground mounted substation or pole mounted substation taking its supply at 11kV and distributing at 400V.
ECP	Electrical Code of Practice
EDB	Electricity Distribution Business
EF	Earth fault
EV	Electric vehicle
EVSE	Electric vehicle supply equipment
Feeder	A physical grouping of conductors that originate from a district substation circuit breaker.
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
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

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
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
MVA	megavolt amp
MW	megawatt
MWh	megawatt hours (one million watt hours)
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.
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
PILC	Paper-insulated, lead-covered - a type of cable insulation.
PQ	Power quality
PRV	Pressure relief valve
Photovoltaic	The conversion of light into electricity using solar panels
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.

Term	Description
SCI	Statement of Corporate Intent
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.
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.
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.

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