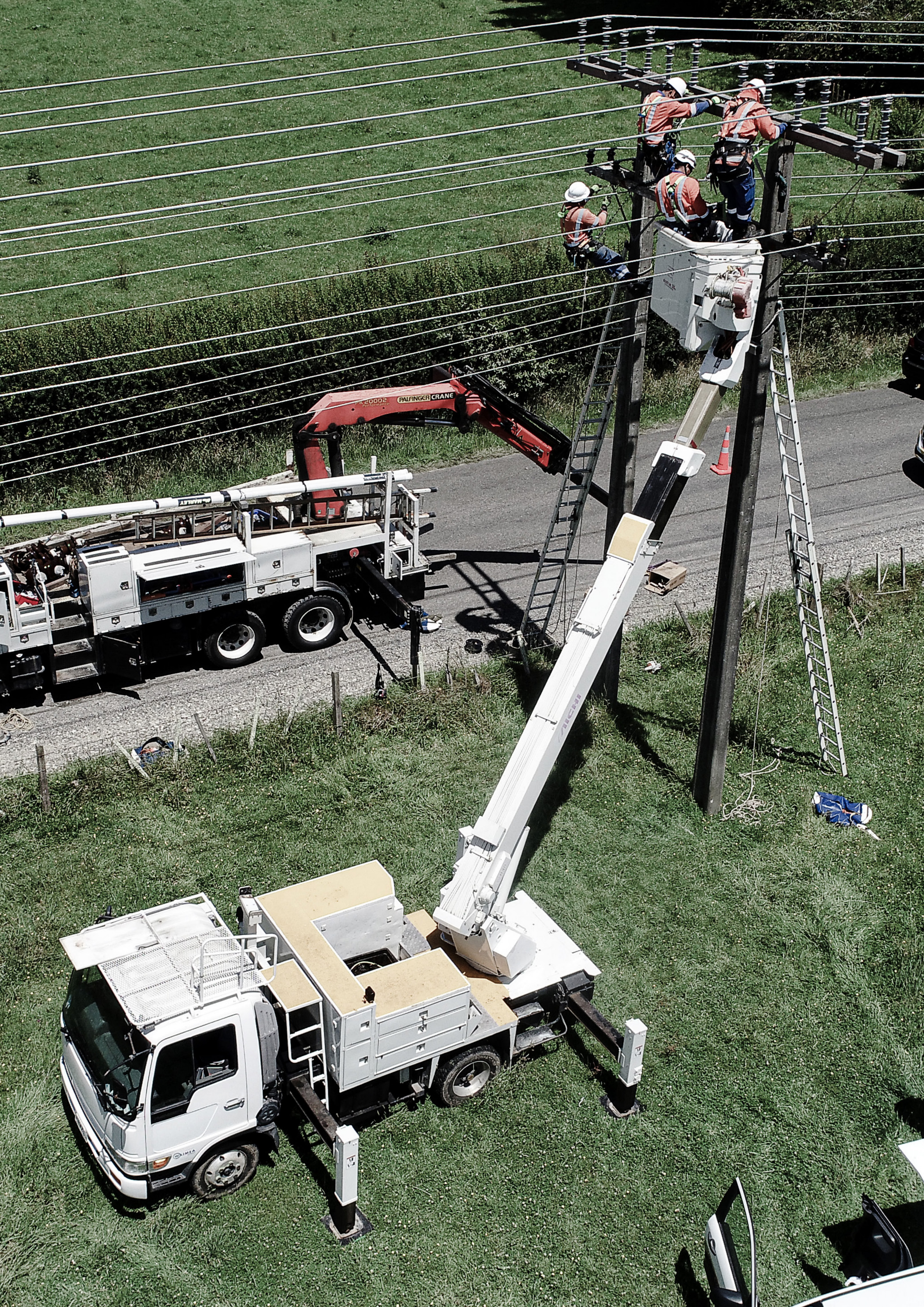
ALWAYS THERE, FOR YOU

# ASSET MANAGEMENT PLAN

2023 - 2033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# LETTER FROM THE CE

It gives me great pleasure to present Electra's Asset Management Plan (AMP) for 2023 to 2033.

Electra has made excellent progress on the delivery of the AMP programme while maintaining customer focus and cost-conscious operation with safety always front of mind.

It has been a year of highs and lows which included celebrating our centenary and hosting the Annual Connection for electricity distribution businesses. However, the lowlights must include Covid-19 is still in the community and three extreme weather events (flooding, tornado and hailstorm) caused widespread outages in our region. Whilst we were relatively unaffected directly by Cyclone Gabrielle, collectively as an industry we will be applying the learnings from this catastrophic event.

The electricity sector is predicted to experience significant growth as New Zealand looks to decarbonise through increased electrification to meet its net zero carbon goals. The Future is Electricity report from BCG[1] has stated 2027 as a turning point where electricity use dramatically increases.

Our energy transformation roadmap, which we developed last year, is well aligned to the solutions outlined in the BCG report. We have been monitoring progress on the transformation, and in response to the pace of change we are seeing we have brought forward some of our intended actions to ensure we are ready for these significant increases in consumption and peak demand. The first few years will be focused on gaining access to consumption information and to develop the management systems like DERMS that will be needed to manage anticipated growth in distributed energy resources.

We are actively contributing to changes in the wider electricity industry by our participation in regulatory change consultations, workshops and studies. This investment of time and resources is necessary so we can promote what is in the best interests of our consumers and be well prepared for change.

We recognise we have a leadership role in promotion of sustainability. The business is building competencies and developing ESG reporting to support greater integration of sustainability into our asset lifecycles and operations.

This AMP includes a material increase in capital expenditure to support decarbonisation, the quality of supply to consumers, and to ensure assets are replaced in a timely manner. In particular, Electra is investing to increase resilience of the network, following the 4R's of robustness, resourcefulness, recovery and redundancy. This resilience also includes preparation for major seismic events through the strengthening of our zone substations and other buildings, and participating in a range of preparedness exercises.

We are also excited about several new projects that include the implementation of ISO 55000, the upgrade of our financial system to Microsoft Business Central, and implementation of the Verosoft TAG enterprise asset management system. The design and implementation of the new ways of working will create planning and operational efficiencies.

We are conscious of the impact the increase in capital expenditure will have on future prices for our customers, and are fully focused on ensuring over the long-term we provide network services that are reliable, sustainable, and affordable. I am confident Electra will safely deliver our asset management plan while preparing us for the exciting challenges of the future.

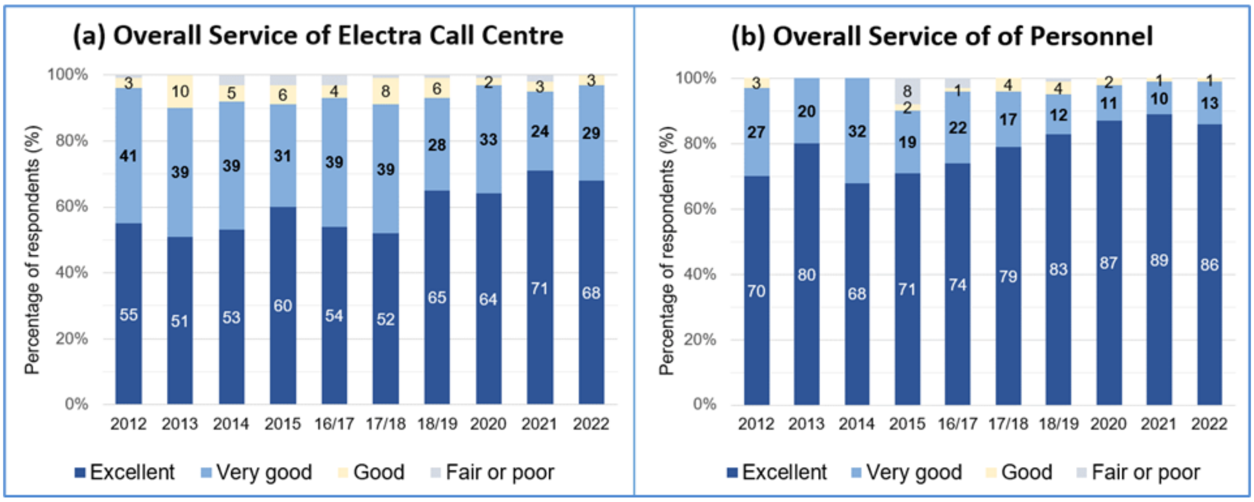
# EXECUTIVE SUMMARY

## STRATEGIC OBJECTIVES

Electra's key strategic objectives are outlined in the following sections, and they provide the direction for setting our asset management strategies and key service levels for our customers and stakeholders.

[1] BCG, *"The Future is Electric: A Decarbonisation Roadmap for New Zealand's Electricity Sector", Oct 2022*

- **Strategic Objective: Focus on Customers**
Our 2022 customer survey has reported both the Call Centre and our service personnel continue to provide very good customer service as shown in the following graphs. This reflects our focus on communication with our customers, investment in outage systems and staff development programme.




Affordability is becoming a key concern to network companies and Electra is working with the Electricity Authority, Commerce Commission, MBIE and electricity retailers in creation of Consumer Care Guidelines to ensure safeguards are in place for vulnerable customers' access to electricity. Electra was one of only four Distributors to participate in the process, as Electra acknowledges customers are key to our decision making.

- **Strategic Objective: 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. A mature safety management system is in place to support attainment of the zero-harm goal set by our Board of Directors. We are pleased to report that that there was only one lost time injury (LTI) in the last financial year, however even one is one too many and we are continually looking for opportunities to improve. This year saw Electra carrying out 952 preventive actions, including 747 proactive safety observations with the remainder made up of safety checks, audits, safety meetings and other safety engagements. This result has been made possible by comprehensive training programme to develop our workforce with increased competencies and career pathways to reflect and promote our values.

- **Strategic Objective: High reliability and cost-conscious operation**
Electra continues to perform well against our peers and based on the last five years' disclosure data, we are in the best performing quartile for planned and unplanned interruptions SAIDI and CAIDI as well as line costs per customer. Our peer group for comparison includes Alpine Energy, Counties Energy, Mainpower, Network Tasman and Northpower. This is based on the Commerce Commission's "Medium Regional" grouping.

Comparison is also made with the overall industry of 29 electricity distributions businesses where we are again best in CAIDI and line cost per customer as well as in the lowest quartile for OPEX per customer, CAPEX per customer, and SAIDI planned/unplanned interuptions. Our analysis concludes the following:

| Measure for period from financial years 2018 to 2022 | Position within peer group | Position within overall industry |
|---|---|---|
| Line charges/costs per customer | Best (lowest) | Best (lowest) |
| OPEX per customer | Second lowest | Within lowest quartile (rank 8th) |
| CAPEX per customer | Second lowest | Within lowest quartile (rank 6th) |
| Planned & unplanned interruptions (Classes B&C SAIDI) | Best (lowest) | Within lowest quartile (rank 5th) |
| Planned & unplanned interruptions (Classes B&C CAIDI) | Best (lowest) | Best (lowest) |

## REGIONAL OUTLOOK

The combination of affordability, location, and government investment in roading in the greater Wellington region is making the Kāpiti and Horowhenua regions attractive places to live, work and play.

Major infrastructure projects such as Waka Kotahi's Wellington Northern Corridor (which includes Transmission Gully and the latest extension of the Kāpiti Expressway of Peka Peka to Ōtaki) continue to stimulate regional growth and create economic opportunities. The halo effect of our proximity to Wellington extends to the Horowhenua district which continues as a strong performer, with most economic indicators outperforming the national average in the year ended 31 December 2021[2].

## MATERIAL PROJECTS

The AMP drives our lines business CAPEX and OPEX expenditure budgets and thereby informs the network pricing process.

When planning and programming material projects we seek to optimise expenditure and delivery of these projects. Timing is key, balancing the programmes for safety, network development, system growth and renewal, customer requirements, reliability and quality.

The significant programmes for the planning period include the following projects:

| Programme | Main Driver | AMP Timing |
|---|---|---|
| **NETWORK PROJECTS** | | |
| Automation of 11kV Ground-mounted switchgear | Quality | FY2024-FY2033 |
| Foxton-Levin West 33kV Bee to Butterfly upgrade | Growth | FY2028-FY2030 |
| Foxton-Shannon Road 11kV upgrade to Bee | Renewal | FY2028-FY2031 |
| Levin East Substation Power Transformer replacement | Renewal | FY2024-FY2025, FY2028-FY2029 |
| Mangahao to Levin East 33kV double-circuit upgrade | Renewal | FY2025-FY2028 |
| New feeder to offload Ōtaki 11kV feeder L351 | Growth | FY2031-FY2032 |
| New substation at Waikawa Beach Road, Manakau | Growth | FY2030-FY2031 |
| New substation for Foxton & Shannon load growth or new GXP | Growth | FY2026-FY2027 |
| Northern Network Protection upgrade | Quality | FY2023-FY2032 |
| Raumati Substation Switchgear upgrade | Renewal | FY2025-FY2026 |
| Seismic Strengthening of zone substation buildings | Legislative | FY2023-FY2028 |
| 11kV feeder upgrade and renewal programme | Renewal | FY2027-FY2032 |
| 11kV link between Hokio Beach and Waitarere Beach | Quality | FY2024-FY2026 |
| Paraparaumu East Power Transformer replacement | Renewal | FY2025-FY2026 |
| Rebuild Raumati zone substation | Renewal | FY2025-FY2026 |
| Network sectionalisation – pole mounted | Quality | FY2024-FY2033 |
| NON-NETWORK PROJECTS | | |
| Huringa Pūngao Energy Transformation Roadmap | | Ongoing |
| Network topology study: Potential for a new GXP | | FY2024 |
| Non-network solutions study: Battery Energy Storage System | | FY2024-FY2026 |

[2] *Economic Monitor for Horowhenua District, Infometrics and Statistics New Zealand*

| Programme | Main Driver | AMP Timing |
|---|---|---|
| **NETWORK PROJECTS** | | |
| Distributed Energy Resource Management System | | FY2024-FY2026 |
| Low voltage data and analysis system(s) | | FY2024-FY2026 |
| Development of DER and DG connections processes | | FY2024-FY2026 |
| ISO 55001: Mahi Tahi Strategic Process Improvement | | FY2024-FY2026 |
| Climate Impact Studies: Refine, develop and implement | | Ongoing |

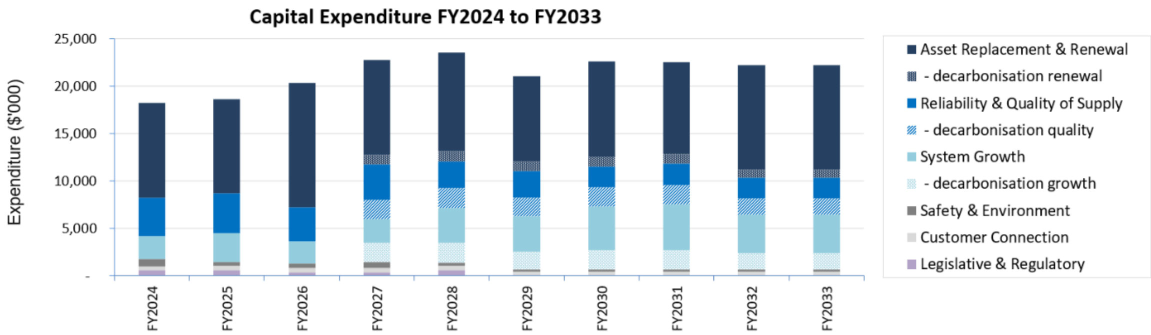
## FORECAST EXPENDITURE

In this AMP horizon we forecast the investment required for growth and reliability will increase significantly. We have been supported in this view by the recent BCG Report which forecasts electricity distribution networks will collectively invest $22 billion, a ~30% increase in spend during the 2026-2030 period.

This increase in investment is due to the impact of increased electrification to meet climate change targets. To highlight this impact we have included decarbonisation impacts in our projected CAPEX and OPEX charts. The three-year period from FY2024 to FY2026 includes a modest increase of $300k per annum to access low voltage consumption information and develop the required Distributed Energy Resource Management (DERMS) and flexibility services systems. This will enable us to better plan and demonstrate the ability to manage increased electrification. From FY2027 onwards, we forecast significant capital investment to meet the expect consumption and peak demands.

Over the whole 10-year AMP horizon projected capital expenditure drivers with the decarbonisation impact are expected to be 52% for renewal and replacement work, 20% for reliability or supply quality, 23% for system growth and 5% for legislative, safety & environmental requirements.

Capital costs (depicted in Figure A) are expected to average $21.4M per year over the next 10 years. The average over the first 3 years is expected to be $19.1M. There is then a lift due to the decarbonisation impacts (primarily growth and reliability drivers) accelerating from FY2027 bringing the expected average of the final seven years to increase to $22.4M. As compared with last year, CAPEX has increased by 39% from an annual average of $15.4M (FY2022 adjusted for inflation) to $21.4M (FY2023) to support the decarbonisation impact as well as our continued asset replacement, renewal and reliability programme.



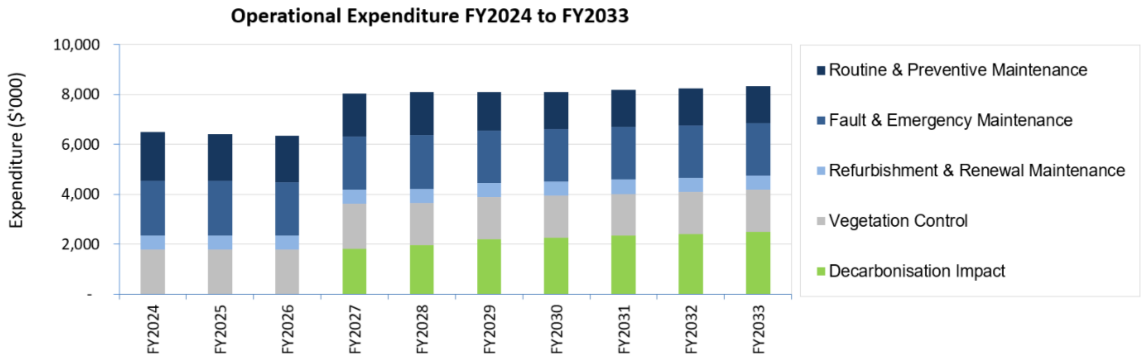

| Capital Expenditure (Current $'000) | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | Average % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Asset Replacement & Renewal | 9,992 | 9,852 | 13,172 | 9,956 | 10,407 | 9,026 | 10,125 | 9,723 | 10,941 | 10,954 | 49% |
| - decarbonisation renewal | - | - | - | 1,029 | 1,065 | 950 | 1,026 | 1,021 | 875 | 876 | 3% |
| Reliability & Quality of Supply | 4,122 | 4,230 | 3,606 | 3,751 | 2,797 | 2,872 | 2,145 | 2,200 | 2,200 | 2,200 | 14% |
| - decarbonisation quality | - | - | - | 2,057 | 2,130 | 1,900 | 2,051 | 2,042 | 1,750 | 1,752 | 6% |
| System Growth | 2,410 | 3,050 | 2,350 | 2,500 | 3,679 | 3,742 | 4,578 | 4,850 | 4,000 | 4,000 | 16% |
| - decarbonisation growth | - | - | - | 2,057 | 2,130 | 1,900 | 2,051 | 2,042 | 1,750 | 1,752 | 6% |
| Safety & Environment | 755 | 422 | 422 | 629 | 308 | 233 | 233 | 233 | 233 | 233 | 2% |
| Customer Connection | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 2% |
| Legislative & Regulatory | 559 | 610 | 400 | 350 | 600 | - | - | - | - | - | 1% |
| **Total (CAPEX) :** | **18,280** | **18,607** | **20,394** | **22,773** | **23,558** | **21,065** | **22,652** | **22,554** | **22,194** | **22,211** | **100%** |
| *Total Decarbonisation Impact* | - | - | - | 5,143 | 5,325 | 4,749 | 5,128 | 5,106 | 4,376 | 4,380 | 16% |

**Figure A: Projected Capital Expenditure from FY2024 to FY2033**

[3] *BCG, "The Future is Electric: A Decarbonisation Roadmap for New Zealand's Electricity Sector", Oct 2022*

Operational costs (depicted in Figure B) are expected to average $7.86m per year over the next 10 years with a similar increase in the final seven years of the period due to capacity reinforcement and reactive maintenance especially on the LV network due to system growth expected due to decarbonisation.

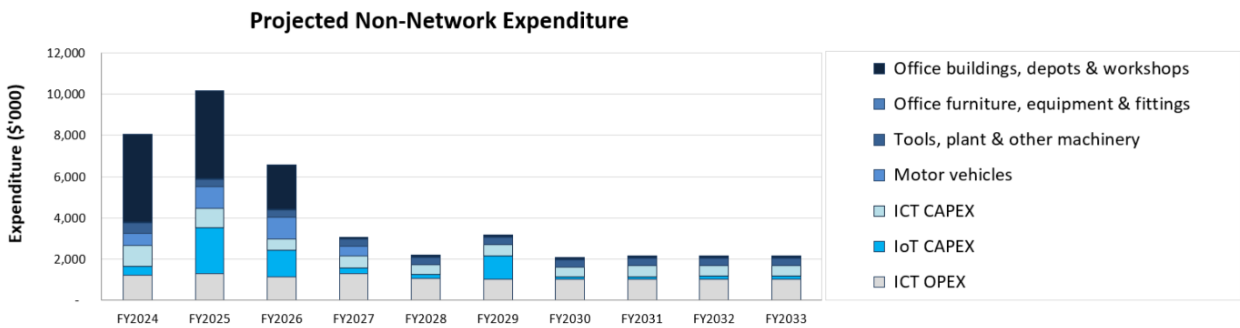
Electra has the flexibility to adjust this investment if growth accelerates beyond our expectations or if growth is delayed. The expenditure forecasts are based on 2023 constant New Zealand dollars.




| Operations & Maintenance (Current $'000) | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | *Average %* |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Routine & Preventive Maintenance | 1,969 | 1,859 | 1,859 | 1,725 | 1,725 | 1,545 | 1,484 | 1,484 | 1,484 | 1,484 | *22%* |
| Fault & Emergency Maintenance | 2,186 | 2,199 | 2,142 | 2,142 | 2,142 | 2,108 | 2,108 | 2,108 | 2,108 | 2,108 | *28%* |
| Refurbishment & Renewal Maintenance | 565 | 565 | 565 | 565 | 565 | 565 | 565 | 565 | 565 | 565 | *7%* |
| Vegetation Control | 1,784 | 1,784 | 1,784 | 1,784 | 1,684 | 1,684 | 1,684 | 1,684 | 1,684 | 1,684 | *23%* |
| Decarbonisation Impact | - | - | - | 1,820 | 1,971 | 2,189 | 2,253 | 2,334 | 2,416 | 2,498 | *20%* |
| **Total (OPEX) :** | **6,504** | **6,407** | **6,350** | **8,035** | **8,087** | **8,092** | **8,095** | **8,176** | **8,258** | **8,340** | ***100%*** |
| Annual Decarbonisation Impact % | 0% | 0% | 0% | 23% | 24% | 27% | 28% | 29% | 29% | 30% | |

**Figure B: Projected OPEX from FY2024 to FY2033**

Provision has been made in the Non-Network Expenditure (Figure C) in the period FY2024 to FY2026 for the purchase of land and constructing a suitable building to replace a long-term leased building depot in the northern region. This was recently assessed as not meeting our expected standard of greater then 67% of NBS for existing buildings where we work. Provision has also been made in the period FY2024 to FY2026 to replace heavy duty trucks in accordance with the company policy. Electra favours the purchase of electric vehicles, including trucks, for fleet renewal.




| Non-Network Capital Expenditure ($'000) | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | *Average %* |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Office buildings, depots & workshops | 4,245 | 4,235 | 2,130 | 80 | 85 | 80 | 80 | 80 | 80 | 80 | *27%* |
| Office furniture, equipment & fittings | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | *1%* |
| Tools, plant & other machinery | 520 | 350 | 350 | 350 | 350 | 350 | 350 | 350 | 350 | 350 | *9%* |
| Motor vehicles | 600 | 1,067 | 1,067 | 467 | - | - | - | - | - | - | *8%* |
| ICT CAPEX | 995 | 935 | 560 | 560 | 475 | 575 | 475 | 560 | 525 | 525 | *15%* |
| IoT CAPEX | 435 | 2,235 | 1,285 | 285 | 205 | 1,135 | 135 | 135 | 175 | 175 | *15%* |
| ICT OPEX | 1,228 | 1,288 | 1,138 | 1,298 | 1,060 | 1,010 | 1,010 | 1,010 | 1,010 | 1,010 | *26%* |
| **Total Capital Expenditure** | **8,047** | **10,134** | **6,554** | **3,064** | **2,200** | **3,175** | **2,075** | **2,160** | **2,165** | **2,165** | ***100%*** |

**Figure C: Projected Non-Network from FY2024 to FY2033**

Electra's comprehensive AMP 2023-2033 is important and your feedback is welcomed. Our Chief Operating Officer of the Lines Business and I would be happy to hear from you.

Kind regards
**Neil Simmonds**
Chief Executive

## Distributed Generation

**51%**

increase in DG connections in last 12 months

**74%**

increase in DG capacity in last 12 months

**59%**

increase in DG applications in last 12 months

## Net energy consumption

2021
421 GWh

2022
425 GWh

2033
forecast
524 GWh

## Electric Vehicles

**70%**

increase in EVs in our region in last 12 months

## ICPs

2021
45,562

2022
45,940

**2033**
**forecast**
**54,700**

## Peak Demand

2021
104 MW

2022
111 MW

**2033 forecast**
**166 MW*1**
**132 MW*2**

*1 = if uncontrolled

*2 = if controlled by demand response

# 2021

| Small scale DG connections | Small scale DG capacity | EVs in our region | EV charging requirements | ICPs | Net energy consumption | Peak demand |
|---|---|---|---|---|---|---|
| 691 | 2.72 MW | 460 | 1,162 MWh | 45,562 | 421 GWh | 104 MW |

# 2022

| Small scale DG connections | Small scale DG capacity | EVs in our region | EV charging requirements | ICPs | Net energy consumption | Peak demand |
|---|---|---|---|---|---|---|
| 1,048 | 5.02 MW | 790 | 1,580 MWh | 45,940 | 425 GWh | 111 MW |

# 2033

| Small scale DG connections | Small scale DG capacity | EVs in our region | EV charging requirements | ICPs | Net energy consumption | Peak demand |
|---|---|---|---|---|---|---|
| 5,300 | 26.5 MW | 23,400 | 63,200 MWh | 54,700 | 524 GWh | 132-166 MW |

# 1 INTRODUCTION

## 1.1 Asset Management Plan Overview

With this AMP it is a timely opportunity for us to set out the context of our current situation and thinking on climate change preparation, decarbonisation and the transition to a net zero economy.

We accept and embrace the widely held belief that EDBs will play a key enabling role in decarbonisation through increased electrification. Whilst the impacts on our network are low at present, the rapid uptake and onset of change will become the most significant change for our network in generations. We are well positioned to embrace this change and will take the first few years of this AMP horizon preparing our systems, processes, and skillsets ready for when the significant impact is felt.

> ***"Decarbonising the NZ economy is a top societal priority"***
>
> *Commerce Commission Nov 2022*

The New Zealand Government recently published their Emissions Reduction Plan, setting out how Aotearoa New Zealand will reduce our impact on the climate. The plan puts Aotearoa New Zealand on a path to achieve our long-term targets and contribute to the global efforts to limit temperature rise to 1.5˚C above pre-industrial levels. It includes the commitment to reach net zero emissions of long-lived greenhouse gases by 2050. These international targets were agreed under the Paris Agreement which was ratified by Aotearoa New Zealand in 2016.

In order to meet these targets, the Government is focusing on emission sources that can be readily addressed by the electricity sector (Figure A). For our context the impactful sectors we are watching closely are the light/medium transport fleet, low/medium temperature process heat, and space/water heating.

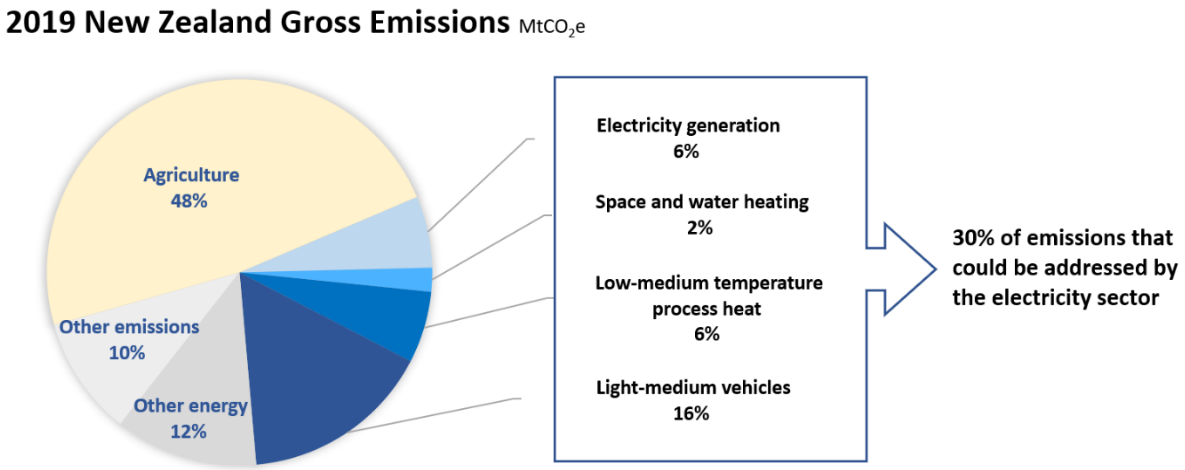



*Figure A: Gross emissions New Zealand 2019*

Land transport accounts for about 50% of our greenhouse gas emissions with light vehicle accounting for two-thirds of that figure. In February 2022 the Clean Car Discount was introduced to make it more affordable to buy low CO2 emissions vehicles through a rebate scheme. This has significantly accelerated the uptake of electric vehicles.

> ***"Electrification is at the heart of decarbonisation"***
>
> *Commerce Commission Nov 2022*

With process heat the government expanded the co-funding available through the Government Investment in Decarbonising Industry. The purpose of the fund is to accelerate business decarbonisation to support emissions reduction goals, easing the transition on New Zealand businesses. The projects supported by this funding typically co-fund the transition of low to medium process heat from coal, oil and gas to electricity or biomass. At Electra we are starting to see the initiation of these projects.

With our peers and industry partners it has also been with interest we have seen their journey and the emerging roadmaps and scenarios they envisage.

[4] Climate Change Commission: Ināia tonu nei: a low emissions future for Aotearoa, May 2021

Transpower continue to provide industry with monitoring reports supplementing their influential Whakamana i Te Mauri Hiko report from 2020.

An independent report published by Boston Consulting Group was published in October 2022 setting out a whole-of-sector view and a credible pathway to achieving New Zealand's decarbonisation goals. In particular this report highlighted the increased investment required by distribution networks that they estimate as a 30% increase in total expenditure in 2026-30 relative to 2021-25.

Flexforum, part of the energy industry organisation Ara Ake, produced a roadmap in August 2022 titled Flexibility Plan 1.0. The plan sets out "initial practical, scalable and least-regrets steps to unlock the value of distributed energy resources and flexibility for households, businesses, community, the powers system and Aotearoa New Zealand".

The ENA commissioned Sapere to consider what total annual average household energy costs will be through to 2040. Their findings, reported in November 2022, concluded that "from 2026 all electric households can expect total annual electricity costs, including the capital costs to switch, to be lower that the combined petrol, gas and electricity bills they would otherwise pay".

In 2021 Electra commissioned and completed Huringa Pūngao, our Energy Transformation Roadmap. This report provided Electra with the framework and pathways to guide us through the uncertainty around decarbonisation and increased electrification (see Section 4.6). In November 2022 we completed an update to this report to ensure that we continue to actively monitor and understand local, national and international developments and that we continue to prepare and build our capabilities. Our work is closely aligned and influenced by the above, giving us confidence that we are on the right path in this transition.

### 1.1.1 Challenges, areas and dimensions of uncertainty

It is also a useful opportunity to set out the challenges, areas and dimensions of uncertainty that Electra, and the whole electrical industry sector, face. Planning functions just a decade or two ago were able to look in the rear-view mirror and provide good levels of confidence of future network volumes (MWh) and peak demand (MW). We now face greater uncertainty about the expectations of our network and some of these uncertainties are highlighted as follows:

- **Electric Vehicles**
  There are uncertainties around the quantity of EV uptake, timings of uptake, charging behaviour, locations, scale and types of chargers, and the degree of control that EDBs will have. We recognise this will inevitably entail a blend and variety of all of these.

- **Solar and Battery Storage**
  We continue to see applications for solar both at a small-scale residential level and for a wide range of larger-scale commercial ventures. These are increasingly being specified with battery storage. There is still considerable potential for growth in this area. The nature of these technologies can be both a benefit and a challenge for our network. This is another area where the degree of control an EDB has of these technologies and the emerging behaviours in their use, provides considerable uncertainty.

- **Residential conversion/withdrawal of reticulated gas**
  The drive to decarbonise may lead to voluntary or involuntary withdrawal of gas for domestic purposes. In other counties they are investigating the potential of green hydrogen to blend or replace natural gas. The natural alternative is electric heat pumps for heating and hot water adding to network volume (MWh) and peak demand (MW).

- **Industrial heat**
  We are already seeing businesses either making or preparing for a transition away from coal, oil and gas. These represent significant volumes of load and have the potential to increase our peak demand.

- **Electrification of rail**
  The rail network runs from Palmerston North to Wellington through our network. The southern section from Waikanae south is electrified for passenger rolling stock. There is potential for the remaining sections to be electrified for passenger stock. There is further potential for freight through the whole of the network.

- **Infill development and change of land use**
  National, regional and local planning changes for new developments, zoning and increased housing density impact network volume (MWh) and peak demand (MW).

[5] *Energy Efficiency and Conservation Authority, "Supercharging decarbonisation & transforming the energy system", May 2022* [6] *Transpower Ltd, "Whakamana i Te Mauri Hiko monitoring report", October 2022* [7] *Transpower Ltd, "Whakamana i Te Mauri Hiko", March 2020* [8] *BCG, "The Future is Electric: A Decarbonisation Roadmap for New Zealand's Electricity Sector", Oct 2022* [9] *Ara Ake, "Flexibility Plan 1.0", August 2022* [10] *Sapere, "Total household energy cost to reduce over time". November 2022*

## 1.1.2 Regional Development

With the recent completion of Transmission Gully and the likely future Ōtaki to Levin extension of the Kāpiti Expressway, our regions will continue to see significant growth and development.

Some of the above issues are really challenging our thinking around our planning assumptions for after diversity maximum demand (ADMD) and will require a range rather than a one-size fits all approach.

> *"Pace of change is faster than widely anticipated"*

The common theme with the above issues is "step change", typically through Government incentives or changes to legislation. These step changes can also occur through new technology and also new behaviour in their use. Past behaviour is not necessarily representative of future behaviour in this changing world.

It's all in the timing! It is apparent the pace of change, particularly with uptake of EVs, is happening more quickly than widely anticipated. The timing of all these changes makes a difference in our response and preparation.

At a GXP level, this growth will almost certainly appear linear and in the first few years many be marginal to detect. However, as we move down through the voltage levels, we expected to see pockets of demand appearing in urban areas. This demand will be less predictable and more sporadic requiring tactical investments.

Some final points that are worth noting are that in the last 12 months we have seen considerable cost pressure across equipment, cost escalation on materials, labour rates and access to capable personnel. Lead times on new equipment we would have once thought of as extraordinary is now ordinary.

## 1.1.3 Our preparation and solutions

Having set the scene in which this AMP has been developed and also having set out the challenges, areas and dimensions of uncertainty, we put forward our response and solutions to these.

It is also vital to note that at Electra we feel well prepared and well placed for the challenge ahead. We have mature, well-developed systems and processes, and skilled people who are passionate about keeping the lights on.

## 1.1.4 Forecasting and understanding the future

In order to understand what we need to do, we need to have a good understanding of what we believe the impact will be on our network and when.

Huringa Pūngao, our Energy Transformation Roadmap, provided a step change in our forecasting, planning and understanding of the challenge ahead. We developed a sophisticated and forward-looking demand forecasting model and are now able to make more informed projections of future demand and consumption.

> *"Within this 10 year AMP horizon we will see significant increased demand in peaks and volume"*

An update in December 2022 included a reforecast using data from our preceding summer and winter peaks together with latest national, regional and local data from a wide range of datasets. We will continue to build on these foundations in the coming years, refining our assumptions based on our observation of the energy transition, increasing our inputs and developing our solutions.

This new approach to our forecasting is a major development and departure from past methodologies. It is complex, probabilistic and takes a wide range of inputs including new EV sales, industrial processes and heating, solar PV uptake and battery storage. This creates a range of scenarios and we then test these scenarios against our network topology and configuration identifying constraints (details in Section 4.6).

- **Our tool kit**
  Having understood where and when network constraints are likely to appear we can then consider solutions. We look at a range of options which includes:

  - managing the risk
  - network reconfiguration
  - uprating existing assets
  - installing new network assets
  - installing network owned battery storage or voltage management
  - seeking flexibility solutions from industry partners

We have at our disposal a wider range of solutions than in the past. One size will not fit all. And we evaluate the options seeking the most suitable solution available to us at that time.

Our investments will be strategic and tactical, using a least regrets approach to delivering solutions just ahead of time.

> ***"Innovation/flexible non-network solutions are likely at the heart of efficient provision of electicity lines services"***
>
> *Commerce Commission Nov 2022*

With this in mind there are two projects we would like to take the opportunity to highlight:

- **Grid Exit Point (GXP)**
  The Electra network is supplied from the Transpower national transmission grid at Mangahao in the Northeast and from Paraparaumu in the South. As detailed in Section 4.8, the Paraparaumu GXP provides our southern network with n-1 security yet the northern network relies on embedded generation at Mangahao during certain network conditions to maintain n-1 security.

  Our forecasting and modelling show that we have thermal or voltage constraints at Waikanae and Ōtaki. In addition, the technical losses on our northern network are inherently high as the point of supply and the major load bases are many kilometres apart.

  In the coming twelve months we will study the engineering, security of supply and economic cases available to us to ensure that the foundations of our northern network continue to provide us with the resilience and cost efficiency we seek.

- **Battery Energy Storage System (BESS)**
  We recognise that a portable distribution scale BESS would be a valuable addition to add to our tool kit in the coming years. The $/MWh has fallen significantly and there are now a range of manufacturers and suppliers offering these products. We have watched our industry peers closely both nationally and internationally and can see the ability to despatch this equipment at relatively short notice and the benefits of investment deferral are worth understanding more fully.

  Their scalability appears to be cost effective for 11kV constraints and more so at higher network levels, where network solutions are more expensive, are often more complex and have long implementation timeframes.

  They offer speed of response to support transient, short term network demand and disturbances as well as offering grid reserves for emergency shortfalls and seasonal load management. They also help improve resilience in load situations exceeding n-1 criteria.

  With their own local control systems, they can be set to operate independently, though may also be integrated into a Distributed Energy Resource Management System (DERMS).

  Multiple installs across the network can be operated in concert to mitigate not only local but also cost effectively mitigate larger regional constraints deferring larger capital cost, large capacity investments.

  We have begun our journey and will continue to develop our understanding over the next twelve months.

### 1.1.5 Major Initiatives

Some other major initiatives we would also like to highlight are:

- **Climate Impact Studies**
  In 2022 we undertook the first of our Climate Impact Studies: A Flood Risk Analysis of Electra's Assets. We recognise that our area is prone to severe rainfall due to the impact of climate change which can cause major damage to Electra's assets. Due to these events increasing in magnitude and frequency we decided to undergo a flood risk assessment of our assets to identify assets that are at increased risk due to flooding in the future.

  Datasets were kindly provided by Kāpiti Coast District Council (KCDC) and Horizons Regional Council (HRC) for the Horowhenua District. These datasets were layered into our Geospatial Information System (GIS) providing a detailed view of our at-risk assets. Further details can be found at Section 7.2.5.

  Over the next twelve months we will build on this foundation and seek to use these findings within our engineering standards, planning and asset management framework.

- **ISO 55001 alignment**
  We continue our journey on asset management maturity to assure the safety and reliability of our services and the needs of the business and stakeholders continue to be met at lowest cost. We have commenced a development roadmap to align our asset management system with the requirements of ISO 55001. Further details can be found at Section 8.6.

- **The Asset Guardian (TAG)**
  The Asset Guardian is an integrated element of our core financial and accounting management system. TAG is an enterprise asset management system and will become the core source of asset information within Electra. Go live for this system is proposed during FY24. Further details can be found at Section 8.7.

- **Condition based asset risk management model (CBARMM)**
  We have been applying a condition-based asset risk management model to our network assets for a number of years now. This is a journey and we continue to develop the inputs and parameters to evaluate the health of an asset addressing the consequence of failure with criticality. Further details can be found at Section 5.1.1.

- **Updating our overhead line standards**
  With the impact of decarbonisation, we are reviewing our overhead lines standards and processes, to ensure the capacity and voltage of our existing lines are systematically monitored with quality monitors, and line renewal and refurbishment programmed into our work plan.

- **Preparing our connections standards and processes**
  Following the Flexforum roadmap we will be reviewing and improving our connections processes, engineering standards and analysis tools ready for the step change we anticipate. This will allow us to ensure efficient assessment and connection of new demand and distributed energy resources.

- **HV monitoring**
  We have installed power quality monitors on the 11kV bus of each of our zone substations. For larger generation connections these devices will provide us with the harmonic assessment data we require to connect new generation without breaching harmonic planning levels.

- **LV monitoring**
  Over the last few years, we have been trialling a few different types of low voltage power quality monitors for installation at both ground and pole mounted distribution transformers. This journey will continue and will provide us not only with valuable data for use in asset management but also for effectively understanding available capacity and harmonic headroom (allowing increased DER penetration). Further details can be found at Section 4.12.

- **LV data analysis and smart meter data**
  To ensure we understand the complex multi-directional power flow already happening, we are undertaking a review of the systems available and will be selecting and implementing a suitable system(s). Using our network topology data, LV power quality data and smart meter data (subject to availability and commercial arrangements) this analysis

system(s) will provide vital insight and understanding of headroom for demand and generation connections. Further details can be found at Section 4.10.

- **Network automation and reliability**
  In 2021 we installed and commissioned our most recent automated 11kV switchgear at Golf Road in Paraparaumu, providing a scripted response in the event of a fault, thereby increasing the reliability of that section of our network. We continue to seek cost-effective opportunities for similar solutions. Further details can be found at Section 4.11.

- **Exploring new ICT systems**
  We will be reviewing our ADMS and SCADA solutions with emerging Distributed Energy Resource Management System (DERMS) and/or DSO influencers in FY2024, to implement a secure solution which will consolidate SCADA, DERMS and Outage Management functions. Further details can be found at Section 8.8. We are partnering with the Electricity Engineer's Association to conduct a trial of implementing OpenADR (automatic demand response) for managing the demand of domestic EV charging in the future. Other details can be found at Section 6.2.3.

We continue to engage widely across the energy and electricity sector to ensure we are taking the most cost effective, least regret, just in time steps to ensure a successful energy transition within our network.

## 1.2 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 Commerce Commission's Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022 together with the recent targeted Information Disclosure review. 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, safety and systemic risk mitigation.

## 1.3 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 1.5 contains the details of other documents and the relationship between these key documents.

### 1.3.1 Mission and vision

Electra's Statement of Corporate Intent (SCI) identifies the Group's vision and mission as "***to enhance the Horowhenua/ Kāpiti 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.

### 1.3.2 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.

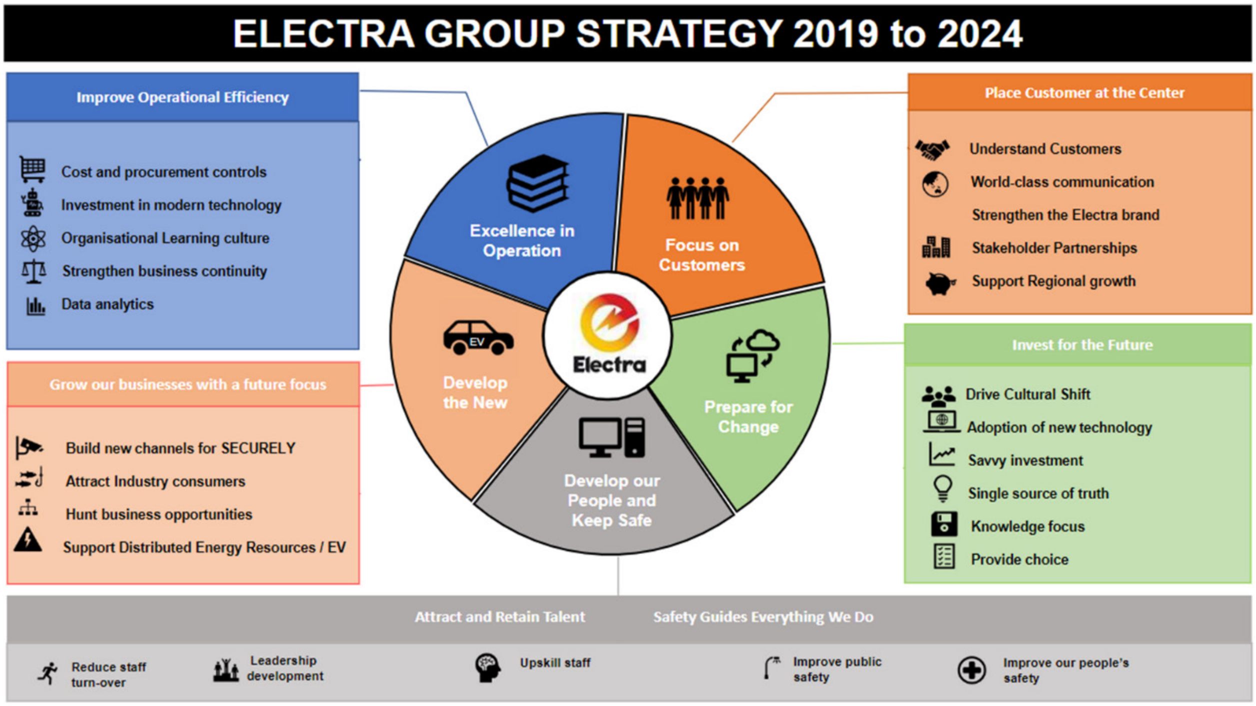



**Figure 1-1: Electra Group strategic model for FY2019 to FY2024**

## 1.3.3 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.

## 1.3.4 Pricing methodology

Electra's pricing methodology is to progressively introduce and refine service-oriented and cost-reflective pricing to recover the economic costs of the network and to be responsive to the evolving market and the changing ways customers are using the network. The near-term focus is to establish new pricing structures to manage the uptake of EVs and DER to ensure efficient cost signals to key customer groups going forward. The adoption of time of use (ToU) pricing is a key step in this strategy.

The Pricing Methodology has been reviewed against the relevant regulatory requirements such as the Electricity Authority's Pricing Principles, the Electricity (Low Fixed Charges Price Options for Domestic Customers and the recent changes to the Transmission Pricing Methodology (TPM) effective 1 April 2023. Further details are available on Electra's website.

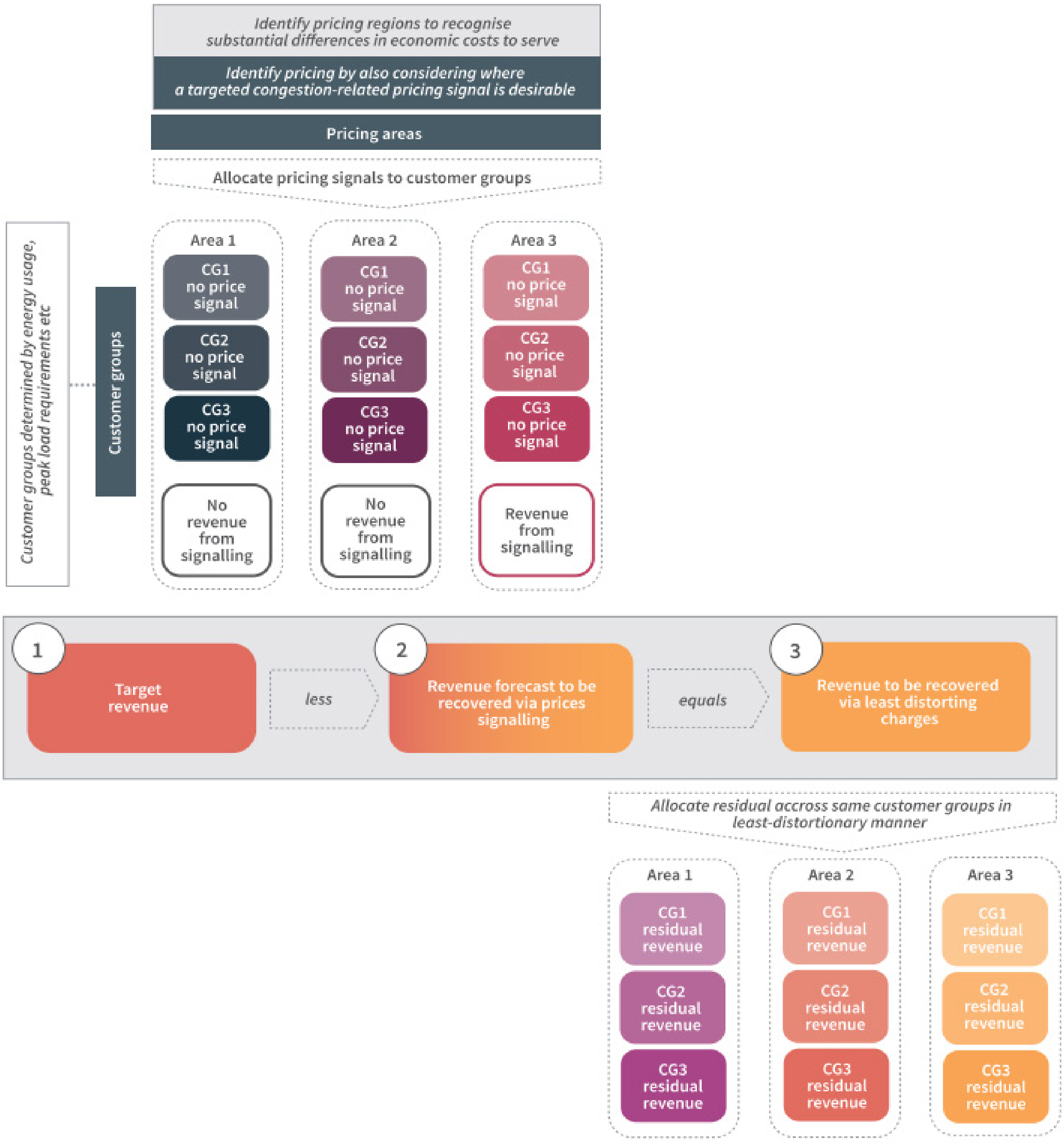



**Figure 1-2: FY2022 Cost-reflective price-setting methodology**

# 1.4 Asset management system

## 1.4.1 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, 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
- Adapt existing governance and risk practices to ensure that climate change opportunities and decarbonisation objectives

- Consider the impact of our business on sustainability elements of social, economic, environmental and cultural, and find a reasonable balance between conflicting demands
- Monitor standards and service levels to ensure 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.

### 1.4.2 **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 1.3.2 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 efficient-costed network | • Development an implementation programme with industry leader<br>• Continued development of asset risk models based on OFGEM<br>• Develop targeted improvements in asset management<br>• Implementing further switching, sensors and data/operational analysis<br>• Continued deployment of protection systems, seismic protection and business continuity<br>• 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<br>• Deliver a competency programme for all staff<br>• Leaders need to foster and demonstrate positive behaviours<br>• The standard that you walk by is the standard you expect<br>• Deploy lone worker devices<br>• Site visits need to have a vision, purpose, and outcome<br>• 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<br>• Advertising campaigns<br>• Proactive in engagement with movers and shakers<br>• Website promotes focus on growth<br>• Better promotion for brand recognition<br>• 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<br>• Demonstrating environmental responsibility initiatives for workspace and work site<br>• Invite and select local artist's/school murals on transformers<br>• Greater engagement with our communities<br>• Refresh website/social media to reflect what customers want/do<br>• Improved communication of planned work, fault restoration and great customer service<br>• Delivery of targeted media campaigns<br>• 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 (DER) | • Create flexibility services and solutions using DERs and Energy Transformation strategy<br>• Implement sustainability, climate change and decarbonisation initiatives<br>• Ensure network is fit for purpose in extreme weather situations<br>• Provide platform for cost reflective pricing<br>• Adopt flexible working and focus on outcomes rather than function<br>• Implement a strategy of improving valued data sets<br>• Improve digital systems that include EAM, ADMS and job management<br>• Improve management systems for controlled documents (EDMS)<br>• 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.

## 1.5 Asset management framework

Electra is implementing an asset management framework (Figure 1-5) which includes the elements within ISO 55001 . 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
- Targeted investments to improve the network resilience to face the challenges of climate change and emerging technologies
- 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).

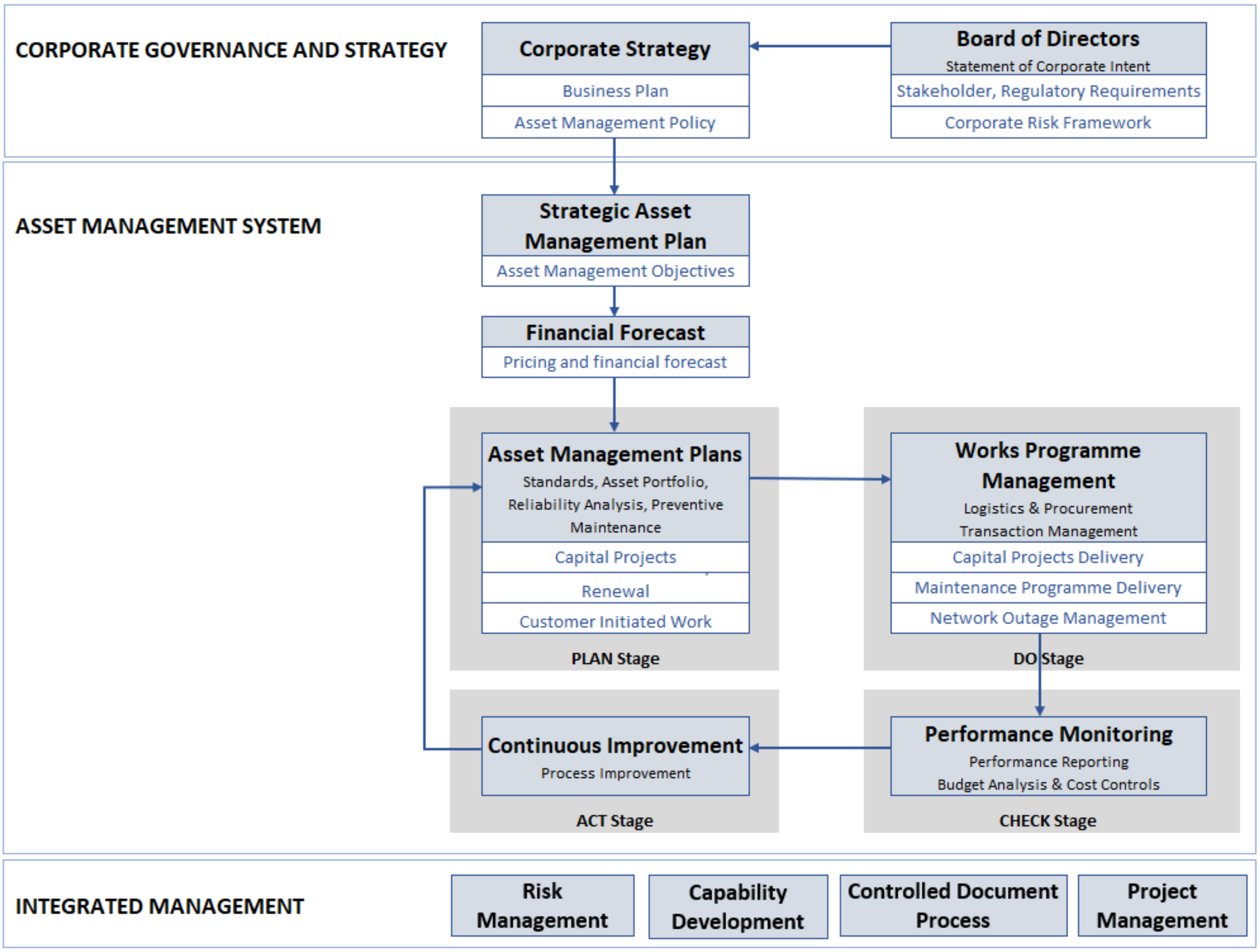



**Figure 1-4: Asset Management Framework**

### 1.5.1 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. |

| Document title | Purpose |
|---|---|
| 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. |

## 1.5.2 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.

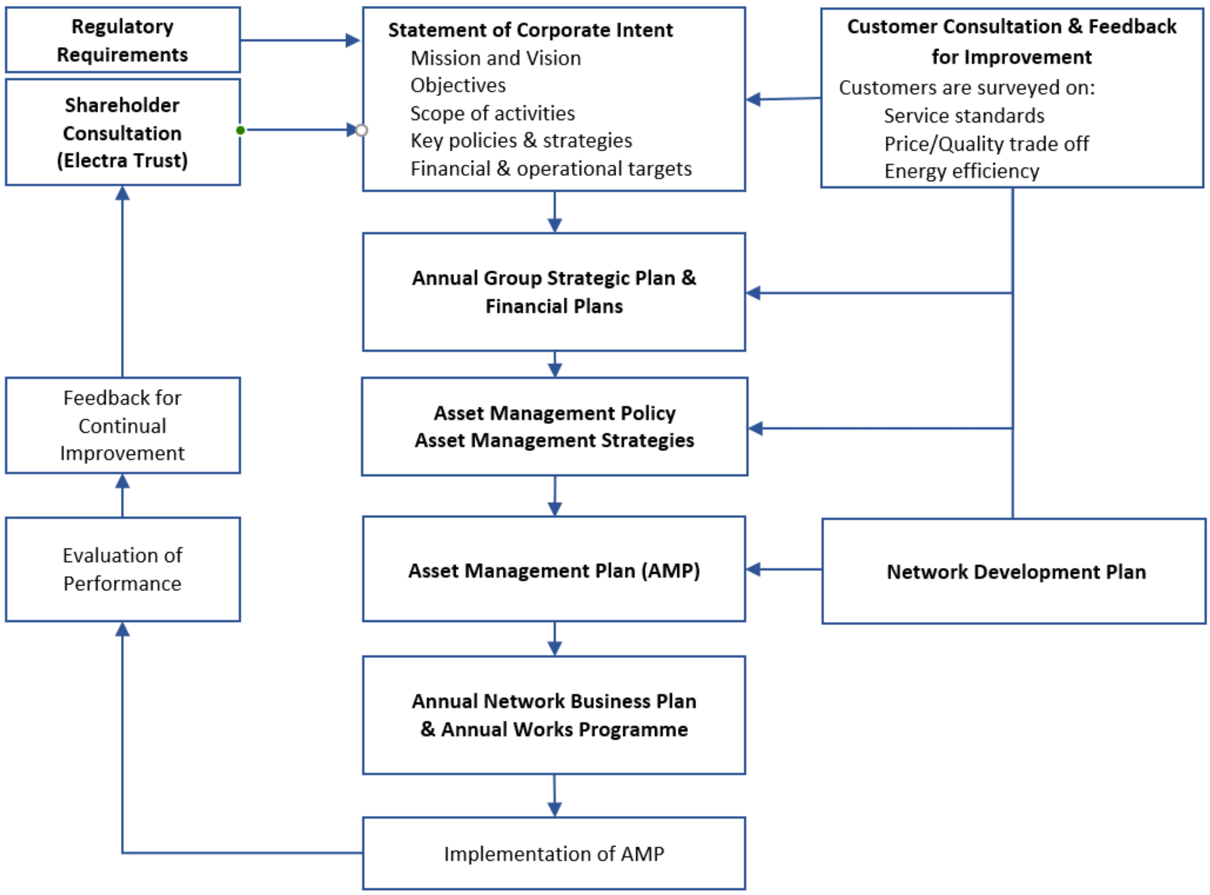



**Figure 1-5: Asset Management Document Links**

## 1.5.3 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.

## 1.6 Planning period

The planning period for this AMP is 1 April 2023 to 31 March 2033. The AMP embodies three levels of increasing certainty for nearer term plans:

| Period | Scope | Cost |
|---|---|---|
| 1 April 2023 – 31 March 2024 | Firm, approved in principle | ±5% |
| 1 April 2024 – 31 March 2029 | Major components | ±10% |
| 1 April 2029 – 31 March 2033 | Indicative | ±25% |

## 1.7 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 by 31 March 2023.

## 1.8 Stakeholder interests

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

### 1.8.1 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. We have included climate change as a new "primary interest" to reflect its importance to New Zealand and the electricity industry:

| Stakeholder | Key stakeholder primary interests | | | | | How those interests are identified |
|---|---|---|---|---|---|---|
| | Viability | Supply quality | Safety | Compli-ance | Climate change | |
| Electra Trust | √ | √ | √ | | | • Statement of Corporate Intent<br>• Quarterly briefings<br>• Discussions with the Board and Chief Executive |
| Bankers | √ | | | | √ | • Terms and conditions of financing arrangements<br>• Quarterly meetings<br>• General negotiations |
| Connected customers | √ | √ | √ | | | • Phone, email, facebook and in person<br>• Questions and comments at AGM<br>• Customer survey responses<br>• Trustee and Community feedback<br>• Electra sponsored business events |

| Stakeholder | Key stakeholder primary interests | | | | | How those interests are identified |
|---|---|---|---|---|---|---|
| | Viability | Supply quality | Safety | Compli-ance | Climate change | |
| Energy retailers | √ | √ | | | | • Negotiation of terms and conditions<br>• Pricing consultation<br>• Regular meetings<br>• Informal communication<br>• Resolution of billing disputes |
| Mass-market representative groups | √ | √ | | | | • Electra AGM<br>• Feedback from interest groups.<br>• Electricity Networks Association (ENA) focus groups |
| Industry representative groups | √ | √ | | | | • Annually via meetings and conferences |
| Staff and contractors | √ | √ | √ | √ | | • Regular staff meeting<br>• Regular contractor meetings<br>• General workplace interactions<br>• Performance appraisals |
| Suppliers of goods and services | √ | | | | | • General interactions during service deliveries<br>• Price and volume negotiations |
| Public (as distinct from customers) | | | √ | | | • As required via 0800 phone number and website enquiry section<br>• General interactions |
| Landowners | | | √ | √ | | • As required for specific projects |
| Councils | | | √ | √ | √ | • Monthly Emergency Management meeting<br>• Annual planning disclosure<br>• As required for specific projects<br>• During and after drills and actual events |
| Waka Kotahi | | | √ | √ | | • Reading of bulletins<br>• Meetings to discuss specific projects |
| Ministry of Business Innovation and Employment | | | √ | √ | √ | • Reading of bulletins<br>• Attending seminars<br>• Responding to consultations |
| Energy Safety Service | | | √ | √ | | • Reading of bulletins<br>• general interaction around safety requirements<br>• Incident investigations |
| Commerce Commission | √ | √ | | √ | √ | • Reading bulletins and determinations<br>• Attending seminars and workshops<br>• Complying with determinations and disclosure requirements |
| Electricity Authority | | | | √ | √ | • Reading bulletins and determinations<br>• Attending seminars and workshops<br>• Complying with Code requirements |
| Utilities Disputes | | √ | | √ | | • Reading bulletins, responding to complaint investigations |
| Ministry of Consumer Affairs | | √ | | √ | | • Reading bulletins<br>• Responding to complaint investigations |
| Transpower | √ | √ | √ | √ | √ | • Quarterly updates<br>• Annual planning meetings<br>• General interactions about grid connections<br>• Discussions about specific grid connection issues such as price and capacity |

### 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. Underground assets are laid following standard depths and appropriately marked.<br><br>Electra's Safety Management System (SMS) provides a structured approach to maintaining public safety<br><br>Electra maintains safety of the staff and contractors by providing all necessary equipment, improving safe work practices, and stopping work in unsafe conditions<br><br>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 2022) 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<br><br>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<br><br>Electra discloses performance information in a timely and compliant fashion. |

## 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.

# 1.9 Climate change and decarbonisation

Electra has heard the urgency of the He Pou a Rangi Climate Change Commission's advice to the Government[3], that strong and decisive action is required to meet Aotearoa New Zealand's emission reduction targets. We have commenced a structured body of work that will include systematic identification, quantification and mitigation of the expected risks of both the changing climate and the changing regulatory and policy environments.

Electra has adopted a Climate Resilience Framework and adapted its existing governance and risk practices to ensure climate opportunities and risks are systematically identified, quantified and mitigated within Electra's existing framework of strategies, asset management plans and business plans. We have strategically aligned our governance, strategy and risk activities with the Task Force on Climate-related Financial Disclosures (TCFD) framework. Further details are included in Section 7.2.3.

[11] *www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/*

Our climate resilience framework sets out how we expect to amend our governance and risk frameworks to:

- Mitigate the physical risks to our assets
- Mitigate the policy and regulatory risks as the sector transitions to low emissions and eventually emissions-free
- Reduce its greenhouse gas (GHG) emissions
- Establish an annual reporting structure to provide internal and external accountability for implementation.

The above framework supports our overarching sustainability policy is built around the three pillars of sustainability: environmental, economic and social, which is in line with our strategic tactics to:

- Implement sustainability in the workplace/operations initiative
- Demonstrate environmental responsibility initiatives for workspace and work site.

Electra has also conducted a baseline carbon footprint assessment which aligned our business with COP26 and sustainability. The carbon footprint baseline assessment helped us understand where emissions are being generated and more importantly, allow us to set a target to manage a reduction in our Greenhouse Gas (GHG) emissions in line with Aotearoa New Zealand's target under the Climate Change Response Act 2002 for net-zero emissions by 2050. Further details of our Huringa Pūngao Energy Transformation Roadmap is included in Section 4.6, which aims to support the reduction of Aotearoa New Zealand's carbon emissions through electrification and increased renewable generation to achieve net-zero 2050.

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.

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 decarbonisation of our regional and 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.

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.

## 1.10 **Accountabilities for asset management**

Electra's organisational structure emphasising the lines business is shown in Figure 1-6.

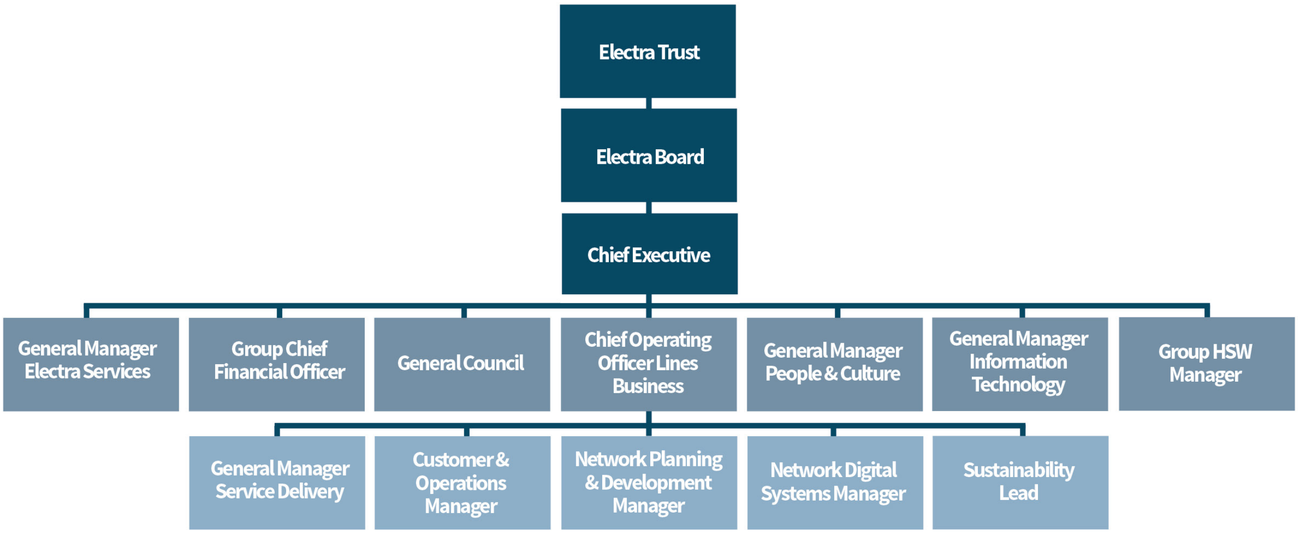



**Figure 1-6: Organisational Chart**

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 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 Chief Operating Officer - Lines Business is accountable to the Chief Executive. There are five managers accountable to the Chief Operating Officer - Lines Business as shown in the organisational chart.

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

### 1.10.1 **Summary of roles, delegated authorities and reporting**

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

| Activity | Board | Chief Executive | COO – Lines Business |
|---|---|---|---|
| Preparing SCI | Key role in preparing and amending under consultation 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 |
| 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 COO – Lines Business authority | In excess of Lines Business Managers' authorities |
| Approval of works not from approved budget | In excess of Chief Executive's authority | In excess of COO – Lines Business authority | In excess of Lines Business Managers' authorities |

| Activity | Board | Chief Executive | COO – Lines Business |
|---|---|---|---|
| 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 |

### 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
- Asset Dynamics for asset management assessment and ISO 55001 preparation
- Adriot SEI for regulatory and policy advice
- Consulink for asset risk management advice
- Eagle Technology for GIS support for the ESRI system
- Energia for regulatory advice and load forecasting
- HV Diagnostix for testing and diagnostics of substation equipment
- ICONA to maintain SCADA and Control Centre radio communications
- PLP Inspection Services for drone inspections of sub-transmission and distribution assets
- Qe-Analytics for asset management plan information analytics
- 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.

## 1.11 Asset management systems and information management

Electra uses the following data repositories and software 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 |
|---|---|---|---|---|
| Milsoft ADMS | 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<br>• Automated customer notifications via multiple platforms (i.e. social media)<br>• Identify additional value from data<br>• Serve to distributed workforce and remote offices. |
| Milsoft 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 | 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) | 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 |
| 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.<br>• Integrate the data into our ADMS and EAMS solutions.<br>• Ingres data from 3rd party devices or services to increase sources of loss-of-power event reports |

| System | Data held | What the data is used for | Extent of integration | Initiatives/ Improvement |
|---|---|---|---|---|
| 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 |
| 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. 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 | |
| Plexus Gateway | Legal Documents such as contracts, supplier agreements etc. | Legal document storage and execution | Integrates with Microsoft Azure Active Directory | |
| InfluxDB | Time-series technical and/or engineering data | Deriving insights from technical data including consumption, power quality, power availability and weather | Stand-alone system | |
| FME | Data Integration/ Manipulation solution. No data is stored. | Manipulating data for the purposes of cross-system/ platform integration | Integrates with a broad number of systems across the business | • Continual growth and adoption of this solution to support critical business functions. |
| TAG enterprise asset management system | Core source of asset and financial information | Primary asset management system | Integrates with BS financial management system, Timefiler, ArcGIS, CBARMM and Milsoft | • Go live during FY24 |

### 1.11.1 Data integrity

Electra is in the process of establishing a multi-year road map focused 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<br>• Site inspection |
| | Age | Accurate to within 6 months | • Documents recording installation |
| 11kV Lines/Cables | Size and material | Accurate | • Documents recording installation<br>• Site inspection |
| | Age | Accurate to within 6 months post 1995<br>Accurate to within 5 years pre-1995 | • Documents recording installation |
| 400V Lines/ Cables<br>Poles<br>Pillars | Size and material | Accurate post 1995<br>70% accurate pre-1995 | • Documents recording installation<br>• Site inspection |
| | Age | Accurate to within 3 months post 1995<br>Accurate to within 5 years pre-1995 | • Documents recording installation |
| Transformers<br>RMUs<br>Circuit breakers | Rating, manufacturer, age | Accurate | • Site inspection<br>• Documents recording installation |
| Other Switches | Rating, manufacturer | Accurate | • Documents recording installation |
| | Age | Accurate to within 3 months post 1995<br>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.

## 1.12 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 Sections 8.3.5 and 8.7.

## 1.12.1 **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.

## 1.12.2 **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.

## 1.12.3 **Development of 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 |
| Feasibility study of utilising non-network asset solutions (either Electra owned/operated or third-party) | Individual site-specific assessment required to determine. Likely outcome is deferral of asset investment. | Ideally nil, probably minimal in practice |
| If the above approaches are 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.

## 1.12.4 **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 those budgets accurately reflect the network condition and capacity utilisation to avoid a long-term accumulation of asset deterioration.

## 1.13 **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 to be returned from field services staff and contractors.

These documentation and data controls are described in Section 1.11.1.

## 1.14 **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 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 8.5.

## 1.15 **Significant assumptions**

Significant assumptions for this AMP are:

| Assumption class | Assumption | Tactic if assumption occurs | Tactic if assumption does not occur |
|---|---|---|---|
| Resident population growth | The Horowhenua District's population is projected to grow at 1.8% per year over the next ten years[12]. The same study also found the population growth is quicker than the average of the past 10 years (1.5% per year) but slower than the average of the past 6 years (2.1% per year).<br>From the 2018 census[13] released by Statistics New Zealand, the district has a population of 32,949, which increased at a rate of 2% per year since 2013. The next census will be conducted in 2023. | 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. |
| | For the Kāpiti Coast District Council (KCDC), the Sense Partners median forecast (see Section 2.1.4) has been identified as the baseline used as the forecast reflected an annual average rate of growth of 1.5% similar to the growth rate Kāpiti had experienced from 1996 – 2020 and the rate of growth identified in KCDC's Long Term Plan 2021 – 414.<br>The 2018 census[15] identified a population of 53,940 residents; the growth rate was 1.9% per annum since 2013. The next census will be conducted in 2023.<br>Internal migration to the region is also another factor considered which is expected to drive up population numbers. | | |
| Pandemic impact | The Covid-19 pandemic which affected many businesses, had little impact on the maximum demand (MD) of our zone substations as zone MDs increased between 1% to 12% per annum from 2019 to 2022. | | |
| Technology uptake | As the Government is increasing the incentives and subsidies for EV, electrification of energy demand is expected to increase by 2021 with an EV uptake of 640 and 160 in Kāpiti and Horowhenua respectively, with a further 270 EVs travelling the SH1 corridor daily[15] | 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 |
| | 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 |
| | 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 |

[12] *Sense Partners, "Horowhenua Socio-Economic Projections Summary and Methods", May 2020*
[13] *Statistics New Zealand, Dataset: "Age and sex by ethnic group (grouped total responses), for census night population counts, 2006, 2013, and 2018 Censuses"*
[14] *Kāpiti Coast District Council, "Regional Housing and Business Development Capacity Assessment – Housing Update", May 2022*
[15] *Source – "Compiling an EV charging strategy" prepared for Electra by Utility Consultants.*

| Assumption class | Assumption | Tactic if assumption occurs | Tactic if assumption does not occur |
|---|---|---|---|
| Financial parameters | Taking into account the latest inflation trends, an average of 8.09% is used in FY2024 and an average of 3% from FY2025 onwards based on 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[16] 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 Kāpiti zone substations as more commuters arrive home earlier may increase coincident GXP demand. Also, possibility of people moving northwards from Wellington to Kāpiti, and from Kāpiti to Horowhenua | Kāpiti 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 |

[16] ANZ, NZ Insight: Inflation and monetary policy – Australia vs New Zealand, Nov 2022

## 1.15.1 **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 EVs that could provide higher subsidies for EVs and restrictions for ICE vehicles (above existing Clean Car Discount scheme rates) | 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[5] |
| | EECA support of up to $25m a year[6] in funding to support adoption of low emission transport technology, innovation and infrastructure. | Increase in peak demand unless charging is incentivised to off-peak periods | Growth CAPEX to meet demand | |
| | 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 increase the cost of work | Increased time per job, resulting in increased costs per job | Reprioritising work volumes to fit within budget subject to risk assessment | Currently strong |
| | Increased requirements for access to land by NZTA or KiwiRail 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 affects 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 |

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[17] *It is noted investor-owned electric car charging companies in California were restricted in their ability to recover the full costs of peak-time charging.*
[18] *EECA, Low emission transport fund, Oct 2021*

## 1.15.2 **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 2023 constant New Zealand dollars.

## 1.15.3 **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 given the increasing number of variables and the rapid and uncertain changes happening to electricity use, a linear extrapolation is no longer fit for purpose. We have therefore developed a far more comprehensive methodology that includes consideration of emerging technologies, declining kWh consumption and increasing kW demand. This methodology utilises probabilistic analysis creating a range of potential scenarios that are then modelled against our network topology to identify emerging constrains
- 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 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

This section provides an overview of the network, our major customers, and the characteristics of customer's demand on the network. It also includes a description of how Electra prices its distribution services.

### 2.1.1 Regions covered

Electra's assets are spread over the Horowhenua and Kāpiti districts on the narrow strip of land between the Tasman Sea and the Tararua Ranges, stretching from Foxton and Tokomaru in the north to Paekākāriki in the south, 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 consumers are:

- Alliance Group, Levin
- Kāpiti Coast District Council
- Oji Fibre Solutions (NZ) Ltd
- Foodstuffs North Island Ltd
- RJ's Licorice (NZ) Ltd
- Wayne Bishop Investments Ltd
- Countdown
- Unisys New Zealand Ltd.

These consumers represent 6% 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, but increasing growth in both MW demand, volume in MWh and in ICP numbers
- A southern network Figure 2-3 supplied predominantly from Valley Road Paraparaumu GXP; supplying Paekākāriki, Paraparaumu East, Raumati, Waikanae and Ōtaki 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 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. Changing work arrangements are however dampening this historic effect

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

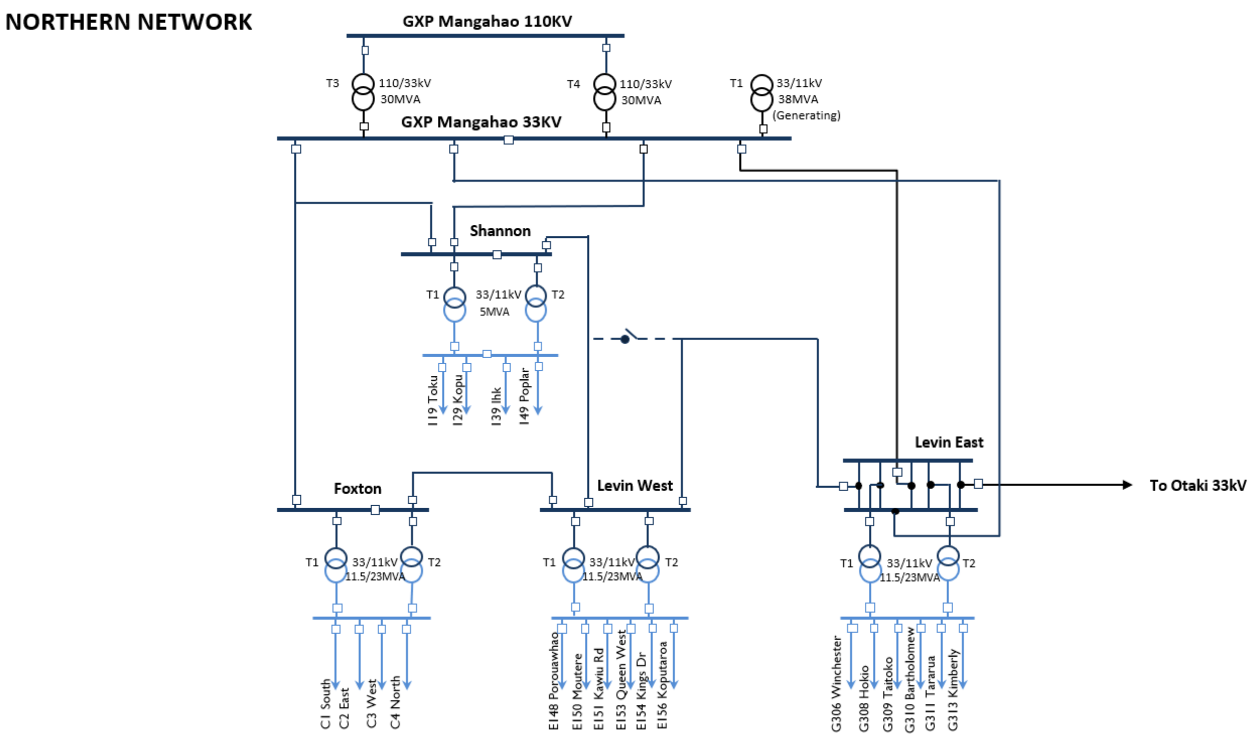



**Figure 2-2: Northern 33/11kV network**

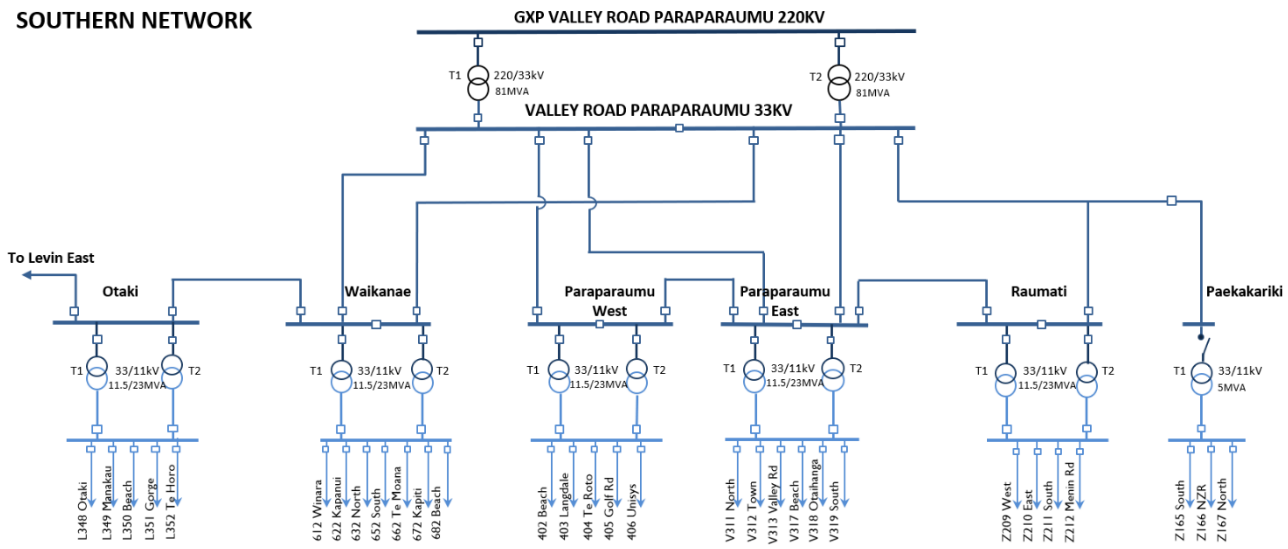



**Figure 2-3: Southern 33/11kV network**

## 2.1.4 **Demand and energy**

Comparison of key parameters of Electra's network from 31 March 2020 to 31 March 2022 is shown in the following table:

| Parameters | 31 March 2020 | 31 March 2021 | 31 March 2022 | % Increase FY20-FY21 | % Increase FY21-FY22 |
|---|---|---|---|---|---|
| Average number of customer connections in disclosure year | 45,192 | 45,562 | 45,950 | 0.8% | 0.9% |
| Maximum demand (MW) | 101 | 104 | 111 | 3.0% | 6.7% |
| Annual electricity delivered (GWh) | 415 | 421 | 424 | 1.4% | 0.7% |
| Total circuit length (km) | 2,323 | 2,330 | 2,354 | 0.3% | 1.0% |
| Number of zone substations | 10 | 10 | 10 | - | - |

| Parameters | 31 March 2020 | 31 March 2021 | 31 March 2022 | % Increase FY20-FY21 | % Increase FY21-FY22 |
|---|---|---|---|---|---|
| Number of distribution transformers | 2,563 | 2,572 | 2,613 | 0.4% | 1.6% |
| Network asset valuation | $202.0M | $209.2M | $226.8M | 3.6% | 8.4% |

The maximum demand (MD) recorded for FY2022 was 111 MW, 7% above the MD of 104 MW in FY2021 whilst the MD increase from FY2020 to FY2021 was 3% only. The percentage increase in energy conveyed from FY2021 to FY2020 was higher at 1.4% as compared to the 0.7% increase from FY2021 to FY2022 (424GWh). This decrease amount may be attributed to enhanced accounting processes with the recent deployment of the Axos Billing system.

As demonstrated by the graph in Figure 2-4a, between 2017 to 2022, ICP growth has been increasing at an average rate of 0.6% annually versus a 0.9% increase of the total system length during the same period. The ICP growth rate in the region is expected to increase as depicted in Figure 2-4b, the population change map based on the 2013 and 2018 census. The next census will be in 2023.

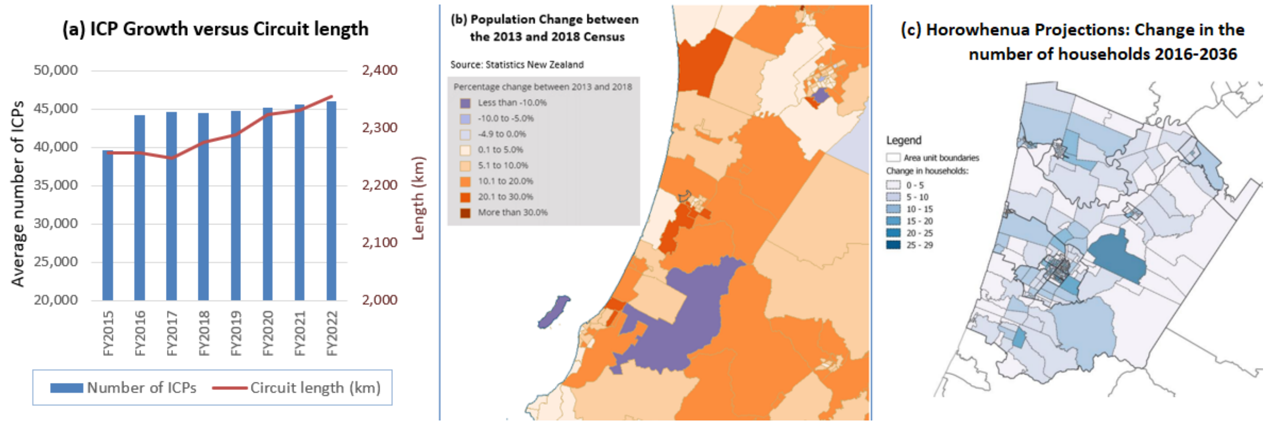



**Figure 2-4: (a) Growth of ICPs and circuit length; (b) Population change between the 2013 and 2018 census; (c) Horowhenua-change in household numbers 2016-2036**

Horowhenua socio-economic projections by Sense Partners suggest widely dispersed population growth as indicated in Figure 2-4c depicting the change in households from 2016 to 2036[7].

Kāpiti Coast District Council[8] has provided a range of forecasts for future growth based on Statistics New Zealand's as well as Sense Partners (SP) ranges of forecasts. SP's median forecast is used as the baseline for Electra's demand forecast and details are provided in Section 4.8.

Engaging with our two District Councils together with developers and land agents is providing us with early understanding of the scale and timings of new development projects within our network. We are experiencing considerable interest in the capacity and ability of our network to supply these developments.

The energy density of existing residential areas is also increasing and recent regional changes have the potential to introduce a step change.

We continue to engage with stakeholders to understand the scale, timings and confidence of these developments.

## 2.2 Network configuration

Electra's network is supplied by two GXPs:

- Mangahao GXP, which supplies the northern area (with an embedded generation plant)
- Valley Road Paraparaumu GXP, which supplies the southern area.

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

[19] *Sense Partners, "Horowhenua socio-economic projections" July 2017*
[20] Kāpiti Coast District Council, "Regional Housing and Business Development Capacity Assessment – Housing Update", May 2022

Key features of these bulk supply points are:

| GXP | Winter firm capacity (MVA) | Peak demand (MW) | |
|---|---|---|---|
| | | *2021* | *2022* |
| Mangahao | 30 | 42.0 (August) | 45.9 (June) |
| Paraparaumu | 120 | 69.1 (August) | 68.3 (July) |

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 firm capacity. Further analysis is included in Sections 4.8 and 4.9.3.

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 | GXPs supplying a coincident maximum demand of 111 MW<br>Embedded hydro generation of 38 MW (Mangahao)<br>About 689 solar installations with a total capacity of 2.72 MW |
| Sub-transmission | 32 km of overhead 110kV line that are being operated at 33kV<br>154 km of overhead 33kV line<br>31 km of underground 33kV cable |
| | Four zone substations supplied from Mangahao GXP<br>Five zone substations supplied from Valley Road GXP<br>One zone substation that can be supplied from either Paraparaumu Valley Road or Mangahao |
| Distribution network | 848 km of overhead line<br>255 km of underground cable |
| Distribution substations | 2,613 substations ranging in capacity from 5 kVA to 1,000 kVA |

The network lengths of Electra's sub-transmission and distribution network as of 31 March 2022 follow:

| Description | Length in km as of 31st March 2022 | | | | Network % |
|---|---|---|---|---|---|
| | 33kV | 11kV | Low Voltage (LV) | Sub-total | |
| Underground cables | 31 | 255 | 511 | 798 | 34% |
| Overhead lines | 186 | 848 | 523 | 1,556 | 66% |
| Total: | 217 | 1,103 | 1,034 | 2,354 | 100% |

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

As per Figure 2-5, we have 848 km of 11kV overhead lines and 255 km of 11kV cables connecting our ten zone substations to distribution substations. This 11kV network is constructed mainly of:

- CBD areas are mainly supplied by underground cables. In older urban areas with low load growth such as Levin and Foxton, these cables are of PILC 185mm2 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 being cabled. These lines are Gopher or 7/0.064".

Electra has 523 km of overhead LV or low voltage line (400V) and 511 km of LV underground cable connecting its distribution substations to its customers, with an associated 10,705 pillars and cabinets.

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

| Zone substation | Number of 11kV feeders | Distribution network length (km) up to 30/05/2022 | | | LV network length (km) up to 30/05/2022 | | |
|---|---|---|---|---|---|---|---|
| | | Overhead line | Underground cable | Total | Overhead line | Underground cable | Total |
| Levin East | 6 | 127 | 36 | 163 | 95 | 71 | 166 |
| Levin West | 6 | 120 | 22 | 142 | 75 | 42 | 117 |
| Shannon | 4 | 185 | 9 | 194 | 71 | 10 | 81 |
| Foxton | 4 | 105 | 17 | 122 | 66 | 20 | 86 |
| Paraparaumu East | 6 | 26 | 32 | 58 | 18 | 65 | 83 |
| Paraparaumu West | 5 | 7 | 32 | 39 | 12 | 82 | 94 |
| Raumati | 4 | 13 | 13 | 26 | 26 | 33 | 59 |
| Waikanae | 7 | 63 | 47 | 110 | 48 | 119 | 167 |
| Paekākāriki | 3 | 16 | 6 | 22 | 10 | 4 | 14 |
| Ōtaki | 5 | 185 | 42 | 227 | 102 | 64 | 166 |
| Total | 50 | 848 | 255 | 1,103 | 522 | 511 | 1,033 |

## 2.3 Asset valuation (RAB) allocation

Electra's Regulated Asset Base (RAB) increased by over 8%, from $209.2 million in FY2021 to $226.8M in FY2022. The FY2022 RAB comprises of network assets is shown in Figure 2-6. This percentage increase of 8% is double the 4% increase from FY2020 to FY2021 reflecting that Electra is renewing and replacing its assets to enhance its services for our increasing customer base and electricity network in line with our corporate strategies for operational excellence, supply quality and growth.

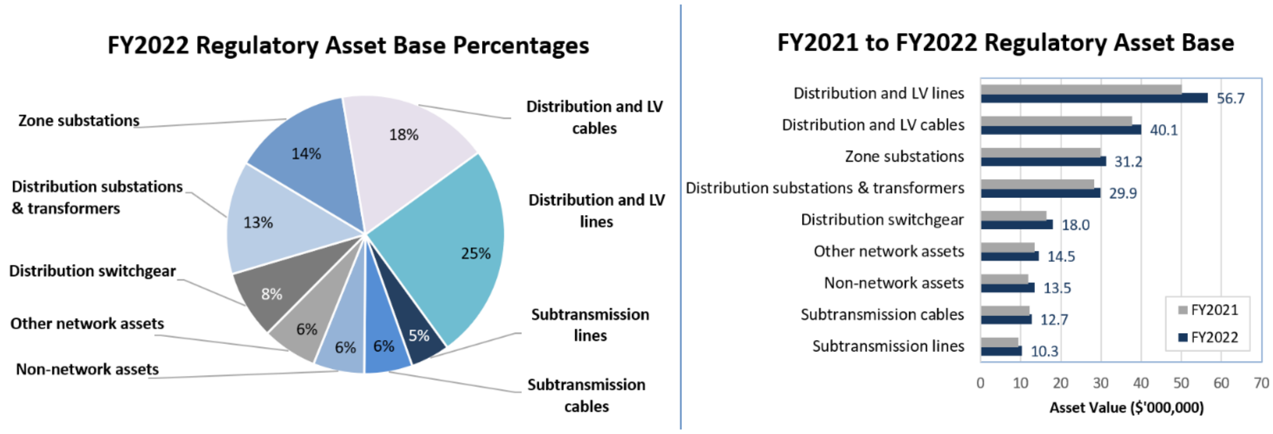



**Figure 2-6: Regulatory Asset Base FY2021 to FY2022 depicting asset categories and values**

# 3 SERVICE LEVELS

## 3.1 Our customers

The AMP is developed to serve current and future customers connected to the network. As of March 2022, there are 45,950 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.

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
- 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 Group business strategic objectives

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

## 3.3 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.

### 3.3.1 System 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.

The section describes how we measure performance. Besides reliability, Electra monitor its performance against a range of other measures including financial efficiency, safety, environmental and legislative compliance.

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

| Measure | Actual (historical) | | | | | Forecast |
|---|---|---|---|---|---|---|
| | FY2018 | FY2019 | FY2020 | FY2021 | FY2022 | FY2023-2028 |
| SAIDI B (Planned) | 26.7 | 32.3 | 19.5 | 28.4 | 28.2 | 20 |
| SAIDI C (Unplanned) | 95.0 | 57.0 | 75.4 | 45.9 | 66.4 | 63 |
| SAIDI B & C | 121.7 | 89.3 | 94.9 | 74.3 | 94.6 | 83 |
| SAIFI B (Planned) | 0.08 | 0.10 | 0.06 | 0.10 | 0.09 | 0.08 |
| SAIFI C (Unplanned) | 2.00 | 1.17 | 1.81 | 0.87 | 1.36 | 1.5 |
| SAIFI B & C | 2.08 | 1.26 | 1.87 | 0.97 | 1.45 | 1.58 |
| CAIDI B (Planned) | 321.2 | 323.2 | 313.4 | 286.8 | 313.3 | 250 |
| CAIDI C (Unplanned) | 47.6 | 48.7 | 41.8 | 52.6 | 48.8 | 42 |
| CAIDI B & C | 58.5 | 70.9 | 50.8 | 76.5 | 65.2 | 52.5 |

In our FY2022 AMP update published in March 2021, we set new reliability targets from FY2022 to FY2023. The targets increased SAIDI planned (B) by five minutes to 20 SAIDI minutes and decreased SAIDI unplanned (C) by 5 minutes to 63 SAIDI minutes. Benchmarked against our peer group of six EDBs based on Commerce Commission's medium regional grouping, our targets were well below that of our peers.

As part of our continuous improvement programme, we have been considering different approaches that we can use to set targets that provide us with a relevant, enduring, and consistent approach and, at the same time gives us flexible and relatable targets to measure our performance in the ever-changing environment in which we operate.

## Historical performance

Comments on the historical performance include:

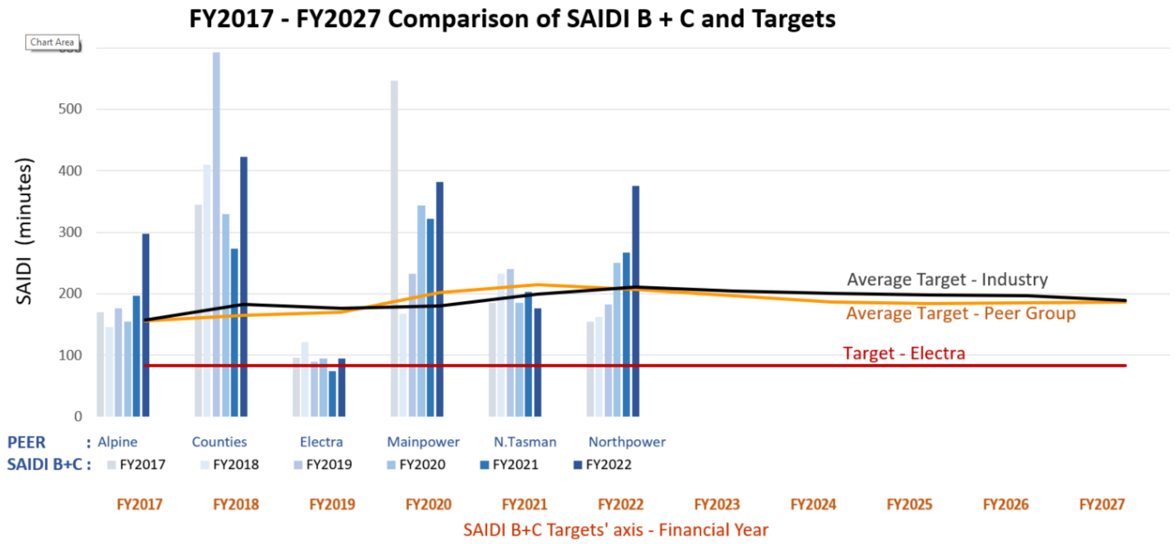
- A 33kV interruption during the FY2018 year focused Electra's attention on the resilience of its 33kV network and resulted in specific programmes of work to systematically improve the reliability of sub transmission network through protection improvements and component replacements
- Unplanned SAIDI 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
- The main contributors for FY2020 were planned work (19.5 minutes), third party interferences (23.61 minutes) including feeder L349 which tripped when a digger dug through 11kV cable, impacting SAIDI by 3.6 minutes
- Planned work for FY2022 exceeded SAIDI B target by over 8 minutes while SAIDI C target was exceeded by over 3 minutes where the highest SAIDI C impact (3 minutes) was caused by a third party of an underground cable at Paraparaumu.

The following events contributed to the higher SAIDI impact for FY2022:

- Two car-versus-pole incidents at Levin and Foxton contributed to a total of 4.68 minutes of SAIDI and 0.057 SAIFI
- An 11kV underground cable fault at Paraparaumu damaged by excavation resulting in 3 minutes SAIDI and 0.03 SAIFI
- A surge arrestor failure on Ōtaki feeder L345 affected 923 customers impacting SAIDI by 2.8 minutes SAIDI and 0.02 SAIFI.

Where an interruption to the supply of electricity distribution services is followed by restoration, and then by a "successive interruption", Electra calculates the SAIDI/SAIFI based on the multiple outages. This treatment is consistent from the 2019 disclosure year.

The total B&C SAIDI targets have been benchmarked with a peer group of six networks namely, Alpine Energy, Counties Energy, Mainpower, Network Tasman, Northpower and Electra, based on the Commerce Commission's "Medium Regional" grouping[21]. Figure 3-1 indicates that our B&C SAIDI target (83 minutes) is way below that of our peers. Our reliability performance is further discussed in Sections 8.2 and 8.2.2.




Note: One EDB has not published Schedule 12D as of 4/10/2022 so the previous year's targets were used for 2023- 2027.

**Figure 3-1: Peer comparison of unplanned and planned SAIDI (B+C SAIDI)**

### 3.3.1.1 System Operator Event

Our total SAIDI was impacted by a Class D outage on 9th August 2021 when Transpower issued a nationwide emergency due to the lack of generation and requested EDBs to carry out load shedding in their respective networks. Our operators manually tripped feeders isolating 4,876 customers for a duration of 2 hours; this event added 6.03 minutes to the total SAIDI and 0.10 SAIFI.

## 3.3.2 Justification for reliability targets

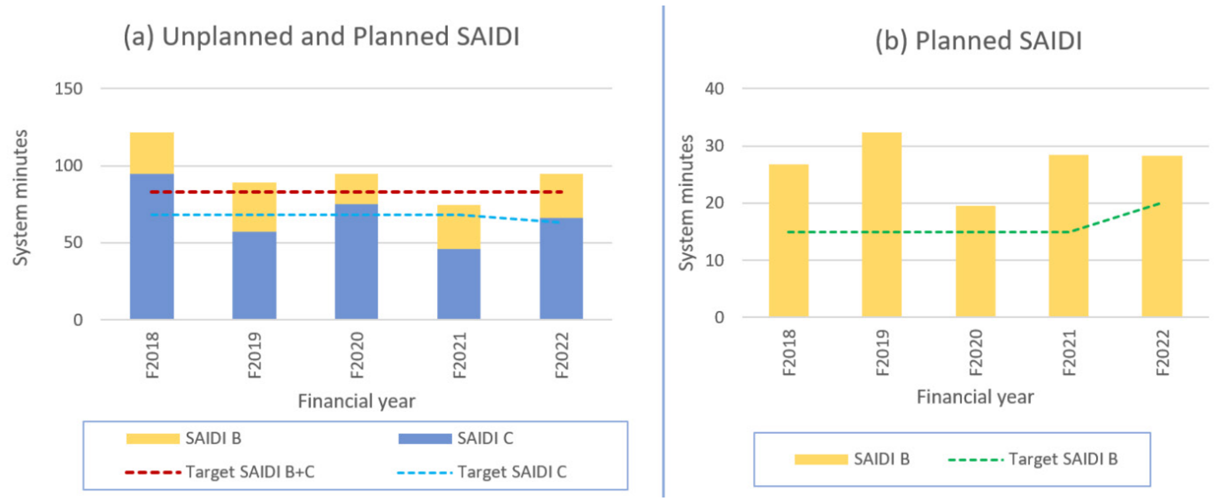



**Figure 3-2: Historical unplanned and planned SAIDI trends**

[21] *Commerce Commission's consultation paper for electricity distributors, "Investment ratio and asset condition dashboards for electricity distribution businesses", 15 March 2018*

Unplanned and planned SAIDI versus the total 83-minute target is shown in Figure 3-2(a) while planned SAIDI against its target is depicted in Figure 3-2(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 95 minutes in FY2020 to 74 minutes in FY2021, then increased to 95 minutes in FY2022.

The frequency of unplanned interruptions or SAIFI has reduced from 1.87 in FY2020 to 0.97 (FY2021) and increased to 1.45 (FY2022) as demonstrated in Figure 3-3a. Planned SAIFI and CAIDI (in Figure 3-3b and Figure 3-3c 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 exceeded the target of 49 minutes, Electra's CAIDI is still the best amongst its peer group. For detailed analysis please refer to Section 8.2.1.

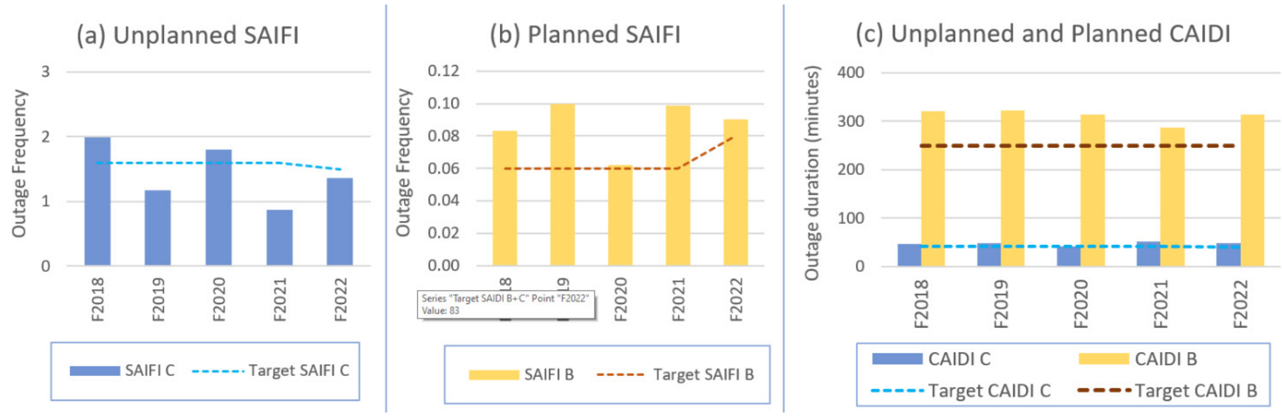



**Figure 3-3: Historical unplanned and planned SAIFI and CAIDI trends**

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"[9]. However, Electra has identified several tactical programmes to maintain the performance at this optimal level and deliver improved customer experience as discussed in Section 3.13.

## 3.4 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 ► | | | | |
|---|---|---|---|---|---|---|
| | | FY2023 | FY2024 | FY2025 | FY2026 | FY2027 |
| Processing new connection application | Number of working days to process | 3 | 3 | 3 | 3 | 3 |

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

| Attribute | Measure | Target ▸ | | | | |
|---|---|---|---|---|---|---|
| | | FY2023 | FY2024 | FY2025 | FY2026 | FY2027 |
| 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 EDBs have identified these service attributes as less important than supply reliability (continuity and restoration). A key feature of these secondary service attributes is they are based on processes rather than fixed asset investments.

Electra undergoes an annual Registry audit where timeliness is a key requirement of process delivery.

Electra shares the view of the ENA study (Section 3.3.2) that identified the ease of connection and timely planned outage notification as two key opportunities to positively influence our customer experience.

## 3.5 Asset performance levels

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 ▸ | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | FY2018 | FY2019 | FY2020 | FY2021 | FY2022 | FY2023 | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 |
| Load factor | 49% | 50% | 51% | 50% | 48% | 50% | 50% | 50% | 50% | 50% | 50% |
| Capacity utilisation | 31% | 30% | 30% | 31% | 32% | 31% | 31% | 32% | 32% | 32% | 32% |
| Network losses | 8.4% | 6.9% | 7.7% | 7.3% | 8.0% | 7.3% | 7.3% | 7.3% | 7.3% | 7.2% | 7.2% |

The above values are also included in the Commerce Commission's Determination Schedule 12c, which is the report on forecast network demand (Appendix 6). Further details of the above measures are included in Section 8.4. Electra commissioned a Power Losses Reduction Initiative to investigate technical losses which is described in Section 8.4.3.

Another indicator we are monitor are the number of voltage complaints received inclusive of harmonics, the areas affected and the number resolved.

## 3.6 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 |
|---|---|---|---|---|
| | FY2020 | FY2021 | FY2022 | |
| Capital expenditure on assets per total circuit length (km) | $10,914 | $6,119 | $5,737 | Increase to be less than 5% of the previous year's figures (inflation adjusted). |
| Capital expenditure on assets per connection point | $561 | $313 | $294 | |
| Operational expenditure on assets per total circuit length (km) | $5,603 | $5,746 | $5,884 | |
| Operational expenditure on assets per connection point | $288 | $294 | $301 | |

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

Asset CAPEX per kilometre and per consumer for FY2022 has decreased to $5,737 and $294 respectively.

The trends in our operational (OPEX) and capital asset expenditure (CAPEX) per ICP and per circuit length (in km) are depicted in Figure 3-4. Electra aims to maintain its OPEX and CAPEX per ICP and per circuit length (km) within 5% of the previous year's figures.

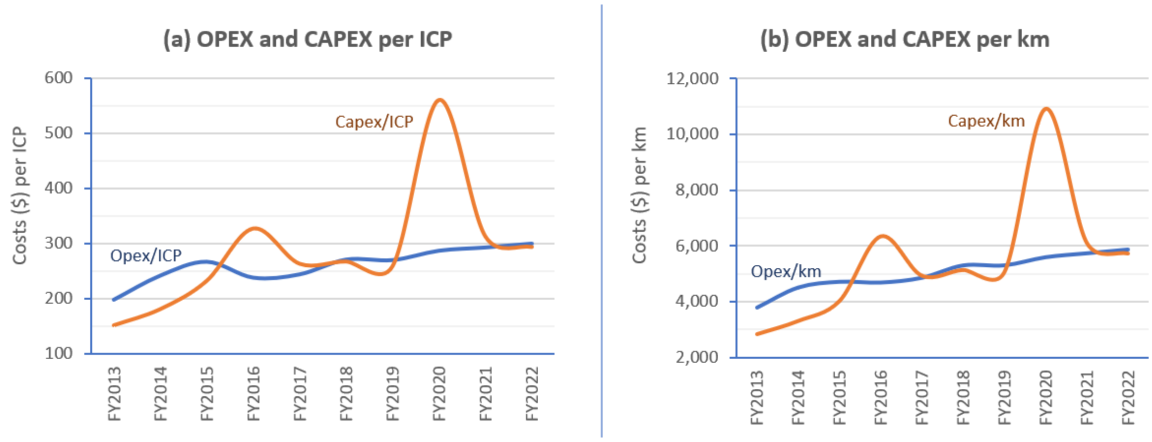



**Figure 3-4: OPEX and CAPEX (a) per ICP, and (b) per circuit length (km)**

The costs for both OPEX per ICP and OPEX per circuit kilometre increased by only 2% from FY2021 to FY2022. CAPEX per ICP and per circuit kilometre has both decreased by 6% from FY2021 to FY2022. The high FY2020 CAPEX indicators were due to a one-off adjustment required to include Network Service Delivery assets and Right of Use assets into our Regulatory Asset Base (RAB).

Electra has historically had a low growth budget. We have had a more recent period of investment in the renewal and replacement of infrastructure and transmission services. Such expenditure is necessary to replace infrastructure initially built in the 60s and 70s to provide improved security and reliability of supply to customers. Increasing costs will also reflect the anticipated growth in consumption and demand driven by increased electrification.

Further evaluation of the above indicators is included in Section 8.4.4.

## 3.7 Safety and environmental performance levels

Electra is committed to ensuring the health and safety of its customers, employees, contractors, and the public. It is critical that our focus on safety is not diminished and our investment in our people and assets continues to ensure that we are continuously improving our safety and environmental levels. The Health and Safety Committee is chaired by a Board Director, another Board member, the Chief Executive, the General Manager (People and Culture) and the Group Manager

(Health, Safety and Wellbeing) as well as other key technical supervisors.

We are conscious of our environmental responsibility and follow our Group's Environmental and Sustainability Policies, and our plans and activities are guided by these policies in environmental-related work thereby minimising the impact on the environment.

Our 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 | Indicator type | FY2018 | FY2019 | FY2020 | FY2021 | FY2022 | Target and forecast |
|---|---|---|---|---|---|---|---|---|
| Public safety: safety of staff, contractors, and the public | Number of incidents | Lag | 8 | 13 | 51 | 68 | 85 | Zero harm |
| Personnel safety | Lost Time Injury (LTI) | Lag | 4 | 3 | 3 | 2 | 1 | Zero LTI |
| Environmental responsibility | Number of environ-mental incidents | Lag | 0 | 0 | 0 | 0 | 0 | Zero harm to the environ-ment |

Asset hits mainly vehicle versus pole incidents, account for the majority of reported public safety incidents, with one notifiable to the Energy Safety, WorkSafe this year relating to a "car versus pole" incident that resulted in the death of the sole occupant. These asset hits were first recorded in FY2020 in the Vault system explaining the large increase in incidents reported.

Proactive and preventive actions included the following audits, safety observations and health & safety activities:

| Key Performance Indicator | Indicator type | Target/ period | FY2018 | FY2019 | FY2020 | FY2021 | FY2022 |
|---|---|---|---|---|---|---|---|
| External Audit Certificate | Lead | Compliant with legislation; annually | Compliant | Compliant | Compliant | Compliant | Compliant |
| Internal Audit Compliance | Lead | Compliant with legislation; annually | Compliant | Compliant | Compliant | Compliant | Compliant |
| Identified Hazard Controls in place | Lead | Compliant with legislation; annually | Compliant | Compliant | Compliant | Compliant | Compliant |
| Asset Inspections poles, pillars, transformers & switchgear | Lead | 100%; 5-yearly cycle | 100% | 100% | 100% | Compliant | Compliant |
| 33kV lines 2-yearly cycle. | Lead | 100%; 2-yearly cycle | 100% | 100% | 100% | Compliant | Compliant |
| 33kV ground inspection yearly | Lead | 100%; annually | 100% | 100% | 100% | Compliant | Compliant |
| 33kV aerial inspection 3 yearly | Lead | 100% | 100% | 100% | 100% | Compliant | Compliant |
| 33kV thermograph survey | Lead | 100% | 100% | 100% | 100% | 100% | 100% |
| Unsafe defective equipment replacement (within legislative requirements) | Lag | 100% | 100% | 100% | 100% | 100% | 100% |
| Contractor Health & Safety audits | Lead | 5 per month | 8 | 22 | 10 | 91 | 150 |
| Contractor work quality audits | Lead | 5 per month | 22 | | 49 | 47 | 53 |
| Public Safety audits | Lead | 5 per month | 57 | 13 | 21 | 22 | 34 |
| Training seminars for contractors | Lead | As required | 14 | 10 | 5 | 5 | 2 |

## 3.8 Regulatory compliance levels

Regulatory compliance levels are based on the requirements set by statutory agencies and include compliance with the legislation listed in Section 3.7.1 as well as the following:

- Compliance with the operative Horowhenua and Kāpiti 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 use 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, where we reached 99% compliance having complied with 2,556 out of 2,657 survey questions.

The following table summarises our performance since 2019 and compliance survey details are included in Section 3.8.2.

| Service criteria | Indicator | 2019 | 2020 | 2021 | 2022 | Target and forecast | Performance measurement |
|---|---|---|---|---|---|---|---|
| Legislative requirements | Compliance with relevant regulations | 98.7% | 99.3% | 98.7% | 99% | 100% compliance | Annual measurement, using Comply With system |

Overall regulatory compliance is rated extremely high with only 1% of responses representing partial non-compliances for the 71 Acts, Codes and Regulations included in the survey that govern our activities.

### 3.8.1 Relevant legislation

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
- Electricity (Safety) Regulations 2010
- Health and Safety at Work Act 2015 including the Health and Safety at Work (Asbestos) Regulations 2016
- Resource Management Act 1991
- Electricity Codes of Practice (ECPs) such as NZECP 34:2001 Electrical Safe Distances, NZECP 35:1993 Power Systems Earthing
- Electricity (Hazard from Trees) Regulations 2003
- Commerce Act 1986 including the Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022
- Electricity Distribution Services Input Methodologies Determination 2012 (in as much as that Determination applies to an exempt EDB)
- AS/NZS 3000:2018: 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
- Privacy Act 2020
- Horowhenua and Kāpiti Coast District Councils requirements
- Climate Change Response Act 2002 including the Climate Change Response (Zero Carbon) Amendment Act 2019
- Maintaining an independently certified Safety Management System, which conforms to the safety management systems for public safety, NZS 7901:2014.

## 3.8.2 Legislation compliance survey

The results of the Group Legislation Compliance Survey 2022, completed by 44 managers and key employees, were reviewed by the Risk and Audit Committee in August 2022. As per Figure 3-5, the survey covered 71 Acts/regulations and overall compliance was rated high with 36 partial non-compliances where remedial actions are being undertaken to cover the following:

- Health and safety responsibilities including safe access to sites and enhanced security
- Review of earthing processes/equipment, rolling outage plans and embedded networks
- Developing new work procedures to support safe working practices.

Management training opportunities have been identified as follows:

- Earthing process currently in place for employees pending arrival of new equipment
- Managing employee well-being issues as well as bullying behaviour and the potential for personal grievance claims
- Application of Electra’s Flexible Working Policy including issues presented by Covid
- Notification of WorkSafe events and process
- Pre-employment disclosure process.

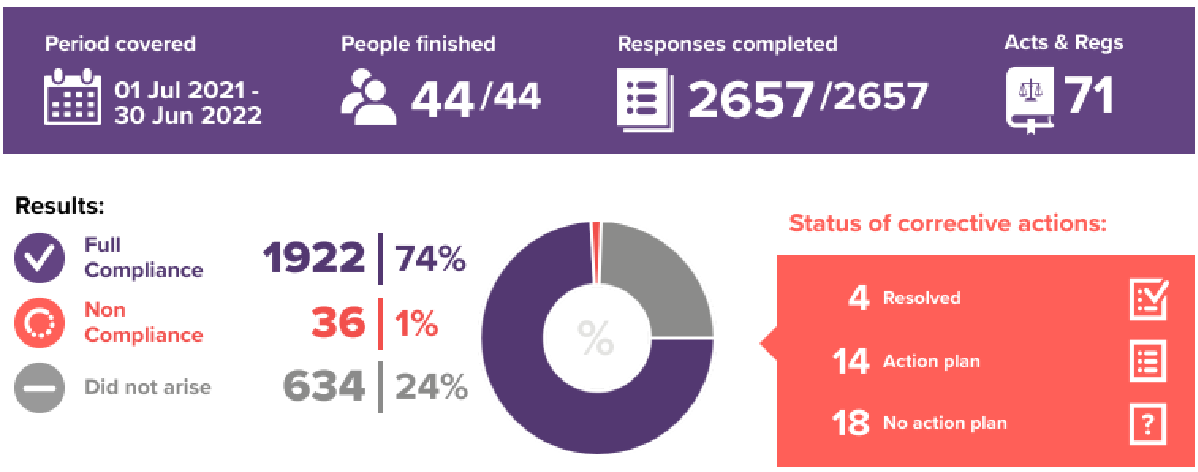



**Figure 3-5: Summary of Electra’s Legislation Compliance Report 2022**

The survey reporting process continues to be well-supported with 100% completion and wide-ranging responses. The small number of minor and partial non-compliances. All instances of partial non-compliance are being tracked through the Corrective Actions module in the ComplyWith system enabling on-going progress monitoring and reporting by managers until full resolution of compliance issues. The General Counsel and the responders monitor the action plans to completion.

## 3.9 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
- Making weather station information available to the public
- Sponsorship of community and business-related activities in both Levin and Paraparaumu.

## 3.10 Justification for service levels

Electra has adopted its current and planned future service levels based on customer expectations, regulatory requirements (as described in Section 3.8) and our group's strategies and objectives.

Customer service levels are an important input into the development of the AMP. Electra strives to deliver services that customers value, that meets their expectations in alignment with our company strategy. Electra will continually improve our customer engagement which will lead to happier customers. Electra endeavours to take on board what our customers tell us about how we can best meet their expectations when we consider our future asset planning.

Customer surveys are an important and meaningful way to engage with our customers and since the late 1990s we gauge customer expectations by conducting yearly Customer Service Surveys. The 2022 survey was enhanced this year to include further customer engagement with consumers on the trade-off between price and quality of supply. The results were obtained from interviewing a cross-section of residential and commercial end-users. These surveys involve interviews with 300 customers. One-half of survey participants were recruited from a randomly selected sample of the general population while the other half were selected from a list of contacts who have contacted Electra's faults service in the two to three months immediately prior to the survey period. Of the 300 respondents interviewed where 200 were residential householders and 100 commercial end-users. The 2022 survey tracks 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' engagement during interruptions to electricity supply, the effectiveness of advertising campaigns as well as offering participating customers the opportunity to provide feedback to our Chief Executive.

### 3.10.1 Preferred information source

Figure 3-6a shows how residential end-users would look for contact details in the event of a fault. The internet (50%) continues to be the leading source of information for contact details in 2022, which has increased significantly from followed by the power bill (17%), telephone directory (9%), fridge magnet (8%), number on mobile (7%) and 0800 number (6%).

Research participants were then asked to identify which information source would be their preferred choice during a fault. As depicted in Figure 3-6b, our survey 2022 again indicated the primary preference was the '0800 Lost Power information line' though this source has decreased from 53% in 2021 to 49% in 2022. Other sources that follow are 'text messaging' (14%), 'Electra website' (12%), 'a call from Contact Centre' (9%), Smartphone App (7%) and Facebook or Twitter (2%). With website improvement, Electra's website has gained popularity from 8-9% in the previous years to 12% in 2022. Electra will continue to monitor and enhance the uptake of newer technologies by its customers.

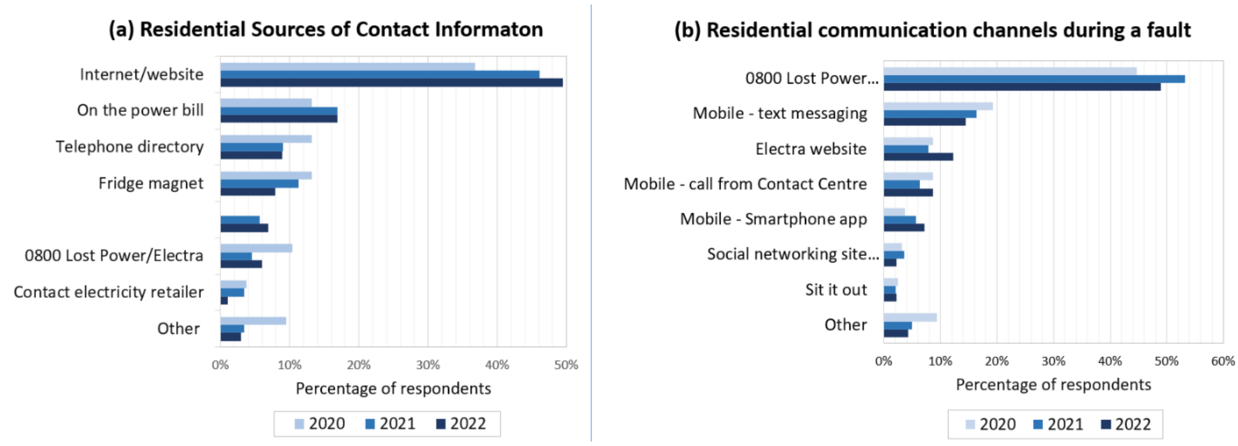



**Figure 3-6: Residential customers (a) Sources of contact information; (b) Preferred customer communication channels during a fault**

## 3.10.2 **Fault resolution and service delivery**

Consistent with earlier findings, satisfaction with the resolution of faults continues to be very high. 99% of the respondents in the survey rated the service '*excellent*' or '*very good*'. As can be seen in Figure 3-7(a), there has been a notable upswing in the level of '*excellence*' from 74% (2018) to 95% (2022). The results in Figure 3-7(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 67% (2018) to 94% (2022).

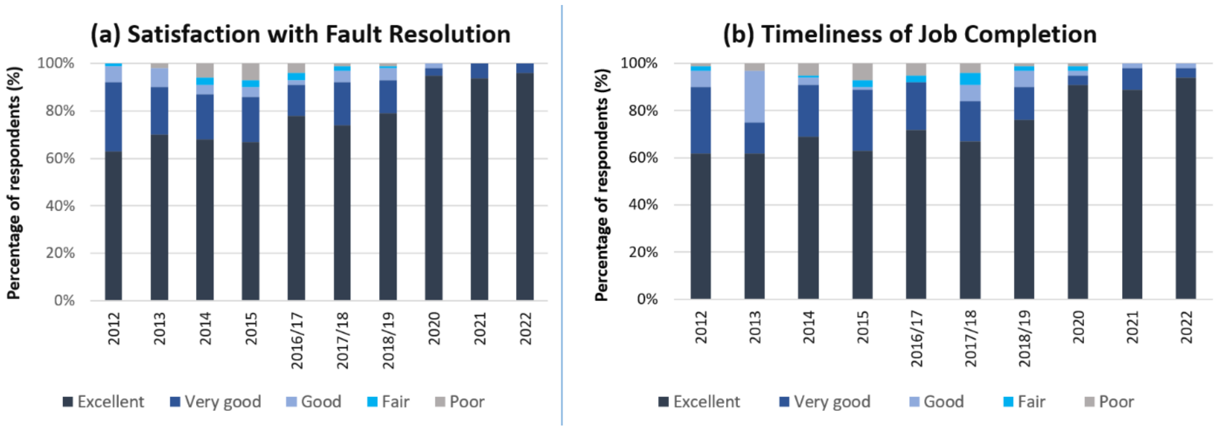



**Figure 3-7: (a) Satisfaction with fault resolution, and (b) Timeliness of job completion**

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 Ōtaki gave near identical ratings in terms of the level of 'excellence' they experienced from the fault crew. Importantly, in this year's survey, none of the end-customers interviewed expressed a negative rating as per the Figure 3-8a.

36% of customers interviewed indicated they called Electra's fault service in the last twelve months. The majority of these respondents stated that the service had been consistent over time, although some had noted a change for the better - as shown in Figure 3-8b.

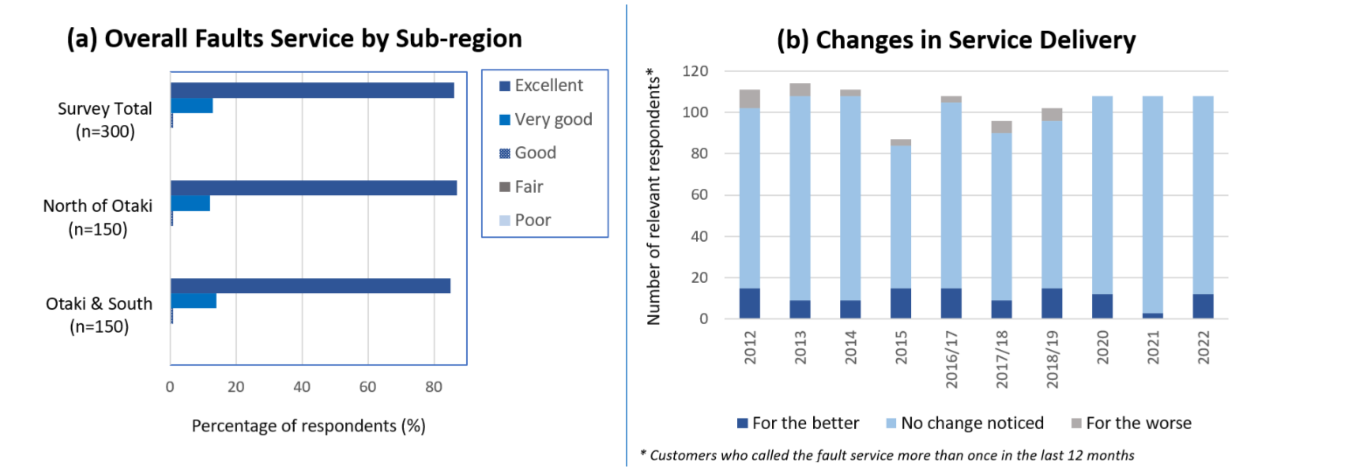



**Figure 3-8: Perception of respondents: (a) Overall faults services by sub-region, and (b) Changes in service delivery**

The overall results of the 2022 survey show that 97% of customers who contacted the Electra Services Call Centre, rated the service as '*excellent*' or '*very good'*. This percentage is an increase from last year's 95% indicating the overall upward trend in satisfaction (Figure 3-9a), achieved in recent years has continued. Similarly, 99% of our 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 3-9b.

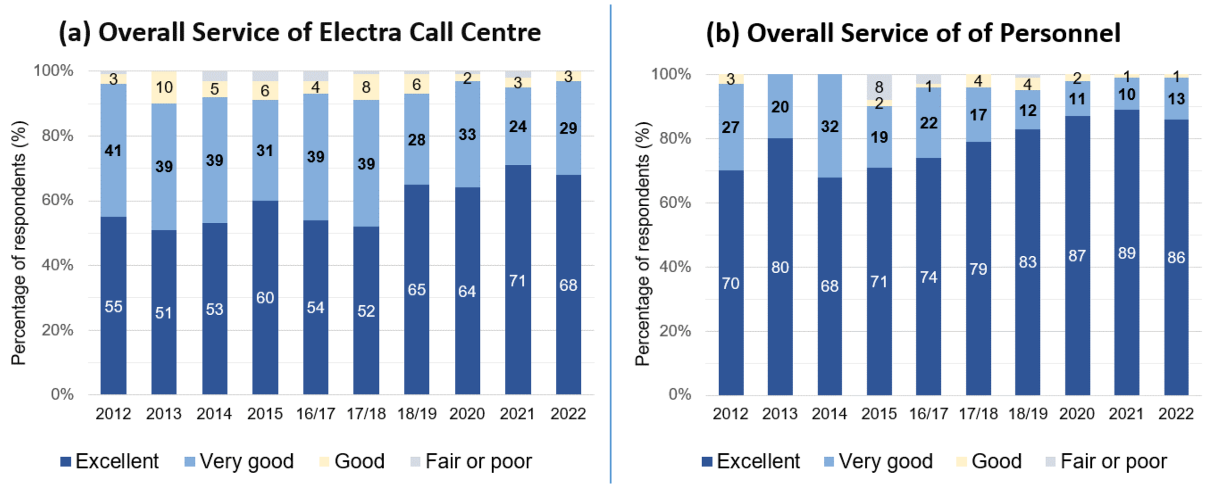



**Figure 3-9: Overall services of: (a) Electra Services Call Centre, and (b) Service personnel**

## 3.10.3 **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 3-10a. This percentage is up from 94% last year.

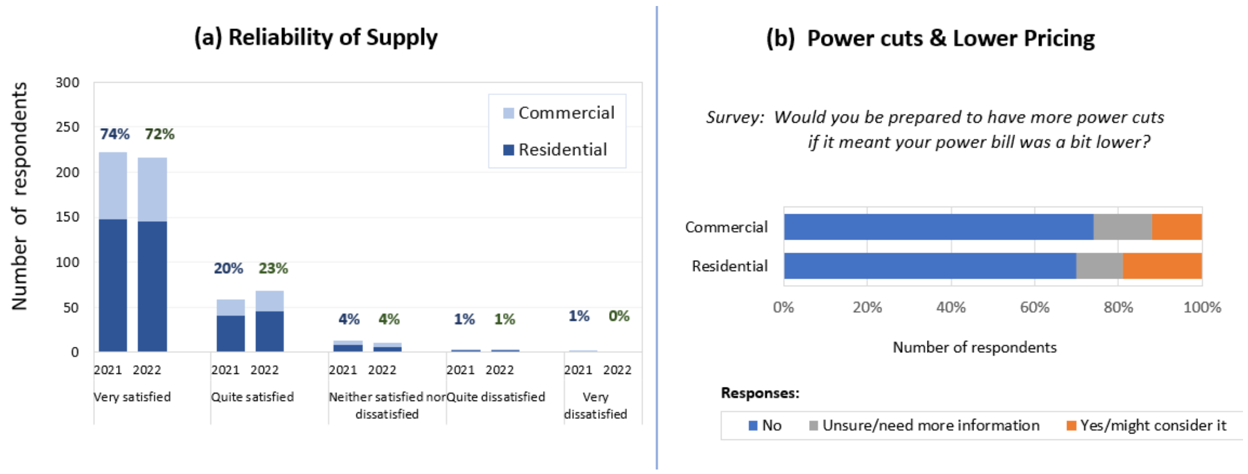



**Figure 3-10: Responses on supply reliability**

Only 4% of respondents this year stated they were 'neither satisfied nor dissatisfied' with the reliability of supply. Importantly, only 1% of the total participants indicated they were *'dissatisfied'* with the reliability of supply. The five respondents who expressed dissatisfaction were asked whether they would be prepared to pay more for a more reliable supply of electricity. All five indicated they would *not be prepared to do so and their rationale follow:*

> ***"Everybody needs reliable power. It is a given. We shouldn't have to pay more than we do now."***

> ***"We pay a fair price now, so we should get a fair service. There should be enough money in the coffers to maintain supply and, indeed, to improve it where and if necessary."***

> ***"We, like other customers, have paid a lot for electricity over the years. Surely there has been enough paid to keep the service at an acceptable level for everyone."***

> ***"I am not prepared to pay more for it. I quite simply couldn't afford it."***

> ***"I don't like the sound of that idea. Electricity companies make enough money now. Deliver what is needed – please."***

The research participants were then asked (Figure 3-10b):

> ***"Would you be prepared to have slightly more power cuts, if it meant your electricity bill was a bit lower?"***

13% of the total respondents interviewed indicated they might be prepared to consider this trade-off, which has decreased slightly on the 16% recorded in last year's survey. Consideration was again notably lower among respondents from the Electra list sample, possibly because many of them had experienced the inconvenience of a recent outage.

## 3.10.4 **Uptake of technology**

Research participants were questioned to gain an indication of how many consumers in the Kāpiti-Horowhenua region have various items of technology for their own use. The overall results show there continues to be a considerable level of potential interest in current and emerging technologies, among residential and commercial consumers. The specific electrical equipment covered in the 2022 survey included heat pumps, solar panels, electric cars and charging facilities, e-bikes, and mobility devices as depicted in Figure 3-11.

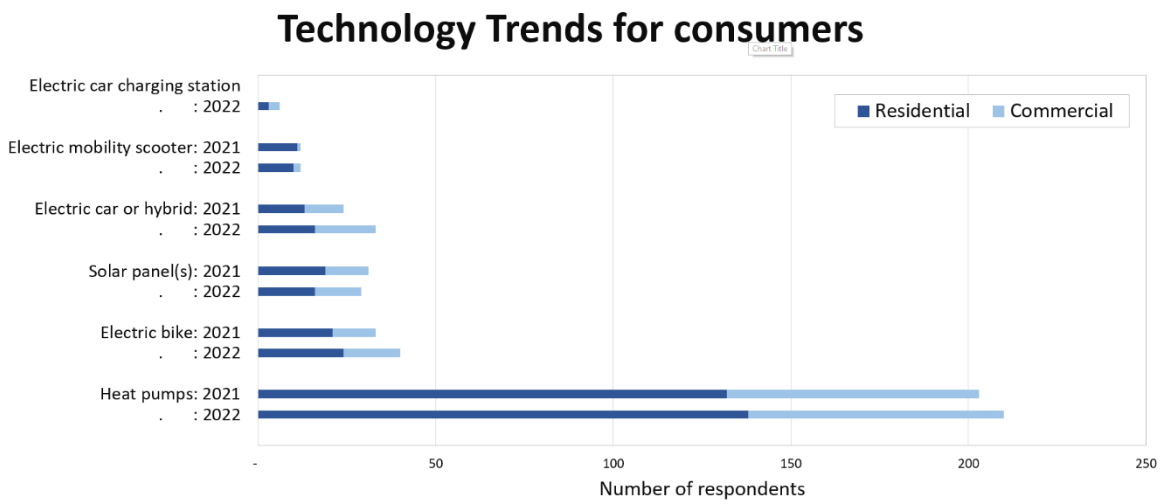



**Figure 3-11: Technology uptake by residential & commercial consumers 2021 to 2022**

The greatest increase in technology uptake from 2021 to 2022 was for electric or hybrid vehicles [up 3%], followed by heat pumps and electric bikes [2.3%]. Growth in electric vehicles or hybrids continue to grow and growth appears to be stronger amongst commercial consumers who participated in the 2022 survey.

A question to establish the level of interest in having a car-charging station connected to your electricity supply was introduced in the 2022 questionnaire and 6 respondents indicated that they currently have one and a further 24 respondents stated that they would consider obtaining one in the next two years. All of these respondents currently have an electric or hybrid vehicle.

## 3.11 **Customer Communications**

With an upgrade of our new Electra Outage Viewer and Mobile App, our website and app continue to function without issue. The new systems provide more accurate outage information while remaining easy to use on any device platform. Figure 3-12 displays the Splunk dashboard used by our customer care team where June 2021 saw more than double the number of visits to the outage website with 51,000 visits in a single day - showing our customer-centric strategy is paying off.

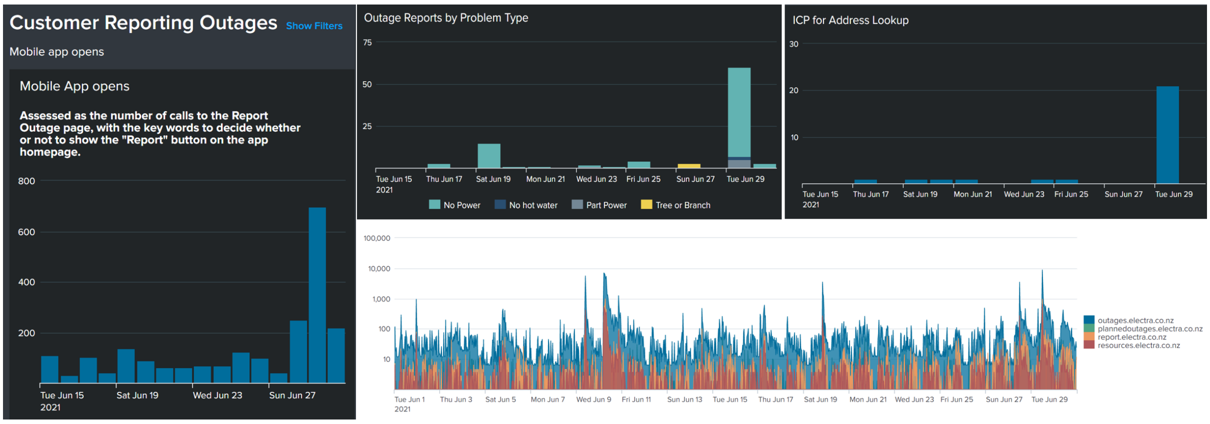
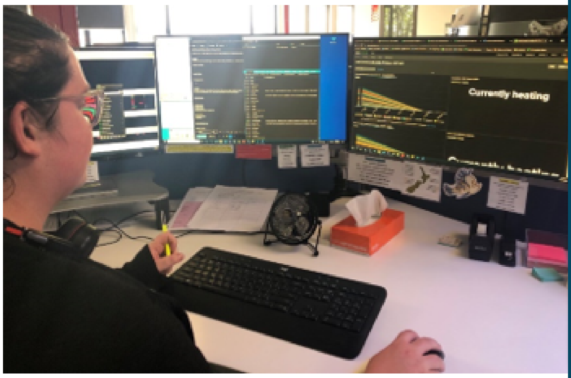



**Figure 3-12: Splunk dashboard monitoring the usage of our Electra mobile app**

Our customer care operators actively use the dashboards that record and display load control information so we can pro-actively aid and provide useful information to our customers when they contact us about hot water faults as demonstrated in Figure 3-13.



**Sep-2021 message from happy customer**

*Woke up to no hot water this morning... "Oh No"... Wife suggested calling* ***Electra*** *first to check on any outages...no outages, but someone would be out to check in the next two hours. Less than an hour later, a knock on the door and a smiling social distanced* ***Electra*** *employee told me that he had found the fault and fixed it! How happy was I!! Thank you from Millvale Street, Waikanae.* **Great service.**

**Figure 3-13: Customer care operator monitoring hot-water demand**

The Electra team has also been working with Chorus to receive notifications on optical fibre connections that report a power-loss or power-on event as displayed in Figure 3-14. This data set is analysed against the outages recorded in ADMS and we are observing good results in earlier notification of outages and assessing when the power is restored.

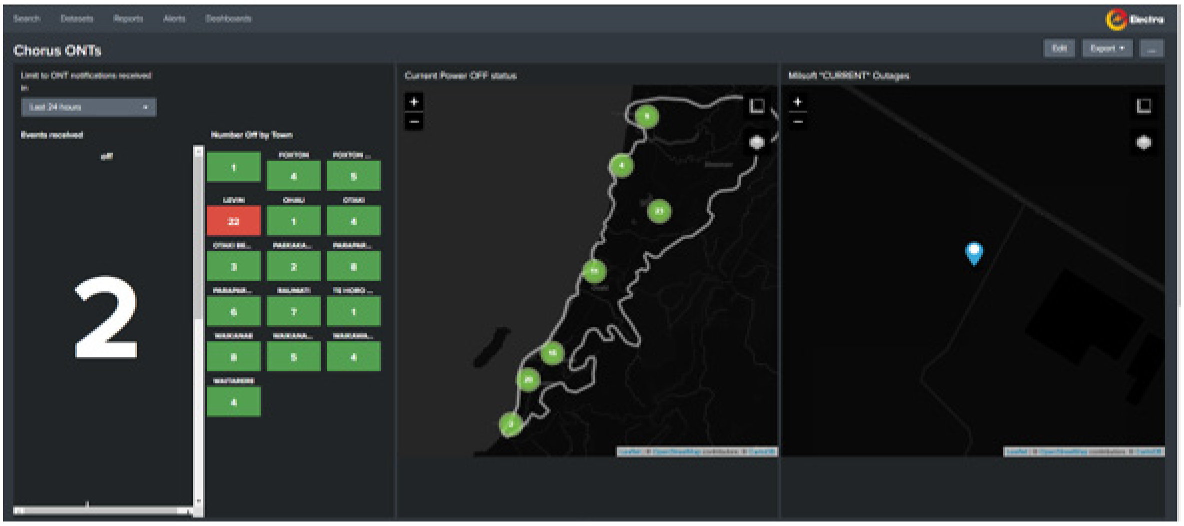



**Figure 3-14: Splunk dashboard indicating power loss on Chorus optical fibre connections**

Electra has also deployed over 250 power loss sensors (Figure 3-15a) that inform us when key customers lost power. The monitoring system is integrated into our ADMS where an alert will be received by Milsoft's DisSPatch software when the sensor loses power (Figure 3-15). Other initiatives are detailed in Section 4.10.

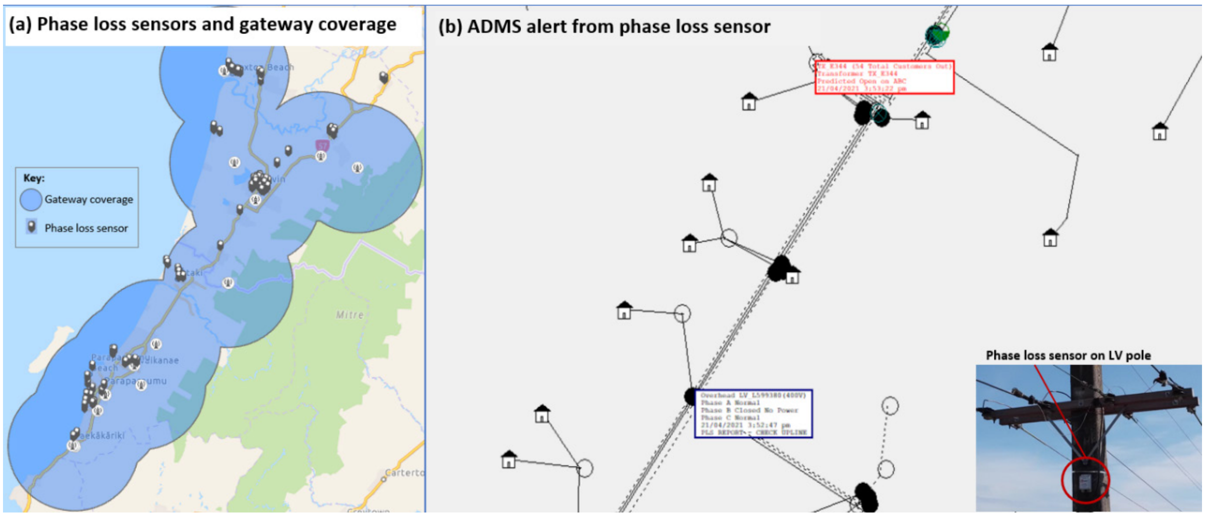



**Figure 3-15: (a) Phase loss sensors and gateway coverage; (b) ADMS**

## 3.12 **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 |

## 3.13 **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 | Updates in 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 | 4.11, 4.14 |
| New connections leading to more customers interrupted by any single fault | Reduce the number of customers effected by an unplanned interruption.<br>Reduce the time to restore supply may result from increased interconnection | Increase network sectionalisation | 4.3.5, 4.14 |
| 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 | 3.13.7, 8.8.5 |
| Thefts of copper earthing | Use alternative earthing installation methods | Replacement of copper earthing | 5.8, 5.9 |

### 3.13.1 **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 are detailed in Section 4.11.1.

### 3.13.2 **Sectionalisation of networks**

As more customers are added to individual feeders (mainly in Kāpiti), 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.

## 3.13.3 **Enhancement of substation fault monitoring and diagnostics**

As part of our reliability improvement programme, Electra continue to enhance the fault monitoring and diagnostics at our substations by the deployment of:

- **Partial discharge monitoring at Shannon Substation:** We are installing partial discharge monitoring at the 33kV circuit breaker at Shannon. Shannon is the first substation out of Mangahao with five 33kV circuits and one ripple control plant. The monitors are a pre-warning system and will detect deterioration or the breakdown of insulation where a message will be sent to the Control Centre.

- **Trojan Dry-Out System:** We have acquired a filtration system for the analysis and removal of moisture, gases and particulate from our zone transformers. Figure 3-16 shows the monitoring of oil temperature and moisture content level at Levin East T1 where the relative saturation (RS) and water in PPM or parts per million are analysed.

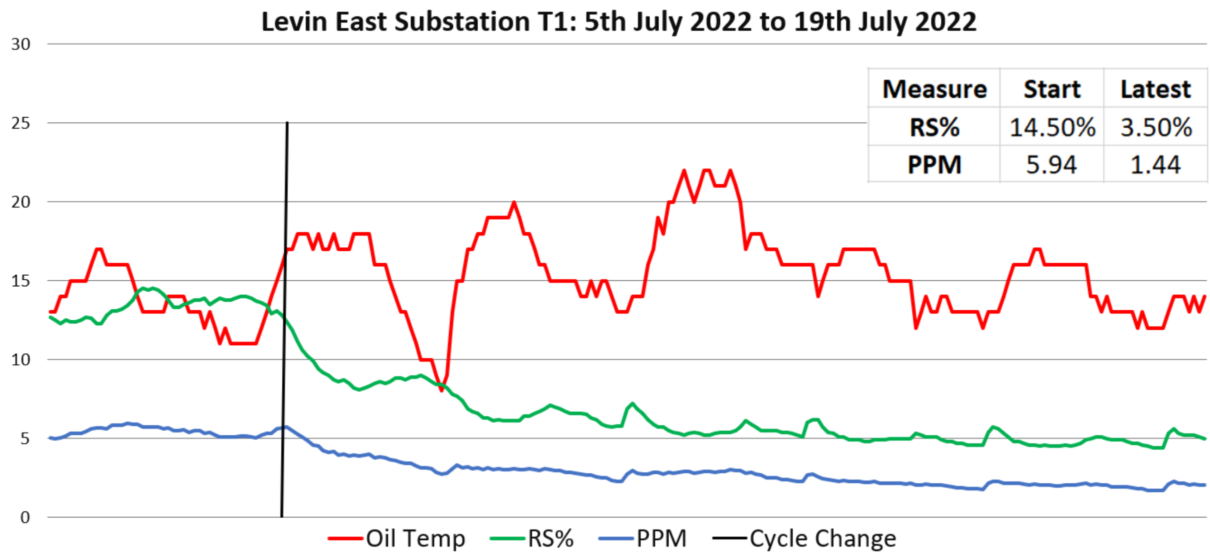



**Figure 3-16: Monitoring of oil temperature and saturation levels at Levin East 33/11kV Transformer T1**

- **Oil Sensory Probe at Zone Transformers:** We have commenced the installation of Schneider oil probes into our zone transformers, with IoT sensors as we shift towards a predictive strategic approach with visibility into the health of our oil transformers. Such information enables us to make data-driven decisions regarding their replacement and maintenance through a condition-based monitoring approach and proactive recommendations. Figure 3-19 shows the analytics for Levin West T1 analytics to help our engineers reduce transformer downtime and extend usable life. The parameters shown include the operating risks, real-time temperature and water content of the oil in parts per million (PPM) as well as the breakdown voltage. All these indicators measured show the transformer is stable and may be operated safely. Another three probes are being installed at our other zone substations.

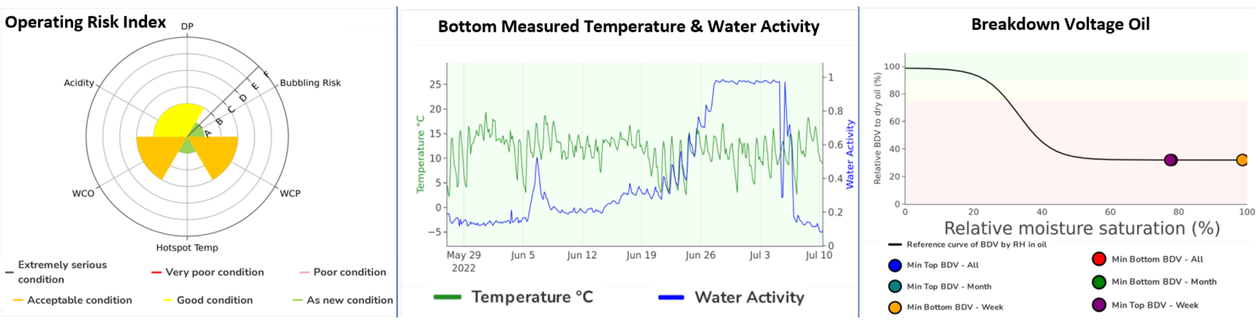



**Figure 3-17: Monitoring (a) operational risk levels, (b) oil temperature & water activity and (c) voltage breakdown, using an oil sensor probe at Levin West Substation T1**

## 3.13.4 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.

We have prioritised the replacement of copper conductors due to these contributing drivers other than just condition-based asset renewal and these issues are being addressed in our overhead line inspections programmes detailed in Section 5.4.

## 3.13.5 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, or 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.

## 3.13.6 Migration to planned tree trimming

Electra's vegetation management programme has evolved over recent years. During 2018 Electra 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 the 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<br>• Tree cutting driven from routine and customer requested survey.<br>• Improve network performance where impacted by vegetation | ▶ | • Risk rather than performance-based management of safety and SAIDI<br>• Progressively reduce reactive trimming, and instead proactively cutting trees back and engaging with tree owners to implement longer term solutions<br>• Systematically reduce risk in network sections between automated switches and circuit breakers<br>• 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 | • | • | • | • |

## 3.13.7 Reduction of repeated power failures

The feedback from customers (Section 3.10) identified the need to reduce the number of repeated power failures. Besides its 33kV resilience programme explained in Section 3.13.1, 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 FY2020 to FY2022. The worst ten 11kV feeders in terms of the number of failures are shown in Figure 3-18 as well as SAIDI (Figure 3-19a) and SAIFI (Figure 3-19b) impact.

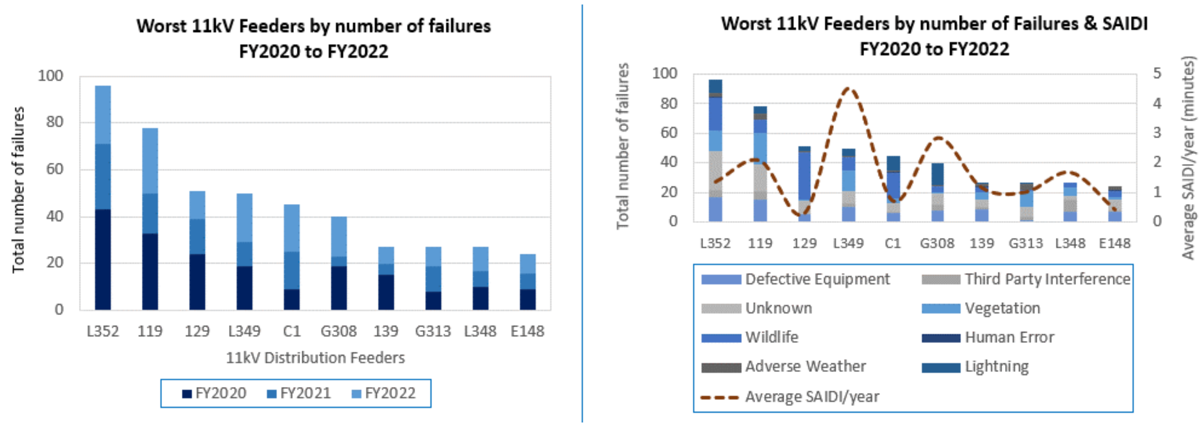



**Figure 3-18: Worst 11kV feeders by: (a) the number of faults and (b) related SAIDI impact: FY2020 to FY2022**

The worst feeders vary when monitoring by the number of failures (L352, 119, 129), the impact to SAIDI (L349, V316, G312) or SAIFI (V311, E153, L351). We have integrated this analysis as a continuous improvement in our worst feeder monitoring process

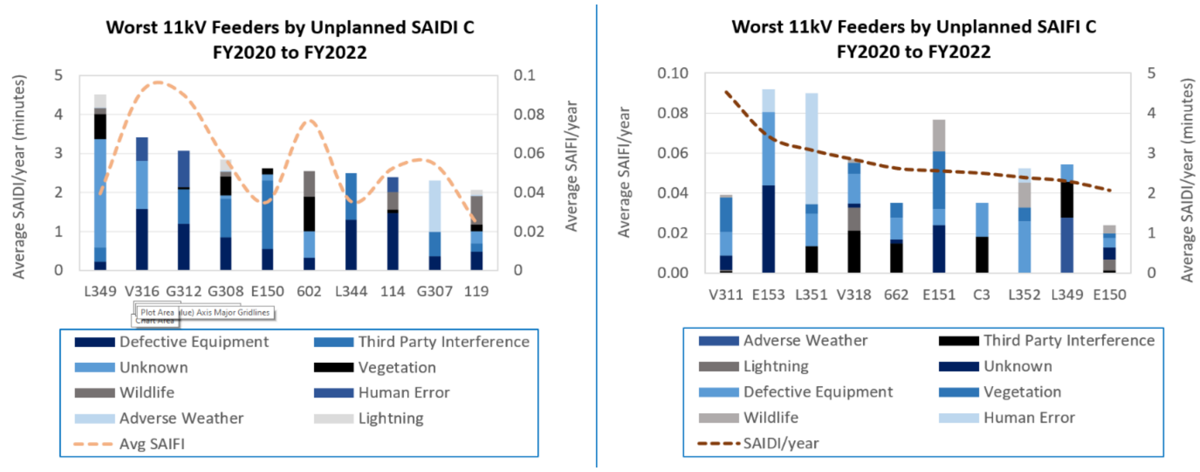
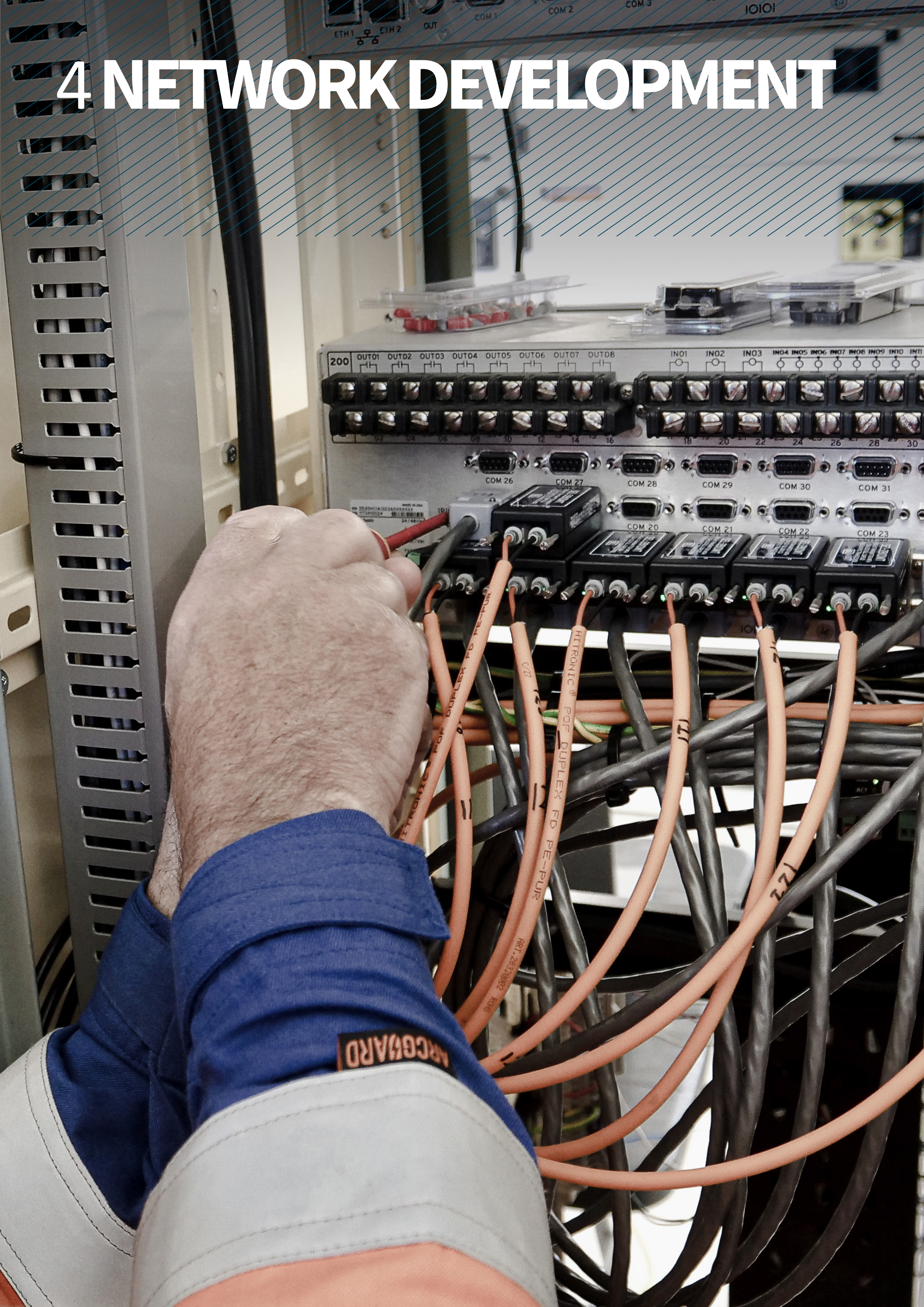



**Figure 3-19: Worst 11kV feeders due to faults for FY2020 to FY2022 by: (a) SAIDI and (b) SAIFI**

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 4.14. The prioritisation process for reliability-improvement projects for the worst feeders is discussed further in Section 8.8.2 where the process flow is shown in Figure 8-38. 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 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 has been 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
- Installation of Tripsavers on spur lines with repetitive nuisance faults. 3 units have been installed at sites that had issues with nuisance faults. These 3 sites averaged 16 outages a year together, since the installation of Tripsavers the number of faults has dropped to 3 in the past year.

# 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 the issues that have historically led to demand growth are now more complex with the uptake of electric vehicles, smart homes, 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
- Load growth forecast
- Demand response potential with pricing options.

### 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 or PQM readings exceed 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 | Maximum demand consistently exceeds 100% of name-plate 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 |

A review of the above triggers is being carried out to ensure that they are fit for purpose in a changing electricity system with emerging technologies.

### 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
- An unplanned SAIDI of 0.5 SAIDI minutes for a fault event where in-depth scrutiny will be conducted by a supervisor to prevent or mitigate such events
- An aggregation of ten feeder faults on any one feeder per year will result in a major intervention.

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 affected by a fault
- Circuit reconfiguration and sectionalisation of the feeder
- 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
- Non-network solutions such as Electra or third party owned Battery Energy Storage Systems or STATCOM
- Non-network solutions such as procurement of flexibility services.

### 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 12 MW 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 12 MW 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 8% of energy entering the network), hence the following approaches are used:

- Upgrading of overloaded conductors to reduce the I2R 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 Options for meeting or managing demand

Electra considers the following four classes of options for meeting or managing demand.

Note that the fourth option in the table below (being non-network alternatives) is currently in the development phase as part of our energy transformation roadmap. We have included in the table below to signal our future approach:

| 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 |
| | 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 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 or STATCOM | Installing an 11kV voltage regulator or STATCOM 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)<br><br>Electra expects 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 the capacity trigger is not exceeded) |
| Non-network alternatives | Issuing an RFP to the market for alternative approaches | In the future there may be merchant generation, battery storage, or interruptible demand aggregation (i.e. flexibility) that could provide a firm alternative to network solutions. |

### 4.3.5 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 1.8).

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 outlined in Section 4.3.4 provide potential solutions that are considered.

## 4.4 Known constraints

Transpower has reported[23] transmission capacity issues for both the Paraparaumu and Mangahao demand forecasts. The limited rating of Transpower transformers can mean full (n-1) security is unavailable when Electra is taking full load and Mangahao is not generating. The supply transformer overload and low voltage issues are managed operationally as Mangahao generation is usually available during peak load periods and load control options (using hot water loads) are available to Electra to offset the risk of a demand shortfall. In addition, Transpower has indicated the Mangahao supply transformers will be due for risk-based condition replacement in the early 2030s.

In consideration of the potential issues at the Mangahao GXP, we are in the process of engaging specialists to set out the roadmap for our 33kV subtransmission network which may include the construction of a new GXP in our northern region.

[23] *Transpower Transmission Planning Report 2022, Section 11 "Central North Island Regional Plan"*

Concerning Paraparaumu, a contingency on the Transpower's Bunnythorpe 220kV bus can lead to low supply bus voltages when the regional load is very high and hydro generation at Mangahao very low. The Mangahao transformers are planned for condition-based renewal in 2031 while the issue at Bunnythorpe is being monitored and reviewed as required.

The annual planning process elaborated in Section 4.8 has revealed a lower rate of demand growth in the Northern area and combined with the fact there is sufficient capacity for the current planning period, means it is unlikely the capacity of any significant assets will be exceeded without sufficient time to react. However, we recognise 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 affected by individual faults.

We measure both winter and summer load demand at all fifty 11kV substation feeders annually to closely monitor seasonal winter and summer demand. Seasonal load profiles remain consistent with recent historical trends with the majority peaking in winter with the exception of four feeders or 8% of our feeders that are summer-peaking, these are: Foxton's C1 South and C4 North, Levin West E153 Queen West and Paraparaumu West 406 feeders.

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
- Seasonal shifts in demand could require planned capacity upgrades to be accelerated or delayed.

## 4.5 Distributed generation assessment

### 4.5.1 Existing distributed generation

Apart from Mangahao (37 MW embedded at the GXP) and Unisys (0.96 MW x 2) generators, there are 1,148 known distributed generation sites on the Electra network with a combined capacity of about 5.02 MW as of November 2022 (as shown in Figure 4-1) 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.

### 4.5.2 Large-scale renewable generation connections

Electra has been approached by several large solar and wind farm projects (over 1 MW) 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.

### 4.5.3 Growth in photovoltaic generation

Residential solar photovoltaic (PV) generation is growing in New Zealand. With the reduction in the price of solar panels and inverters, the Electricity Authority's EMI monitor indicates there are 39,611 New Zealand residential connections who have installed solar panels (as of 30 September 2022) with a combined capacity of 167 MW. These statistics indicate that there are 7,403 more connections (23% increase) than the same time last year with a combined capacity of 39.8 MW more than a year ago[24].

The energy provided by PVs makes up a low percentage of our network, but this uptake is trending upward as illustrated in Figure 4-1. This PV yearly uptake rose from 126 connections in FY2021 to 153 connections in FY2022, with 134 connections in FY2023 up to November. Most of the PV panels installed are less than 10kW capacity and we will continue

[24] *Electricity Market Information (EMI) website, Electricity Authority as at 1/11/2022*

to monitor and support the development of distribution generation in line with our policies. Electra has also installed a 3kW photovoltaic panel (with an 8kWh battery capacity) at our Head Office to better manage and understand the imapct (Section 6.3.1) on the network and provide assistance to customers.

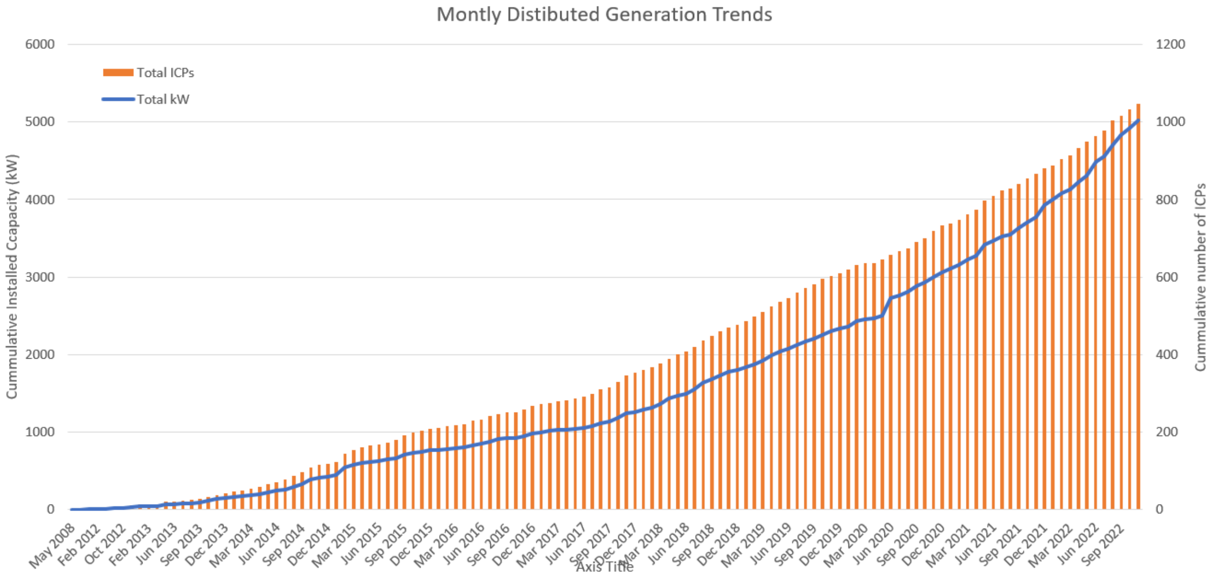



**Figure 4-1: Electra installed solar distributed generation trends**

### 4.5.4 **Further development and response to DG and DER growth**

Electra is engaging with prospective customers and partners to integrate controllable Distributed Energy Resources (DERs) into the network. Concurrently Electra keeps a watching brief on regulatory developments by the Electricity Authority, developments in overseas markets, and approaches made by other EDBs.

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.

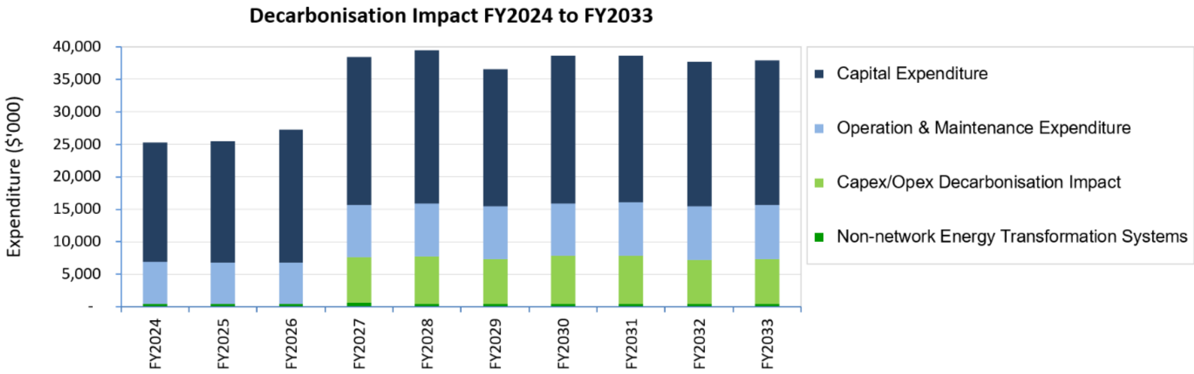
## 4.6 **Flexibility Solutions**

Flexibility solutions use distributed energy resources (DERs) which are small-scale, distribution-connected assets that either reduce load or inject more power for generation (such as solar panels), storage (batteries), or automated load management devices[25].

Ara Ake's FlexForum Plan 1.0[26] sets out a plan to unlock the value of distributed energy resources (DER) and flexibility. Many steps identified for the initial stages of flexibility reside with EDBs and MBIE's plan stresses the need for EDBs to have efficient connection processes, understand headroom/constraints and analyse PQ parameters.

Electra's Huringa Pūngao initiative, our Energy Transformation Roadmap[27], aims to reduce our carbon emissions through electrification and increase renewable generation to achieve net-zero 2050, where DERs are a key factor to achieving decarbonisation. The impact of decarbonisation on our expenditure is depicted in Figure 4-2 where expenditure is estimated to accelerate from $27.2M (FY2026) to over $38.4M from FY2027 due to the impact of decarbonisation. This expected increase in decarbonisation expenditure from FY2027, was referred to in our AMP Overview (Section 1.1) concerning an October 2022 BCG publication[28] highlighting the increased investment required by distribution networks estimated at a 30% increase in total expenditure in FY2027-30 relative to FY2022-26. Initial spending related to decarbonisation is included in our ICT forecast from FY2024 as shown in Figure 4-2.

[25] *Electricity Authority's Discussion Paper July 2021, "Updating the Regulatory Settings for Distribution Networks - Improving competition and supporting a low emissions economy".*
[26] *Ministry of Business, Innovation & Employment, "A Flexibility Plan 1.0", 31 August 2022*
[27] *Energia, Huringa Pūngao Energy Transformation Roadmap Final Report, October 2021*
[28] *BCG, "The Future is Electric: A Decarbonisation Roadmap for New Zealand's Electricity Sector", Oct 2022*




| Network & Non-network Expenditure ($'000) | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | Average % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Expenditure | 18,280 | 18,607 | 20,394 | 22,773 | 23,558 | 21,065 | 22,652 | 22,554 | 22,194 | 22,211 | 62% |
| Operation & Maintenance Expenditure | 6,504 | 6,407 | 6,350 | 8,035 | 8,087 | 8,092 | 8,095 | 8,176 | 8,258 | 8,340 | 22% |
| Capex/Opex Decarbonisation Impact | - | - | - | 6,963 | 7,296 | 6,938 | 7,381 | 7,440 | 6,792 | 6,878 | 14% |
| Non-network Energy Transformation Systems | 450 | 450 | 475 | 650 | 500 | 450 | 450 | 450 | 450 | 450 | 1% |
| | 25,235 | 25,465 | 27,219 | 38,421 | 39,441 | 36,546 | 38,578 | 38,621 | 37,694 | 37,878 | 100% |

**Figure 4-2: Decarbonisation impact on Capex, Opex and ICT expenditure**

Decarbonisation, particularly relating to increased renewable generation, electrification of transport and process heat is widely forecast by Transpower and other EDBs to lead to higher maximum demand and higher total energy distributed through networks. This has been supported by our Huringa Pūngao studies and increased CAPEX spend resulting from this is now flowing into AMP horizons.

Two scenarios were developed consistent with Transpower's Whakamana i Te Mauri Hiko "Accelerated Electrification" scenario, which is the most aligned to the likely direction for New Zealand, and Transpower's most recent monitoring report supports this view. The drivers considered in determining the scenarios included:

- Population growth
- Future electricity intensity
- Uptake of electric vehicles
- Electrification of gas
- Demand control
- Uptake of distributed energy resource.

## 4.7 Huringa Pūngao Energy Transformation Update

### 4.7.1 Energy transformation roadmap

During FY2022 we prepared an Energy Transformation Roadmap to ensure that we supported the electrification of New Zealand. A summary of the roadmap was included in our FY2022 AMP Update.

How the energy transformation will unfold is not yet clear, in particular how demand control (i.e. hot water control) will evolve and at what speed the transformation occur. The Energy Transformation Roadmap (coupled with ongoing monitoring and adjustments) is intended to guide Electra through this uncertainty. It does this by defining two pathways - one where Electra continues to enjoy the benefits of demand control, and one where it needs to augment the network in the absence of "firm" demand control.

### 4.7.2 Review of indicators for the energy transformation

As mentioned, the energy transformation roadmap comprises two pathways (access to flexibility and network augmentation) and as part of the most recent update we have assessed the pathway indicators (see table below). Our assessment indicates that the signposts are clearly pointing towards the accessing flexibility pathway, however, whether Electra can access "firm" flexibility still remains unclear. Given this uncertainty, we continue to keep both roadmap pathways open.

| Signpost | Accessing flexibility pathway | Network Augmentation Pathway | Status Comments |
|---|---|---|---|
| Flexibility market rules are developed by the EA | More likely | Less likely | Real-time wholesale market price live from 1/11/2022. From April 2023 the dispatch notification product will enable the inclusion of DER and aggregated demand management in the wholesale market |
| EA develops rules that undermine the existing ripple control system | Less likely | More likely | From April 2023 the dispatch notification product will enable the inclusion of DER and aggregated demand management in the wholesale market |
| Integrated EV, DER, and smart appliance load management systems become widely available and cheap to install | More likely | Less likely | No material change |
| Retailer offers tariff products (i.e. payments/discounts) for flexibility services at their call | Less likely | More likely | Commercial customer products available (e.g. Simply Energy and Contract Energy) |
| Retailer or generator issues an RFP for flexibility services to firm intermittent generation | Less likely | More likely | No RFP observed, however these are likely on the back of the April 2023 market changes, however both Contact and Meridian are undertaking grid battery projects |
| Distributor issues an RFP for flexibility services to defer a network project | More likely | Less likely | Aurora Energy and SolarZero partnership in Upper Clutha and Wanaka to provide flexibility (via residential PV+Battery systems). WEL Networks building a 35 MW Battery for network support. Vector issued RFI for non-network alternatives in the Warkworth region |
| Retailers offer products and services that result in the disabling or removal of hot water ripple receivers | Less likely | More likely | Influx are offering a hot-water control product—the impact the product will have on hot-water control is still being assessed |
| Independent flexibility trader enters the market and actively purchases flexibility from consumers | Less likely | More likely | Commercial customer products available (e.g. Simply Energy and Contract Energy).<br>Not observed for residential customers. |
| Existing player in the Transpower instantaneous reserves market offers control device to consumers (by-passing existing ripple control receivers) | Less likely | More likely | Not observed |

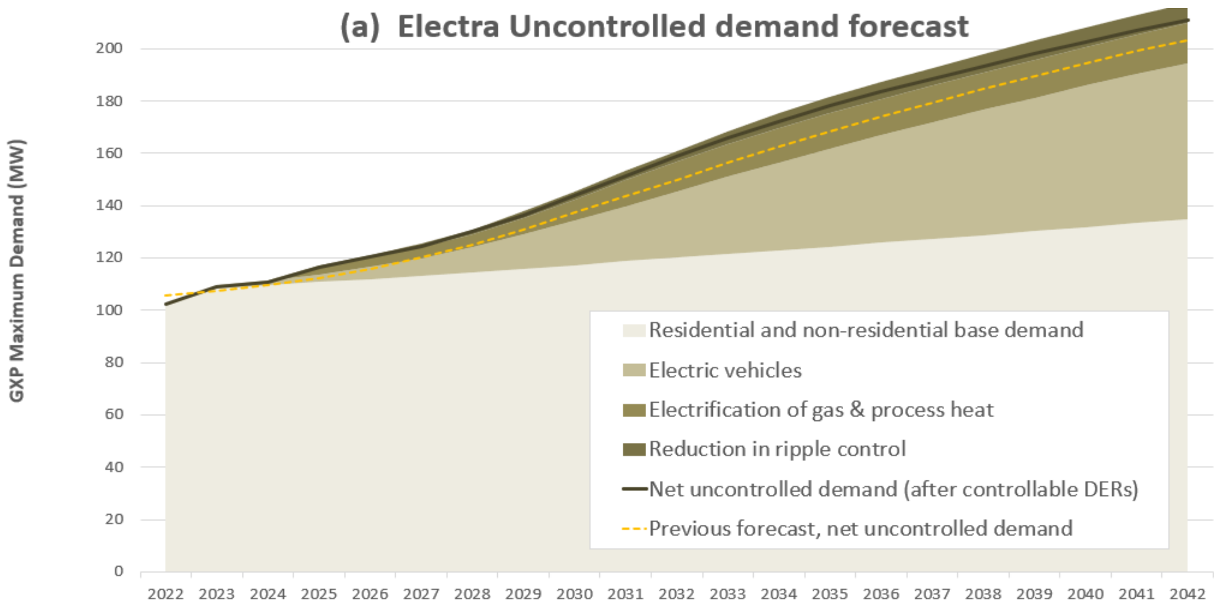
### 4.7.3 The importance of ensuring future demand is controlled

As Figure 4-3 illustrates, there is a significant difference between the uncontrolled and controlled demand scenarios. Our previous assessment indicated that an uncontrolled outcome could require an additional $85 million of capex between now and 2042 when compared to the controlled scenario. Most of the additional spend is required beyond 2030.

The difference between uncontrolled and controlled demand is driven by two factors:

- Electric vehicle charging load-shifting at 53 MW
- Demand flexibility from hot-water control and industrial demand response, at 12 MW.

Hence, the most significant issue is to ensure we progress down the *accessing flexibility* pathway to ensure we maximise EV charging load shifting and access to hot-water flexibility.



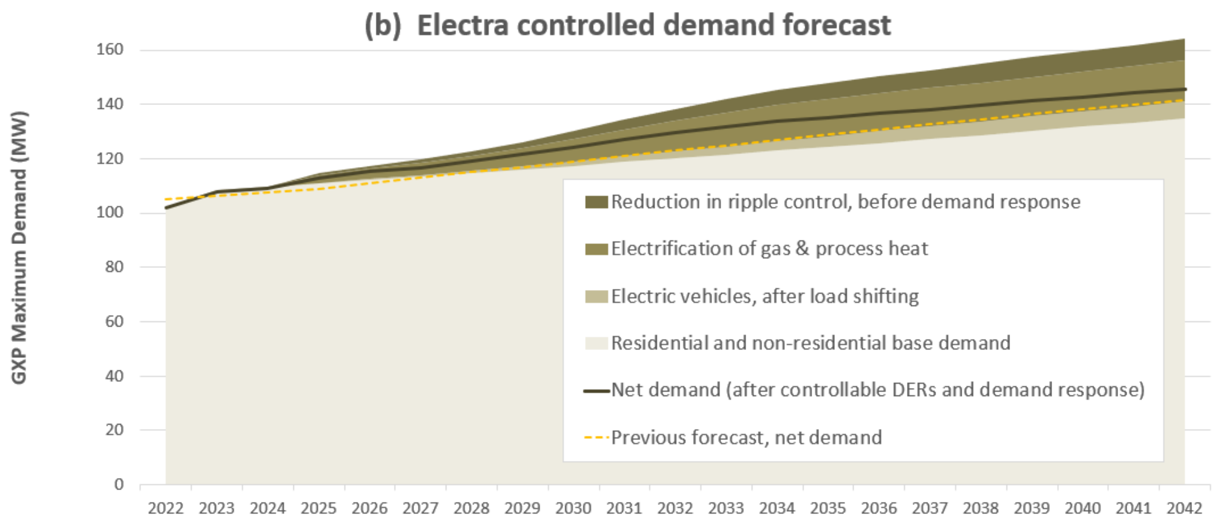




**Figure 4-3: Updated demand scenarios for energy transformation from 2022 to 2042: (a) Uncontrolled demand forecast; (b) Controlled demand forecast**

## 4.8 Demand forecasts

### 4.8.1 Current system demand

Based on thirty-minute mean demands at our Mangahao and Valley Road GXPs, the maximum coincident winter demand was 108.2 MW recorded on 21 July 2022, an increase of only 0.8% as compared to the previous year's increase of 3.3%. Figure 4-4 shows the demand profile as well as the associated time duration analysis on the percentage of time the load was exceeded.

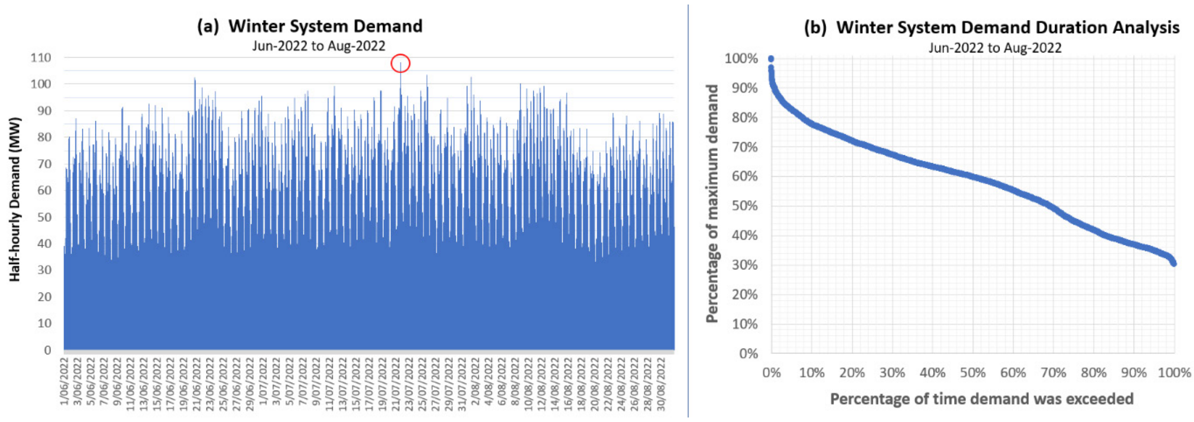
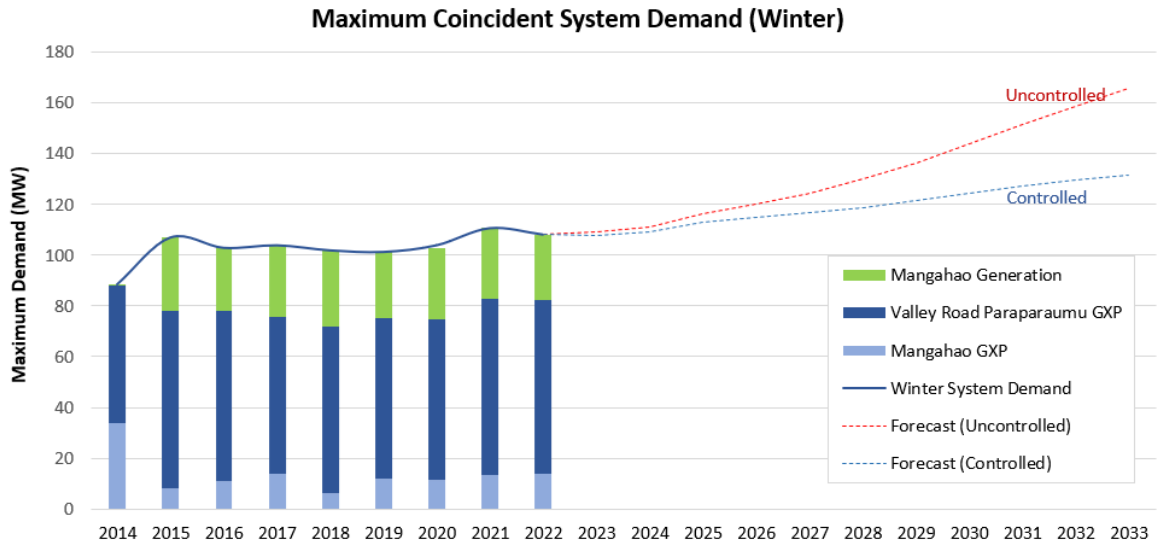



**Figure 4-4: (a) Winter system demand profile for June-August 2022; (b) Demand duration analysis**

In Figure 4-5 the Huringa Pūngao Energy Transformation future scenarios use the starting point of our current winter maximum coincident system demand of 108.2 MW which occurred on 21 July 2022 at 6 pm. The scenarios for demand depict the low (controlled) and high (uncontrolled) demand forecasts at 2.2% and 5.2% respectively.




| Electra Network | Actual 2022 (MW) | Forecast Maximum Demand (MW) | | | | | | | | | | | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | Increase % |
| Maximum Coincident System Demand | | | | | | | | | | | | | |
| - Uncontrolled Scenario | 108.2 | 109 | 111 | 117 | 120 | 125 | 130 | 137 | 144 | 151 | 159 | 166 | 5.2% |
| - Controlled Scenario | | 108 | 109 | 113 | 115 | 117 | 119 | 121 | 124 | 127 | 130 | 132 | 2.2% |

**Figure 4-5: Electra network - Maximum coincident system demand**

## 4.8.2 **Approach to system demand forecasts**

Electra has changed its approach to forecasting demand based on the Huringa Pūngao report and recent update. Huringa Pūngao has been a step-change improvement in our forecasting. Our new methodology includes a wide range of inputs to produce scenario-based forecasting.

Our Huringa Pūngao Energy Transformation studies continue to forecast separate uncontrolled and controlled demand, as access to demand response still remains unclear. The factors that drive the difference between the two forecasts are:

- Residential flexibility (demand response replacing hot water ripple control)
- EV charging load-shifting
- Industrial demand response.

The demand forecasts consider the following drivers:

| Demand driver | Consideration |
|---|---|
| Residential and non-residential connection growth | • Horowhenua District's population is projected to grow at 1.8% per year over the next ten years[29]. The same study also found the population growth is higher than the average of the past 10 years (1.5% per year) but more slowly than the average of the past 6 years (2.1% per year)<br>• For the Kāpiti Coast District Council (KCDC), Sense Partners median forecast[34] has been identified as the baseline used as the forecast reflected an annual average rate of growth of 1.5% similar to the growth rate Kāpiti had experienced from 1996 – 2020 and the rate of growth identified in KCDCs Long Term Plan 2021 – 4110<br>• The Covid-19 pandemic, which affected many businesses, had little impact on the maximum demand of our zone substations as zone maximum demands increased between 1% to 12% per annum from 2019 to 2022. Paekākāriki increased from 2.28 MVA in 2019 to 3.12MVA in 2022 |
| Residential and non-residential electricity intensity | • Changes in electricity intensity was applied consistent with Te Mauri Hiko (accelerated electrification) scenario<br>• Residential electricity intensity is forecast to decline by 0.6% p.a. and non-residential is forecast to decline by 1.3% p.a. This is higher than the historical CAGR of -0.4% p.a |
| Uptake of electric vehicles | • The uptake of electric vehicles was based on Te Mauri Hiko (accelerated electrification) moderated by regional household income levels and current vehicle numbers<br>• Current LEV numbers were slightly below prior forecasts, and are 85% of Te Mauri Hiko (AE) as at 2022. The household income moderation was 77% and 88% for the Mangahao GXP and Paraparaumu GXP respectively<br>• Vehicle consumption and charging patterns reflected Te Mauri Hiko (accelerated electrification) for both the *controlled and uncontrolled* scenarios |
| Electrification of residential and commercial gas | • The rate of conversion of residential and commercial gas to electricity was applied consistent with Te Mauri Hiko (accelerated electrification), with all gas usage converted by 2050 |
| Electrification of industrial process heat | • A conservative assumption was made in relation to the electrification of low temperature industrial process heat conversion (50% of Te Mauri Hiko (accelerated electrification) scenario)<br>• We are planning to undertake more detailed analysis of the current process lead load within the Horowhenua and Kāpiti Coast regions during FY2024<br>• No high temperature process heat is forecast to be converted to electricity |
| Residential demand response | • Current hot-water ripple control is assessed at 3.9 MW for consumers connected to Mangahao GXP and 6.1 MW for consumers connected to Paraparaumu GXP<br>• In the *uncontrolled* scenario this demand response is forecast to be "by-passed" and no longer available to Electra, with the ripple control system being retired around 2045<br>• In the *controlled* scenario hot-water demand response is 10 MW (in 2042) |
| Industrial demand response | • For the *controlled* scenario, with the inclusion of the electrification of process heat we have included industrial demand response in relation to 30% of the converted demand<br>• In the *controlled* scenario industrial demand response is 1.8 MW (in 2042) |
| Distributed energy resources (DERs) | • Growth in DERs was as per Te Mauri Hiko (accelerated electrification) moderated for relative sunshine hours. Relative sunshine hours is used as a proxy for poorer economics of the installation which slows uptake<br>• Controllable DERs reduce demand by 7.2 MW in 2042. This is the same for both the *uncontrolled and controlled* scenarios |

## 4.8.3 **Long-term system demand forecasts**

As part of the Huringa Pūngao project we prepared demand forecasts to reflect the potential outcomes under each of the pathways. The two scenarios were:

- The uncontrolled scenario is where consumers operate in an uncontrolled manner and Electra has little influence and control over demand behaviour
- The controlled scenario is where consumers respond to incentives and Electra can shift consumption to control demand at a cost that is economic.

[29] *Sense Partners, "Horowhenua Socio-Economic Projections Summary and Methods", May 2020*
[30] Kāpiti Coast District Council, "Regional Housing and Business Development Capacity Assessment – Housing Update", May 2022

Over the past year we updated the demand forecast for these two scenarios. For the uncontrolled scenario (shown in Figure 4-3a) demand is forecast to increase 106% from 103 MW (2022) to 211 MW (in 2042). The 2042 forecast demand is 8 MW (3.7%) higher than our previous forecast due mainly to the inclusion of the electrification of low temperature process heat and higher population growth in the Kāpiti region.

For the uncontrolled scenario (shown in Figure 4-3b) demand is forecast to increases 43% from 103 MW (2022) to 146 MW (in 2042). This represents a 3.5% increase over our prior forecast, due to the same reasons as mentioned above.

The key changes from our prior forecasts were:

- The electrification of industrial process heat, and a slight increase in the electrification of commercial gas connections
- Higher forecast growth in the number of households in Kāpiti, which drives an increase in base demand and an increase in EV demand.

We intended to iteratively build on this model, reviewing annually and expect the granularity down through our voltage levels to progress annually.

# 4.9 GXP, substation demand and capacity-security assessment

## 4.9.1 Demand forecasting process

Electra uses the following forecasting process:

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

## 4.9.2 Demand drivers

Electra considers the demand drivers as set out under the considerations of Section 4.8.2 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.

Additional details on these drivers are provided in the following table:

| 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, Kāpiti 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, Paraparaumu, Ōtaki and Levin | Minimal of itself | Increase |
| | Commercial growth around Paraparaumu and Levin | Minimal of itself | Increase |

| Class of driver | Detailed driver | Impact on demand per customer | Impact on number of customers |
|---|---|---|---|
| Transport policy | Acceleration or 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 increase/decline in new house growth in Horowhenua. Possible increase in density throughout region |
| | Uptake of EVs, 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 |
| Reticulated gas | Policies that restricts new or existing use of reticulated gas | Possibly 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 |
| Decarbonisation of process heat | Policies that incentivise process heat to convert to electricity | Possibly significant | Minimal |

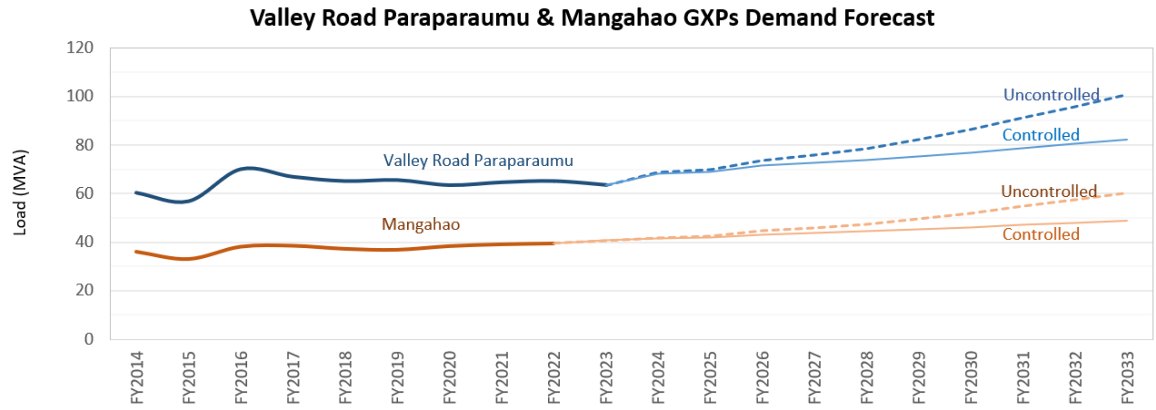
The following specific technologies and their likely implications for demand growth or contraction have been considered:

| 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<br>• Declining load factor<br>• Declining power factor<br>• Increasing harmonics |
| Roof top solar | Injection | • Possible off-set of GXP demand (but probably not during peak periods)<br>• Possible increase in peak loading of some feeders, possibly leading to export congestion<br>• Over voltages during periods of high generation and low demand<br>• Increased bi-directional power flows that require changes to protection and control settings<br>• Reduced kWh sales if located behind the meter<br>• Peak seen by the GXPs may shift later into summer evenings |
| Batteries | Consumption | • Possible improving load factor if charging restricted to off-peak. |
| | Injection | • Possible off-set of GXP demand<br>• 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<br>• 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 |

## 4.9.3 GXP demand forecasts

Our Huringa Pūngao Energy Transformation report indicates two scenarios for future uncontrolled and controlled demand (Section 4.6) relating to the uptake of DERs and Figure 4-6 shows the Valley Road Paraparaumu and Mangahao GXP demand forecasts. Using the Huringa Pūngao methodology, the forecasted controlled and uncontrolled scenario projections are based on the average of the top-10 peak half-hour periods.

Comparing the GXP winter maximum demands (MD) for calendar years 2021 and 2022, Valley Road Paraparaumu's peak MD decreased slightly from 69MVA to 63MVA while Mangahao's peak decreased from 42MVA to 41MVA.




| GXP | Scenario | Actual | Forecast Maximum Demand (MVA) | | | | | | | | | | Avg Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | FY2023 | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | Increase % |
| Valley Road Paraparaumu | Uncontrolled | 63.4 | 68.7 | 69.9 | 73.4 | 75.9 | 78.7 | 82.1 | 86.3 | 91.2 | 95.9 | 100.6 | 5.3% |
| | Controlled | 63.4 | 68.0 | 68.8 | 71.4 | 72.8 | 73.7 | 75.2 | 76.9 | 78.8 | 80.7 | 82.4 | 2.3% |
| Mangahau | Uncontrolled | 40.6 | 41.8 | 42.4 | 44.6 | 46.0 | 47.5 | 49.5 | 51.9 | 54.7 | 57.5 | 60.2 | 5.0% |
| | Controlled | 40.6 | 41.4 | 41.8 | 43.1 | 43.8 | 44.5 | 45.2 | 46.1 | 47.0 | 48.0 | 49.0 | 2.0% |

**Figure 4-6: Winter system demand forecasts for Valley Road and Mangahao GXPs**

### 4.9.3.1 GXP capacity/security assessment

Network constraints Electra may face in the future will occur mainly at the Mangahao grid exit point on the network. Two 110/33kV transformers supply Mangahao's load, providing:

- A total nominal capacity of 60 MVA
- n-1 capacity if 37/39 MVA (summer/winter).

As depicted in Figure 4-6, Mangahao GXP first exceeded the transformers (n-1) winter capacity of 37MVA by approximately 2.5 MW in 2015 and for the winter demand this year, the (n-1) capacity was exceeded by 2.2MVA. The Mangahao generation station is connected to the 33kV bus and the supply transformer overload is managed operationally as Mangahao generation is usually available during peak load periods. If Mangahao continues to generate at 13 MW 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 Ōtaki Expressway projects in 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 Kāpiti area.

The table below assesses the forecast capacity (at the required level of security) for the GXPs. Presently the description of the constraint related to the *controlled* demand. That is, our assessment assumes we are progressing down the *access to flexibility* pathway.

We have included the *uncontrolled* demand in the table below to provide visibility of potential constraints should it emerge we are heading down the *network augmentation* pathway.

| GXP | Firm Capacity (MVA) | Maximum demand (MVA) | | | Provision for growth |
|---|---|---|---|---|---|
| | | FY2023 | FY2033 Controlled | FY2033 Uncontrolled | |
| Mangahao | 37.0[31]<br>[50.0][32] | 40.6 | 49.0 | 60.2 | Mangahao GXP first exceeded the transformers (n-1) winter capacity of 37MVA by approximately 2.5 MW in 2015 and for the winter demand this year, the (n-1) capacity was exceeded by 2.2MVA.<br>Presently the risk of a supply transformer overload is managed operationally by Mangahao generation which is usually available at peak load periods. If Mangahao continues to generate at 13 MW or more, there will be no binding constraint within the forecast period.<br>The Mangahao transformers are due for risk-based condition replacement in the early 2030. The replacement transformers will be upgraded to 60MVA (or greater).<br>In consideration of the potential issues at the Mangahao GXP, Electra is in the process of engaging specialists to set out the roadmap for our 33kV subtransmission network which may include the construction of a new GXP in our northern region. |
| Valley Road Paraparaumu | 120 | 63.4 | 82.4 | 100.6 | No constraints over the forecast period.<br>This GXP has recently been reconfigured to obtain supply from Transpower's 220kV network and the 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 AMPs to delay upgrade work are no longer needed. |

## 4.9.4 **Zone substation demand forecasts**

Our zone substation demand forecasts follow a similar approach to the Huringa Pūngao methodology but adjust the demand growth rates for factors that will influence demand at each zone substation.

The additional regional factors considered included:

- Differences in sub-region growth rates (consistent with that forecast by Horowhenua District Council and Kāpiti Coast District Council)
- Known large residential subdivisions
- Known new industrial customers or growth at existing industrial sites.

The table below summarises the growth drivers for each zone substation.

| Zone substation | Nature of growth | Average annual demand growth | | | Annual average population growth[33] |
|---|---|---|---|---|---|
| | | FY2021 | FY2022 | FY2023 | |
| Shannon | Mainly lifestyle blocks around Tokomaru | 1.8% | 1.9% | 5% | 2.9% |
| Foxton | Mainly residential development at Foxton Beach | 2.7% | 2.7% | 3% | 2.3% |
| Levin East | Mainly commercial and lifestyle blocks to the south and east of Levin. Possible large off-peak industrial load growth | 1.8% | 2.0% | 4% | 2.2% |
| Levin West | Mainly residential properties at Waitarere Beach and lifestyle properties to the north and west of Levin | 1.9% | 2.0% | 3% | 2.2% |
| Ōtaki | Mainly lifestyle blocks in Manakau and Te Horo. Residential greenfield development in/near Ōtaki planned. | 2.2% | 2.3% | 4% | 2.4% |
| Waikanae | Mainly residential.<br>Residential greenfield development in/near Waikanae planned. | 2.9% | 2.8% | 4% | 3% |
| Paraparaumu East | Mainly commercial and residential infill | 1.4% | 1.7% | 2% | 1.7% |

*[31] Excluding Mangahao generation*
*[32] Including average generation output from Mangahao. Security assessed on a N-g-1 approach.*

| Zone substation | Nature of growth | Average annual demand growth | | | Annual average population growth[33] |
|---|---|---|---|---|---|
| | | FY2021 | FY2022 | FY2023 | |
| Paraparaumu West | Mainly commercial and residential infill | 1.3% | 2.0% | 2% | 1.7% |
| Raumati | Mainly residential infill | 0.9% | 1.2% | 2% | 1.6% |
| Paekākāriki | Mainly residential infill | 0.8% | 1.5% | 5% | 0.8% |

The Horowhenua District's population is projected to grow at 1.8% per year over the next ten year[34]. The same study also found the population growth is higher than the average of the past 10 years (1.5% per year) but more slowly than the average of the past 6 years (2.1% per year).

For the Kāpiti Coast District Council (KCDC), Sense Partners median forecast (see Section 2.1.4) has been identified as the baseline used as the forecast reflected an annual average rate of growth of 1.5% similar to the growth rate Kāpiti had experienced from 1996 – 2020 and the rate of growth identified in KRDC's Long Term Plan 2021 – 41[35].

The Covid-19 pandemic, which affected many businesses, had little impact on the maximum demand of our zone substations as zone maximum demands increased between 1% to 12% per annum from 2019 to 2022. Paekākāriki increased from 2.28 MVA in 2019 to 3.12MVA in 2022.

The ten-year demand forecasts for zone substations are built-up from an assessment of a range of factors at each GXP:

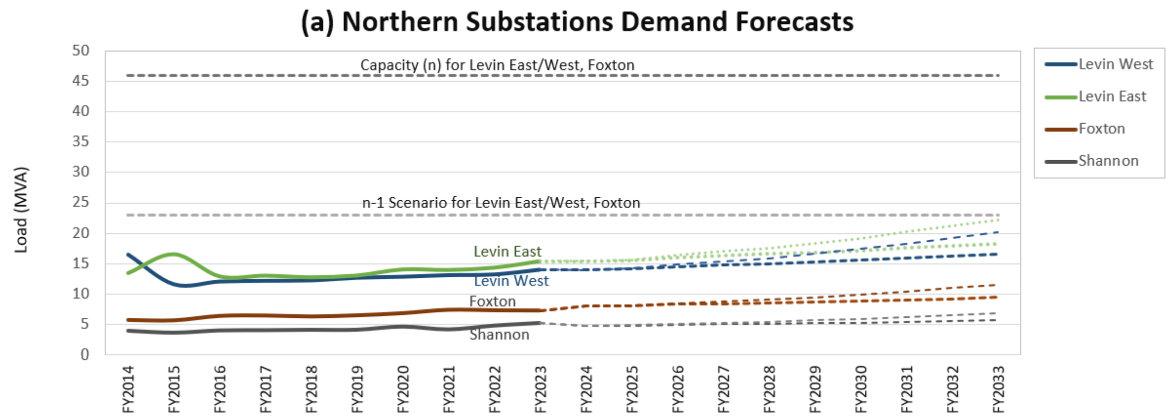
- Residential and non-residential base connection and demand
- Electric vehicles
- Electrification of gas and process heat
- Residential demand response
- Industrial demand response
- Distributed energy resources.

The northern substations' demand forecasts are shown in Figure 4-7a for both the controlled and uncontrolled scenarios. The annual growth rate over the ten-year forecast (2023 to 2033) is 5% for the northern substations of Levin East, Levin West, Foxton and Shannon based on our Huringa Pūngao Energy Transformation impact studies in Section 4.6. These rates for Levin and Foxton are well below their n-1 capacity, so no action is required.

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 in each instance and carry out dedicated maintenance to lessen the 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. The projected demand for Shannon substation suggests the (n-1) rating will be exceeded after 2025 if the growth continues at 1% to 3% per annum. However, this increase is being managed by some load shifts at 11kV feeder level to Foxton substation.

[33] *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). The next census will be in 2023.*
[34] *Sense Partners, "Horowhenua Socio-Economic Projections Summary and Methods", May 2020*
[35] Kāpiti Coast District Council, "Regional Housing and Business Development Capacity Assessment – Housing Update", May 2022

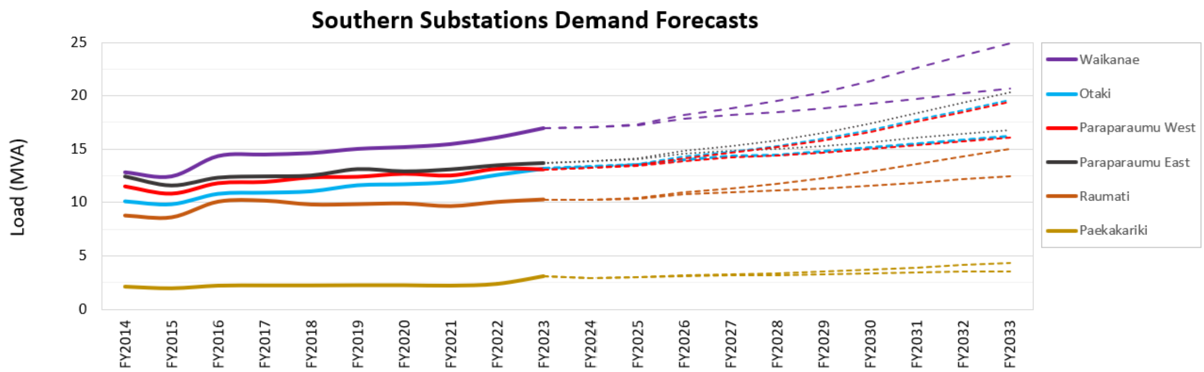



Note: Capacity (n) for Shannon is 10 MVA; all other substations = 46 MVA. The (n-1) scenario for Shannon is 5 MVA; all others = 23 MVA.

| Zone Substation | Actual | Forecast Maximum Demand (MVA) | | | | | | | | | | Avg Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | FY2023 | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | Increase % |
| **Controlled scenario** | | | | | | | | | | | | |
| Levin East | 15.4 | 15.4 | 15.6 | 16.1 | 16.3 | 16.6 | 16.9 | 17.2 | 17.6 | 17.9 | 18.3 | 1.9% |
| Levin West | 14.0 | 14.0 | 14.1 | 14.6 | 14.8 | 15.0 | 15.3 | 15.6 | 15.9 | 16.3 | 16.6 | 1.8% |
| Foxton | 7.3 | 8.0 | 8.1 | 8.3 | 8.4 | 8.6 | 8.7 | 8.9 | 9.1 | 9.3 | 9.4 | 3.0% |
| Shannon | 5.3 | 4.8 | 4.8 | 5.0 | 5.1 | 5.1 | 5.2 | 5.3 | 5.4 | 5.6 | 5.7 | 0.8% |
| **Uncontrolled scenario** | | | | | | | | | | | | |
| Levin East | 15.4 | 15.4 | 15.7 | 16.5 | 17.0 | 17.6 | 18.3 | 19.2 | 20.2 | 21.2 | 22.2 | 4.4% |
| Levin West | 14.0 | 14.0 | 14.2 | 14.9 | 15.4 | 15.9 | 16.6 | 17.4 | 18.3 | 19.2 | 20.1 | 4.4% |
| Foxton | 7.3 | 8.0 | 8.1 | 8.5 | 8.8 | 9.1 | 9.5 | 9.9 | 10.4 | 11.0 | 11.5 | 5.8% |
| Shannon | 5.3 | 4.8 | 4.9 | 5.1 | 5.3 | 5.4 | 5.7 | 5.9 | 6.3 | 6.6 | 6.9 | 3.1% |

**Figure 4-7: Northern substations demand forecasts**

The southern substations demand forecasts are shown in Figure 4-8. The growth forecast is estimated based again on Huringa Pūngao impact studies for the zone substations of Ōtaki, Paraparaumu East, Paraparaumu West and Raumati and these rates for both controlled and uncontrolled scenarios are below their n-1 capacity so no action is needed. For Waikanae, the capacity will be exceeded after 2030 for the uncontrolled scenario and should the event arise, feeder reconfiguration and load transfer to other zone substations will be carried out. Paekākāriki's forecast at 3.8% for the uncontrolled scenario will be below 5MVA for the AMP forecast period.




Note: Capacity (n) for Paekakariki is 5 MVA; all other substations = 46 MVA.
The (n-1) scenario for all substations except Paekakariki = 23 MVA.

| Zone Substation | Actual | Forecast Maximum Demand (MVA) | | | | | | | | | | Avg Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | FY2023 | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | Increase % |
| **Controlled scenario** | | | | | | | | | | | | |
| Waikanae | 17.0 | 17.0 | 17.2 | 17.9 | 18.2 | 18.5 | 18.8 | 19.3 | 19.7 | 20.2 | 20.6 | 2.2% |
| Paraparaumu East | 13.7 | 13.8 | 14.0 | 14.5 | 14.8 | 15.0 | 15.3 | 15.7 | 16.0 | 16.4 | 16.8 | 2.2% |
| Paraparaumu West | 13.1 | 13.3 | 13.4 | 13.9 | 14.2 | 14.4 | 14.7 | 15.0 | 15.4 | 15.7 | 16.1 | 2.3% |
| Otaki | 13.2 | 13.4 | 13.5 | 14.0 | 14.3 | 14.5 | 14.8 | 15.1 | 15.5 | 15.9 | 16.2 | 2.3% |
| Raumati | 10.3 | 10.3 | 10.4 | 10.8 | 11.0 | 11.1 | 11.3 | 11.6 | 11.9 | 12.2 | 12.4 | 2.1% |
| Paekakariki | 3.1 | 2.9 | 3.0 | 3.1 | 3.2 | 3.2 | 3.3 | 3.3 | 3.4 | 3.5 | 3.6 | 1.4% |
| **Uncontrolled scenario** | | | | | | | | | | | | |
| Waikanae | 17.0 | 17.0 | 17.3 | 18.2 | 18.8 | 19.5 | 20.4 | 21.4 | 22.6 | 23.8 | 25.0 | 4.7% |
| Paraparaumu East | 13.7 | 13.8 | 14.1 | 14.8 | 15.3 | 15.9 | 16.6 | 17.4 | 18.4 | 19.3 | 20.3 | 4.8% |
| Paraparaumu West | 13.1 | 13.3 | 13.5 | 14.2 | 14.6 | 15.2 | 15.8 | 16.7 | 17.6 | 18.5 | 19.4 | 4.9% |
| Otaki | 13.2 | 13.4 | 13.6 | 14.3 | 14.8 | 15.3 | 16.0 | 16.8 | 17.7 | 18.7 | 19.6 | 4.8% |
| Raumati | 10.3 | 10.3 | 10.4 | 11.0 | 11.3 | 11.7 | 12.3 | 12.9 | 13.6 | 14.3 | 15.0 | 4.6% |
| Paekakariki | 3.1 | 2.9 | 3.0 | 3.2 | 3.3 | 3.4 | 3.5 | 3.7 | 3.9 | 4.1 | 4.3 | 3.8% |

**Figure 4-8: Southern substations demand forecasts**

### 4.9.4.1 Zone substation capacity/security assessment

Figure 4-9 assesses the forecast capacity (at the required level of security) for Electra's zone substation. Presently the description of the constraint related to the *controlled* demand. That is, our assessment assumes we are progressing down the access to *flexibility* pathway.

We have included the *uncontrolled* demand in Figure 4-9 to provide visibility of potential constraints should it emerge that we are heading down the *network* augmentation pathway.

The only substation with capacity issues for *controlled* demand is Foxton and it is intended the demand is managed by feeder reconfiguration to transfer load to adjacent zone substations.

For *uncontrolled* demand only Waikanae substation is forecast to exceed the capacity after 2030. Should this occur, feeder reconfiguration and load transfer to other zone substations will be undertaken.

Figure 4-9 identifies a number of feeder augmentation projects. The specific project are discussed further in Section 4.14.

| Zone substation | Firm Capacity (MVA) | Maximum demand (MVA) | | | Description of constraint and solution for controlled demand growth |
|---|---|---|---|---|---|
| | | FY2023 | FY2033 Controlled | FY2033 Uncontrolled | |
| Shannon | 5.0 | 5.3 | 5.7 | 6.9 | Load managed by feeder reconfiguration and transfer to other zone feeders. |
| Foxton | 23 | 7.3 | 9.4 | 11.5 | None required |
| Levin East | 23 | 15.4 | 18.3 | 22.2 | An additional feeder is proposed within the planning period to offload G308, G310, G311 and meet the increasing demand. |
| Levin West | 23 | 14.0 | 16.6 | 20.2 | Sections of three feeders to be reinforced within the planning period to meet the increasing demand. |
| Ōtaki | 23 | 13.2 | 16.2 | 19.6 | 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 | 23 | 17.0 | 20.6 | 24.9 | Capacity on existing feeders continues to increase before end-of-life replacement. |
| Paraparaumu East | 23 | 13.7 | 16.8 | 20.3 | Increased utilisation of existing capacity. The construction of Paraparaumu West has allowed much of the former load to be transferred |
| Paraparaumu West | 23 | 13.1 | 16.1 | 19.4 | An additional 11kV feeder is proposed to Kāpiti Rd to off-load Feeder 405 and also to supply the increasing demand |
| Raumati | 23 | 10.3 | 12.4 | 15.0 | An additional feeder is proposed to Matai Rd to offload Feeder Z210 and supply the increasing demand |
| Paekākāriki | 23 | 3.1 | 3.6 | 4.3 | No loading parameters are expected to be exceeded during the planning period; therefore no growth-related projects are proposed |

**Figure 4-9: Zone substations demand forecasts**

## 4.10 Emerging technology and initiatives

Smart technology initiatives supporting our key strategies for operational excellence and developing/growing new technologies include the following activities listed in Sections 4.11 to 4.12.

## 4.11 Reliability improvement initiatives

### 4.11.1 Electrical protection upgrade

To improve the network performance and protection security, the Kāpiti 33kV protection was upgraded in FY2021 with a primary line current differential protection scheme providing robust high-speed protection. Other protection upgrades include the following:

### 4.11.1.1 Southern network

The Kāpiti 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 resulting in the upgrade to a line differential protection scheme with high measuring accuracy allowing fast fault clearance thereby improving public safety and asset protection.

Other upgrades carried out in FY2022 include:

- **Ōtaki 11kV Feeder protection upgrade:** SEL 751 relays have been installed on all 11kV feeders. The protection scheme provides a combination of protection and fault-locating features. Two new protection elements added included Broken Conductor Alarm and High Impendence Fault detections. This project was completed end of January 2022.

### 4.11.1.2 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, protection upgrades completed in FY2022 include:

- **Shannon Busbar protection:** A combined busbar and breaker failure scheme was installed at Shannon Substation. The SEL 487B relay was configured to provide a two-zone busbar protection function for the 33 kV bus. The busbar protection scheme reduces arc flash hazards for bus faults and minimises equipment damage while the breaker failure protection significantly reduces the risk of transformer fire or explosion.

- **Levin East Transformer protection upgrade:** SEL787 and SEL 751 relays were installed on T1 and T2 banks at Levin East Substation. Outdoor 33kV CTs were also installed on each transformer bank. The upgraded protection will reduce the risk of transformer fire or explosion and enhance the fast clearance of the faults.

Upcoming projects in FY2023 include:

- **Mangahao Substation 33kV protection upgrade:** Transpower recently completed a 33kV ODID at Mangahao and Electra has scheduled to replace the switchgear-mounted Micom Protection 2 relays at Mangahao with panel-mounted SEL 411L line differential relays to enhance fault analysis and improve network security across 33kV network to assist mitigation of mutual coupling risks. Line differential protection upgrade will allow Electra to put both 33kV circuits from MHO in service.

- **Shannon Substation 33kV protection upgrade:** SEL 311L relays will be replaced with SEL 411L relays at three 33kV circuits. The new protection relays and SEL line differential relays will provide fast fault clearance and allow both 33kV circuits from MHO to be put in service versus the existing scheme which has protection performance limitations.


**Figure 4-10: (a) Levin East transformer protection upgrade; (b) New outdoor 33kV CTs at Levin East; (c) Ōtaki Substation 11kV feeder protection upgrade.**

Fibre will be used for the Mangahao to Shannon upgrade by FY2023 while an overlay UHF network utilising Mimomax Tornado radios with factory engineered C37.94 interfaces will be considered for communications at the other zone substations in FY2024.

## 4.11.2 Power quality monitoring

Over one hundred low voltage power quality meters have been installed at our distribution transformer panels. These smart devices monitor changes in demand from newly installed solar panels, the charging of electric cars and the changing demands of our consumers. These monitors are paired with those installed within the zone substations to provide an overview of the power quality of our network. The devices feed telemetry back to the Milsoft ADMS solution and provide additional information in the event of a fault. We intend to continue this installation programme for the next few years at strategic and tactical locations.

## 4.11.3 Installation of sensors at zone substations

Twenty partial discharge detectors and four transformer sensors have been installed at our zone substations. These sensors will enable our engineers to monitor oil temperature, moisture and vibrations which will allow our engineering team to better plan maintenance and prevent potential interruptions at substations. A thermal camera has been installed at Levin East substation.

## 4.11.4 Installation of S&C TripSavers

These are cut-out-mounted reclosers that eliminate momentary faults for customers when power is restored automatically for transient faults, avoiding a sustained outage as the TripSaver recloses. The recloser uses a lateral reclosing protection strategy to respond to temporary faults before it drops open (up to three reclosings) with a visible gap for a permanent fault. This technology improves reliability by cutting momentary interruptions as well as sustained service interruptions and will potentially reduce SAIDI further as customers on the healthy parts of the feeder will have energy restored in minutes rather than hours. Distance to fault function in the ADMS is then used to estimate the location of the fault. We continue to seek suitable sites (see Figure 4-11) and install  TripSavers where we see the benefits these will bring to our customers.

## 4.11.5 Equipping ring main units (RMUs) with remote terminal units

We installed remote terminal units or RTUs at key distribution substations enabling RMUs to be monitored by our SCADA communication network and allow the automated switch-over to an alternative healthy circuit. In 2021, feeder 405 Paraparaumu West, one of our most populated 11kV feeders, was interconnected with feeder 402 Paraparaumu West. We continue to seek suitable sites for automated RMUs noting the considerable reliability benefits that these can deliver.

Installation of a new four-way remotely operatable RMU D324-D327 as part of Waka Kotahi’s roading improvements was completed in September 2021 on the eastern side of Levin. These updated switches not only sense and report fault currents but they allow the network to be reconfigured remotely from our Control Centre. A fault can be rapidly located on the network, the affected section isolated and power restored to undamaged sections of the network without the need for faults teams to carry out switching at the site. This tactic cuts down time delays in network switching allowing work crews to begin repairs earlier on the damaged network equipment.

## 4.11.6 Installation of power quality monitors on 11kV zone substation busbars

One monitor has been installed at each substation to monitor 11kV busbars’ voltage and current. These monitors will indicate substation power quality on the 11kV network as well as contribute to the continued investigation of losses on the network.

**Figure 4-11: (a) Eneida LV PQ monitor installation at transformer C113; (b) Tripsaver deployment at P453 on Feeder L352 Ōtaki Gorge Road**

To enable our IoT projects, our IoT Gateways have been upgraded to more capable 16-channel versions and additional gateways have been installed to improve coverage.

Telemetry from these sensors is integrated with several systems using the FME platform with data warehoused in Splunk for event-based data analysis and Influx DB for time series-based data analysis such as LV metering data.

A benefit of the power quality monitoring equipment we install is a greater understanding of technical and non-technical losses on our network. The monitoring equipment at zone substations gives us a top-down understanding and each new LV power quality monitor gives us insight to losses on our low voltage network.

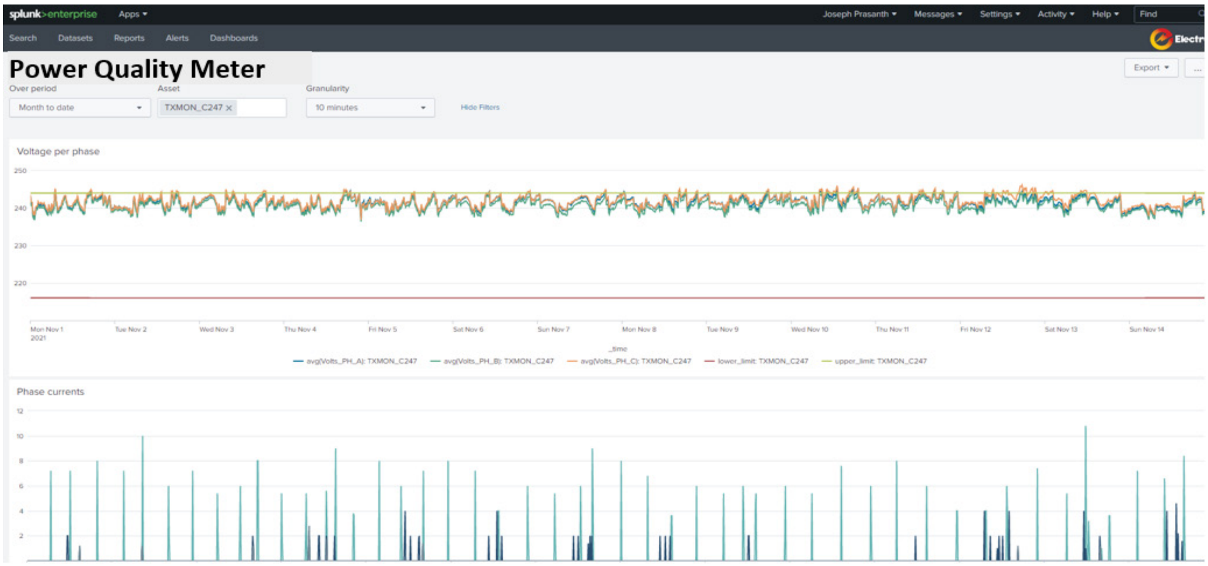



**Figure 4-12: Power quality meter output on Splunk dashboard**

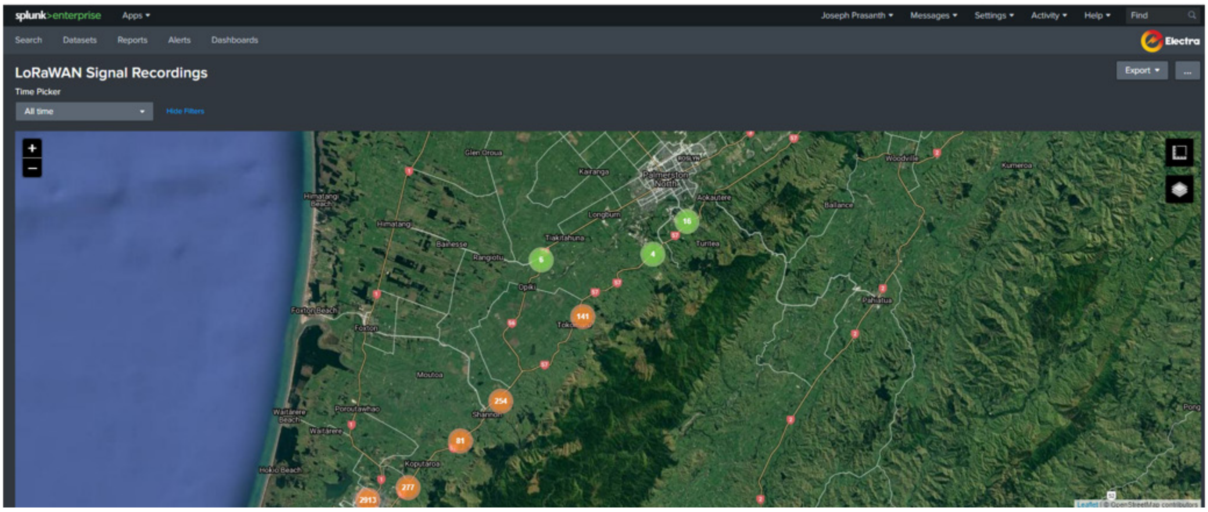



**Figure 4-13: LoRaWAN signal monitoring on Splunk dashboard**

Electra is committed to the continual deployment of "smart" devices to improve operational visibility over the low voltage network and optimise our decision making through integration with our new Enterprise Asset Management solution.

### 4.11.7 **Fault passage indicators**

Twenty fault passage indicators or FPIs have been installed on 11kV feeders with frequent interruptions where causes cannot be determined. These solar-powered FPIs - mounted on our overline network – will significantly reduce fault location time as FPIs on the fault path will transmit an alarm to the control room where the operator may section the faulty section and restore supply to other healthy circuits while sending technicians to the fault location.

## 4.12 **Initiatives to support Huringa Pūngao Energy Transformation**

### 4.12.1 **Electric Vehicle Supply Equipment (EVSE) management**

Electra continues to be committed to our EV strategy 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.

Chargers, available to the public, are located within its network including three dual sets of chargers at Foxton, Paraparaumu East and Shannon and single chargers at Levin, Ōtaki, Waikanae, Paekākāriki and Waikanae. EV charging facilities are being rolled out to every Electra zone substation to further support the migration of the Electra fleet vehicles towards fully electric and plugin electric hybrids (PHEV). Electra's carbon footprint assessment indicates that outside of Network losses, transportation is the highest contributor.

### 4.12.2 **Low voltage network status monitoring**

In the low voltage monitoring arena, our organisational capability is demonstrated by building and deploying low-cost sensors on our network together with a reliable communications infrastructure.

Accessibility to low voltage data and data analysis is vital as we move towards greater penetration of DER and to enable flexibility. 79 Eneida LV power quality monitors and 25 smart MDIs have been installed across our distribution transformers. Our LV modelling data, tools and processes are being review to ensure that they are fit for purpose as we prepare for future flexibility solutions and a rapidly changing energy future, being guided by MBIE's FlexForum Flexibility Plan.

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. We continue to seek suitable sites (see Figure 4-11) and install as shown in Figure 4-14.

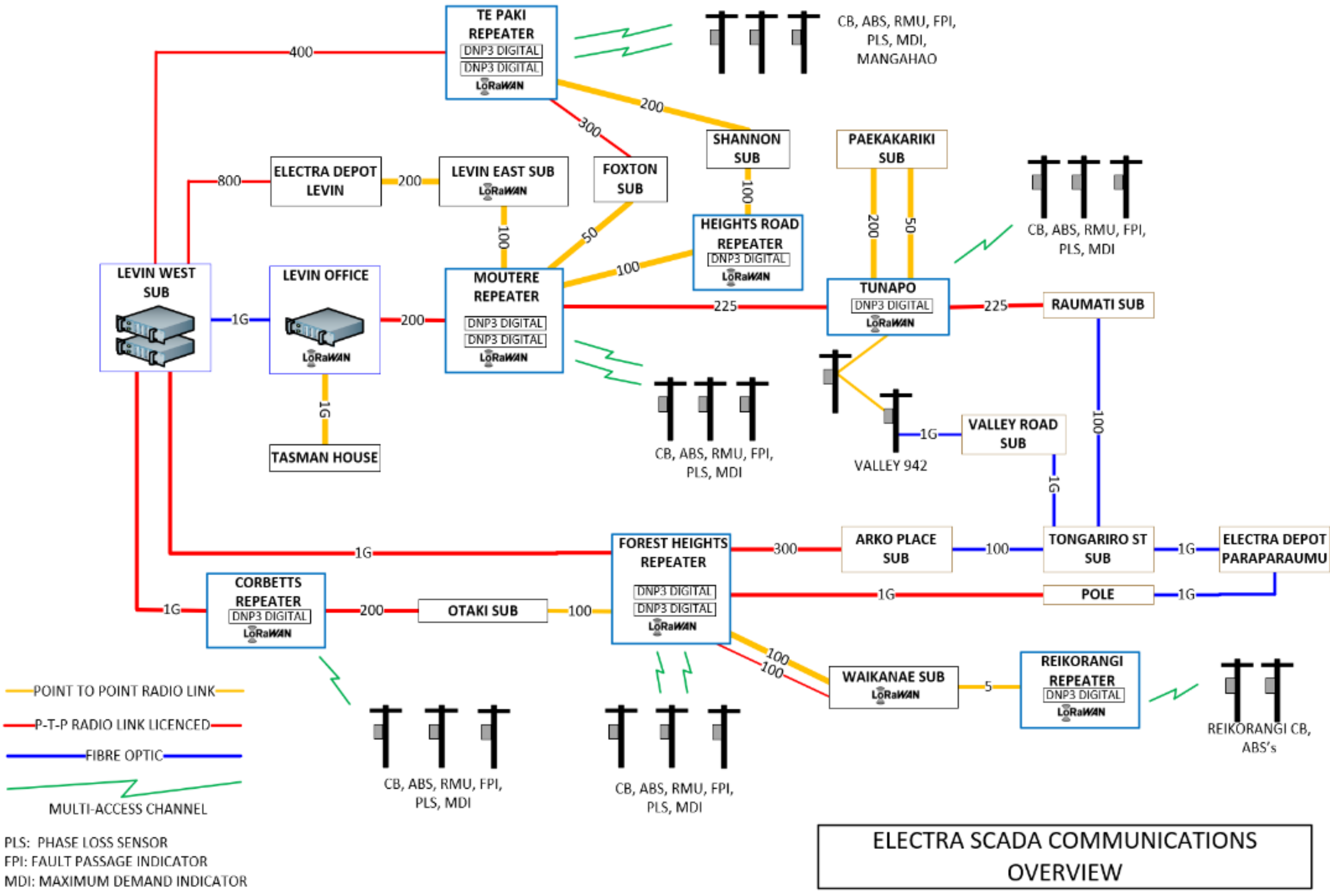



**Figure 4-14: Electra IoT communications overview**

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[37].

Other initiatives undertaken by the network team include the following projects.

## 4.12.3 Engaging with customers on our energy transformation journey

Electra has commenced engaging customers concerning the use of DERs to better understand the impact on system demand as well as to educate customers on sustainability and decarbonisation. Our customer survey includes questions on these matters and we plan to further improve customer engagement via annual surveys, customer focus groups as well as the use of pamphlets and website bulletins.

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

## 4.13 Enhancement of maintenance practices

Electra continues to improve its maintenance practices (Section 5) to meet both reliability and cost efficiency measures. These improvements include:

- Thermal imaging: 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
- Diagnostic testing: 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 zone substations, 33kV and 11kV overhead structures and relevant key assets
- Usage of hot-stick mounted with GoPro cameras.

**Figure 4-15: Continued improvement of condition-based risk monitoring of assets using UAV drone inspections and thermal imaging**

## 4.14 Development projects

The following sections contain the development projects planned for the ten-year period commencing from 1 April 2023 until 31 March 2033. Schedule 11a: Report on Forecasted Capital Expenditure in Appendix 2 reflects the costs incurred in these sections. Figure 4-16 displays the location and estimated budgeted costs of major network projects in the Kāpiti and Horowhenua districts.

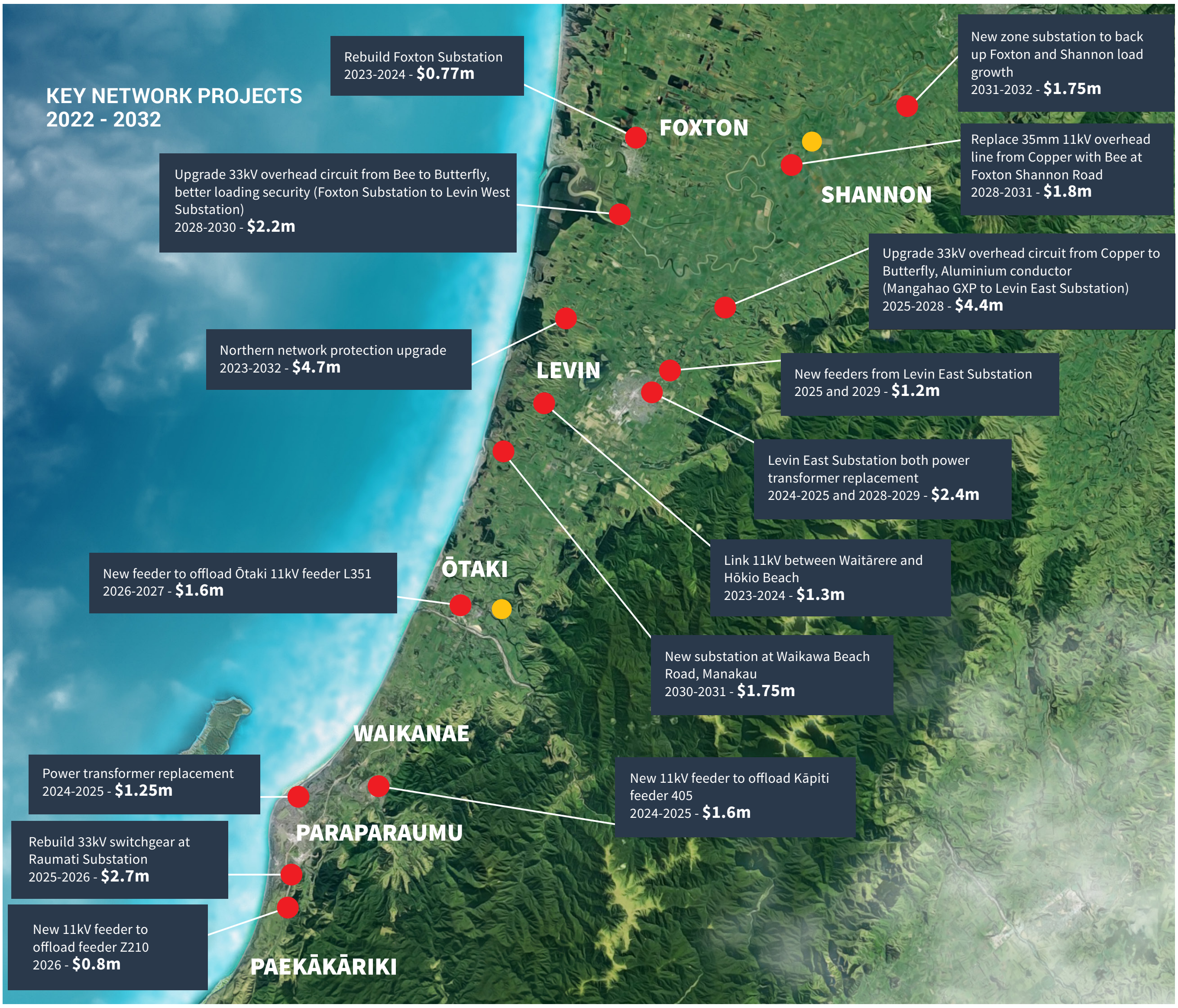



**Figure 4-16: Key network projects**

## 4.14.1 **Development projects for FY2024 year**

Development projects over $200,000 for FY2024 as well as their alternative options are tabulated in the following table.

| Ref. | Description and purpose of project | Category | Cost | Options considered | | | Option chosen and reason |
|---|---|---|---|---|---|---|---|
| | | | | Do-Nothing | Non-Network | Network | |
| 1 | New Feeder out of Levin East substation | Growth | $1,087,000 | Continue with low overhead capacity for the Southern Levin Network area. Limit development options in the new Roe St industrial Park | No current economically viable non-network solutions identified | Run a new 11kV feeder from Levin East substation | Run new feeder<br>There is consistent interest from medium sized residential developments as well as light industrial customers in the Southern Levin area |
| 2 | Rebuild Foxton zone substation bus | Renewal | $797,000 | Continue with existing bus layout | N/A | Replacement of the 33kV outdoor bus and CBs with modular equipment<br>or<br>Renewal of the outdoor bus and CBs | Replacement of the 33kV outdoor bus and CBs with modular equipment<br>Increased efficiency and reliability with modular units. Reduced maintenance costs. Increased safety |
| 3 | Substation protection and communication work | Quality | $703,000 | Risk of loss of supply due to slow fault clearance<br>Risk of equipment damage<br>Potential risk to people's safety<br>Lack of ability to perform post-fault analysis | N/A | 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<br>Slow fault clearance is both an operational and a safety risk<br>New NER at Mangahao GXP<br>Address protection scheme non-conformance to reduce the risk of equipment damage<br>Reduce the risk of high impedance fault<br>Obsolete protection relays and insufficient relay functions<br>Mitigate the risk of arc flash hazards for indoor switchgears |
| 4 | Upgrade the first run of cable for feeder E153, at Levin West substation. Feeder is currently over planned capacity rating and has the most energy throughput of any feeder on the Network | Growth | $673,000 | Risk faults at the head of feeder E153 due to overloading of the cable. Limited back feeding options. Potentially long restoration times. Risks damage to adjacent feeders severely limiting restoration options | No current economically viable non-network solutions identified | Upgrade 200m of 3/185mm HDPE to 3/300mm XLPE | Upgrade 200m of 3/185mm to 3/300mm XLPE. Feeder is currently over planned capacity. Upgrade will increase capacity and improve security of supply. Two adjacent feeders (E151 and E156) to be upgraded at the same time for efficiency savings |
| 5 | Replace 33kV "rocket launcher" and "dog box" 33 kV circuit breakers at Levin East Substation | Renewal | $673,000 | Continue using breakers that are close to end of life | N/A | Replace breakers with new breakers | Upgrade outdoor 33kV circuit breakers at Levin East. Safety, reliability and security of supply |

| Ref. | Description and purpose of project | Category | Cost | Options considered | | | Option chosen and reason |
|---|---|---|---|---|---|---|---|
| | | | | Do-Nothing | Non-Network | Network | |
| 6 | Automate existing ground mounted switchgear for remote operation and sectionalisation | Quality | $643,000 | Continue with existing feeder sections | | Install sectionalisers on specific feeder locations | Sectionalise feeders<br><br>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 |
| 7 | Seismic strengthening of zone substation buildings | Legislative | $559,000 | Continue with high-risk buildings, which are prone to earthquake damage | N/A | Have 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 |
| 8 | Northern Network protection and communication upgrades for zone sub protection | Quality | $549,000 | Continue with slower and less capable communication network | | Upgrade Northern protection and communication network equipment to allow faster responses to faults | Upgrade Northern protection and communication network |
| 9 | Install pole-mounted sectionalisers on specified feeders to reduce number of customers affected by faults | Quality | $507,000 | Continue with existing feeder sections | N/A | Install line sectionalisers on specific feeder locations | Sectionalise feeders<br><br>As more customers are added to feeders, the number of customers affected by a fault will also increase, which is undesirable. Sectionalising will reduce the number of customers affected |
| 10 | Sub-division extensions | Customer Connection | $443,000 | Continue with existing LV network configuration | N/A | Install links between LV circuits<br><br>Increased capital contribution allowance as network extension policy being updated in FY 2021 | Install links between LV circuits<br><br>Allow faster restoration rather than repair time |
| 11 | Install LV -power quality monitors | Quality | $250,000 | Continue with no visibility of LV power quality information | Procure smart meter data | Install smart sensors on selected distribution transformers | Install LV PQ monitors on selected transformers<br><br>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. Smart meter data provides limited coverage at this time |

| Ref. | Description and purpose of project | Category | Cost | Options considered | | | Option chosen and reason |
|---|---|---|---|---|---|---|---|
| | | | | Do-Nothing | Non-Network | Network | |
| 12 | Network study for the feasibility of a new northern GXP | Growth | $250,000 | Continue with the assumption the Transpower owned transformers at MHO GXP are replaced when they reach end of life | Procure flexibility services or install large scale battery storage in northern network | Investigate the benefits and costs associated with alternative GXP arrangements | Investigate the benefits of a new GXP location<br>As the MHO GXP transformers are due for end-of-life replacement near the end of the 2020s, it is timely for Electra to investigate if continuing with a Mangahao site is the best available option |
| 13 | Upgrade VTs and CTs in substations to upgrade protection capabilities | Quality | 220,000 | Continue with existing VTs, CTs, and protection capabilities | N/A | Upgrade existing VTs and CTs | Upgrade VTs and CTs<br>The improved clearance speed, reducing fault levels |

* includes “low investment” options.

Non-material projects (<=$200,000) for FY2024 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 | |
| 14 | Reconductoring of 35 mm Cu, Tiro Tiro Rd and Mako Mako Rd, Levin | Renewal | $165,000 | Run existing conductor to end-of-life | N/A | Replace conductor | • Replace conductor.<br>• Conductor is reaching end-of-life |
| 15 | Reconductoring of 16 mm Cu, Engles Rd, Shannon | Renewal | $140,000 | Run existing conductor to end-of-life | N/A | Replace conductor | • Replace conductor.<br>• Conductor is reaching end-of-life |
| 16 | Replacement of 11kV cable Bath St Levin | Renewal | $130,000 | Run existing conductor to end-of-life | N/A | Replace conductor | • Replace conductor.<br>• Conductor is reaching end-of-life |
| 17 | Retrofit pole-mounted transformers with high risk of lightning strikes with lightning arrestors | Quality | $134,550 | Do not install lightning arrestors | N/A | Install lightning arrestors on transformers found to be at high risk of lightning using NIWA information | • Retrofit high risk transformers with lightning arrestors.<br>• The Network is seeing a greater regularity of lightning strikes to assets |
| 18 | Replace “Witchhat”/”Jester boot” wildlife protectors on Southern Entec LBS’ affected by water ingress | Quality | $41,400 | Leave terminations of the LBS’ in water | N/A | Replace existing wildlife protection with a non-water-tight design. Drain, clean, and denzo tap terminations | • Replace existing wildlife protectors.<br>• Equipment installed as recently as 2021 have been found to have advancing corrosion on terminations, due to the water ingress |

* includes “low investment” options.

## 4.14.2 **Development projects for FY2025 to FY2028**

The development projects proposed for FY2025 to FY2028 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 | Feeder upgrade programme. For Feeders with backbone conductors reaching end-of-life and or capacity | Growth | $7,500,000 | Continue with existing feeders approaching load constraint and or end-of-life | Procure flexibility services or install large scale battery storage for project deferral | Install new feeders to offload existing feeders and take on new load | • Develop a feeder upgrade scheme to highlight and solve constraint and end-of-life problems on the Network. This may include flexibility or non-network solutions as an interim step. This will be considered on a case-by-case basis |
| 2 | Upgrade 2nd Mangahao to Levin East 33kV circuit to increase N-1 capacity | Quality | $4,875,000 | Continue with existing 33kV circuit | N/A | Upgrade circuit to have matching butterfly circuits | • Upgrade 2nd circuit<br>• Existing conductor limits the N-1 feed this line is parallel with |
| 3 | Rebuild Raumati substation | Quality | $2,992,000 | Continue with existing substation at Raumati | N/A | Rebuild Raumati substation | • Rebuild Raumati substation<br>• Improves ability to run more 11kV feeders<br>• Replaces equipment at substation approaching end-of-life |
| 4 | Automate existing ground mounted switchgear for remote operation and sectionalisation | Quality | $2,573,000 | Continue with existing feeder sections | N/A | Install sectionalisers on specific feeder locations | • Sectionalise feeders<br>• As more customers are added to feeders, the number of customers affected by a fault will also increase, which is undesirable. Sectionalising will reduce the number of customers affected |
| 5 | Substation protection and communication work | Quality | $2,438,000 | Risk of loss of supply due to slow fault clearance<br>Risk of equipment damage<br>Potential risk to people's safety<br>Lack of ability to perform post-fault analysis | N/A | 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<br>• Slow fault clearance is both an operational and a safety risk<br>• New NER at Mangahao GXP<br>• Address protection scheme non-conformance to reduce the risk of equipment damage<br>• Reduce the risk of high impedance fault<br>• Obsolete protection relays and insufficient relay functions<br>• Mitigate the risk of arc flash hazards for indoor switchgears |
| 6 | Install pole-mounted sectionalisers on specified feeders to reduce number of customers affected by faults | Quality | $2,029,000 | Continue with existing feeder sections | N/A | Install line sectionalisers on specific feeder locations | • Sectionalise feeders<br>• As more customers are added to feeders, the number of customers affected 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 11kV feeder 401, out of Paraparaumu West substation, to offload 405 | Growth | $2,000,000 | Continue with constrained Network in Paraparaumu Beach and Raumati Beach | Procure flexibility services or install large scale battery storage for project deferral | Install new feeder to offload existing feeders and take on new load | • Install new feeder<br>• The Network is seeing a large amount of growth in the area<br>• Existing feeders are at, or quickly approaching, planning capacity |
| 8 | Seismic strengthening of zone substation buildings | Legislative | $1,960,000 | Continue with high-risk buildings, which are prone to earthquake damage | N/A | Have 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 |
| 9 | Subdivision extensions | Customer connection | $1,600,000 | Continue with existing LV network configuration | N/A | Install links between LV circuits<br><br>Increased capital contribution allowance as network extension policy being updated in FY2024 | • Continue with existing LV network configuration |
| 10 | Replace power transformer at Paraparaumu East Substation | Renewal | $1,385,000 | Run existing power transformer to end-of-life | N/A | Replace power transformer as it approaches end-of-life | • Replace power transformer |
| 11 | Replace power transformer at Levin East Substation | Renewal | $1,330,000 | Run existing power transformer to end-of-life | N/A | Replace power transformer as it approaches end-of-life | • Replace power transformer |
| 12 | Link between Waitarere Beach and Hokio Beach townships | Quality | $1,250,000 | Continue with existing feeder configurations | Procure flexibility services or install large scale battery storage for project deferral | Create a backfeeding option for two 11kV spurs which supply small townships | • Create backfeeding option<br>• Both feeders have long runs along roads that often have car vs poles, which result in long outages. If a suitable route cannot be found a non-network alternative will be considered |
| 13 | Install LV -power quality monitors | Quality | $750,000 | Continue with no visibility of LV power quality information | Procure smart meter data | Install smart sensors on selected distribution transformers | • Install LV PQ monitors on selected transformers<br>• 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. Better availability of smart meter data may change the option chosen nearer the time |
| 14 | Underground ring, Milne Drv and Kiwi Rd | Quality | $540,000 | Continue with existing feeder configurations | N/A | Install a cable section to close ring | • Create backfeeding option<br>• Both feeders are dense residential feeders which will allow for faster restoration of power during faults |
| 15 | Underground ring, Jeep Rd to SH1 Raumati South | Quality | $525,000 | Continue with existing feeder configurations | N/A | Install a cable section to close ring | • Create backfeeding option<br>• Both feeders are dense residential feeders which will allow for faster restoration of power during faults |

| Ref. | Description and purpose of project | Category | Cost | Options considered | | | Option chosen and reason |
|---|---|---|---|---|---|---|---|
| | | | | Do Nothing | Non-Network | Network | |
| 16 | Upgrade Existing Bee to Butterfly for the 33kV circuit between Foxton and Levin West zone substations | Quality | $500,000 | Continue with existing 33kV circuit | Procure flexibility services or install large scale battery storage for project deferral | Upgrade circuit to Butterfly | • Upgrade to Butterfly<br>• Increases alternate feed capacity for N-1 and possible N-2 situations |
| 17 | Install an additional ripple control plant | Growth | $500,000 | Continue with the two existing ripple injectors | Utilise flexibility services or alternative load control | Install a 3rd ripple injector | • Install a new ripple plant<br>• Currently the existing ripple injectors are unable to cover the entire Network in an N-1 scenario, installing a third in the centre of the existing Network will allow for continued ripple control during faults |
| 18 | Link between Q91 and P271 | Quality | $450,000 | Continue with existing feeder configurations | Procure flexibility services or install large scale battery storage for project deferral | Create a backfeeding option for two 11kV spurs which supply small townships | • Create backfeeding option<br>• Create a backfeed between Te Horo Beach and Peka Peka Beach for an alternative supply for Te Horo Beach, as Te Horo Beach is currently feed from a single feeder |
| 19 | Install ring feed cable to back up L470 to L332-Manakau Village | Quality | $375,000 | Continue with existing feeder configurations | Procure flexibility services or install large scale battery storage for project deferral | Install a cable section to close ring | • Install ring feed cable<br>• Meshing of circuits allows reduced restoration times |
| 20 | Link between W42 and W293 -Paraparaumu Airport and install CFC | Quality | $360,000 | Continue with existing feeder configurations | Procure flexibility services or install large scale battery storage for project deferral | Install a cable section to close ring | • Install ring feed cable<br>• Meshing of circuits allows reduced restoration times which is consistent with Electra's strategy of improving reliability |
| 21 | Arc flash protection upgrades | Safety | $305,000 | Continue with existing arc flash risk | N/A | Install require arc flash protection | • Install require arc flash protection to reduce clearance times, reduce restoration times and increase safety |
| 22 | Retrofit pole-mounted transformers with high risk of lightning strikes with lightning arrestors | Quality | $260,000 | Do not install lightning arrestors | N/A | Install lightning arrestors on transformers found to be at high risk of lightning using NIWA information | • Retrofit high risk transformers with lightning arrestors<br>• The Network is seeing a greater regularity of lightning strikes to assets and is an increased rate of asset replacement |
| 23 | Retrofit carbon tetrafluoride fused transformers with HRC fuses | Safety | $240,000 | Continue to operate transformers with carbon tetrafluoride fuses until end-of-life | N/A | Retrofit HRC fuses to replace carbon tetrafluoride insulated fuses | • Retrofit transformers fuses<br>• Minimises the safety risk that we expose our contractors to when working on our transformers |

* includes "low investment" options.

## 4.14.3 Development projects for FY2029 to FY2033

Development projects proposed for FY2029 to FY2033 that have been considered are:

| Ref. | Description | Category | Cost |
|---|---|---|---|
| 1 | Feeder upgrade programme. For Feeders with backbone conductors reaching end-of-life and or capacity | Growth | $12,500,000 |
| 2 | New zone sub near Tokomaru to back up Foxton and Shannon and load growth and possible new grid exit point Growth | Growth | $3,250,000 |
| 3 | Automation of ground mounted switchgear | Quality | $3,216,000 |
| 4 | Sub-division extensions | Customer connection | $2,216,000 |
| 5 | Upgrade Foxton to Levin West to Butterfly | Quality | $1,883,600 |
| 6 | Northern network protection work | Quality | $1,551,200 |
| 7 | Network sectionalisation using pole mounted switchgears | Quality | $1,329,600 |
| 8 | Power Transformer replacement Levin East | Renewal | $1,329,600 |
| 9 | Upgrade to butterfly Levin East to Levin West | Renewal | $886,400 |
| 10 | Link LV network where gaps exist | Quality | $554,000 |
| 11 | Steel Link Pillar removal /safety issues | Safety | $554,000 |
| 12 | Install additional new technology to improve reliability e.g. FPIs - Permanent | Quality | $375,000 |

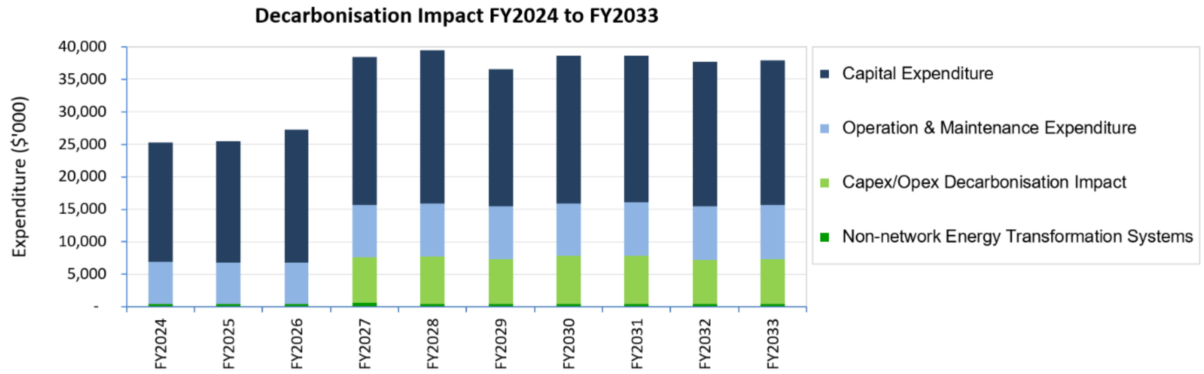
## 4.15 Summary of our expenditure to support decarbonisation

A key role for EDBs is to support growth in flexibility solutions. Flexibility solutions comprise controllable distributed energy resources (DERs) which are small-scale, distribution-connected assets that either reduce load or inject more power (such as solar panels and batteries) and controllable load management devices[38].

Ara Ake's FlexForum Plan 1.0[39] sets out a plan to unlock the value of distributed energy resources (DER) and flexibility. Many steps identified for the initial stages of flexibility reside with EDBs and MBIE's plan stress the need for EDBs to have efficient connection processes, understand headroom/constraints and analyse PQ parameters.

Electra's Huringa Pūngao initiative, our Energy Transformation Roadmap[40], aims to support New Zealand's net-zero 2050 through supporting electrification, increasing renewable generation and enabling DERs. Our investment in supporting decarbonisation is shown in Figure 4-2 and amounts to an increase in CAPEX of $~5M p.a. from 2027 and an increase in OPEX of $~2M p.a. over the forecast period. This level of expenditure in broadly consistent with the additional electricity distribution investment forecast by BCG[41]. Initial spending to support decarbonisation relates to ICT from FY2024 as shown in Figure 6-4 under the Energy Transformation project Figure 4-2.

[38] *Electricity Authority's Discussion Paper July 2021, "Updating the Regulatory Settings for Distribution Networks - Improving competition and supporting a low emissions economy".*
[39] *Ministry of Business, Innovation & Employment, "A Flexibility Plan 1.0", 31 August 2022*
[40] *Energia, Huringa Pūngao Energy Transformation Roadmap Final Report, October 2021*
[41] *BCG, "The Future is Electric: A Decarbonisation Roadmap for New Zealand's Electricity Sector", Oct 2022. The report highlighted the increased investment required by distribution networks, which was estimated at a 30% increase in total expenditure in FY2027-30 relative to FY2022-26.*




| Network & Non-network Expenditure ($'000) | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | *Average %* |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Capital Expenditure | 18,280 | 18,607 | 20,394 | 22,773 | 23,558 | 21,065 | 22,652 | 22,554 | 22,194 | 22,211 | *62%* |
| Operation & Maintenance Expenditure | 6,504 | 6,407 | 6,350 | 8,035 | 8,087 | 8,092 | 8,095 | 8,176 | 8,258 | 8,340 | *22%* |
| Capex/Opex Decarbonisation Impact | - | - | - | 6,963 | 7,296 | 6,938 | 7,381 | 7,440 | 6,792 | 6,878 | *14%* |
| Non-network Energy Transformation Systems | 450 | 450 | 475 | 650 | 500 | 450 | 450 | 450 | 450 | 450 | *1%* |
| | **25,235** | **25,465** | **27,219** | **38,421** | **39,441** | **36,546** | **38,578** | **38,621** | **37,694** | **37,878** | ***100%*** |

**Figure 4-17: Decarbonisation impact on Capex, Opex and ICT expenditure**

Decarbonisation, particularly relating to increased renewable generation, electrification of transport and process heat is widely forecast by Transpower and other EDBs to lead to higher maximum demand and higher total energy distributed through networks. This has been supported by our Huringa Pūngao studies and increased CAPEX spend resulting from this is now flowing into AMP horizons.

Two scenarios were developed consistent with Transpower's Whakamana i te Mauri Hiko "Accelerated Electrification" scenario, which is the most aligned to the likely direction for New Zealand, and Transpower's most recent monitoring report supports this view. The drivers considered in determining the scenarios included:

- Population growth
- Future electricity intensity
- Uptake of electric vehicles
- Electrification of gas
- Demand control
- Uptake of distributed energy resource.

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# 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.

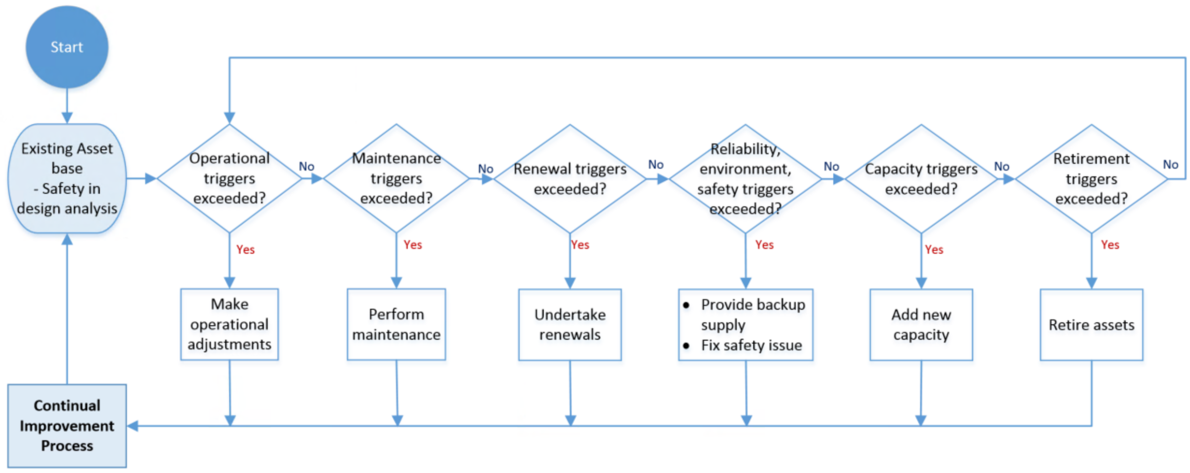



**Figure 5-1: Management of the asset lifecycle**

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 asset risk management

We have progressively adopted the Ofgem Common Methodology[42] to develop our Condition-Based Asset Risk Management Model (CBARMM). The project started in 2018, and analytical models have been built for our entire network assets over the past four years. We are using the CBARMM as a tool to apply a risk-based, information-driven approach in our asset investment planning and decision-making processes.

The Common Methodology provides industry-specific guidance and references to quantify risk on an individual asset basis by evaluating the health of an asset and relating it to its performance and addressing the consequence of failure with criticality for present and future years.

The core value of the Common Methodology is that it links the performance of the asset class to the health indices of the individual assets to calculate the probability of failure.

Whilst the principles and the key calculations of the Common Methodology are adopted in developing CBARMM, the inputs and calibration parameters and factors are customised to align with our asset working environmental and operating conditions and business strategies.

The CBARMM models allows us to make decisions by identifying asset renewal needs and evaluate the outcomes of varying asset investment scenarios. The effect of potential replacement, refurbishment or changes to maintenance regimes can also be modelled to quantify the potential risk reduction associated with different strategies.

With the condition related risks identified for the individual assets and represented on asset class basis by asset health indices profiles, risk matrices and the total risk for current year and in the future, the investment plans and intervention options to mitigate the risks can be evaluated, justified and communicated efficiently.

The process of the CBARMM development has provided a systematic review of our current asset management practice on information availability and quality, condition test and data collection, asset performance, and consequence of failure. With precisely defined inputs for risk profiling, any missing information is identified for future improvement.

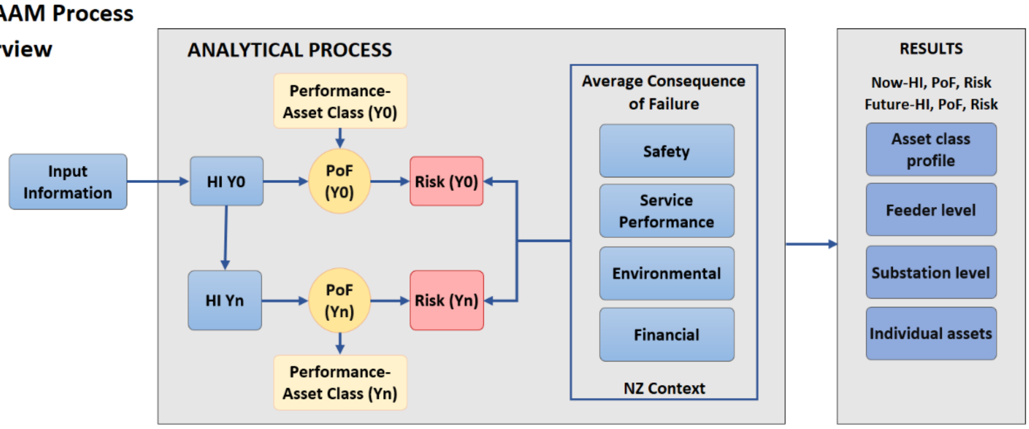
The CBARMM process provides health index and criticality for individual assets which identify the main contributors to asset risk. These main contributors can either be the condition of an asset or its criticality to the network. The cost/benefit of intervention options for replacing or changing the existing configuration can be clearly compared.

Using this approach, we have developed an alternative strategy plan to reduce the risk of ground mounted distribution transformers by changing the arrangement of the connection between the distribution transformer and the ring main unit for selected types of configurations instead of just replacing them.

CBARMM is a structured process that combines asset information, engineering knowledge and practical experience to estimate future condition, performance, and risk of network assets for current and future years. The overview of the process is shown in Figure 5-2a.

The process consists of two main parts and the key calculations are created in each part of the process. The fundamental part is to assess the condition status of the individual assets and to link the health index of each individual asset to the performance of its group. As a result, a Probability of Failure (PoF) for each asset is determined. The second part is to assess the Consequences of Failure (CoF) on an asset class basis for four risk categories and then evaluating the severity of the CoF for the individual assets within that asset class. For an individual asset, its probability and consequences of failure are combined to quantify risk. The total risk associated with an asset group is then obtained as a combination of the risks of individual assets. Key calculations include the Health Index (HI) and Probability of Failure (POF).

**(a) CBRAAM Process Overview**




[42] A common framework of definitions, principles and calculation methodologies published by Ofgem adopted by all GB Distribution Network Operators, for the assessment, forecasting and regulatory reporting of Asset Risk.

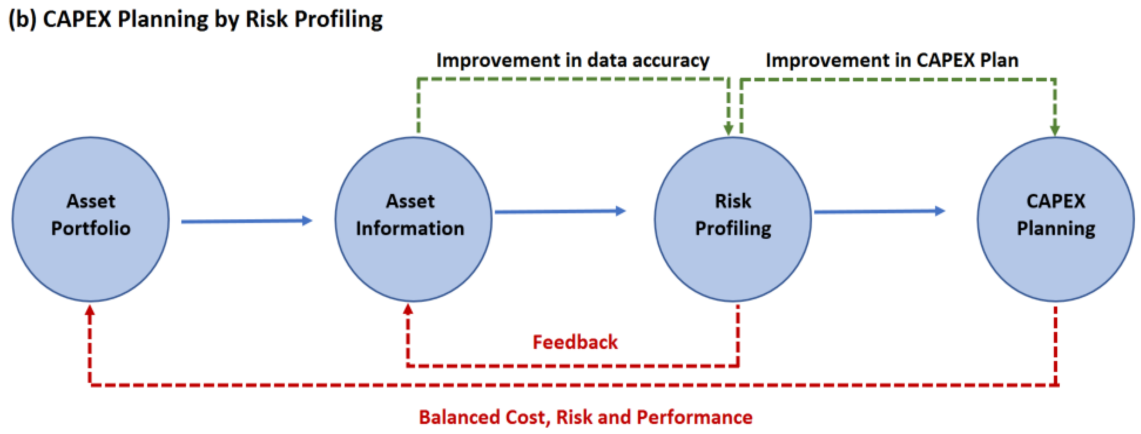



**Figure 5-2: (a) CBRAMM Process Overview; (b) CAPEX Planning by Risk Profiling of Assets**

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.

In September 2022 we created a cross-functional group, the Standards Review Forum to meet regularly. The purpose has been to create a decision-making forum governing approval and performance review of engineering standards, equipment approvals, and procedures. Using a RACI matrix the group seeks to build consensus around standards and equipment approvals. This includes systemic issues identified through audit, observation and event investigations being incorporated into amended standards or procedures.

### 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
- Use of hot-stick mounted with GoPro cameras.

We are also exploring the potential deployment of LiDAR for the inspection of our overhead lines network. The data gathered could be used to remedy minimum distance issues on the network, for growth limit zone encroachment and minimum sag to ground distances of lines.

## 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. Figure 5-3 below 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<br>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<br>Transformer fuses blow repeatedly | Signs of overheating on fittings<br>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<br>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<br>LV fuse blows repeatedly<br>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<br>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<br>Core hot-spot temperature exceeds manufacturers' recommendations |
| 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 4.14 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. 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 4.14.

### 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 Service Delivery 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 4.14 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 criterion 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 Section 5.3 and 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. These inspection areas are currently under review by Electra, with plans to rearrange timings of inspection areas, so that a more representative sample of the Network is inspected each year.

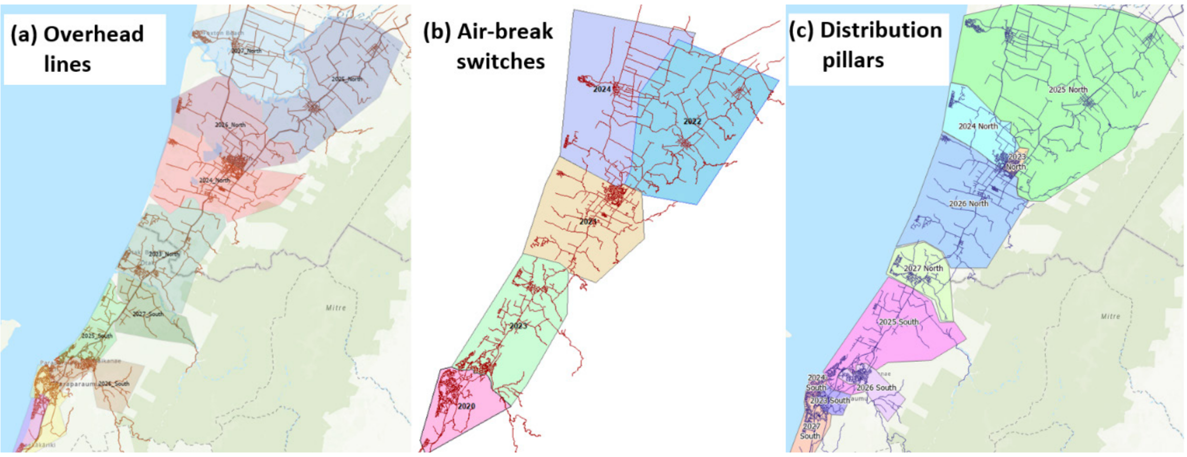



**Figure 5-4: Five-year inspection cycle areas for (a) Overhead lines and poles; (b) Air break switches; (c) Distribution pillars**

As countermeasures against copper thefts, Electra uses alternative earthing installation methods such as steel-reinforced copper for our 11kV and 33kV distribution earthing requirements to ensure that safety standards are retained. The “Public Safety Earthing Standard SMS 56739” revised in March 2021, specifies the requirements for new earthing installations 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 programme.

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[43]:

| Commerce Commission | | Electra | |
|---|---|---|---|
| Grade | Determination Definition | Code | Description |
| H1 | Replacement recommended | 0 | • Imminent risk of failure<br>• 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<br>• 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.

[43] Commerce Commission, “Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018)”

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

- Means that good quality data is not available for any of the assets in the category and estimates are likely to contain significant error
- 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
- 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
- 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 4.14 on Development projects.

# 5.3 Overhead structures

## 5.3.1 Concrete and steel poles

Electra has 20,507 concrete poles and 25 steel poles on its network. These range in age from new to 82 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 | 2,676 | Each | 13.0% | No known concerns but observed that heavily loaded poles are deteriorating faster |
| Solid concrete | 17,656 | Each | 86.0% | No known concerns but observed that heavily loaded poles are deteriorating faster |
| Ex-Transpower concrete | 173 | Each | 0.8% | Drone inspection conducted prior to energisation on March 2020 |
| Spun concrete | 2 | Each | 0.01% | |
| Steel | 19 | Each | 0.09% | |
| Oclyte | 6 | Each | 0.03% | |
| **Total** | **20,532** | **Each** | **100%** | |

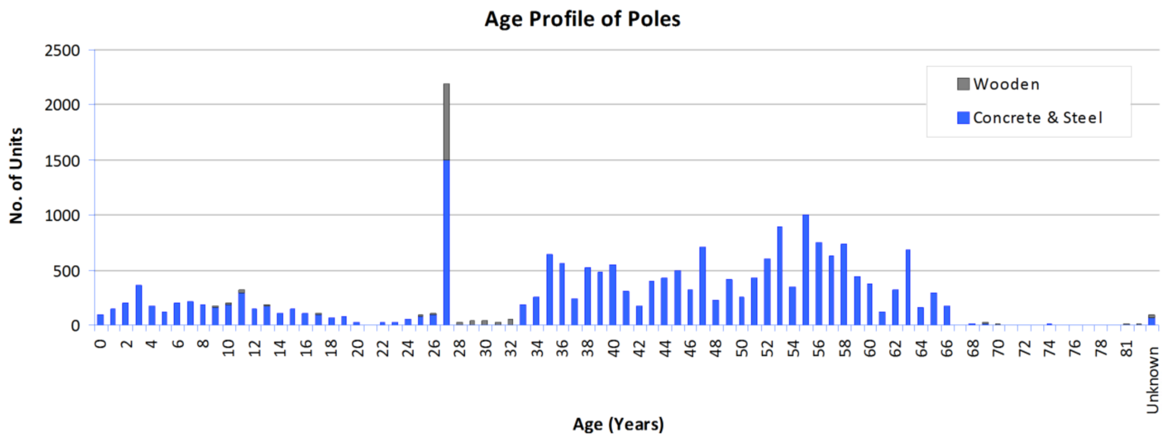



**Figure 5-6: Age profile of poles**

It should be noted the peak at year 27 is due to legacy data and we have a programme in place to correctly allocate these age profiles.

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 |
|---|---|---|---|---|---|---|
| | | 2.3% | 92.70% | 5.0% | 3 | 2.50% |

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 |
| 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 FY2024:

| Ref | Location | Description | Category | Cost |
|---|---|---|---|---|
| 1 | All | 400V pole replacements (approx. 35 poles) - inspection driven | Renewal | $265,920 |
| 2 | All | 11kV pole replacements (approx. 30 poles) - inspection driven | Renewal | $337,940 |
| 3 | All | 33kV pole replacements (approx. 13 poles) - inspection driven | Renewal | $188,360 |
| 4 | All | Fault/urgent defect replacement | Renewal | $83,100 |

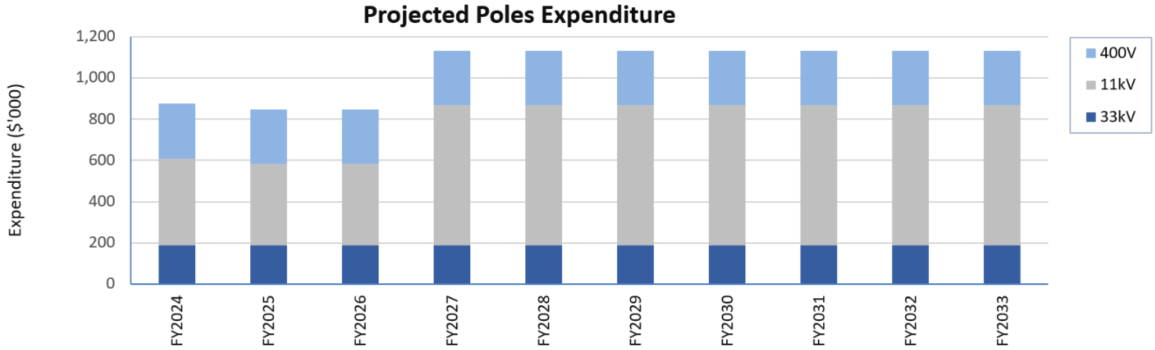
Projects and programmes FY2025 to FY2028:

| Ref | Location | Description | Category | Cost |
|---|---|---|---|---|
| 1 | All | 400V pole replacements (approx. 131 poles) - inspection driven | Renewal | $1,063,680 |
| 2 | All | 11kV pole replacements (approx. 122 poles) - inspection driven | Renewal | $1,921,631 |
| 3 | All | 33kV pole replacements (approx. 52 poles) - inspection driven | Renewal | $753,440 |
| 4 | All | Fault/Urgent defect replacement | Renewal | $221,600 |

Projects and programmes FY2029 to FY2033:

| Ref | Location | Description | Category | Cost |
|---|---|---|---|---|
| 1 | All | 400V pole replacements (approx. 164 poles) - inspection driven | Renewal | $1,329,600 |
| 2 | All | 11kV pole replacements (approx. 255 poles) - inspection driven | Renewal | $3,114,377 |
| 3 | All | 33kV pole replacements (approx. 65 poles) - inspection driven | Renewal | $941,800 |
| 4 | All | Fault/urgent defect replacement | Renewal | $277,000 |

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




| Description | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| 33kV | 188 | 188 | 188 | 188 | 188 | 188 | 188 | 188 | 188 | 188 |
| 11kV | 421 | 393 | 393 | 678 | 678 | 678 | 678 | 678 | 678 | 678 |
| 400V | 266 | 266 | 266 | 266 | 266 | 266 | 266 | 266 | 266 | 266 |
| **Total:** | **875** | **848** | **848** | **1,133** | **1,133** | **1,133** | **1,133** | **1,133** | **1,133** | **1,133** |

**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:

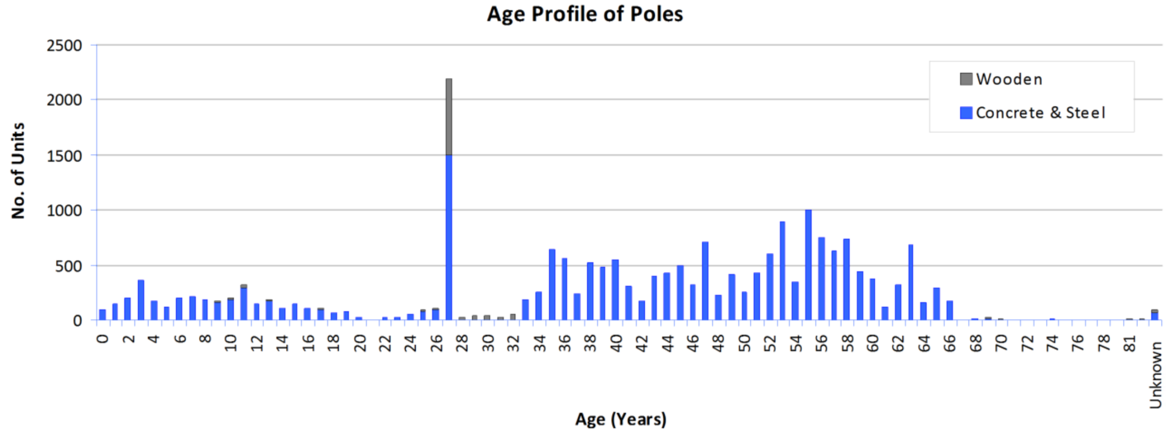



Figure **5-6**.

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

| Sub-class | Number | Unit | Percent |
|---|---|---|---|
| Soft wood | 817 | Each | 69% |
| Hard wood | 300 | Each | 25% |

| Sub-class | Number | Unit | Percent |
|---|---|---|---|
| Ex Transpower hardwood | 70 | Each | 6% |
| Ex Transpower softwood | 1 | Each | 0.1% |
| **Total** | **1,188** | | **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 | - | 40% | 60% | - | - | 2 | 45% |

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

Electra has developed a customer-owned (wood) pole strategy which presented 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 |
| 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.

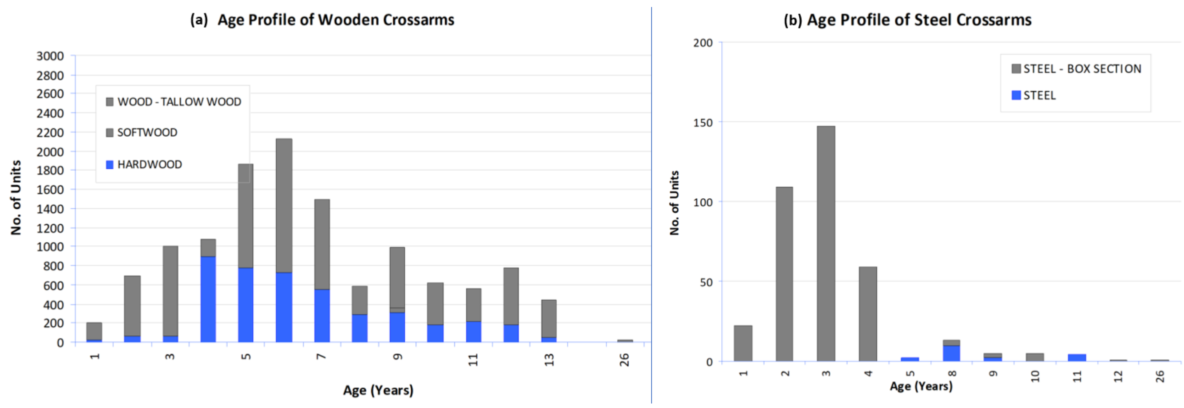



**Figure 5-8: (a) Wooden and (b) Steel crossarms age profile**

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<br>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<br>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<br>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<br>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<br>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 FY2024:

| No. | Location | Description | Category | Cost |
|---|---|---|---|---|
| 1 | All | Inspection driven crossarm replacements - 11kV | Renewal | $387,800 |
| 2 | All | Inspection driven crossarm replacements - 400V | Renewal | $443,200 |
| 3 | All | Inspection driven crossarm replacements - 33kV | Renewal | $387,800 |
| 4 | All | Fault/urgent defect replacement of cross arms | Renewal | $77,560 |

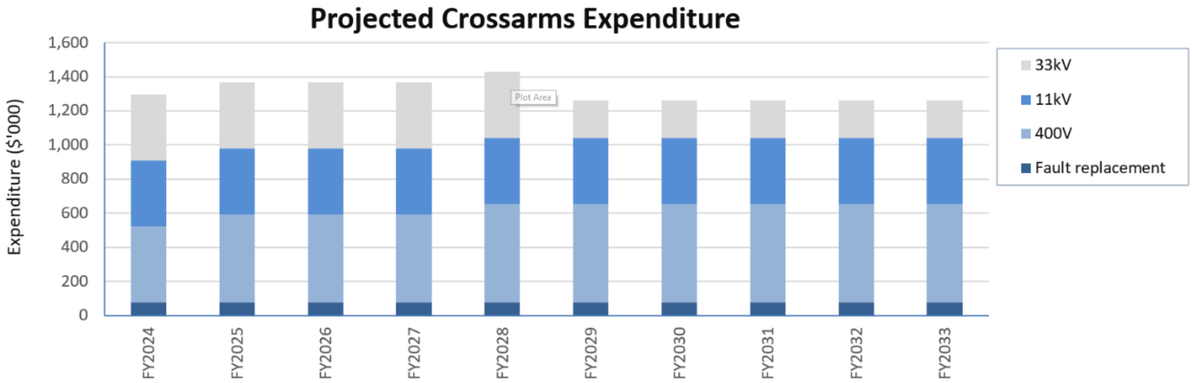
The projects and programmes for FY2025 to FY2028:

| No. | Location | Description | Category | Cost |
|---|---|---|---|---|
| 1 | All | Inspection driven crossarm replacements – 11kV | Renewal | $1,551,200 |
| 2 | All | Inspection driven crossarm replacements – 400V | Renewal | $2,123,911 |
| 3 | All | Inspection driven crossarm replacements – 33kV | Renewal | $1,551,200 |
| 4 | All | Fault/urgent defect replacement of cross arms | Renewal | $310,240 |

The projects and programmes for FY2029 to FY2033:

| No. | Location | Description | Category | Cost |
|---|---|---|---|---|
| 1 | All | Inspection driven crossarm replacements – 11kV | Renewal | $1,939,000 |
| 2 | All | Inspection driven crossarm replacements – 400V | Renewal | $2,880,800 |
| 3 | All | Inspection driven crossarm replacements – 33kV | Renewal | $1,108,000 |
| 4 | All | Fault/urgent defect replacement of cross arms | Renewal | $387,800 |

The budget forecast is depicted in Figure 5-9.




| Description | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| 33kV | 388 | 388 | 388 | 388 | 388 | 222 | 222 | 222 | 222 | 222 |
| 11kV | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| 400V | 443 | 516 | 516 | 516 | 576 | 576 | 576 | 576 | 576 | 576 |
| Fault replacement | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 |
| **Total:** | **1,296** | **1,369** | **1,369** | **1,369** | **1,429** | **1,263** | **1,263** | **1,263** | **1,263** | **1,263** |

**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 N1 rating when feeding Ōtaki |
| | Mangahao – Levin East 2 | 390 | 32% | 31% | Mangahao CB 312 will be replaced before its rating of 390A is likely to be constrained by n1 rating when feeding Ōtaki |
| 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 – Paekākāriki | 600 | 3% | 3% | Nil |

Electra has 185 km of 33kV overhead conductor (including 32km of 132kV construction), 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 Figure 2-5.

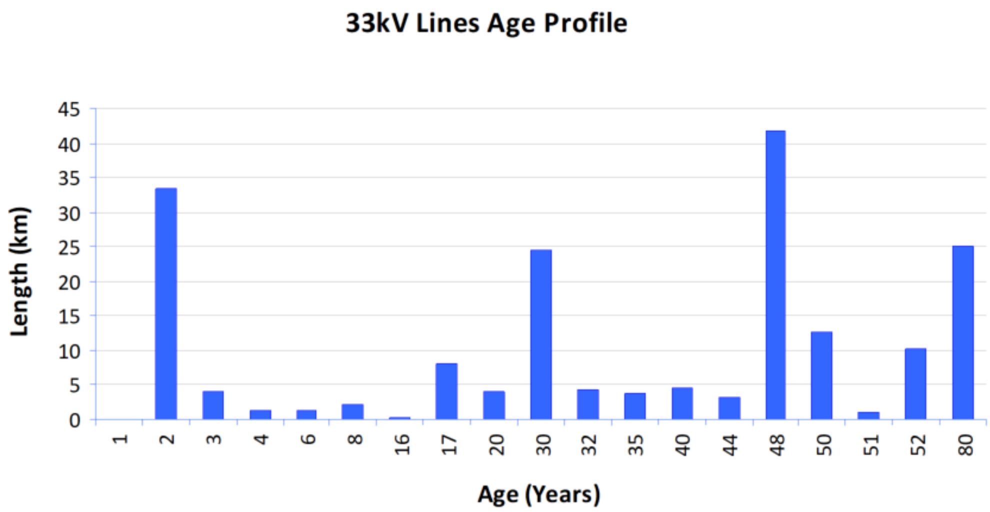



**Figure 5-10: 33kV line age profile**

### 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 | | 9.50% | 87.9% | 2.6% | | 4 | 10.0% |

### 5.4.1.5 Reliability analysis

Figure 5-11a shows our sub-transmission fault rate compared to other EDBs over the last two years. Our average fault rate has fallen from 3.4 to 0.8, below the median of 2.7 for FY2021 to FY2022. This sizeable decrease in the fault rate is attributed to our recent 33/11kV electrical protection upgrade. Figure 5-11b graph will be discussed in Section 5.4.2.1.

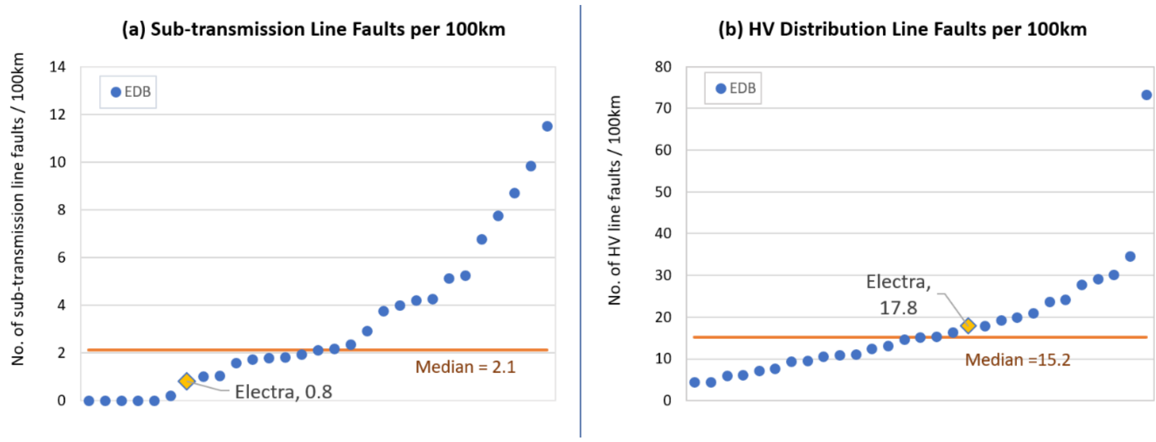



**Figure 5-11: FY2021-FY2022 Average number of faults per 100km of line for (a) Sub-transmission lines, and (b) HV distribution lines**

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. It should be noted the three peaks at years 20, 45 and 62 are due to legacy data and we have a programme in place to correctly allocate these age profiles.

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 |

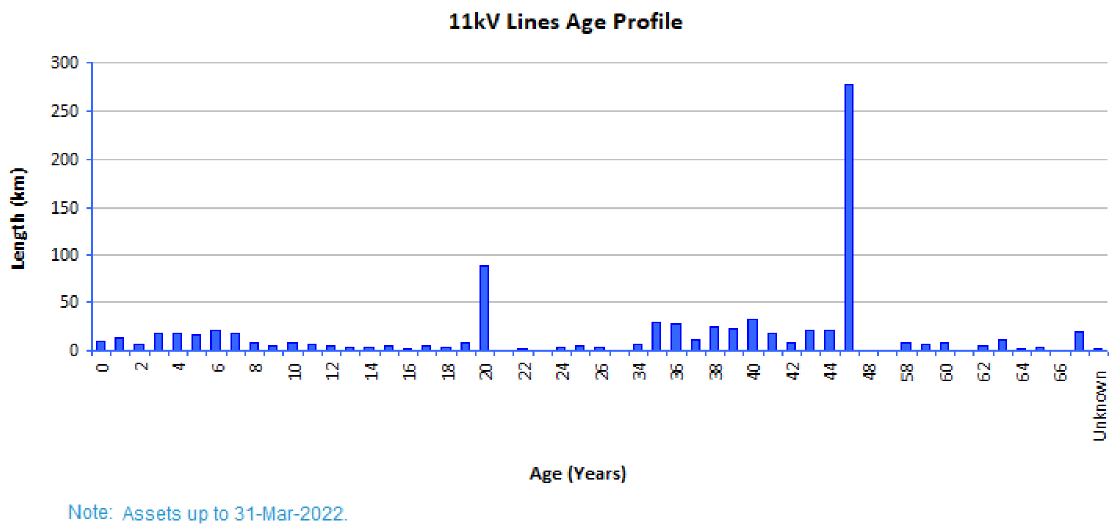



**Figure 5-12: 11kV line age profile**

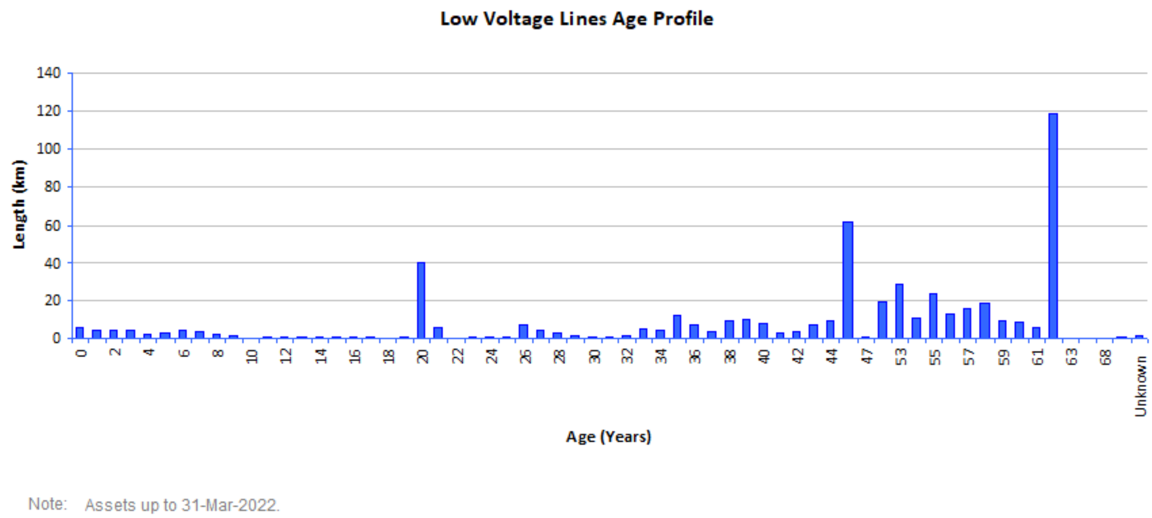



**Figure 5-13: Low voltage line age profile**

### 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% | 83.4% | 9.60% | | 3 | 7.2% |
| LV conductor | | 4.0% | | 2.3% | 93.70% | 2 | 4.0% |

Capacity, security and reliability constraints have been identified in Section 4.3.5.

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 FY2021 to FY2022. The two-year fault rate per 100km has dropped from 29.2 (FY2019-FY2020) to 17.8 (FY2021-FY2022) and these faults include broken lines, line clashes and defects due to poles, crossarms, insulators and connectors.

### 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 FY2024 follow:

| Ref | Location | Description | Category | Cost |
|---|---|---|---|---|
| 1 | All | 400V Reconductoring | Renewal | $1,329,600 |
| 3 | SH1, Manakau | Replace 35mm Cu with BEE (2km) | Renewal | $301,380 |
| 4 | Ngarara Road, Waikanae | Replace 16mm Cu with BEE (1.2km) | Renewal | $186,830 |
| 5 | Tiro Tiro Road, Levin | Replace existing 35mm Cu with BEE (2.5kms in 2 yrs) | Renewal | $186,830 |
| 6 | Engles Road, Shannon | Replace 16mm Cu with Gopher (2km in 2yrs) | Renewal | $150,690 |
| 7 | Tame Porati St, Ōtaki | Replace existing 16mm Cu with Gopher (0.46kms) | Renewal | $69,320 |
| 8 | Armagh Street, Levin | Replace 16mm Cu with Gopher (0.22km) | Renewal | $44,320 |
| 9 | Bledisloe Street, Levin | Replace 16mm Cu with Gopher (0.21km) | Renewal | $44,320 |
| 10 | Read Street, Levin | Replace 16mm Cu with Gopher (0.21km) | Renewal | $44,320 |
| 11 | Titoki Street, Ōtaki | Replace existing 16mm Cu with Gopher (0.2kms) | Renewal | $44,320 |
| 12 | Alexander Road, Raumati | Replace 16mm Cu with Gopher (0.28km) | Renewal | $42,190 |

Projects and programmes for FY2025 to FY2028 are:

| Ref | Location | Description | Category | Cost |
|---|---|---|---|---|
| 1 | All | 400V Reconductor | Renewal | $5,318,000 |
| 2 | Mangahao to Levin East | Upgrade 33kV to Butterfly double circuit | Renewal | $4,875,000 |
| 3 | All | Inspection driven conductor replacements | Renewal | $3,819,000 |
| 4 | Foxton to Levin West | Upgrade 33kV to Butterfly | Renewal | $554,000 |
| 5 | Foxton Shannon Road | Replace 35mm Cu with Bee | Renewal | $450,000 |
| 6 | SH1 and Waitarere Beach Road | Replace Mink with Bee | Renewal | $340,000 |
| 7 | Bryce Street, Shannon | Replace 16mm Cu with Gopher | Renewal | $244,800 |

| Ref | Location | Description | Category | Cost |
|---|---|---|---|---|
| 8 | SH1, South of Levin | Replace 35mm Cu with Bee | Renewal | $244,800 |
| 9 | Makora Road, Paraparaumu | Replace 16mm Cu with Bee | Renewal | $176,800 |
| 10 | SH1 South of Levin | Replace 35mm Cu with Bee | Renewal | $163,200 |
| 11 | Engles Road, Shannon | Replace 16mm Cu with Gopher | Renewal | $150,700 |
| 12 | SH1, South of Levin | Replace 35mm Cu with Bee | Renewal | $111,500 |
| 13 | Wilton Street, Levin | Replace 16mm Cu with Gopher | Renewal | $54,000 |
| 14 | Whyte Street, Paraparaumu | Replace 16mm Cu with Gopher | Renewal | $32,640 |

Projects and programmes FY2029 to FY2033 follow:

| Ref | Location | Description | Category | Cost |
|---|---|---|---|---|
| 1 | All | Inspection driven conductor replacements | Renewal | $7,670,000 |
| 2 | All | 400V Reconductoring | Renewal | $6,648,000 |
| 3 | Foxton to Levin West | Upgrade to Butterfly | Renewal | $1,883,600 |
| 4 | Foxton Shannon Road | Replace 35mm Cu with Bee | Renewal | $1,350,000 |
| 5 | Levin to Levin West | Upgrade to Butterfly | Renewal | $886,400 |
| 6 | Rata Road, Raumati | Replace 16mm Cu with Gopher | Renewal | $60,000 |
| 7 | SH1, South of Levin | Replace 35mm Cu with Bee | Renewal | $12,910 |

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

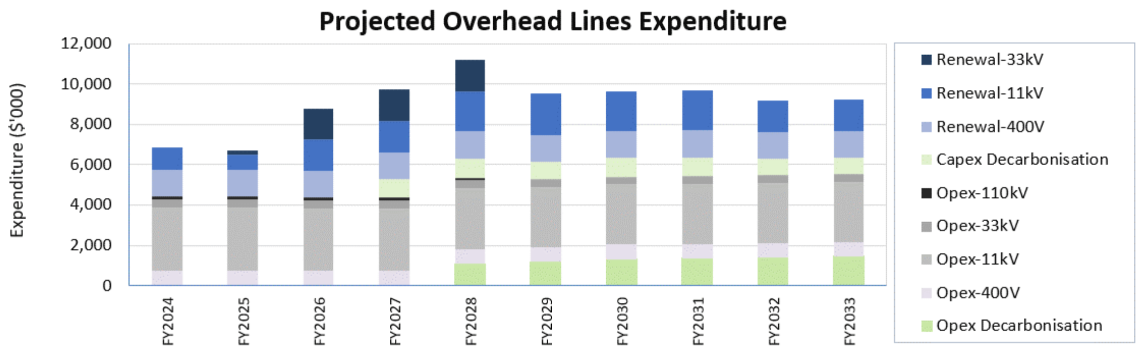
## 5.4.3 Customer-owned lines

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 | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| Renewal-33kV | 0 | 222 | 1,551 | 1,551 | 1,551 | 0 | 0 | 0 | 0 | 0 |
| Renewal-11kV | 1,103 | 735 | 1,534 | 1,534 | 1,984 | 2,044 | 1,984 | 1,984 | 1,534 | 1,547 |
| Renewal-400V | 1,330 | 1,330 | 1,330 | 1,330 | 1,330 | 1,330 | 1,330 | 1,330 | 1,330 | 1,330 |
| Decarbonisation effects | 0 | 0 | 0 | 926 | 958 | 855 | 923 | 919 | 788 | 788 |
| **Total (Capex):** | **2,432** | **2,287** | **4,415** | **5,341** | **5,823** | **4,228** | **4,237** | **4,233** | **3,651** | **3,665** |
| **Operational Expenditure ($'000)** | | | | | | | | | | |
| Opex-110kV | 137 | 137 | 137 | 137 | 137 | 0 | 0 | 0 | 0 | 0 |
| Opex-33kV | 396 | 396 | 396 | 396 | 396 | 396 | 396 | 396 | 396 | 396 |
| Opex-11kV | 3,178 | 3,178 | 3,121 | 3,121 | 3,021 | 2,988 | 2,988 | 2,988 | 2,988 | 2,988 |
| Opex-400V | 713 | 713 | 713 | 713 | 713 | 713 | 713 | 713 | 713 | 713 |
| Decarbonisation effects | 0 | 0 | 0 | 0 | 1,092 | 1,183 | 1,314 | 1,352 | 1,401 | 1,450 |
| **Total (Opex):** | **4,424** | **4,424** | **4,366** | **4,366** | **5,359** | **5,279** | **5,410** | **5,448** | **5,497** | **5,546** |

**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 Kāpiti 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.

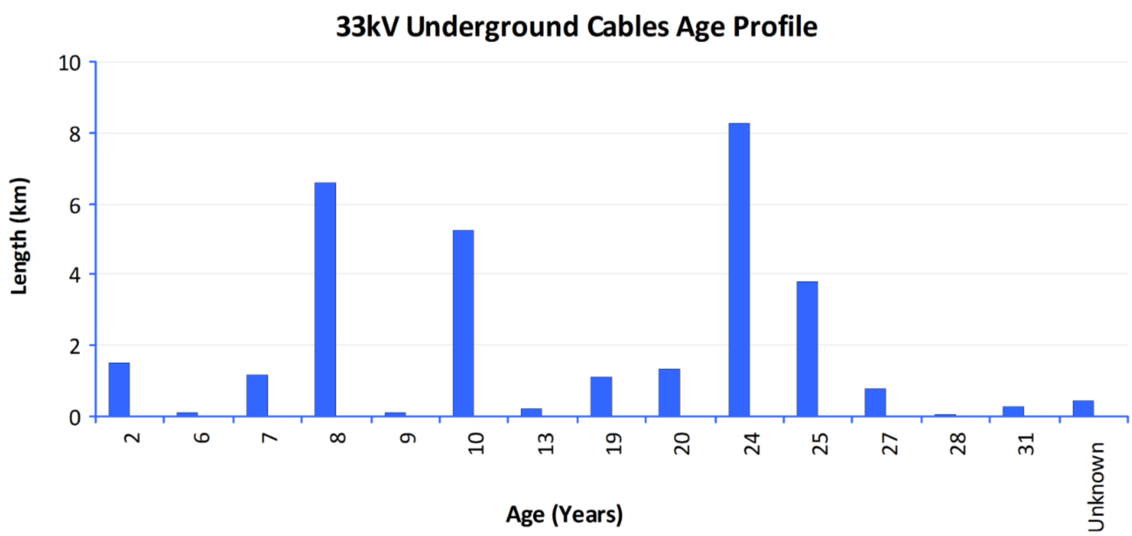



**Figure 5-15: 33kV cable age profile**

### 5.5.1.4 **Condition-monitoring**

The condition of these cables is tabulated in the following table and 4% are forecast 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 is 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, 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 below 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 cables and the composition of the cables follows:

| Sub-class | Number | Unit | Percent |
|---|---|---|---|
| PILC | 117 | km | 46% |
| XLPE, PVC or HDPE | 138 | km | 54% |
| **Total** | **255** | **km** | **100%** |

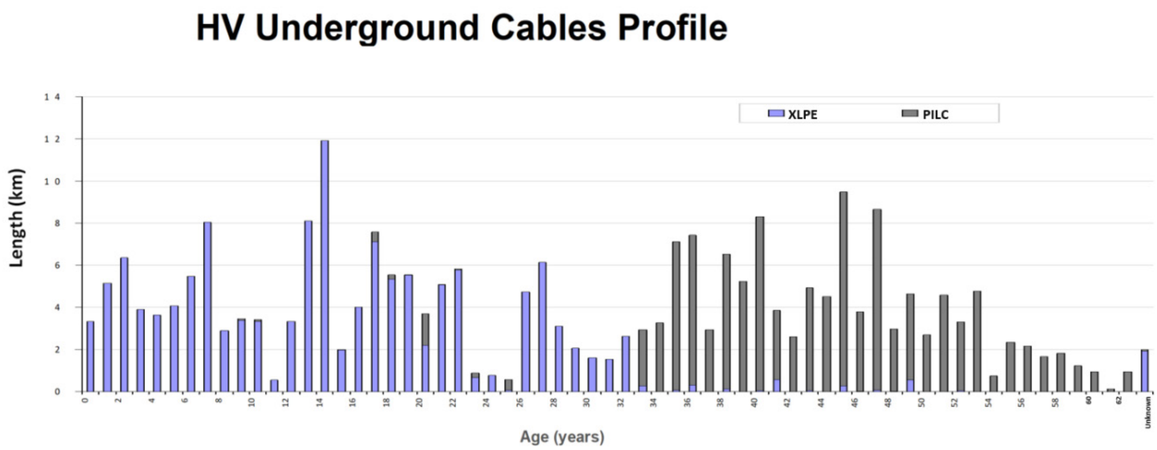



**Figure 5-16: 11kV XLPE and PILC underground cables age profile**

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 | - | - | 91.20% | 8.8% | - | 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 two-year fault rate has decreased from 10.7 to 5.4 faults per 100km slightly above the median of 5.0. Besides faults due to cable joints and terminations, faults include equipment faults such as ground-mounted switchgear and transformers.

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

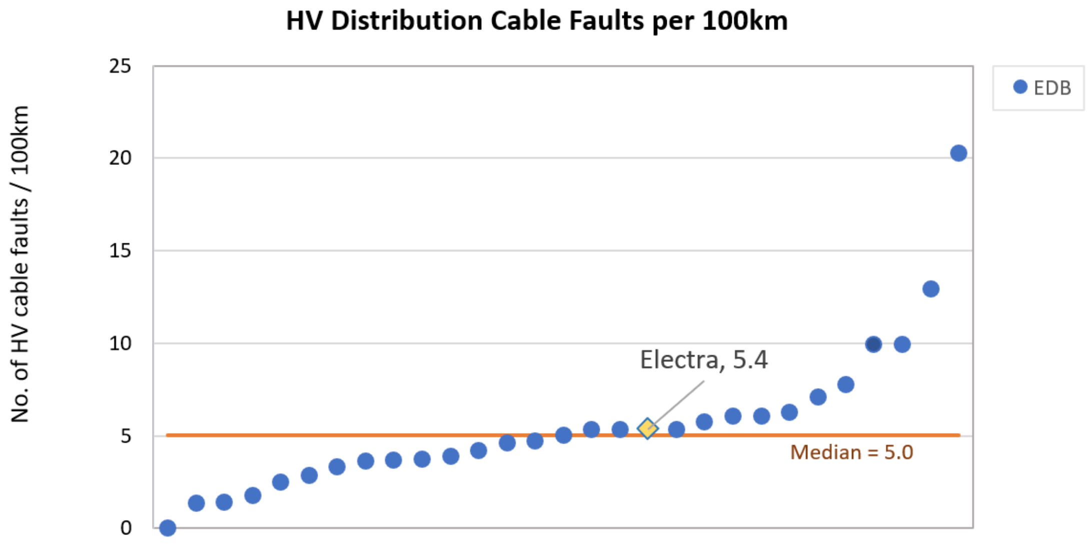



**Figure 5-17: FY2021 to FY2022: Average HV underground cable faults per 100km for EDBs**

### 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:

- 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.ar.

### 5.5.2.4 Major projects and programmes

The projects and programmes for FY2024 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 FY2025 to FY2028 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 FY2029 to FY2033 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 |
| 3 | All | Replace pitch filled potheads with Raychem terminations | Safety | $200,000 |

| Ref | Location | Type of work | Category | Cost |
|---|---|---|---|---|
| 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 511 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 |

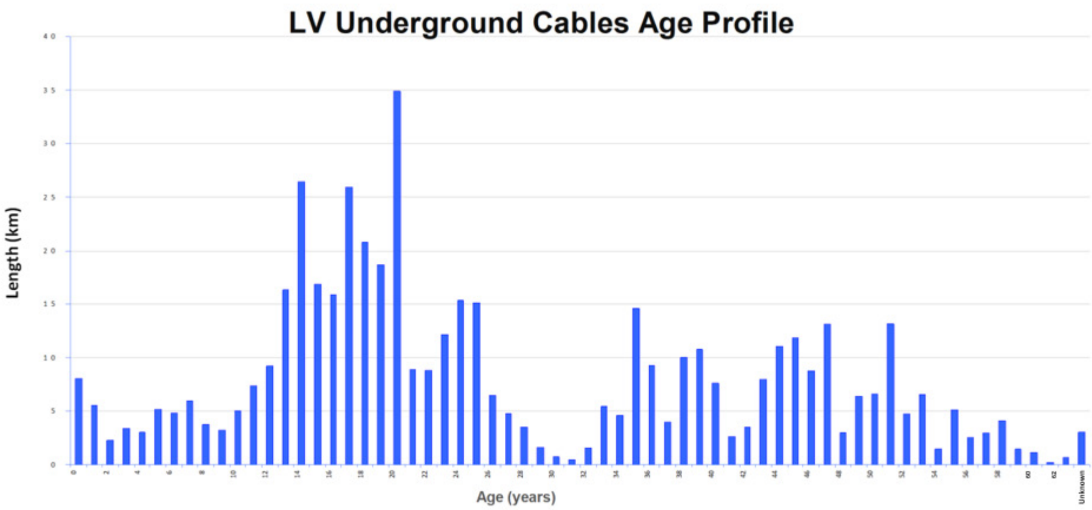



**Figure 5-18: Low Voltage (LV) underground cable age profile**

### 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 FY2024 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 |

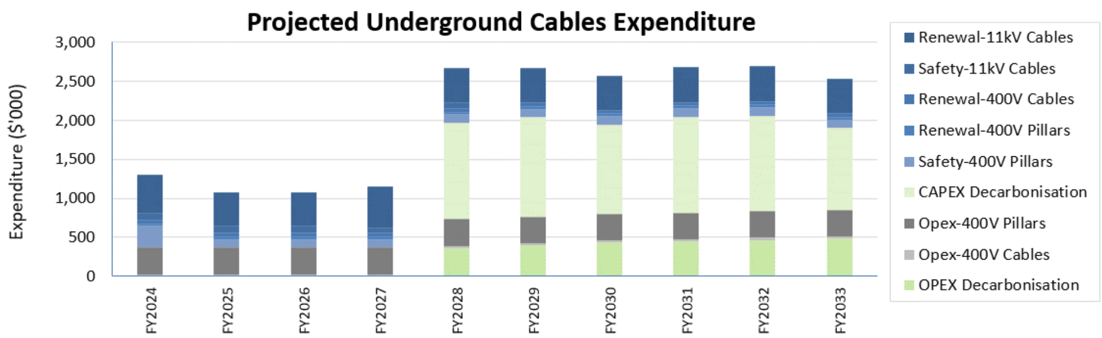
Projects and programmes 2027 to 2031:

| 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 | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| Renewal-11kV Cables | 488 | 425 | 425 | 525 | 443 | 443 | 443 | 443 | 443 | 443 |
| Safety-11kV Cables | 90 | 90 | 90 | 75 | 75 | 0 | 0 | 0 | 0 | 0 |
| Renewal-400V Cables | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| Renewal-400V Pillars | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| Safety-400V Pillars | 277 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 |
| Decarbonisation effects | 0 | 0 | 0 | 0 | 1,234 | 1,278 | 1,140 | 1,231 | 1,225 | 1,050 |
| **Total (Capex):** | **932** | **704** | **704** | **788** | **1,941** | **1,909** | **1,771** | **1,862** | **1,857** | **1,682** |
| **Operational Expenditure ($'000)** | | | | | | | | | | |
| Opex-400V Cables | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 | 26 |
| Opex-400V Pillars | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 | 341 |
| Decarbonisation effects | 0 | 0 | 0 | 0 | 364 | 394 | 438 | 451 | 467 | 483 |
| **Total (Opex):** | **367** | **367** | **367** | **367** | **731** | **762** | **805** | **818** | **834** | **850** |

**Figure 5-19: Projected underground cables expenditure**

# 5.6 Service connections

Connection assets connect Electra's 45,950 consumers (as of March 2022) 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. It should be noted that the two peaks at years 26 and 42 are due to legacy data and we have a programme in place to correctly allocate these age profiles.

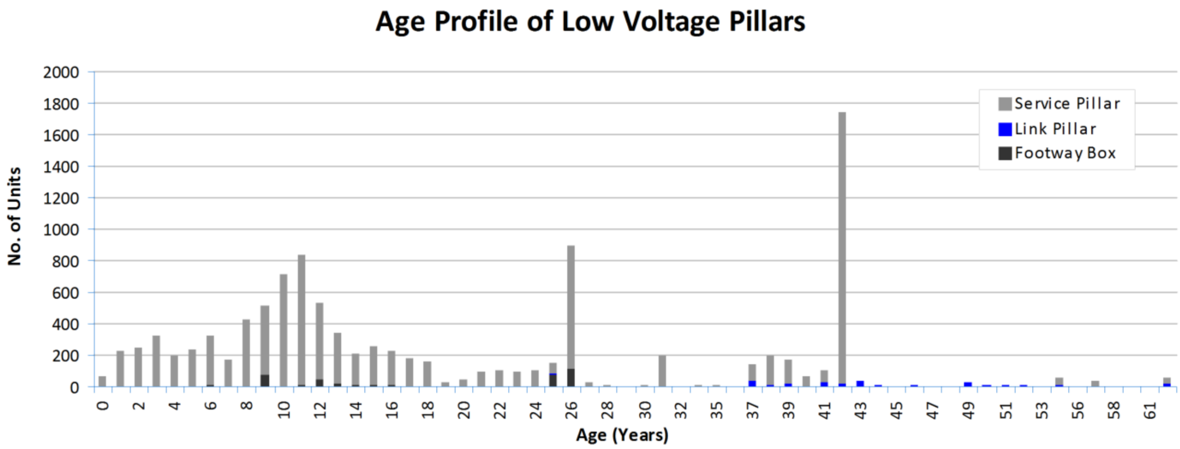



**Figure 5-20:- Age Profile of Pillars**

## 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 |
|---|---|---|---|---|---|---|---|
| | 2% | 18% | 3.5% | 74% | | 3 | 24% |

The condition of pillars is monitored using the CBARMM 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 FY2024 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 FY2024 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 FY2025 to FY2028:

| 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 |

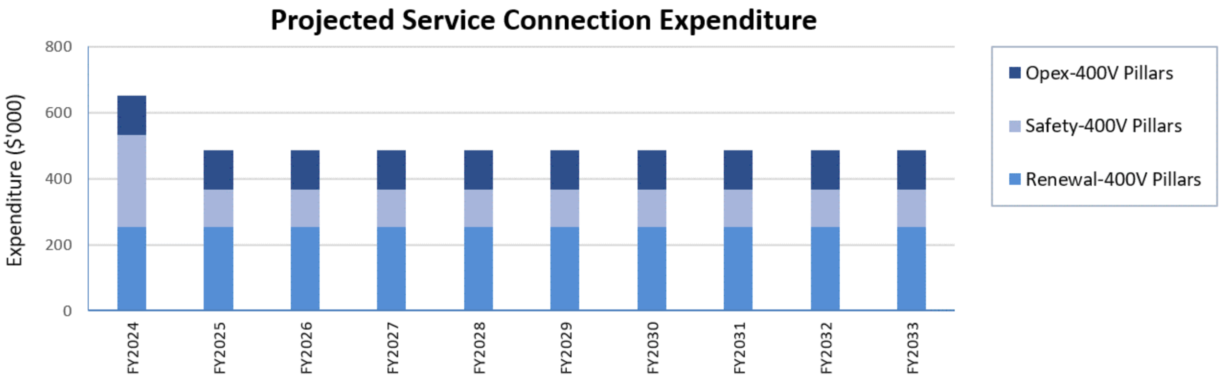
Projects and programmes FY2029 to FY2033:

| Ref | Location | Type of work | Category | Cost |
|---|---|---|---|---|
| 1 | All | Inspection driven pillar replacement | Renewal | $990,425 |

| Ref | Location | Type of work | Category | Cost |
|---|---|---|---|---|
| 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 | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| Renewal-400V Pillars | 255 | 255 | 255 | 255 | 255 | 255 | 255 | 255 | 255 | 255 |
| Safety-400V Pillars | 277 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 | 111 |
| **Total (Capex):** | **532** | **366** | **366** | **366** | **366** | **366** | **366** | **366** | **366** | **366** |
| **Operational Expenditure ($'000)** | | | | | | | | | | |
| Opex-400V Pillars | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 |
| **Total (Opex):** | **120** | **120** | **120** | **120** | **120** | **120** | **120** | **120** | **120** | **120** |

**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 Paekākāriki substation are dual transformer substations. Therefore, all substations have (n-1) security as shown in the following table except for Paekākāriki 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.

The Ōtaki substation was seismically upgraded in April 2022 (Figure 5-22), and this upgrade brings the total number of zone substations seismically upgraded to withstand a major event to three - Paraparaumu West, Waikanae, and Ōtaki substations. Electra anticipates to complete Raumati and Shannon substations by FY2023 with the challenging ground conditions that are affecting the design cost and civil work.

| Zone substation | Description | Security | Nature of load | Performance and risk concerns | Upgrades |
|---|---|---|---|---|---|
| Shannon | • Dual transformer<br>• Indoor switchgear<br>• Built in 2010<br>• No. of ICPs: 2,021 | (n-1) | Mix of urban load in Shannon and rural load toward Tokomaru and Opiki | No known issues<br>Performing within specification | Seismic upgrade scheduled for completion FY2023 |
| Foxton | • Dual transformer<br>• High-level steel structure outdoor<br>• Significantly rebuilt in 2004<br>• No. of ICPs: 3,702 | (n-1) | Predominantly urban load in Foxton with some rural load in all directions | No known issues<br>Performing within specification | Seismic upgrade scheduled for FY2024 |
| Levin East | • Dual transformer<br>• High-level steel structure<br>• Built in 1990<br>• No. of ICPs: 6,342 | (n-1) | Predominantly urban, although with some rural load to the south and east of Levin | No known issues<br>Performing within specification | Seismic upgrade scheduled for FY2024 |

| Zone substation | Description | Security | Nature of load | Performance and risk concerns | Upgrades |
|---|---|---|---|---|---|
| Levin West | • Dual transformer<br>• High-level steel structure<br>• Built in 1974<br>• No. of ICPs: 5,796 | (n-1) | Predominantly the rural areas to the north and west of Levin, Waitarere Beach, some urban load in the western parts of Levin | • Performing within specification<br>• Geotechnical drilling and seismic design investigation indicate subsidence. | • Further investigation to confirm the impact of a seismic event<br>• Investigation into possible solutions ongoing |
| Ōtaki | • Dual transformer<br>• Indoor substation<br>• Built in 1994<br>• No. of ICPs: 6,387 | (n-1) | Predominantly urban load in Ōtaki with some rural load in Ōtaki Gorge, Manakau, Te Horo and Waikawa Beach | No known issues<br>Performing within specification | Upgraded to 100% IL4 seismic NBS in FY2022 |
| Waikanae | • Dual transformer<br>• Indoor substation<br>• Built in 1996<br>• No. of ICPs: 7,416 | (n-1) | Dense urban load in and around Waikanae, some rural load to the north in Peka Peka and to the east in Reikorangi | No known issues<br>Performing within specification | Upgraded to 100% IL4 seismic NBS in FY2022 |
| Paraparaumu East<br>(Paraparaumu renamed Paraparaumu East) | • Dual transformer<br>• High-level concrete pole outdoor<br>• Built in 1970, rebuilt in 2015<br>• No. of ICPs: 4,500 | (n-1) | Dense urban load in the eastern and central parts of Paraparaumu, some rural load on the immediate outskirts of Paraparaumu | • Increased inspection frequency for T1<br>• Geotechnical drilling and seismic design investigation indicate subsidence | • Further investigation to confirm the impact of a seismic event<br>• Investigation into possible solutions ongoing |
| Paraparaumu West | • Dual transformer<br>• Indoor substation<br>• Built in 2002<br>• No. of ICPs: 5,417 | (n-1) | Dense urban load in central and western parts of Paraparaumu | No known issues<br>Performing within specification | Upgraded to 100% IL4 seismic NBS in FY2020 |
| Raumati | • Dual transformer<br>• High-level steel structure outdoor substation<br>• Built in 1988<br>• No. of ICPs: 4,119 | (n-1) | Dense urban load in and around Raumati | No known issues<br>Performing within specification | Seismic upgrade scheduled for completion FY2023 |
| Paekākāriki | • Single transformer<br>• High-level outdoor substation<br>• Built in 1982<br>• No. of ICPs: 925<br>• *33 kV circuit backed up by 11kV feeder from Raumati; KiwiRail traction substation is on 'n' security but backed up by other KiwiRail feeders to north and south | (n-1)* | Mix of light urban and semi-rural load around Paekākāriki | No known issues<br>Performing within specification | Seismic upgrade scheduled for FY2024 |

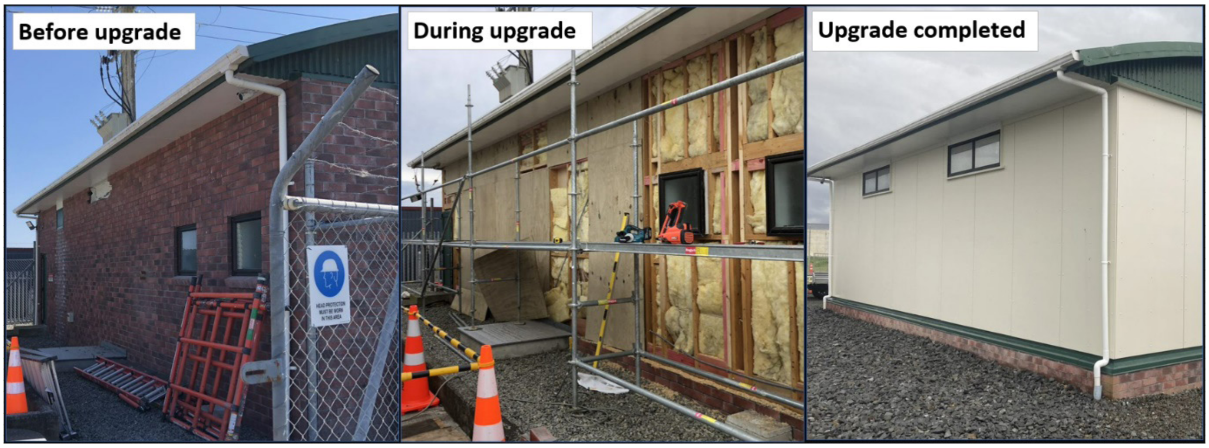



**Figure 5-22: Ōtaki Substation seismic upgrade completed in May 2022**

## 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 | FY2021 | FY2022 |
| Shannon | Two 5 MVA | ONAN | 1977 | 1974 | 85% | 109% |
| Foxton | Two 11.5/23 MVA | ONAN, ONAF | 2004 | 2004 | 32% | 39% |
| Levin East | Two 11.5/23 MVA | ONAN, ONAF | 1979 | 1973 | 61% | 76% |
| Levin West | Two 11.5/23 MVA | ONAN, ONAF | 2011 | 2000 | 57% | 69% |
| Ōtaki | Two 11.5/23 MVA | ONAN, ONAF | 1976 | 1976 | 52% | 67% |
| Waikanae | Two 11.5/23 MVA | ONAN, ONAF | 1996 | 1996 | 67% | 85% |
| Paraparaumu East | Two 11.5/18/23 MVA | ONAN, ONAF, OFAF | 1970 | 1970 | 57% | 69% |
| Paraparaumu West | Two 11.5/23 MVA | ONAN, ONAF | 2001 | 2001 | 54% | 66% |
| Raumati | Two 11.5/23 MVA | ONAN, ONAF | 2011 | 1987 | 42% | 51% |
| Paekākāriki | One 5 MVA | ONAN | 1960 | - | | |

Shannon is the only substation being loaded to its firm (n-1) capacity and we are shifting the 11kV load to Foxton or Levin East feeders.

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 CBARMM (or Condition Based Asset Risk Management Model) to align with ISO 50001 requirements, Electra has been systematicall carrying out condition-monitoring for its power transformers. The yearly inspection for all 19 power transformers was completed in September 2022 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.

Paekākāriki 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 has 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 Paekākāriki.

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 5-23.

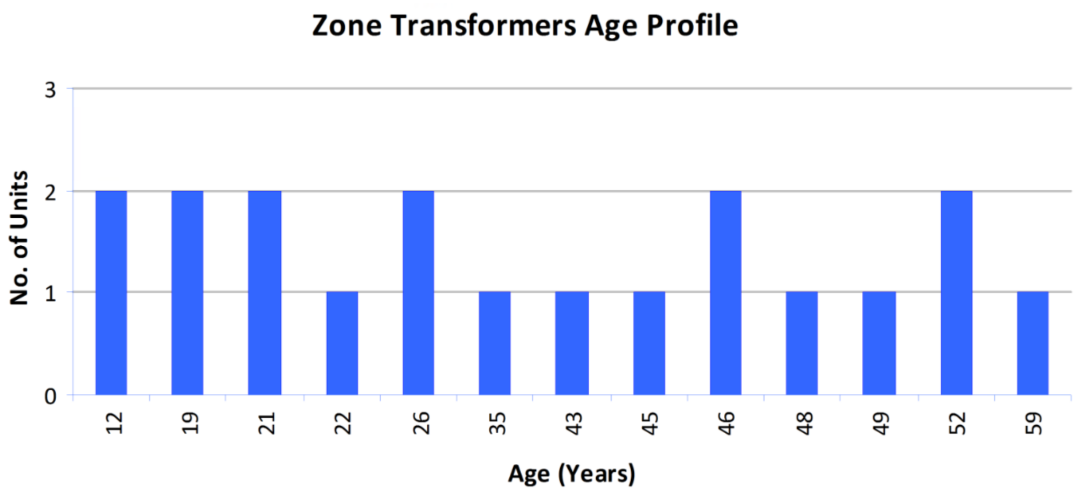



**Figure 5-23: Zone transformers age profile**

### 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 |
|---|---|---|---|---|---|---|---|
| | | | 89.5% | 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.

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 FY2024.

Projects and programmes FY2025-2028 follows:

| Ref | Location | Type of work | Category | Cost |
|---|---|---|---|---|
| 1 | Levin East substation | Power transformer T1 replacement | Renewal | $1,329,600 |
| 2 | Paraparaumu East Substation | Power transformer replacement | Renewal | $1,385,000 |

Projects and programmes FY2029-2033 follows:

| Ref | Location | Type of work | Category | Cost |
|---|---|---|---|---|
| 1 | Levin East substation | Power transformer T2 replacement | Renewal | $1,329,600 |
| 2 | Paekākāriki substation | 2$^{nd}$ transformer on cold standby | Quality | $175,000 |

The budget forecast for zone transformers is shown in Figure 5-25.

## 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<br>2003: three circuit breakers | 10% | 11% |
| Levin East | 7 outdoor SF6 circuit breakers | 2019: one circuit breaker<br>2015: one circuit breaker<br>2009: two circuit breakers<br>2007: one circuit breaker<br>2003: one circuit breaker<br>1987: one circuit breaker | 20% | 21% |
| Levin West | 5 outdoor SF6 circuit breakers | 2012: two circuit breakers<br>2009: one circuit breaker<br>2007: one circuit breaker<br>2000; one circuit breaker | 19% | 19% |
| Ōtaki | 5 indoor SF6 circuit breakers | 2003: one circuit breaker<br>1995: four circuit breakers | 8% | 9% |
| Waikanae | 6 indoor SF6 circuit breakers | 1996: all | 11% | 11% |
| Paraparaumu East | 8 indoor SF6 circuit breakers | 2015: eight circuit breakers<br>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<br>2007: one circuit breaker<br>2005: one circuit breaker<br>1989: one circuit breaker<br>1988: one circuit breaker | 7% | 7% |
| Paekākāriki | 1 outdoor SF6 circuit breaker | 2009: one circuit breaker | 3% | 3% |

Some information 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 |
|---|---|---|
| Shannon | 7 Reyrolle LMVP | 2007 |
| Foxton | 7 Reyrolle LMVP | 2004 |
| Levin East | 8 South Wales SF6<br>1 Reyrolle LMVP | 2006: one circuit breaker<br>1989: eight circuit breakers |
| Levin West | 9 Reyrolle LMVP | 2012: one circuit breaker<br>2011: two circuit breakers<br>2000: six circuit breakers |
| Ōtaki | 8 Reyrolle LMVP | 1996: three circuit breakers<br>1995: five circuit breakers |
| Waikanae | 10 Reyrolle LMVP | 2020: one circuit breaker<br>2010: one circuit breaker<br>1996: eight circuit breakers |
| Paraparaumu East | 10 Reyrolle LMVP | 2015: all |
| Paraparaumu West | 8 Reyrolle LMVP | 2007: one circuit breaker<br>2002: seven circuit breakers |
| Raumati | 7 Reyrolle LMVP | 2018: four circuit breakers<br>2005: two circuit breakers<br>1997: one circuit breaker |
| Paekākāriki | 3 Reyrolle LMT oil<br>1 Reyrolle LMVP | 2013: one circuit breaker<br>1982: three circuit breakers |

The typical loading for the switchgear is at 630A capacity rating). 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 5-24.

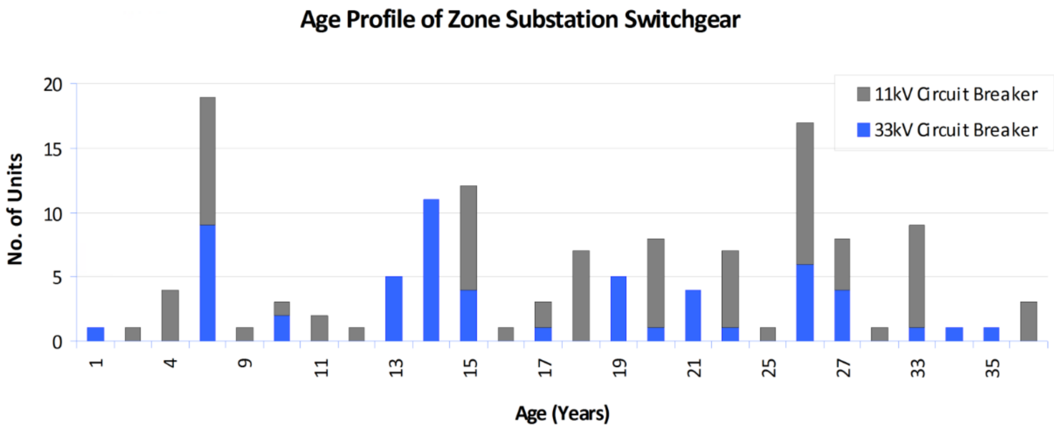



**Figure 5-24: 11kV and 33kV zone switchgear age profile**

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 22kV or 33kV | | | 50% | 50% | | 4 | |
| Outdoor 22kv or 33kV | | | 90% | 10% | | 4 | |
| 3.3kV, 6.6kV, 11kV or 22kV | | 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 FY2024:

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

Projects and programmes FY2025-2028:

| Ref | Location | Type of work | Category | Cost |
|---|---|---|---|---|
| 1 | Raumati | Rebuild substation | Renewal | $2,700,000 |
| 2 | Foxton | Rebuild substation | Renewal | $1,300,000 |
| 3 | All | Unplanned capital | Renewal | $540,000 |
| 4 | Paekākāriki | Circuit breaker replacement | Renewal | $350,000 |

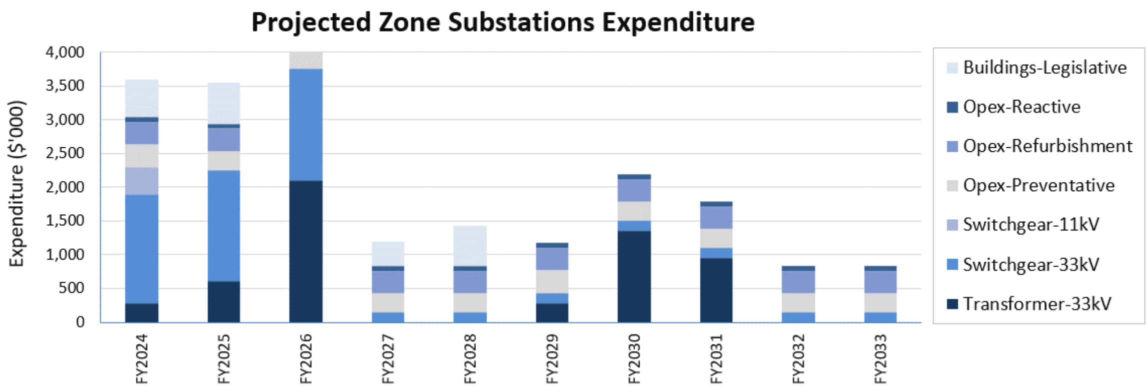
Projects and programmes FY2029-2033:

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

The budget forecast for zone switchgear is shown in Figure 5-25.

## 5.7.4 Zone substations forecast

The projected zone substations expenditure for zone transformers and switchgear is shown in Figure 5-25.




| Description | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| Buildings-Legislative | 559 | 610 | 400 | 350 | 600 | 0 | 0 | 0 | 0 | 0 |
| Transformer-33kV | 277 | 609 | 2,105 | 0 | 0 | 277 | 1,353 | 950 | 0 | 0 |
| Switchgear-33kV | 1,619 | 1,645 | 1,645 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| Switchgear-11kV | 399 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total (Capex):** | **2,854** | **2,865** | **4,151** | **500** | **750** | **427** | **1,502** | **1,100** | **150** | **150** |
| **Operational Expenditure ($'000)** | | | | | | | | | | |
| Opex-Preventative | 341 | 285 | 285 | 285 | 285 | 346 | 285 | 285 | 285 | 285 |
| Opex-Refurbishment | 332 | 332 | 332 | 332 | 332 | 332 | 332 | 332 | 332 | 332 |
| Opex-Reactive | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| **Total (Opex):** | **743** | **688** | **688** | **688** | **688** | **748** | **688** | **688** | **688** | **688** |

**Figure 5-25: 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 East 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 own 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% | 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 |
| 3 & 4 | Continue to inspect, amend grade as required | Refurbish major components<br>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 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 | Seismic upgrade in FY2023. 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 | Seismic assessment in 2018 and seismic upgrade will be completed in FY2024. Normal deterioration monitored in normal inspection cycle |
| Levin West | Masonry shear walls | 1976 | Seismic assessment in 2018 and seismic upgrade under investigation. Normal deterioration monitored in normal inspection cycle |
| Ōtaki | Timber framed | 1995 | Seismic upgrade in FY2023. Normal deterioration monitored in normal inspection cycle |
| Waikanae | Timber framed | 1982 | Seismic upgrade in FY2023. Normal deterioration monitored in normal inspection cycle |
| Paraparaumu East | Masonry shear walls | 1973 | Seismic assessment in 2018 and seismic upgrade under investigation. Normal deterioration monitored in normal inspection cycle |
| Paraparaumu new | Masonry shear walls | 2016 | Good or as new condition |
| Paraparaumu West | Timber framed | 2002 | Seismic upgrade in FY2023. Normal deterioration monitored in normal inspection cycle |
| Raumati | Masonry shear walls | 1987 | Seismic upgrade in FY2023. Normal deterioration monitored in normal inspection cycle |
| Paekākāriki | Masonry shear walls | 1982 | Seismic assessment in 2018 and seismic upgrade will be completed in FY2024. Normal deterioration monitored in normal inspection cycle |

Detailed seismic assessments were done for all zone substations in 2018.

We are mid-way through a programme of works to seismically strengthen our zone substation buildings. This programme includes geotechnical drilling and assessment, site specific investigation and detailed engineering studies and design through to issue and completion of the works.

By March 2023, we will have completed works at Shannon, Ōtaki, Waikanae, Paraparaumu West and Raumati. We will complete works at Paekākāriki, Levin East and Foxton in FY2024. The remaining sites, which are Levin West and Paraparaumu East, are under investigation .

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 1,629 overhead distribution transformers and 984 ground-mounted distribution transformers of various kVA ratings as follows:

| Transformer rating | Pole-mounted (quantity) | Ground-mounted (quantity) | Total (quantity) |
|---|---|---|---|
| 1-phase 10kVA | 8 | 0 | 8 |
| 1-phase 15kVA | 20 | 0 | 20 |
| 1-phase 30kVA | 7 | 0 | 7 |
| 1-phase 100kVA | 1 | 0 | 1 |
| 3-phase 5kVA | 1 | 0 | 1 |
| 3-phase 7kVA | 2 | 0 | 2 |
| 3-phase 10kVA | 2 | 0 | 2 |
| 3-phase 15kVA | 76 | 0 | 76 |

| Transformer rating | Pole-mounted (quantity) | Ground-mounted (quantity) | Total (quantity) |
|---|---|---|---|
| 3-phase 25kVA | 6 | 0 | 6 |
| 3-phase 30kVA | 865 | 36 | 901 |
| 3-phase 50kVA | 377 | 70 | 447 |
| 3-phase 75kVA | 2 | 0 | 2 |
| 3-phase 100kVA | 222 | 109 | 331 |
| 3-phase 150kVA | 1 | 0 | 1 |
| 3-phase 200kVA | 34 | 235 | 269 |
| 3-phase 250kVA | 0 | 7 | 7 |
| 3-phase 300kVA | 5 | 418 | 423 |
| 3-phase 500kVA | 0 | 86 | 86 |
| 3-phase 750kVA | 0 | 15 | 15 |
| 3-phase 1000kVA | 0 | 8 | 8 |
| Total: | **1,629** | **984** | **2,613** |

The population and age profile of these transformers are shown in Figure 5-26.

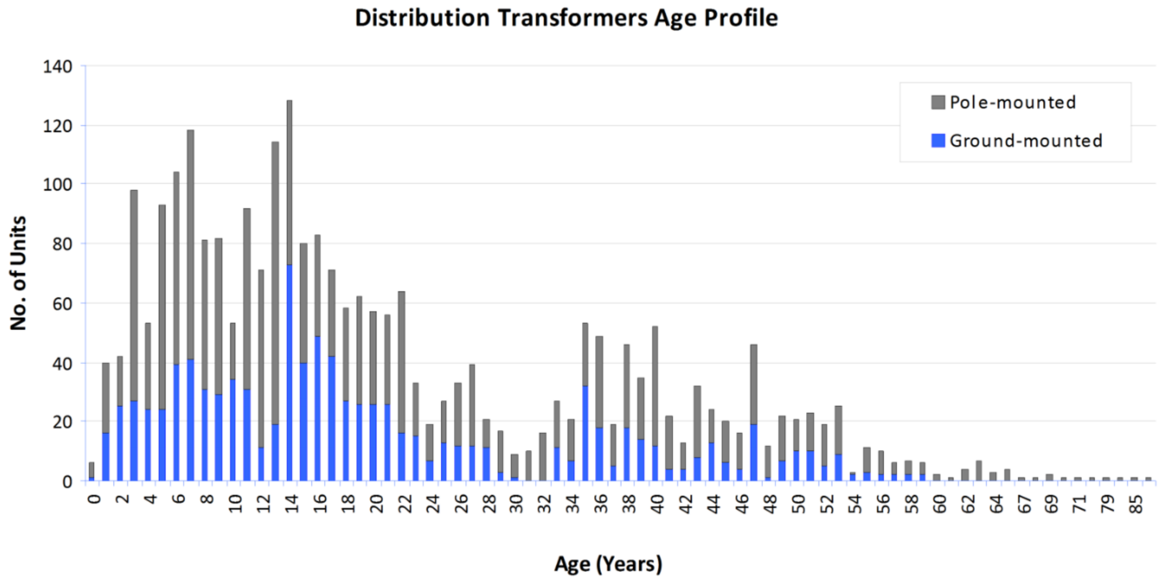



**Figure 5-26: Distribution transformers age profile**

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 | - | 4% | 74% | 22% | - | 4 | 5% |
| Ground mounted | - | 4% | 55% | 41% | - | 4 | 4.0% |

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 5-27 for faults from FY2016 to FY2022 including the SAIDI 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; in FY2021, there was only one transformer fault and none in FY2022. 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 CBARMM (Condition-based Asset Risk Management Model) described in Section 5.2 into our process.

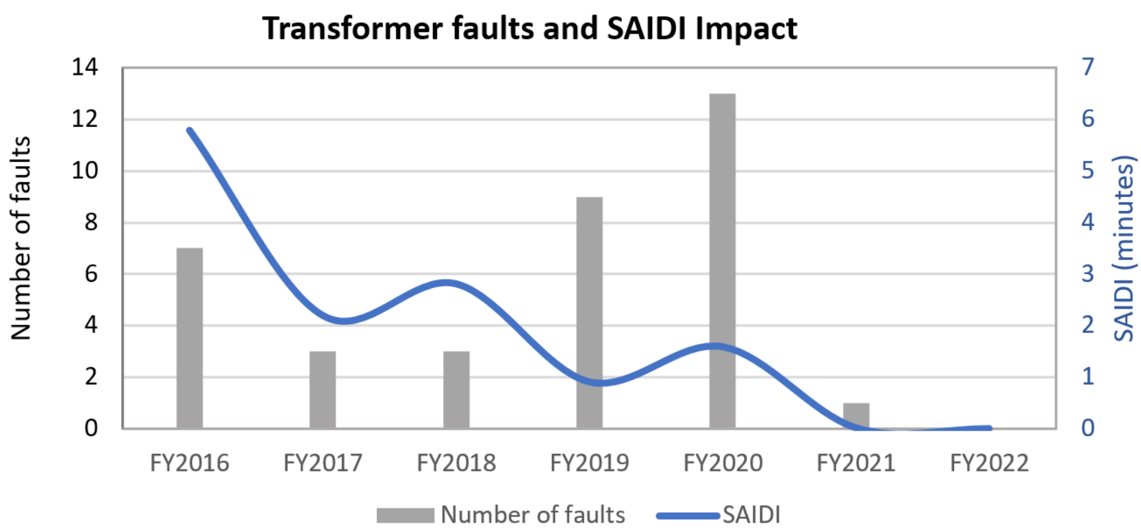



**Figure 5-27: FY2015 to FY2020 - Distribution transformer faults with SAIDI-SAIFI impact**

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 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 FY2024:

| 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 FY2025 to FY2028:

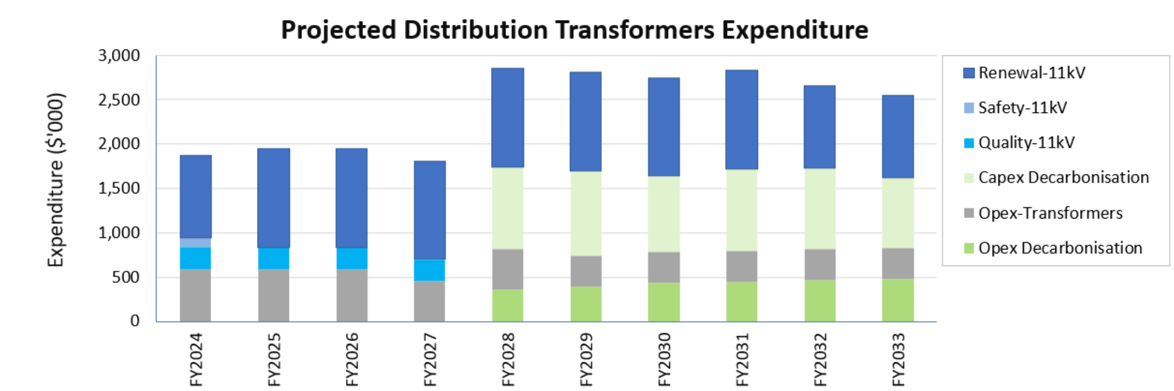
| Ref | Location | Constraint description | Category | Cost |
|---|---|---|---|---|
| 1 | All | Ground transformer replacements | Renewal | $2,200,000 |
| 2 | All | Pole transformer replacements | Renewal | $728,000 |
| 3 | All | Ground transformer faults | Renewal | $400,000 |
| 4 | All | Indoor substations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

Projects and programmes for FY2029 to FY2033:

| 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 5-28.




| Description | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| Renewal-11kV | 927 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 1,109 | 927 | 927 |
| Safety-11kV | 111 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Quality-11kV | 250 | 250 | 250 | 250 | 0 | 0 | 0 | 0 | 0 | 0 |
| Decarbonisation effects | 0 | 0 | 0 | 0 | 926 | 958 | 855 | 923 | 919 | 788 |
| **Total (Capex):** | **1,288** | **1,359** | **1,359** | **1,359** | **2,034** | **2,067** | **1,963** | **2,032** | **1,846** | **1,715** |
| **Operational Expenditure ($'000)** | | | | | | | | | | |
| Opex-Transformers | 587 | 587 | 587 | 453 | 453 | 349 | 349 | 349 | 349 | 349 |
| Decarbonisation effects | 0 | 0 | 0 | 0 | 364 | 394 | 438 | 451 | 467 | 483 |
| **Total (Opex):** | **587** | **587** | **587** | **453** | **816** | **743** | **787** | **800** | **816** | **832** |

**Figure 5-28: Projected distribution transformers expenditure**

## 5.9 **Distribution switchgear**

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

| Sub-class | Number | Percent |
|---|---|---|
| Ground mount switches | 170 | 6% |
| Air break switches | 350 | 13% |
| Auto reclosers | 72 | 2% |
| In-line drop-out fuses | 2,052 | 79% |

| Sub-class | Number | Percent |
|---|---|---|
| Total | 2,614 | 100% |

The age profiles of the 153 ring main switches and are shown in Figure 5-29.

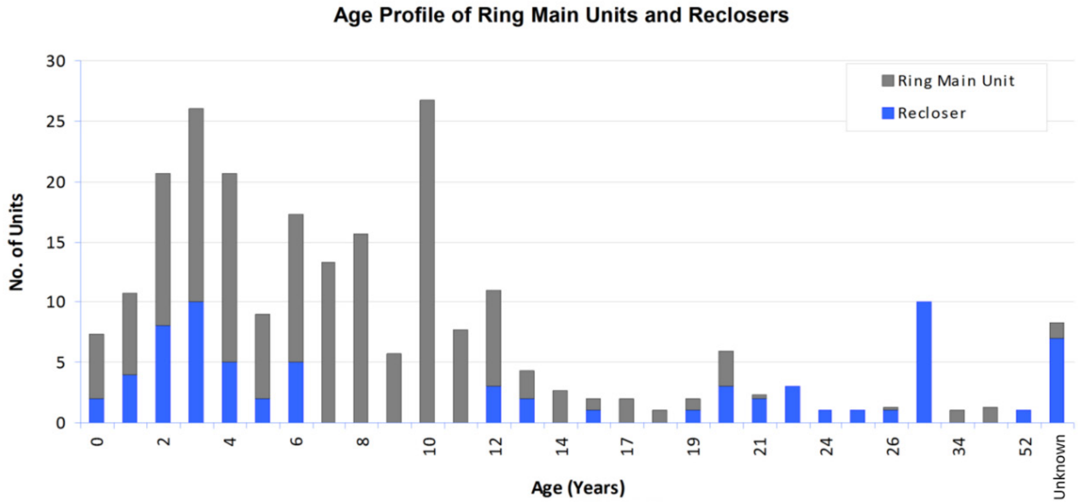



**Figure 5-29: Ring main units and reclosers age profile**

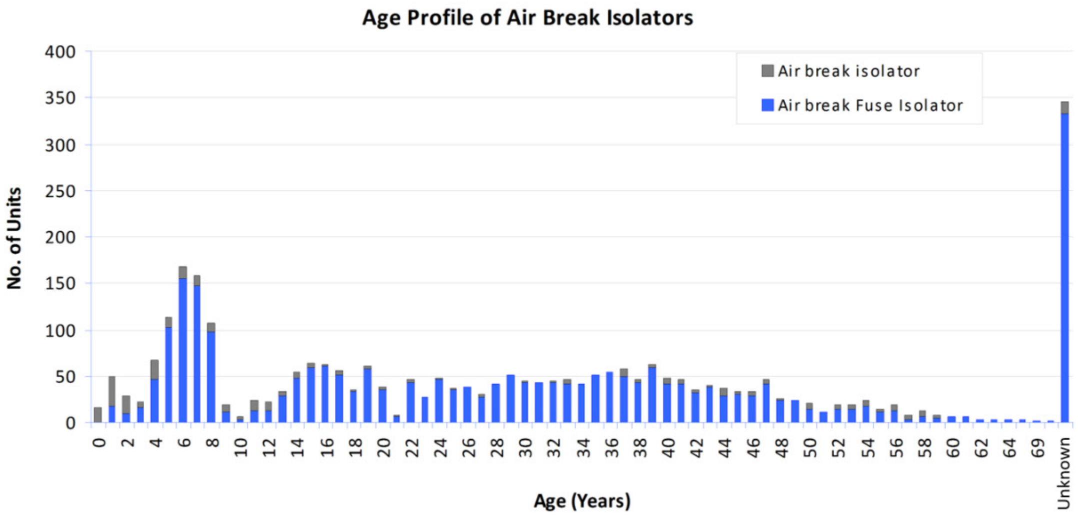



**Figure 5-30: Air break isolators age profile**

It should be noted the unknown allocations are due to legacy data and we have a programme in place to correctly allocate these age profiles.

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% | 77.50% | 20.00% | 4 | 2.50% |
| Indoor circuit breakers | | 5.12% | 76.88% | 18.00% | 4 | 5.20% |
| Pole mounted switches and fuses | | 3.50% | 90.5% | 6.00% | 3 | 4.50% |
| Ring main units | | 6.0% | 88.50% | 5.5% | 3 | 6.5% |

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 mandatory before operation
- Drone inspections to be undertaken every year on the identified ABSs to determine any further deterioration
- Capex allocation has 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 FY2024:

| 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 | Replace ring main units | Renewal | $130,000 |

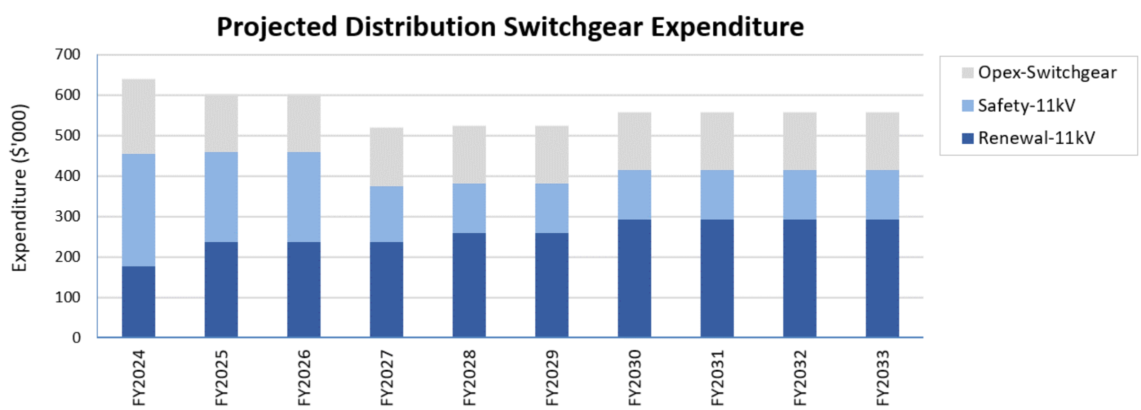
Projects and programmes FY2025 to FY2028:

| 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 FY2029 to FY2033:

| 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 5-31.




| Description | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| Renewal-11kV | 177 | 237 | 237 | 237 | 259 | 259 | 292 | 292 | 292 | 292 |
| Safety-11kV | 277 | 222 | 222 | 139 | 122 | 122 | 122 | 122 | 122 | 122 |
| **Total (Capex):** | **454** | **459** | **459** | **376** | **381** | **381** | **414** | **414** | **414** | **414** |
| **Operational Expenditure ($'000)** | | | | | | | | | | |
| Opex-Switchgear | 185 | 143 | 143 | 143 | 143 | 143 | 143 | 143 | 143 | 143 |

**Figure 5-31: 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<br>• Mechanical protection: Buchholz/ PRV | Shannon: Busbar differential/CB fail | OC/ EF/ Auto-Reclose | Fuse |
| Southern | Line Differential/ Distance/ OC/ EF/ Inter-tripping | • Electrical protection: Differential/ REF/ OC/ EF/ CB Fail<br>• Mechanical protection: Buchholz/ PRV | Paraparaumu East & Raumati: Busbar Differential/ CB Fail | OC/ EF/ Auto-Reclose Paraparaumu East: Arc flash protection | 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 171 protection relays, with ages as shown in Figure 5-32.

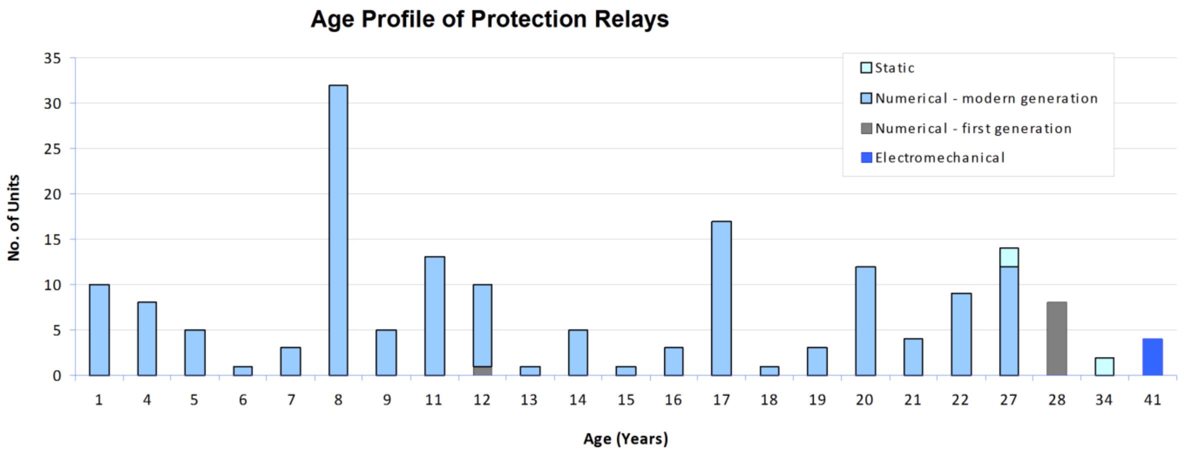



**Figure 5-32: Protection relays age profile**

### 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 |
|---|---|---|---|---|---|---|
| | | 10.0% | 55.0% | 35.0% | 4 | 15.0% |

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.

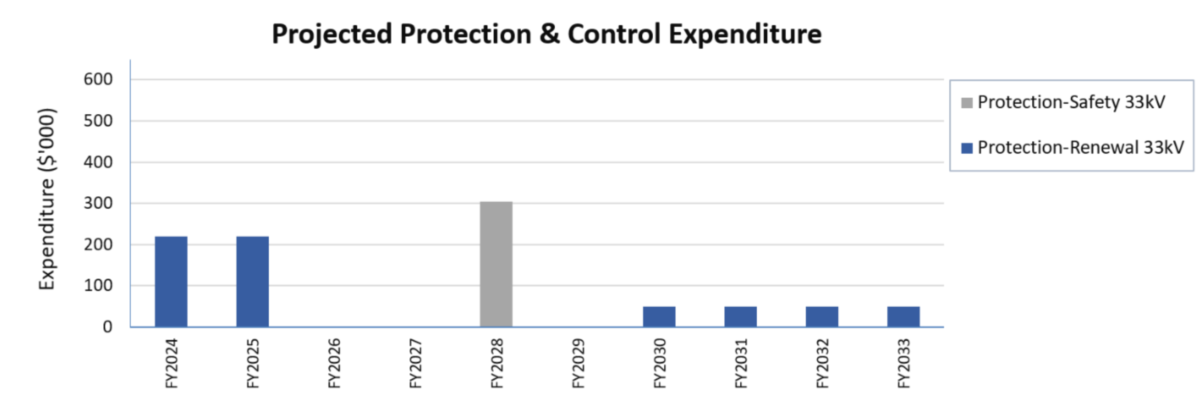
Due to the criticality and low value of individual protection and control plant, components are usually replaced rather than refurbished.

### 5.10.1.3 Major projects and programmes

The projects and programmes as well as budget forecast follow:

| Year | Ref | Location | Description | Category | Cost |
|---|---|---|---|---|---|
| FY2024 to FY2027 | 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 |
| FY2028 to FY2033 | 1 | All | 33kV protection | Renewal | $150,000 |

The projected protection and control expenditure are depicted in Figure 5-33.




| Description | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| Protection-Renewal 33kV | 220 | 220 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 50 |
| Protection-Safety 33kV | 0 | 0 | 0 | 0 | 305 | 0 | 0 | 0 | 0 | 0 |
| **Total:** | **220** | **220** | **0** | **0** | **305** | **0** | **50** | **50** | **50** | **50** |

**Figure 5-33: 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 5-34:

- Forest Heights, Waikanae
- Mataihuka south of Paraparaumu Moutere Hill west of Levin
- Levin West substation
- Tunapo at Paekākāriki.

The ages of remote terminal units or RTUs range from one to ten years.

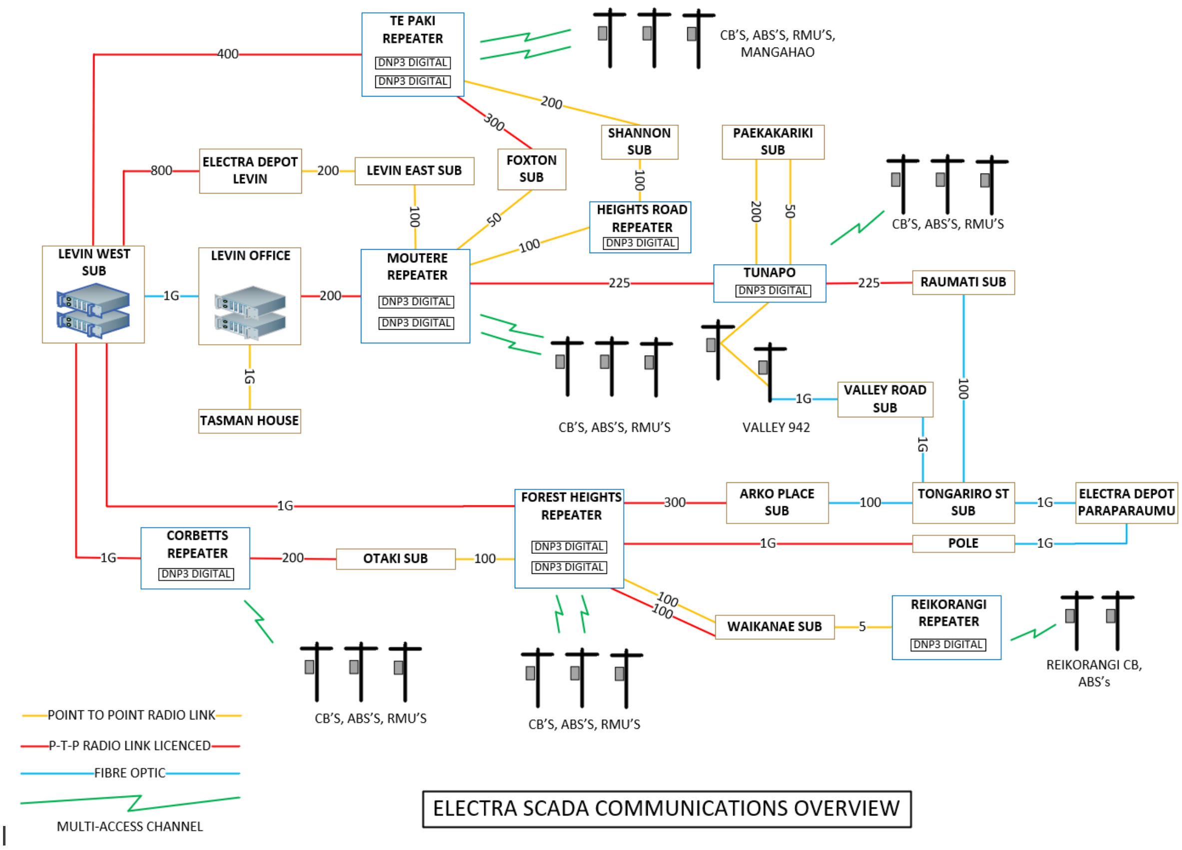



**Figure 5-34: SCADA communications overview**

### 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<br>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.

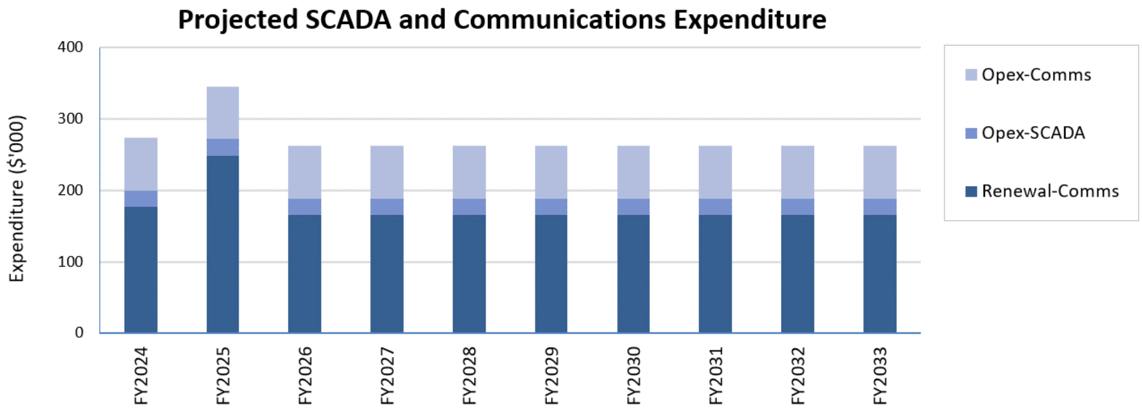
### 5.10.2.3 Major projects and programmes

The projects, programmes and budget forecast follow:

| Year | Ref | Location | Description | Category | Cost |
|---|---|---|---|---|---|
| FY2024 | 1 | Control Centre | SCADA upgrade | Renewal | $175,000 |
| | 2 | All | Comms general - FMS | Renewal | $135,000 |
| FY2025 to FY2028 | 1 | Control Centre | SCADA upgrade | Renewal | $700,000 |
| | 2 | All | Comms general - FMS | Renewal | $645,000 |
| FY2029 to FY2033 | 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 5-35.




| Description | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capital Expenditure ($'000)** | | | | | | | | | | |
| Renewal-Comms | 177 | 249 | 166 | 166 | 166 | 166 | 166 | 166 | 166 | 166 |
| **Total (Capex):** | **177** | **249** | **166** | **166** | **166** | **166** | **166** | **166** | **166** | **166** |
| **Operational Expenditure ($'000)** | | | | | | | | | | |
| Opex-SCADA | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| Opex-Comms | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 | 73 |
| **Total (Opex):** | **96** | **96** | **96** | **96** | **96** | **96** | **96** | **96** | **96** | **96** |

**Figure 5-35: 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
- Paekākāriki
- Shannon
- Tunapo
- Te Paki
- Waikanae.

The Electra IoT Communications framework is shown in Figure 4-14.

### 5.10.4.1 Condition-monitoring

The LoRa gateways are recent additions to the Electra communications network.
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:

- Faulty operation indicates imminent failure as reliability is critical
- 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<br>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 programmes and budget are detailed in Section 6.2.4.

## 5.10.5 Advanced Distribution Management System (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.

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.

Benefits include:

- 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
- Enhanced data capture
- The web outage viewer has proven to be a significant benefit – not only with the increase of customers accessing the viewer for accurate outage information but has also resulted in reduced call volumes.

### 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. We have contracts in place for the hire/lease of a small fleet of generators ranging from small single-phase units up to larger 880kVA units. We plan to include a 0.4/11kV step-up transformer including advanced protection allowing the control of multiple generators.

## 5.11 **Strategic spares**

In line with our strategy to achieve excellence in our operations, Electra commenced the development of a critical spares database in September 2020. This database covers the inventory and details of critical spares stored in substations and stores including switchgear, circuit breakers, transformers, bushings, drives and motors. The project was completed in 2022 and included dashboards, pivot tables and charts for various equipment including their location. The project highlighted areas of focus and in FY2023 and FY2024 we will be procuring additional critical spares on a risk-based approach.

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 | 2 | 2 Levin East Substation |
| | 15kVA 3 phase | 2 | 1 Levin East Substation, 1 Levin Depot |
| | 30kVA 1 phase | 2 | Levin East Substation |
| | 30kVA 3 phase | 6 | 4 Levin East Substation, 2 Levin Depot |
| | 50kVA 3 phase | 7 | 4 Levin East Substation, 1 Levin Depot, 2 Paraparaumu West Substation |
| | 100kVA 3 phase | 4 | 3 Levin East Substation, 1 Levin Depot |
| | 200kVA 3 phase | 1 | Levin East Substation |
| Ground Mount Transformer | 50kVA micro sub | 3 | 2 Levin East Substation, 1 Paraparaumu West Substation |
| | 100kVA 3 phase | 9 | 8 Levin East Substation, 1 Paraparaumu West Substation |
| | 200kVA 3 phase | 1 | Paraparaumu West Substation |
| | 200kVA 3 phase | 2 | Levin East Substation |
| | 300kVA 3 phase | 1 | Levin East Substation |
| | 500kVA 3 phase | 2 | Levin East Substation |
| | 750kVA 3 phase | 1 | Levin East Substation |
| | 1000kVA 3 phase | 1 | Levin East Substation |
| | Transformer pad | 1 of each | Levin East Substation: 75kVA-100kVA, 100kVA–300kVA, 500kVA–1000kVA |
| Switchgear/Fuses | Schneider RN62c | 3 | Waikanae Substation |
| | ABB | 4 | Waikanae Substation: 1 CCC, 1 CFC, 2 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[44] that provides direction on how to proactively manage vegetation risk, to improve supply reliability, security, performance and the safety of our network.

### 5.12.1 **Condition-monitoring**

Electra's overhead lines are surrounded by trees of varying heights, foliage types, growth rates and ownership classes. Our vegetation management process integrates a planned programme where cyclic trimming is undertaken based on a risk-based assessment strategy.

Figure 5-36a shows a gradual increase in our vegetation OPEX since FY2016 to FY2019 and a resulting decrease in vegetation SAIDI from 7.8 minutes in FY2018, to 0.67 minutes in FY2020. The decrease in OPEX to $1.5M in FY2022 has seemingly coincided with the increase in vegetation SAIDI to 14.9 minutes in FY2022 (faults due to higher-than-average storm damage). However, our average vegetation SAIDI of 7.2 minutes over FY2020 to FY2022 is 15 minutes or 67% below the industry median of 21.8 minutes (Figure 5-36b); the SAIDI performance versus vegetation OPEX is discussed further in Section 8.3.2.

[44] Electricity Networks Association and Electricity Engineers Association, "Risk Based Vegetation Management Guide", July 2016

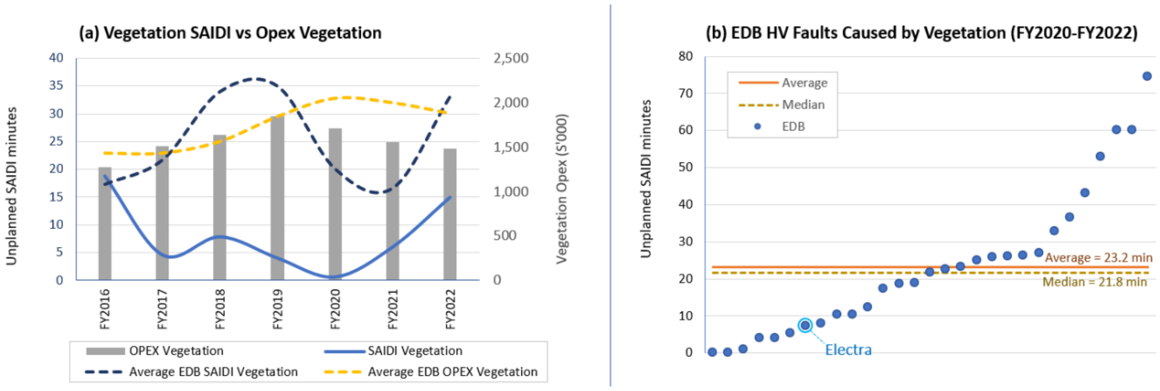



**Figure 5-36: (a) Electra HV faults caused by vegetation, and (b) FY2020 -FY2021 EDB SAIDI vegetation faults**

Our vegetation control team has continued with a strong performance this year where the team has issued 341 hazard warning notices to tree owners and completed 395 hazard warning notices jobs around the network. In addition, 110 cut-or-trim notices were also issued, and of those 134 cut-or-trim jobs completed on our network. We continue to use a vegetation management database to record all notices issued, be it hazard warning notices or cut-or-trim notices, including tree owner, contact details, number of trees identified, species, voltage involved, between pole/plant numbers, work completion date and information regarding the work site or ownership. By using this system to its full potential, we build a history of the site, including reinspection intervals. This minimises travel and revisits to the potential vegetation hazards around our network and optimizes our delivery capabilities, thereby reducing our carbon footprint.

We use environmental-friendly chain bar oil and have systematically replaced large older less efficient petrol chainsaws with lighter more fuel-efficient versions. We have introduced a trial of two models of battery electric chainsaws per crew to lead the industry in our efforts to be greener in the delivery of vegetation control. The team is pleasantly surprised with the performance of the new chainsaws especially when we do not have to wait for the unit to cool down before refuelling but insert a new battery to carry on with the task. Inverters have been installed in the vehicles to ensure another charged battery is always on hand.

## 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 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<br>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 focused 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.

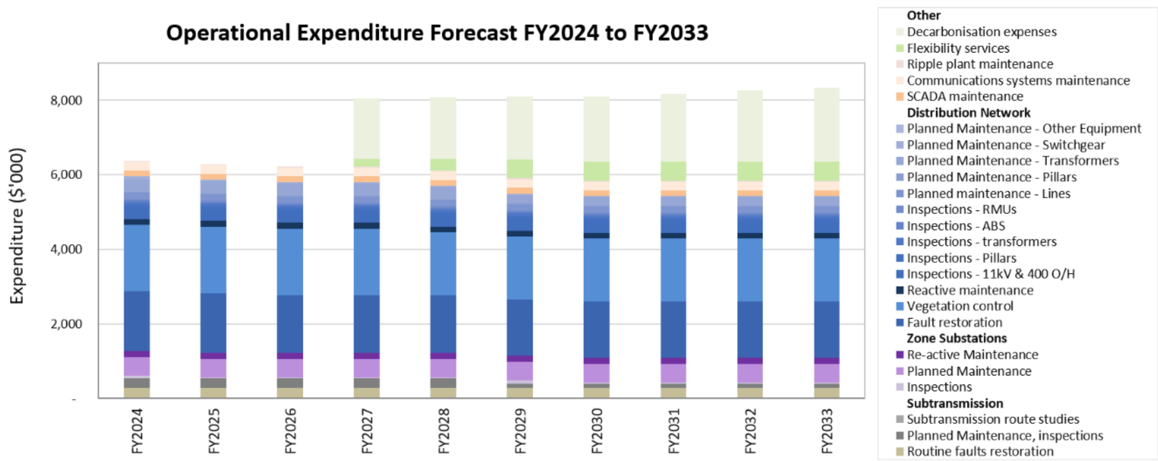
The programmes for the indicated financial years follow and the tree or vegetation control operational budget is included in the following table as well as in Figure 5-37.

| Year | Ref | Location | Type of work | Category | Cost |
|---|---|---|---|---|---|
| FY2024 | 1 | All | Vegetation control (not faults) | Vegetation | $1,784,000 |
| FY2025 to FY2028 | 2 | All | Vegetation control (not faults) | Vegetation | $7,036,000 |
| FY2029 to FY2033 | 3 | All | Vegetation control (not faults) | Vegetation | $8,421,000 |

## 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 5-37: Projected operational expenditure (OPEX) for FY2024 to FY2033.

These costs for OPEX are also reflected in Schedule 11b Report of Forecast Operational Expenditure in Appendix 3.



| Operations & Maintenance (Current $'000) | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Subtransmission** | | | | | | | | | | |
| Routine faults restoration | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 | 274 |
| Planned Maintenance, inspections | 259 | 259 | 259 | 259 | 259 | 122 | 122 | 122 | 122 | 122 |
| Subtransmission route studies | - | - | - | - | - | - | - | - | - | - |
| **Zone Substations** | | | | | | | | | | |
| Inspections | 84 | 29 | 29 | 29 | 29 | 90 | 29 | 29 | 29 | 29 |
| Planned Maintenance | 498 | 498 | 498 | 498 | 498 | 498 | 498 | 498 | 498 | 498 |
| Re-active Maintenance | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 |
| **Distribution Network** | | | | | | | | | | |
| Fault restoration | 1,594 | 1,607 | 1,549 | 1,549 | 1,549 | 1,516 | 1,516 | 1,516 | 1,516 | 1,516 |
| Vegetation control | 1,784 | 1,784 | 1,784 | 1,784 | 1,684 | 1,684 | 1,684 | 1,684 | 1,684 | 1,684 |
| Reactive maintenance | 153 | 153 | 153 | 153 | 153 | 153 | 153 | 153 | 153 | 153 |
| Inspections - 11kV & 400 O/H | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 |
| Inspections - Pillars | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 |
| Inspections - transformers | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 |
| Inspections - ABS | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| Inspections - RMUs | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 |
| Planned maintenance - Lines | 174 | 174 | 174 | 174 | 174 | 174 | 174 | 174 | 174 | 174 |
| Planned Maintenance - Pillars | 22 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Planned Maintenance - Transformers | 336 | 336 | 336 | 336 | 336 | 233 | 233 | 233 | 233 | 233 |
| Planned Maintenance - Switchgear | 71 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Planned Maintenance - Other Equipment | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Other** | | | | | | | | | | |
| SCADA maintenance | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 152 |
| Communications systems maintenance | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 | 235 |
| Ripple plant maintenance | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| Flexibility services | - | - | - | 200 | 300 | 500 | 500 | 500 | 500 | 500 |
| Decarbonisation expenses | - | - | - | 1,620 | 1,671 | 1,689 | 1,753 | 1,834 | 1,916 | 1,998 |
| **Total Operations & Maintenance** | **6,370** | **6,273** | **6,215** | **8,035** | **8,087** | **8,092** | **8,095** | **8,176** | **8,258** | **8,340** |

**Figure 5-37: Projected operational expenditure (OPEX) for FY2024 to FY2033**

The next sections cover our employees and the resourcing strategy to implement our development and maintenance plans.

## 5.14 Our employees

Electra's most valuable asset is our employees. Their safety, working environment, well-being and job satisfaction are paramount to Electra. The success of Electra's business is reliant on the contribution of all our employees.

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 building leadership capability through a Leadership Development programme, developing our talent, talent attraction and retention, implementing an HRIS system, employee wellbeing through promotion of EAP services as well as fully funded Medical Insurance through Southern Cross and associated member benefits.

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.

### 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 have 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.

To ensure effective communication of our asset management policies and objectives, key managers such as the Chief Operating Officer - Lines Business, the Group 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.

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. A 100% competency success rate was also achieved during our Arborists' 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 5,755 training hours, encompassing 325 enrolments in FY2022, and we expect to continue our commitment to training in the following years.

In FY2022, team members who work on our distribution assets attained 16 New Zealand Certificates. The certifications include:

- 3 x New Zealand Certificate in Electricity Supply (Introduction) (Level 2)
- 2 x New Zealand Certificate in Electricity Supply (Line Mechanic) (Level 4)
- 3 x New Zealand Certificate in Electricity Supply (Electrical) (Level 4) with strands in Electricity Supply Electrician, Electrical Fitter and Electrical Technician
- 4 x New Zealand Certificate in Electricity Supply (Fault Response) (Level 4)
- 4 x New Zealand Certificate in Electricity Supply (Transmission – Liveline)

The team attended two Safety Days meeting EWRB requirements with 100% success rate as well as electrical safety testing and first aid refresher. Other training activities included: Cable fault location techniques, AMPACT tool refresher, Liveline refresher, First Aid refresher, 4WD training, forklift licensing/refresher and Team Mate to Team Leader courses.

Electra's Arborist Team attended their annual refresher training with 100% success. Many of the team also participated in a workplace literacy programme, encompassing information technology and public speaking. Other teams increased or refreshed their skills attending: Fundamentals of the Electricity Sector, industry specific training, Traffic Management, 4WD safety, business writing and communications courses and a range of industry conferences.

Electra hosted the 2022 Annual Connection – Connexis Linesmen Competition (Figure 5-38) which showcased our people participating with other specialist line mechanics and cable jointers from other Electricity Distribution Businesses across New Zealand for the three-day event. We registered two Line Mechanic teams, both strong contenders throughout the competition evident with the Levin team winning the "Test to Ensure Safety" event, and Paraparaumu winning the "Rigging" and the "Old School" events. Both teams jointly captured the Dougie Trophy, awarded to the Best Presented Line Mechanics team.

**Figure 5-38: Annual Connection - Connexis Linesmen Games, September 2022**

## 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 programmes.

### 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 EDBs 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%, remaining consistent in the last two years. Utilisation and productivity are areas of continued focus. Reporting, feedback and process development aim to lift this to 82%.

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 FTEs 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 FTEs and vacancies in the process of being filled.

The expected resources, the surplus and shortfalls for works delivery from FY2023 to FY2028 is depicted in Figure 5-39.

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.

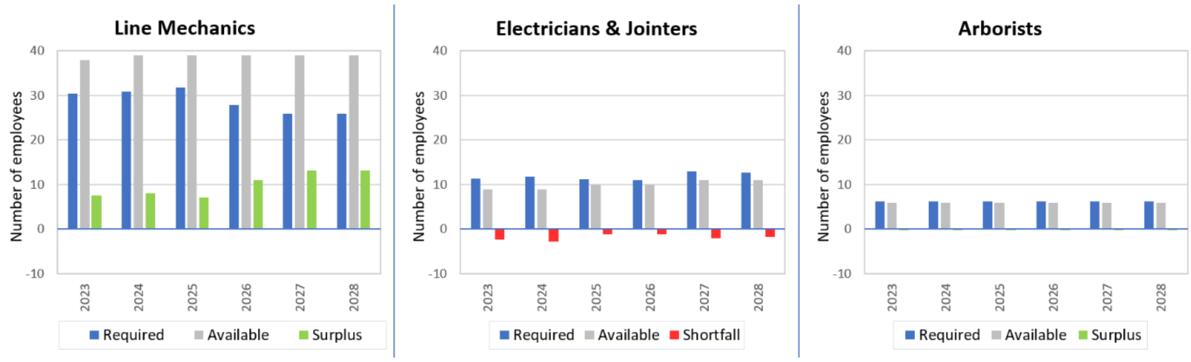



**Figure 5-39: Works delivery projected resources**

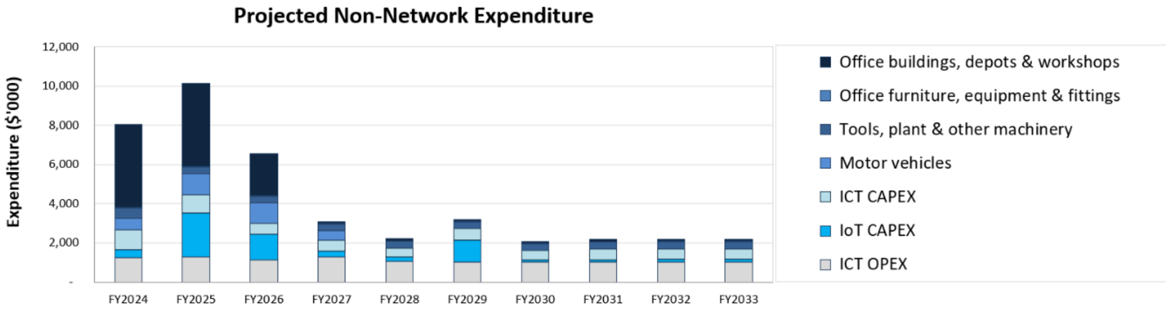
# 6 NON-NETWORK SYSTEMS

## 6.1 Summary of non-network assets

Electra's non-network assets include:

| Asset class | Description | Approximate value to FY2022 | Criticality to asset management |
|---|---|---|---|
| Non-network ICT and AMIS | Financial system - Microsoft Nav-Dynamics (Being replaced under the Mahi Tahi Project) | 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 | $90,855 (NBV) | |
| | In-house outage management and job dispatch system | $6,742 (NBV) | Fault dispatch work would be disrupted. Criticality is about 12 hours |
| | Customer Resource Management System (CRM) | $ Disposed of in 2022 (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) | $Nil Value (NBV) | Real-time operations would require manual HV switching. Criticality is minutes |
| AM systems | NIMS – based on ESRI GIS, but largely in-house | $1,595,524 (NBV) | Existing work could continue, but new jobs couldn't be created. Criticality is about 30 days |
| | Milsoft ADMS suite | $0 (NBV)<br>Fully depreciated | Outage resolution would be delayed increasing SAIDI |
| Buildings | Head Office (Levin) | $969,176 (NBV)<br>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) | $18,027 (NBV) | Not critical |
| Office furniture | Desks and workstations<br>Chairs | $742,826 (NBV)<br>Includes PCs and related IT equipment | Not critical as easily replaced |
| Vehicles | Cars<br>Vans<br>2WD Utes<br>4WD Utes Bucket Trucks | $3,728,000 (NBV) | Not critical as alternatives can be arranged |
| Tools, plant and machinery | Hand tools<br>Test Equipment<br>Power tools | $136,666 (NBV) | Not critical as easily replaced through local retailers or specialised suppliers |

The overall projected non-network expenditure is shown in Figure 6-1 covering building development, vehicles, tools, fittings, tools, plant and equipment




| Non-Network Capital Expenditure ($'000) | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | Average % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Office buildings, depots & workshops | 4,245 | 4,235 | 2,130 | 80 | 85 | 80 | 80 | 80 | 80 | 80 | 27% |
| Office furniture, equipment & fittings | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 1% |
| Tools, plant & other machinery | 520 | 350 | 350 | 350 | 350 | 350 | 350 | 350 | 350 | 350 | 9% |
| Motor vehicles | 600 | 1,067 | 1,067 | 467 | - | - | - | - | - | - | 8% |
| ICT CAPEX | 995 | 935 | 560 | 560 | 475 | 575 | 475 | 560 | 525 | 525 | 15% |
| IoT CAPEX | 435 | 2,235 | 1,285 | 285 | 205 | 1,135 | 135 | 135 | 175 | 175 | 15% |
| ICT OPEX | 1,228 | 1,288 | 1,138 | 1,298 | 1,060 | 1,010 | 1,010 | 1,010 | 1,010 | 1,010 | 26% |
| **Total Capital Expenditure** | **8,047** | **10,134** | **6,554** | **3,064** | **2,200** | **3,175** | **2,075** | **2,160** | **2,165** | **2,165** | **100%** |

**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 as per Section 1.3.2 namely:

- 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.<br>Reduce procurement and operational costs<br>Growth potential in subsidiaries<br>New business in technology centric business | CRM, Integrations and correct data<br>Collaborate with CIO's in other ELBs<br>Support and develop acquisitions<br>Search and bring to the table |
| | Threats | Cyber and physical threats to operation<br>Disruption of significant regional disasters<br>Data Breach/Disclosure<br>Pandemic | Collaborate, strength, educate and test<br>Plan and prepare and practice<br>Controls, classification and education<br>Improved support of distribution or remote workforce |
| Internal Factors | Strengths | ICT operation and management expertise<br>Modern business information systems<br>Progressive company strategy<br>Strategic partners | Document and teach for succession<br>Leverage and develop tools<br>Research, innovate and learn<br>Develop and maintain strong relationship |
| | Weaknesses | Limited business intelligence and analytics<br>Phased ADMS implementation<br>ICT staff lacking expertise in various systems | Investigate, select and develop<br>Develop and extend<br>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 **Our 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:

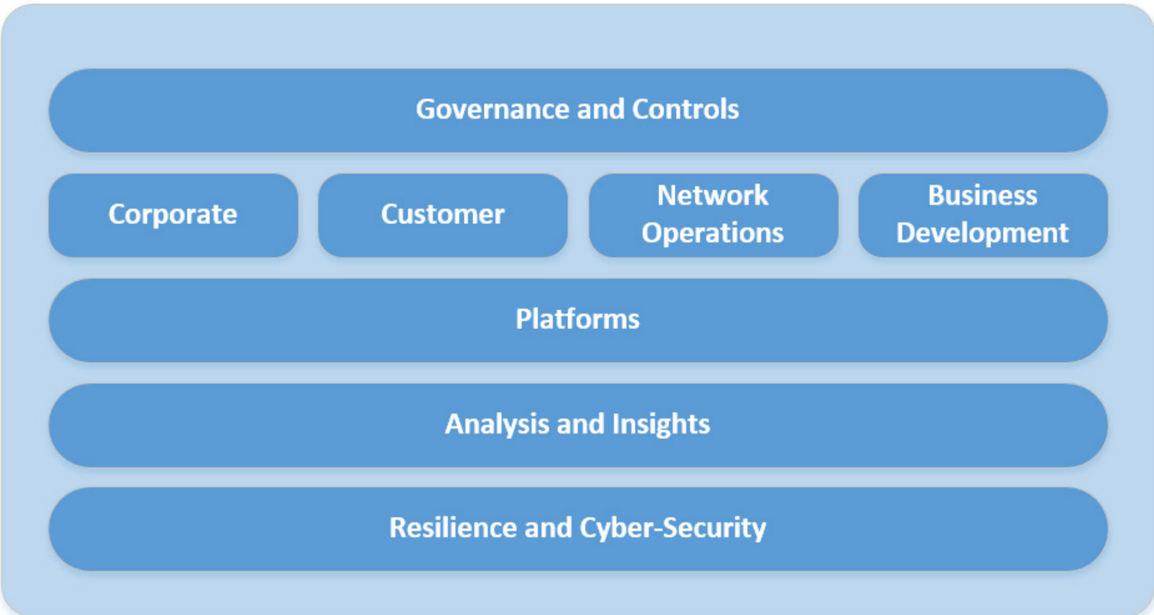



**Figure 6-3: Electra ICT asset and capability framework**

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

In FY2018, 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 continue to realise 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 have completed the initial implementation of Milsoft FieldSyte to replace Clevest. FieldSyte incorporates much of the functionality historically only available from the office and enables field-based staff access to information and tools which improve decision making and safety in the field.

We continue to grow and improve our IoT platform capability. Over the past 12 months we have upgraded our IoT gateways to improve capacity and performance.

Electra implemented the FME (Feature Manipulation Engine) solution. This solution enables the integration of information from our IoT devices as well as that from third party systems to better inform ADMS for better outage identification and management.

In late 2022 Electra was awarded a partnership in the Electricity Engineer's Association trial of implementing OpenADR (automatic demand response) for managing the demand of domestic EV charging in the future. The project will run for approximately 12 months and findings will be reported to EEA members.

Electra's goals for participating in the trial are:

- Establishing a demand response scheme on our network as an alternative to ripple control. OpenADR will allow flexibility service providers to create a secondary market for demand response. This is in line with Electra's energy transformation goals of procuring flexibility services in the future to offset peak demand growth.

- Building experience with a DERMS. Transpower have donated the use of their DER platform[45], FlexPoint™, for the trial. Utilising FlexPoint™ will allow the management of:

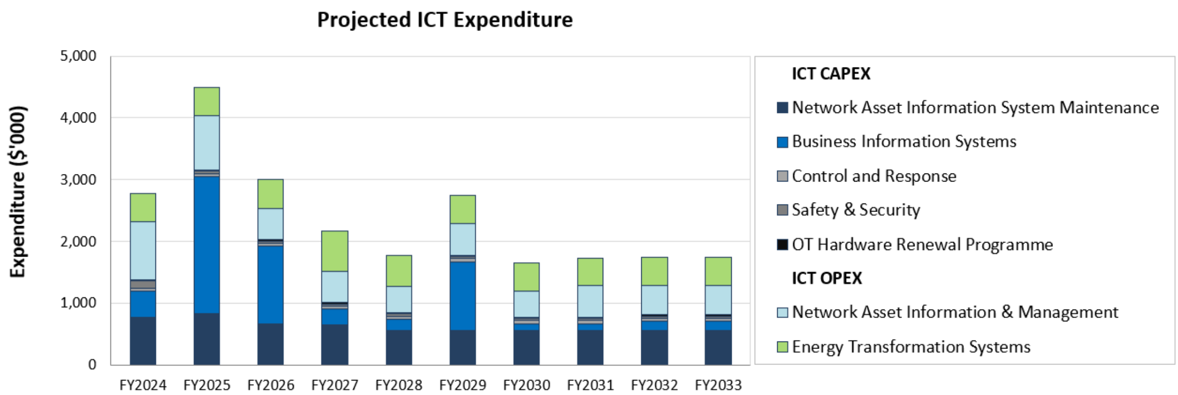
  * Ripple control of hot water and participation of large commercial consumers
  * Reduce and flex demand in real time through turning smart appliances down, up, on or off
  * Reduce and flex demand by using solar PV or batteries to meet load locally
  * Shift demand from peak to off peak times by controlling when smart devices such as appliances, hot water cylinders or EV chargers operate.

The OpenADR trial will inform our thinking around Electra's requirements for a Distributed Energy Resource Management System (DERMS). We recognise the requirement for a DERMS, yet from an architectural, technical and contractual basis there are a number of ways in which this can be implemented. We commit to raising our understanding so that we can make an informed decision within the next 12-24 months.

## 6.2.4 ICT 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.

Cyber security initiatives, information security management, network asset information improvement and the development of spatial capabilities are included in ICT operational expenditure.




| ICT CAPEX | FY2024 | FY2025 | FY2026 | FY2027 | FY2028 | FY2029 | FY2030 | FY2031 | FY2032 | FY2033 | Average % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Network Asset Information & Management | 945 | 885 | 510 | 510 | 425 | 525 | 425 | 510 | 475 | 475 | 24% |
| Business Information Systems | 415 | 2,215 | 1,265 | 265 | 185 | 1,115 | 115 | 115 | 155 | 155 | 26% |
| Safety & Security | 120 | 35 | 30 | 30 | 35 | 30 | 30 | 30 | 30 | 30 | 2% |
| Control and Response | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 0% |
| OT Hardware Renewal Programme | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 1% |
| **ICT OPEX** | | | | | | | | | | | |
| Network Asset Information System Maintenance | 778 | 838 | 663 | 648 | 560 | 560 | 560 | 560 | 560 | 560 | 27% |
| Energy Transformation Systems | 450 | 450 | 475 | 650 | 500 | 450 | 450 | 450 | 450 | 450 | 20% |
| **Total CAPEX & OPEX** | **2,778** | **4,493** | **3,013** | **2,173** | **1,775** | **2,750** | **1,650** | **1,735** | **1,740** | **1,740** | **100%** |

**Figure 6-4: ICT forecast**

[45] Transpower, FlexPointTM Distributed Energy Resources Management System

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)<br>• Upgrade and integration of Navision (ERP)<br>• Upgrade of GIS/Spatial solution (ESRI)<br>• Network Asset Information Improvement project<br>• Network Asset Condition Monitoring improvement project |
| Safety & Security | • Replacement/Upgrade of security and surveillance systems for Network Zone Substations and other critical locations<br>• Replacement/Upgrade of security and surveillance systems for Server Rooms<br>• Lone worker solution |
| Control & Respond | • Development and enhancement of SCADA platform (iFIX)<br>• Development and enhancement of ADMS (Milsoft)<br>• Establish secondary control room<br>• Strategic and continual improvement programme for secure network communications |
| Business Information Systems | • HRIS Solution<br>• Replace/Upgrade security and surveillance systems for corporate offices<br>• Business Information Systems (BIS) core architecture upgrade<br>• Corporate Website Update<br>• CRM Development<br>• Business Information Systems (BIS) Service Delivery Solution replacement |

The investment in FY2024 reflects the need for Electra to improve the quality and quantity of network asset and engineering data. Included is the improvement or implementation of systems to interpret the data and provide insights to assist with operational management and planned growth of the distribution network.

Improved data insights are necessary enablers to many of Electra's strategic projects especially those related to Network Transformation and support of the government's decarbonisation goals.

In FY2023/2024 we will be reviewing our ADMS and SCADA solutions in line with emerging DERMS/DSO influencers. The goal is to implement a secure solution which will consolidate SCADA, DERMS and Outage Management functions.

### 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. Electra continues to raise its cyber security maturity, using industry recognised standards and controls. We have partnered with leading hardware and software vendors, adopting the latest technologies in artificial intelligence to secure our infrastructure and environment. This includes a planned maintenance and replacement schedule of all key architecture to support growth and resilience.

## 6.3 Buildings and property

| Asset class | Key policies | Strategies and initiatives |
|---|---|---|
| Buildings | Head office (Levin)<br>Depot (Levin)<br>Depot (Paraparaumu) | The Control Room layout has been optimised in preparation for technology and system upgrades.<br>A new location and building to replace our Levin depot is underway and targeted for completion in FY2024. |

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 organisation structure evolves
- Specific plans for system control, especially back-up (cuts across ICT)
- Reviewing of civil work requirements in order to identify the most efficient yet expedient options.

### 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 was 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<br>Chairs<br>Cabinets and storage | No specific strategy, typically low value items that simply follow the need for staff work patterns and duties.<br>An emphasis is being placed on stand-up options for desks/ workstations. |

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 supports New Zealand's transition into a low carbon economy and transport decarbonisation initiatives. We have started to transition our own vehicle fleet to electric vehicle variants, installing EV chargers at all 10 of our zone substations, at our offices and depots, and an incentive for our staff to switch to EVs by providing 2-hour free charging every day. Increased charging opportunities at the three office and depot locations will be available.

Electra has also adopted a vehicle leasing strategy with operating maintenance leases for its light vehicle fleet and other electric vehicles from 2022. This strategy will see benefits of lower fleet operational costs, increased safety, and energy efficiency ratings via the lowering of average fleet ages while reducing the impact of Capex expenditure on fleet replacement.

Electra has the following electric or hybrid vehicles:

- Light vehicles: Three electric/hybrid pool vehicles comprising of Hyundai Ioniq, MG ZS and a Mitsubishi Outlander PHEV and two LDV electric vans are currently in operation within the fleet
- Heavy vehicles: One truck with hybrid technology and three more vehicles with hybrid technology will be included in our fleet replacement programme by March 2024 or earlier if available
- A further three BYD electric vehicles will be purchased to expand the fleet. One of these will replace the Hyundai Ioniq.

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 |

| Asset class | Key policies | Strategies and initiatives |
|---|---|---|
| Other Vehicles | Cars (petrol): replace after 130,000km or 4 years<br>Cars (diesel): replace after 160,000km or 4 years<br>Vans and Utes: replace after 160,000km or 6 years<br>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<br>Power tools<br>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.<br>Six petrol powered chainsaws have been replaced with battery operated chainsaws, with future replacements to also be battery operated. |

The replacement policies aim to match the depreciation of the assets.

# 7 RISK MANAGEMENT

Electra has an established comprehensive risk management policy and framework based on the internationally recognised ISO 31000:2018 Risk Management standard that includes the following line-of-sight linkages from risk governance through to detailed risk identification and mitigation.


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 and regulation, 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 reviewed four times annually by the Board Risk and Audit committee and Management, in line with the requirements of the Health and Safety at Work Act 2015.

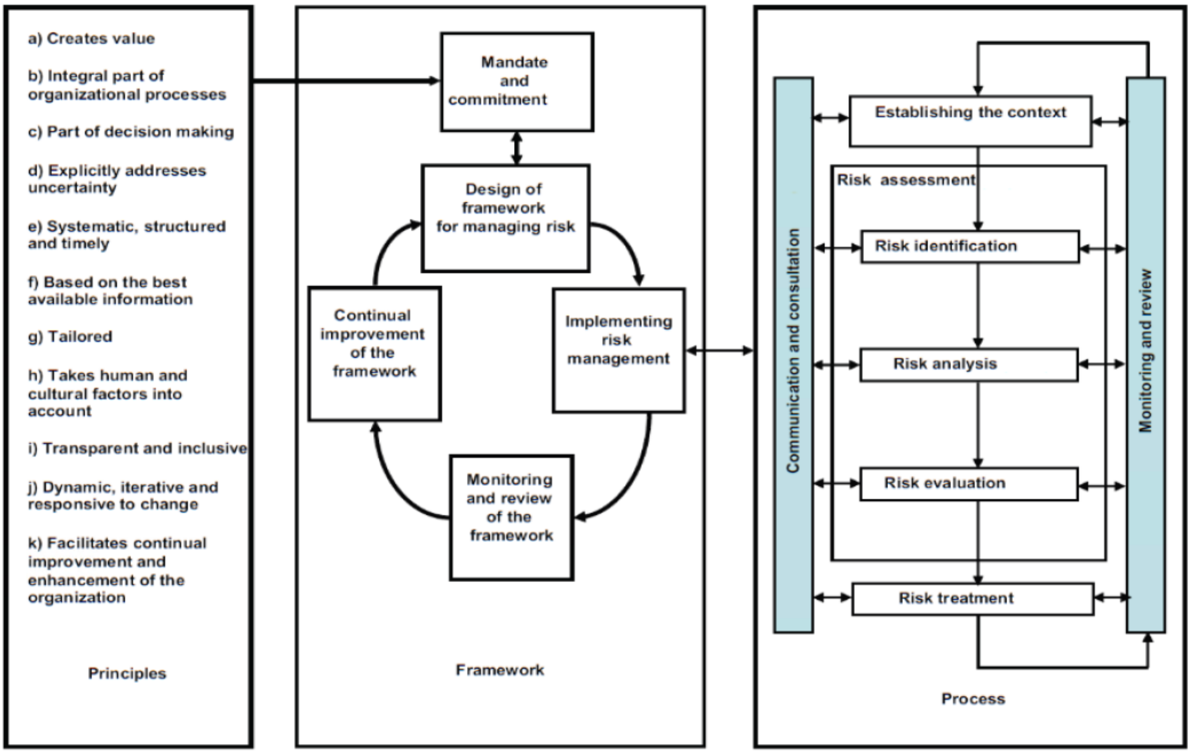



**Figure 7-1: Risk management framework based on AS/NZS ISO 31000:2009**

This framework uses an established process based on AS/NZS ISO 31000:2009 to:

- Identify risks that affect the Electra group, the public, contractors, and the environment
- Assess the consequence and likelihood of the risk occurring
- Identify controls that will mitigate the risk
- Identify the top 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.

An annual workshop with senior management and board members is held to review all the enterprise risks and identify the highest risks. In 2022 external consultants were engaged to facilitate this workshop and identify any new risks, agree collectively the risk profile, and risk maturity within Electra and against the wider industry.

## 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.

The scoring matrix in Figure 7-2 quantifies probability against the consequence to identify the risk profile. A scoring system has been adopted to ensure consistency of scoring across all risks. This was updated in 2022 reporting year to reflect increased values of infrastructure and media coverage of any risk.

| | Minor | Moderate | Serious | Major | Catastrophic |
|---|---|---|---|---|---|
| Frequent | 50-Low | 150-Medium | 250-High | 350-Very High | 500-Very High |
| Probable | 40-Low | 120-Medium | 200-High | 280-High | 400-Very High |
| Occasional | 30-Low | 90-Low | 150-Medium | 210-High | 300-High |
| Remote | 20-Low | 60-Low | 100-Medium | 140-Medium | 200-High |
| Improbable | 10-Low | 30-Low | 50-Low | 70-Low | 100-Medium |

**Figure 7-2: Risk matrix**

## 7.1.2 Risk register

The Group maintains a Risk Register which is reviewed at least four times annually 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 the 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 detailed in Section 3.8.2.

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). Our staff and management regularly complete a comprehensive risk analysis on the network and the supporting management structures. The risk analysis is reviewed and agreed by the Risk and Audit committee comprised of Electra Directors, the Chief Executive, Chief Financial Officer, and the Risk Manager. From this analysis, Electra identifies critical elements and plans required to manage these risks. An example of the risk register is shown in Figure 7-3 where the current and target risk matrix scores are applied.

| Risk ID | Subject | Raw Probability | Raw Consequence | Raw Risk Score | Current Probability | Current Consequence | Current Risk Score | Target Probability | Target Consequence | Target Risk Score |
|---|---|---|---|---|---|---|---|---|---|---|
| 166 | Climate Risk & Sustainability | 3 | 50 | **150** | 4 | 30 | **120** | 2 | 30 | **60** |
| 194 | Asset Planning & Management | 4 | 50 | **200** | 3 | 30 | **90** | 2 | 30 | **60** |
| 147 | Regulatory Change | 4 | 70 | **280** | 4 | 50 | **200** | 2 | 50 | **100** |
| 157 | Theft or Fraud | 4 | 70 | **280** | 2 | 30 | **60** | 1 | 30 | **30** |

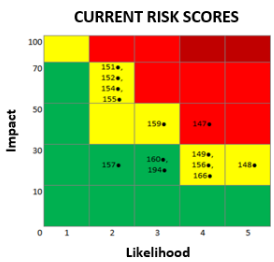




**Figure 7-3: Sample of risk register**

The Electra Group Risk and Control Environment is updated to reflect the progress of agreed actions.

The major risks Electra have identified are regulatory change, staff retention and recruitment, climate risk and sustainability, decarbonisation, harm to workers and the public.

## 7.2 Specific risks

The following risks are listed as subset of the risk maintained in the Vault Risk Management System.

### 7.2.1 Regulatory Reform

Regulatory reform of the energy sector has been identified as the greatest current risk for both the industry and Electra. Electra is participating more in industry forums, workshops, and working groups provided by the EA, ENA and EEA, to be able to better understand the changes and influence the industry by responding to regulatory consultations.

The volume of regulatory reform has increased substantially in the last year. A regulatory group, including external experts, has been established to provide oversight on consultations and the response required. Electra responds both individually or as part of a collective of distributors.

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 2022, completed by 44 managers and key employees, were reviewed by the Risk and Audit Committee in November 2022. The survey covered 71 pieces of legislation with 2,657 responses completed. 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 Section 4.5.1 depicts the process.


**Figure 7-4: Legal risk management process**

### 7.2.2 Staff retention and recruitment

With increasing demands on the requirement for highly skilled and competent employees the past two years have been challenging in both recruiting and retaining staff, particularly in the engineering and finance fields. Closed borders have restricted overseas recruitment, and new immigration rules continue to provide challenges. Recruitment campaigns have been successful, however other businesses also looking for staff with these specific skill sets are making employment offers Electra is unable to match. Electra has begun an engineering graduate programme to provide experience and possible career paths for future engineers and looks to benefit from this going forward.

## 7.2.3 **Changing Climate and Sustainability**

Changing climate features (sea level rise, changing rainfall patterns, increased air temperatures and increasing numbers of windy days) are widely regarded as the single biggest risk facing civilisation in general and built infrastructure. A Sustainability Group has been established to provide strategic guidance on sustainability issues, material issues and risks relevant to the performance of the business. The Group's responsibilities include the review, evaluation and endorsement of relevant sustainability policies, frameworks, strategies, and targets as well as the integration of sustainability considerations into business planning, risk management, prioritisation of sustainability activities and analysis of the impact of our sustainability policies and practices.

Two critical projects have been launched to define and shape our sustainability strategy:

- Sustainability materiality assessment: We interviewed both internal and external stakeholder to gauge their views on the importance and impact on Electra's sustainability objectives and our findings has enabled Electra to prioritise sustainability activities that are vital and will have a significant impact, not just for Electra but for our community
- Target-setting for GHG reduction: Electra's carbon footprint baseline assessment has helped us understand where emissions are being generated and more importantly, allow us to set a target to manage a reduction in our GHG or Greenhouse Gas emissions in line with New Zealand's target under the Climate Change Response Act 2002 for net zero emissions by 2050.

Electra's proposed sustainability framework is depicted in Figure 7-5.

| **Purpose** | **Empower the future** | | | | | |
|---|---|---|---|---|---|---|
| **Our Goals** | Nurturing safety and connection | | Ensuring a resilient and reliable network | | Enabling energy efficient, renewable solutions | |
| **Activities** | Health, safety & wellbeing | Diversity & inclusion<br>Talent & employee experience | Affordability & accessibility<br>Customer Service | Business resilience<br>Transparency & disclosure<br>Investments & returns | Energy efficient grid<br>Distributed generation | Network waste<br>Climate change risk |
| **Impact categories** | Workforce | | Customer & community | Governance | Environment | |
| | | | | Economic | Customer & community | |

**Figure 7-5: Proposed Sustainability Strategy Framework**

The Ministry for the Environment has identified the top 42 climate risks for New Zealand in their 2020 National Climate Change Risk Assessment report. Based on these risks, we have prioritised those that required the most action and assessed the climate impact on our physical assets as well as on our commercial and regulatory impacts of our business in the short, medium and long term.

Electra is committed to reduce the human impact on climate change and ensure we understand how Electra's activities can materially impact this change. Our network is not immune to changes in the environment like coastal erosion and the rising sea level and we are exploring how these types of changes impact the way we build and support our network with a view of augmenting our procedures and processes to enable a more resilient network into the future. Section 7.2.5 details the flood risk assessment conducted for our assets in November 2022.

Electra also participates in relevant national workgroups and events and maintains a watching brief on the market.

Further, we have committed to ensure we fully establish sustainability as a core part of our operations. This includes:

- A commitment towards establishing a sustainability strategy and roadmap
- Hiring a Sustainability Lead who will guide and lead our overall sustainability plan
- Establishing the ideal ESG reporting framework for Electra. This will be finalised before 31 March 2023, with the intention of beginning measurements from 1 April 2023. Reports from the results will be provided quarterly
- Identifying clear in-house sustainability initiatives with increasing funding made available.

## 7.2.4 Decarbonisation

Electra is committed to supporting 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, we are:

- 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
- Participating in relevant national workgroups and events.

To ensure we know what areas we need to prioritise, Electra has contracted an external party to conduct a baseline carbon footprint assessment, designed to give us a view of our current carbon emissions and provide insight on how we can reduce or eliminate such effects. Electra will look to defining the targets to support carbon emissions and integrate low or zero emission technology into its business.

Decarbonisation is also included in Electra's strategy for management of DER and PV demands.

The publication in late 2022 of the Boston Consulting Group's Climate Change in New Zealand: The future is Electric report highlights the level of investment required by the distribution sector over the next 10 - 20 years to meet changing energy requirements. Indications are investment will be much higher than expected. Electra have considered this as part of the AMP and future pricing requirements.

## 7.2.5 Flood risk analysis

Electra has obtained flooding data information from the two local authorities in our network area (Kāpiti and Horowhenua District Councils). The details have been overlaid onto our GIS systems (depicted in Figure 7-6) to provide insight of where and how equipment may be appropriately deployed such as installing pole rather than ground-mounted transformers (Figure 7-9).

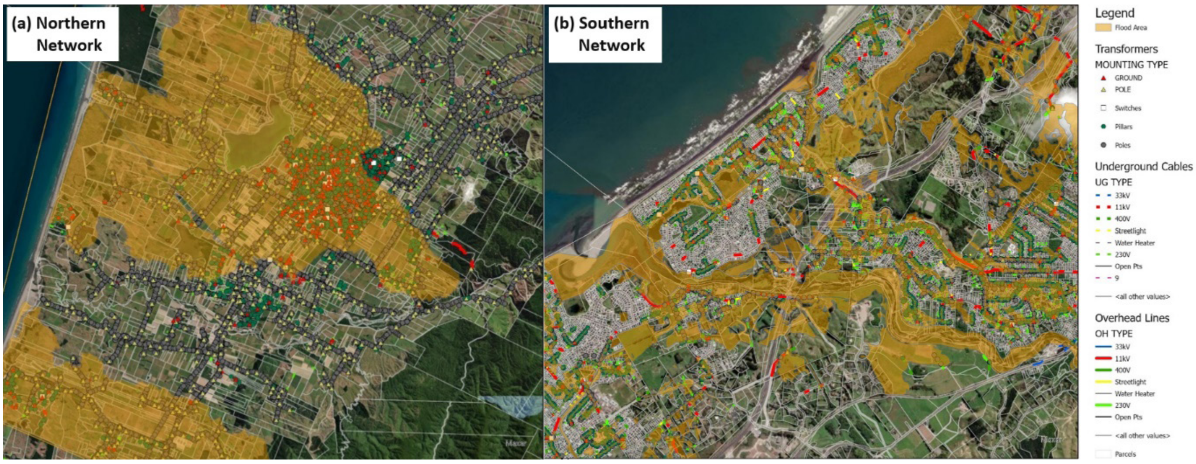



**Figure 7-6: Assets at risk of flooding in (a) northern and (b) southern areas.**

## 7.2.6 Fire risks

To prevent any untoward fire events in our substations, we carry out regular inspections of our buildings and equipment, to ensure that fire risks are minimised.

Our auto-reclosers could automatically be enabled/disabled by network segments in response to localised weather data during fire seasons so we can reduce fire risk and also reduce supply interruptions.

### 7.2.7 **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 NZS7901:2014 currently. Electra was first certified in 2012 and our certification renewed in 2021. Audits are conducted annually. Documents contributing to PSMS are being reviewed to ensure they comply with NZS7901:2014, the standard we currently operate to. Outside contractors are engaged to provide support to. An external review takes places annually to ensure ongoing compliance.

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.

### 7.2.8 **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 biennially.

### 7.2.9 **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 4.3.5.

### 7.2.10 **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.

### 7.2.11 **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.

Our Energy Transformation or Huringa Pūngao initiative is covered in Section 4.5.1. Some of the key risks implicated in the study include:

- Uncertainty on the availability of load control and DERs for network demand response as these are seen as benefiting the efficiency of the entire electricity system and not just distribution networks
- An increased risk of regulatory interventions should distributors become an impediment to greater electrification and the use of DERs
- The risk of stranded investments depending on the strategic pathway which Electra will take versus the pathway that the industry is heading towards.

Section 4.5.1 covers the recommendations from the study.

### 7.2.12 **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. Over the last two and a half years we have successfully adapted our safe work practices to minimise the risk to our people, our customers, and the public. This included the formation of a Pandemic Governance team, the creation of smaller teams operating in work 'bubbles', introduction of rapid antigen tests (RATs) for screening, and formulation of policy and vaccine mandates for those in critical roles in line with Government mandates. Increased use of working from home and video calls was encouraged for office-based staff.

The Group pandemic plan is regularly reviewed, to reflect the steps required to maintain business during a pandemic.

The various Health, Safety and Wellbeing Committees continue to monitor and support our business activities to ensure that we "keep the lights on" for our customers. Our technical response and customer care teams continue to operate safely from their homes and work bubbles during the pandemic. Well-defined and safe operating procedures maintain our core monitoring, customer response services with intra-team support across work shifts.

Line business' depot meetings are being held monthly with operational management engaging positively with staff on wellbeing, safety, and code compliance. Engagement with our staff, contractors and third parties working in the network continues to show high levels of compliance with safe working practices, with the most common findings relating to PPE and documentation.

### 7.2.13 **Cyber Security**

As cyber-related attacks continue to increase globally and in New Zealand, Electra has carried out a series of assessments and have undertaken a series of activities on cyber security controls. Networking with similar EDBs is on-going to drive the sharing of knowledge and key learnings in the industry around cyber security controls, policy, and framework for information security management.

A SCADA recovery exercise was carried out in October 2021 to simulate our response if there was a loss in control of our SCADA system due to unauthorised access. The team proved that unusual activity could be detected and that they could undertake a recovery from a backup secondary system and determined the recovery time objective (RTO). The primary SCADA server and communications array at Levin West were isolated from communications, simulating a loss of control whence the control server was recovered from backup. The mock exercise ran successfully with the control server restored to a point where the remote SCADA control could resume within two hours setting the RPO.

Data/configuration was up to 12 hours old determining the recovery point objective (RPO) which is the age of files that must be recovered from backup storage for normal operations to resume. The complete recovery of systems and services recovery (including IoT) was 8 hours.

### 7.2.14 **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 fare 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 will 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<br>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<br>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<br>All zone transformers have individual oil containment with oil spill kits located at each zone substation in case of other spills<br>Where a distribution transformer or switchgear has leaked, all affected ground is removed and suitably disposed of in accordance with local by-laws<br>VESDA sniffer systems for fire containment are installed at each zone substation's switchgear building<br>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<br>All buildings are built to the relevant building code<br>Electra has seismically engineered bracing on all power transformers at zone substations, with seismic bracing for switchgear and other components as required<br>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<br>Electra completed security fences at the remaining zone substations in 2004<br>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.<br>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<br>Underground cables are specified to withstand through short-circuit faults along with capacity requirements<br>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<br>Foxton, Ōtaki and Paekākāriki are not on the closed 33kV rings; these substations are backed up by the 33kV and 11kV network through automatic changeover schemes<br>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<br>Individual zone substations have site-specific spares stored at each site as appropriate<br>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 Service Delivery 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<br>Field repairs | No major work required (e.g. clearing tree branch off a line)<br>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)<br>Field repairs | Equipment damaged (e.g. pole hit by car, transformer needs changing, overhead line needs repairs or replacing)<br>Time depends on cause, available personnel, and extent of switching |

| Level of response | Means of response | Work required |
|---|---|---|
| Long (12 hours to 48 hours) | SCADA or field switching (most consumers restored by switching)<br>Field repairs | Major equipment damaged e.g. loss of a zone substation, replacing part or all of a damaged 33kV bus<br>Time depends on cause, available personnel, and spares |

Our maintenance crews are often working in trying conditions or locations, remote from easy access, undertaking difficult tasks that require careful planning and hazard assessment. An example is depicted in Figure 7-7 where line crews worked alongside arborists and civil contractors, tasked with removing a large tree from a 33kV line near Mangahao. Care is being taken to ensure safety is not compromised as the tree was removed without causing further damage to the lines nor endangering people.

**Figure 7-7: June 2022 Tree fallen on Mangahao-Levin East 33kV line during adverse weather**

### 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 Ōtaki, Waikanae or Manawatu rivers
- 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 Kāpiti and Horowhenua districts. The plan was enacted during severe weather events in May and June 2022 that resulted in short term damage and disruption to some supply.

### 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 |
| 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 |

| No. | Documents | Description |
|---|---|---|
| 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 7-8: 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. 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.

Ensuring public safety as well as the health of our assets are key responsibilities for Electra. An example of our prompt risk response and staff commitment is demonstrated recently when we were informed that a ground-mounted transformer (see Figure 7-9a) was becoming flooded due to a combination of rising water table and stormwater following heavy rain at Union Street, Foxton. Network Operations engineers worked with Service Delivery teams to find a suitable solution and resolved the problem by replacing the ground-mount with a pole-mounted transformer (Figure 7-9b). It was an excellent example of collaboration across various teams with personnel understanding the implications and delivering a successful solution. We have initiated a programme to monitor similar climate-changing situations through our Climate Resilience strategy and tactics.


**Figure 7-9: Foxton, Union Street Transformer C160: (a) Ground-mount subjected to flooding during heavy storms; (b) Pole-mount replacement.**

# 8 Performance evaluation

## 8.1 Works delivery performance

This section outlines Electra's progress against budgeted targets FY2022.

### 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 | FY2022 Target ($'000) | FY2022 Actual ($'000) | Variance ($000) | Variance (%) | Reasons for variances |
|---|---|---|---|---|---|
| Service interruptions and emergencies | 1,894 | 2,294 | +400 | +21% | • Increased number of faults and historic damage pay-outs settled during FY2022<br>• Increased number of faults consistent with worsened SAIDI and SAIFI, caused by higher than average storm damage and rainfall (the year ended 31 March 2022 had 53% more rainfall than the previous 20 years). |
| Vegetation management | 1,645 | 1,488 | -157 | -10% | • Less than forecast due to efficiency improvements and cross-training within the vegetation management team to work on other areas of the network. |
| Routine and corrective maintenance and inspection | 1,050 | 1,447 | +397 | +38% | • Additional inspections carried out for pillars and transformers<br>• Priority pole-straightening work identified during the inspection process not included in the forecast for FY2022. |
| Asset replacement and renewal | 418 | 616 | +198 | +47% | • Overhead lines repair exceeded budget due to additional traffic management requirements<br>• Expenditure included replacement of substation tap changers and replacing cracked bushings. |
| System operations and network support | 4,841 | 3,716 | -1,125 | -23% | • Underspend attributed to vacant positions within the Network team for much of the disclosure year, and less training and travelling occurring due to Covid-19 restrictions and vacant positions. |
| Business support | 4,131 | 4,290 | +159 | +4% | • IT support agreements greater than forecast due to emphasis on cloud-based products which is a subscription pricing model and work required to increase cyber security resiliency. |
| Total | 13,979 | 13,851 | -128 | -1% | • No material variation |

Overall, our operational expenditure was $128K 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.

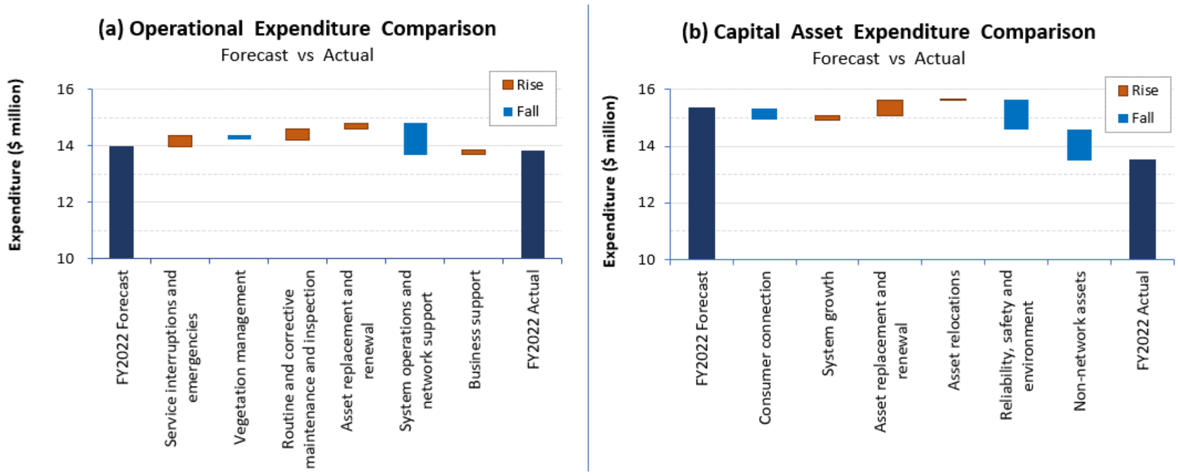



**Figure 8-1: Variations between forecast and actual expenditures for: (a) Operational expenditure (OPEX), and (b) Capital asset expenditure (CAPEX)**

## 8.1.2 Network development plan delivery

Overall expenditure on assets was $1.8m under 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 | FY2022 Budget ($'000) | FY2022 Actual ($'000) | Variance ($000) | Variance (%) | Reasons for variances |
|---|---|---|---|---|---|
| Consumer connection | 400 | - | -400 | -100% | • The budget for this category was reallocated to Asset Replacement and Renewal during the disclosure year to cover expenditure on the 400V overhead network |
| System growth | - | 155 | +155 | - | • During the detailed design phase of the new 11kV Kāpiti feeder, Electra identified an intelligent automation scheme to alleviate the reliability concerns and a more permanent solution for future load growth due to airport/commercial developments; the switchgear required did not arrive in time for completion within the previous disclosure year, resulting in expenditure in FY2022 |
| Asset replacement and renewal | 7,147 | 7,686 | +539 | +8% | • Renewal expenditure exceeded due to repairs of increased damaged assets by third parties |
| Reliability, safety, and environment | 4,292 | 3,256 | -1,036 | -24% | • Lesser salaried costs capitalised due to vacancies within the Network team, lesser projects involving managerial capacity<br>• Replacement of pitch-filled potheads with Raychem terminations have been carried forward into the 2023 disclosure year due to access issues |
| Asset relocation | - | 16 | +16 | - | • Cable relocation from sewer pipe to trench in Levin |
| Non-network assets | 3,498 | 2,390 | -1,108 | -32% | • Due diligence on selecting an EAM product took longer than anticipated where some expenditure has been deferred to FY2023<br>• ADMS & SCADA development deferred to FY2023. |
| Total Expenditure on Assets | 15,337 | 13,503 | -1,834 | -12% | • Differences as per reasons given 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 FY2022 year for the key customer service attributes is shown in the following table.

| Attribute | Measure | FY2022 target | FY2022 actual | Comment |
|---|---|---|---|---|
| Network reliability: planned outages | SAIDI B (minutes) | 20 | 28.2 | • Increased renewal/maintenance projects with increase of network assets and circuits<br>• Lack of connection points for generation for 11kV reconductoring projects. |
| | SAIFI B | 0.08 | 0.09 | |
| | CAIDI B (minutes) | 250 | 313 | |
| Network reliability: unplanned outages | SAIDI C (minutes) | 63 | 66.4 | • Increased number of faults consistent with worsened SAIDI, caused by higher-than-average storm damage and rainfall where FY2022 had 53% more rainfall than the previous 20 years<br>• Lengthy third-party interference faults with cable excavation and vehicle-versus-pole incidents (Section 3.3). |
| | SAIFI C | 1.5 | 1.36 | • Compliant. |
| | CAIDI C (minutes) | 42 | 49 | • Lengthy unplanned outages mainly to vehicle-pole incidents. |
| Network reliability: planned & unplanned outages | SAIDI B&C (minutes) | 83 | 94.6 | • Non-compliant due to the increase of renewal/ maintenance projects and lengthy vehicle-pole incidents. |
| | SAIFI B&C | 1.58 | 1.45 | |
| | CAIDI B&C (minutes) | 52.5 | 65 | |
| Public safety | Electricity (Safety) Regulations 2011 | Compliant | Compliant | • Continued compliance to NZS 7901. |

Electra's performance for planned and unplanned outages are shown in Figure 8-2 with the reliability triangle comparing SAIDI against SAIFI for EDBs, averaged over a three-year period (FY2020 to FY2022[46]). Out of 29 EDBs, Electra is one of sixteen EDBs in the first quadrant below SAIDI, SAIFI industry averages of 235 minutes and 2.12 respectively. Electra is also one of nine EDBs below the CAIDI industry average of 111 minutes and ranked best amongst 29 EDBs for CAIDI. Electra is ranked fifth lowest for SAIDI (planned and unplanned) over the three years.

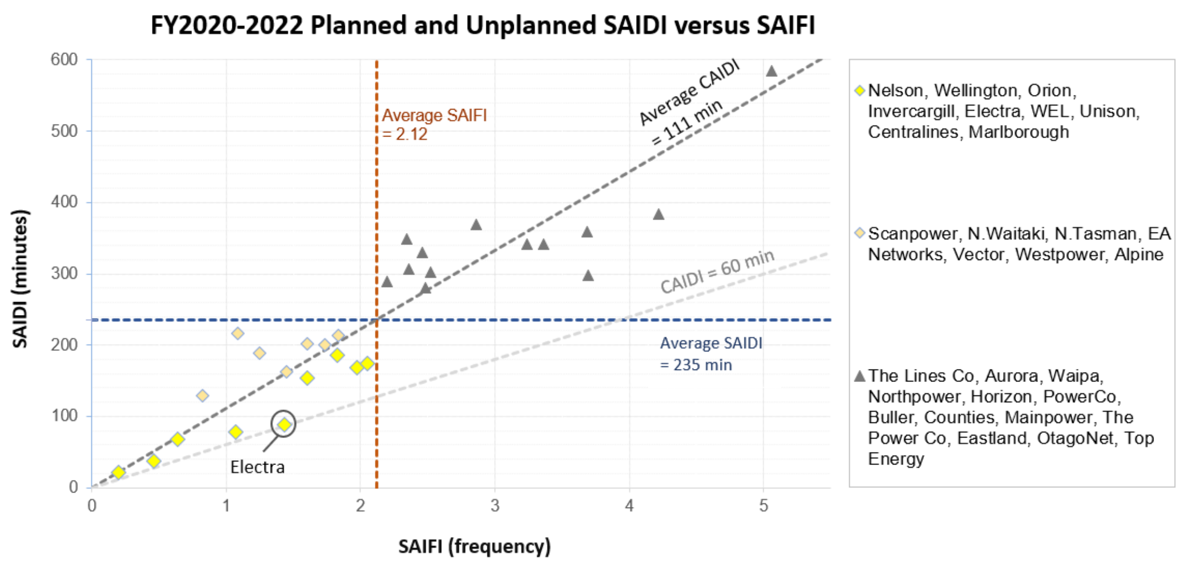



**Figure 8-2: FY2020 to FY2022 SAIDI for planned B and unplanned C outages for EDBs**

[46] *FY2022 data is extracted from information disclosures from the relevant EDB's websites as at 15/9/2022 while earlier data was extracted from Commerce Commission's Performance summaries for electricity distributors.*

To better manage the planned outage process, a standard operating procedure (SOP) has been developed to establish planned SAIDI minutes and frequency SAIFI to meet reliability targets. The SOP specifies the processes and allocates responsibilities to ensure that planned reliability targets are met yearly and understood by the concerned parties.

## 8.2.2 Causes of faults

A cause analysis into our network reliability performance is depicted in Figure 8-3. The highest cause of faults impacting SAIDI in FY2022 (Figure 8-3a) is defective equipment (30%) followed by third party interference (27%), vegetation (22%), human error (8%) and wildlife (5%). A further investigation based on the frequency of causes or SAIFI (Figure 8-3b) gave the highest fault contributors as defective equipment (32%), vegetation (29%), third party interference (15%) unknown (9%) and human error (7%). Other causes of faults include wildlife and lightning.

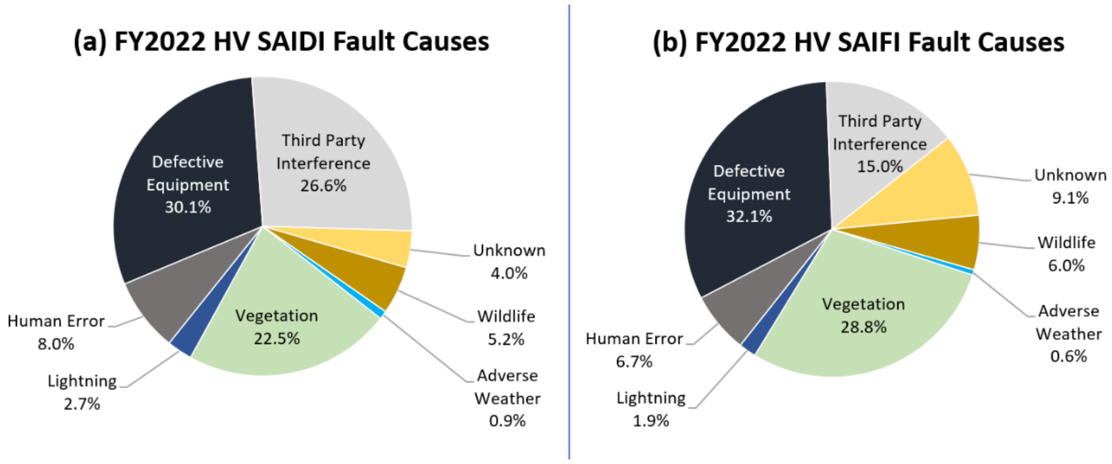



**Figure 8-3: Causes of HV faults (a) FY2022 SAIDI, (b) FY2022 SAIFI**

The SAIDI impact and the number of HV faults between FY2017 to FY2022 are also shown in Figure 8-4. The number of unplanned outages in FY2020 is 354, dropping by over 30% to 245 outages in FY2021 and slightly increasing to 266 outages in FY2022.

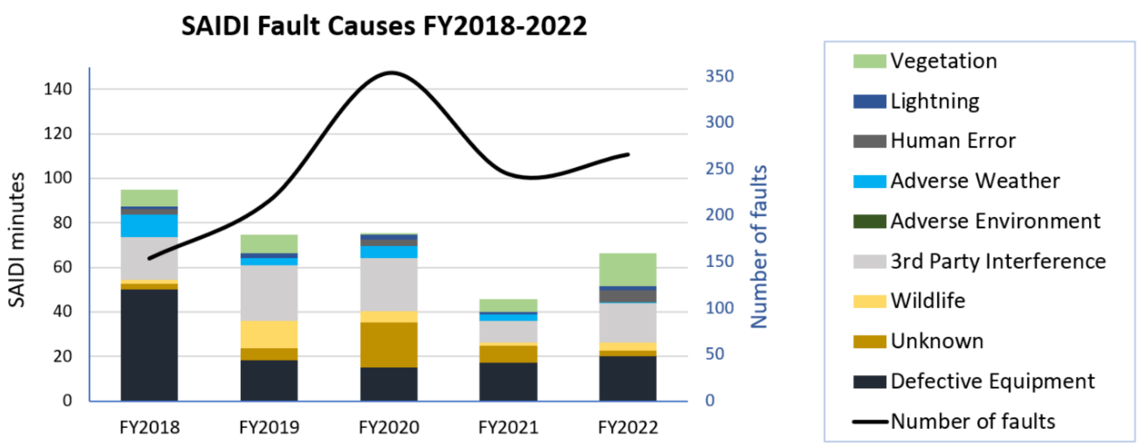
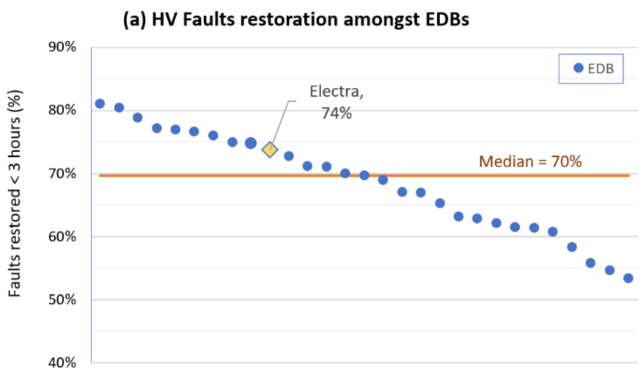



**Figure 8-4: SAIDI and Number of HV faults from FY2018-FY2022**

## 8.2.3 Restoration of faults

The information disclosure includes the performance indicator for faults restoration within a period of three hours. Figure 8-5a compares the performance of Electra against other EDBs from FY2020-FY2022 where our average performance of 74% is higher than the industry's median of 70%. Our performance between FY2018 to FY2022 is shown in Figure 8-5b where our performance peaked in FY2019 when we restored 85% of faults within three hours followed by FY2020 where 270 faults or 76% of faults were restored within the three-hour period. In FY2022, 193 faults or 73% of faults were restored within three hours.

Our Reliability Committee scrutinises faults over 0.5 SAIDI minutes employing extensive investigations where customers may be affected for an extended outage time or large customers affected. The analyses conducted have resulted in drop-out fuses being replaced by TripSavers, switchgear automation and reinforcement projects.



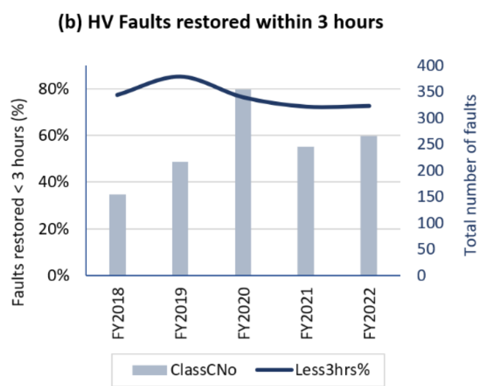




**Figure 8-5: Faults restored within 3 hours: (a) EDB benchmarking from FY2020-FY2022, and (b) Electra FY2018-FY2022**

Reliability investigation, root cause analysis and network resilience enhancement are continuously being reviewed and conducted and an average of $3.9M has been allocated annually for reliability and quality of supply.

A further review of faults or interruptions of supply to the network follow in the next section.

## 8.3 Review of Commerce Commission's reliability target areas and asset information

The next sections cover further faults analyses of the targeted areas raised by Commerce Commission in their recent publication[47] on the apparent deterioration of reliability citing extended duration interruptions, causes due to unknown interruptions, vegetation-related and defective equipment interruptions. Electra has reviewed the concerns and carried out a detailed analysis together with a review of our Public Safety Network Operating Procedures. Wind gust, direction and precipitation data were linked to each interruption in the last six years, the information extracted from NIWA[48] though only Levin Station data was available. Some of the analyses undertaken are included in the following sub-sections.

### 8.3.1 Extended duration interruptions

This section evaluates "extended duration interruptions" where such interruptions stretch over three hours on the network. Figure 8-6 shows the trend of extended duration interruptions on our network trending downwards from FY2016 [34 outages, 40% of total unplanned interruptions] to FY2019 [32 outages, 15%] and increasing gradually to FY2022 with 73 or 27% of total unplanned interruptions. Compared to other EDBs, the proportion of our extended duration interruptions is consistently less than the industry averages as evident (Figure 8-6) from FY2017 to FY2022.

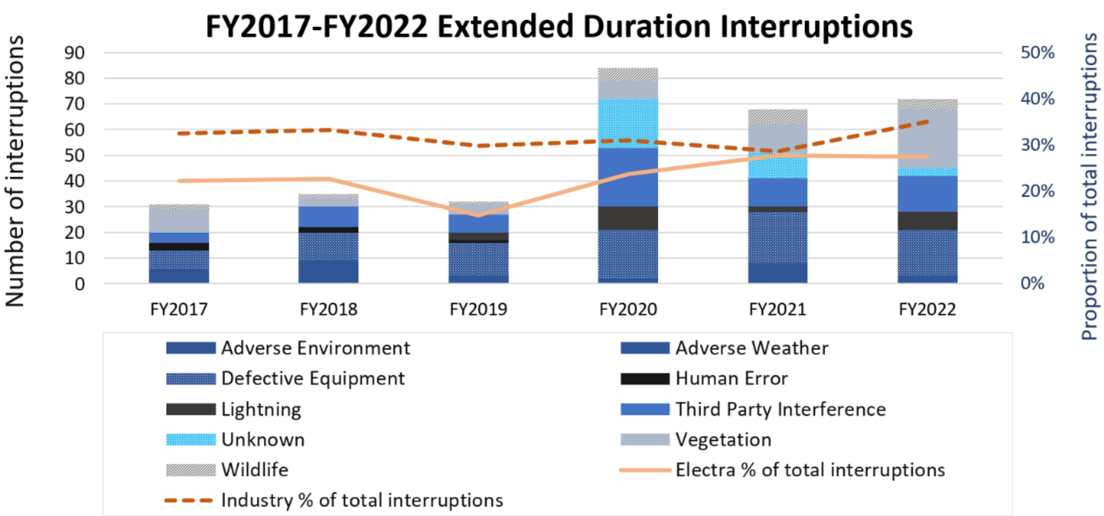



**Figure 8-6: FY2017 to FY2022: Number of extended duration interruptions and proportion of total unplanned interruptions – comparison of Electra with Industry averages**

[47] Commerce Commission, "Reporting of asset management practices by EDBs", July 2021.
[48] NIWA, "Daily and Hourly Observations", Wind & Precipitation for Levin Ews, latitude -40.62699, longitude 175.26193.

[Figure 8-7a](#) further shows the SAIDI impact attributed to extended duration interruptions causes from FY2020 to FY2022. The total SAIDI from these interruptions was 42.8 minutes in FY2020, dropping to 22 minutes in FY2021 and 36 minutes in FY2022. Analysing these extended interruptions in FY2022, the highest SAIDI impact (Figure 8-7b) is caused by third party interference (39% from 14 outages) followed by defective equipment (34% from 18 outages) and vegetation (21% from 23 outages). Lightning, adverse weather, wildlife and human error causes had a smaller SAIDI impact. Unknown causes contributed to only a 1% SAIDI from 3 outages.

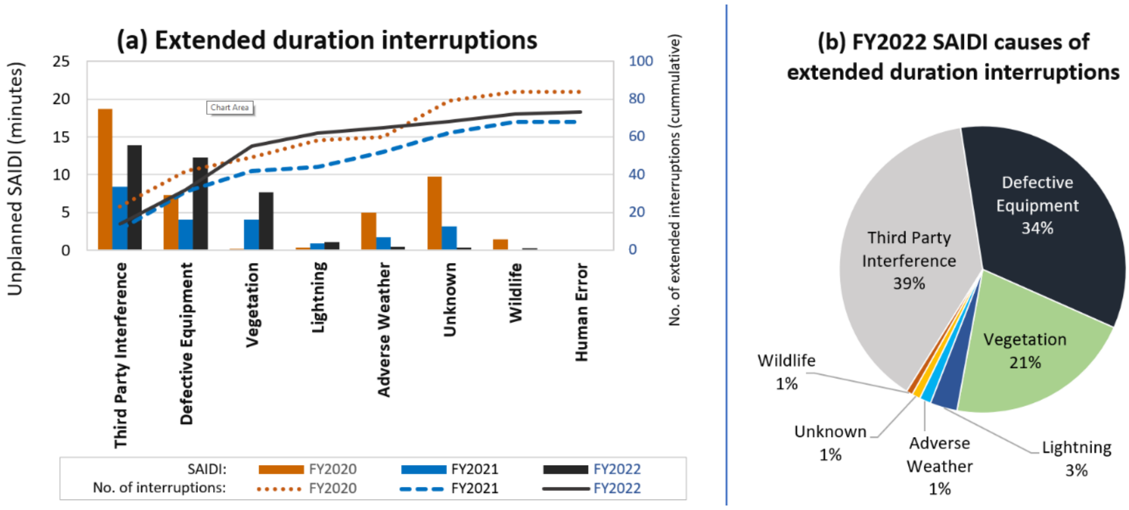



**Figure 8-7: Extended duration interruptions (a) FY2020-FY2022 Causes for faults: SAIDI and cumulative number of interruptions; (b) FY2022 SAIDI causes composition.**

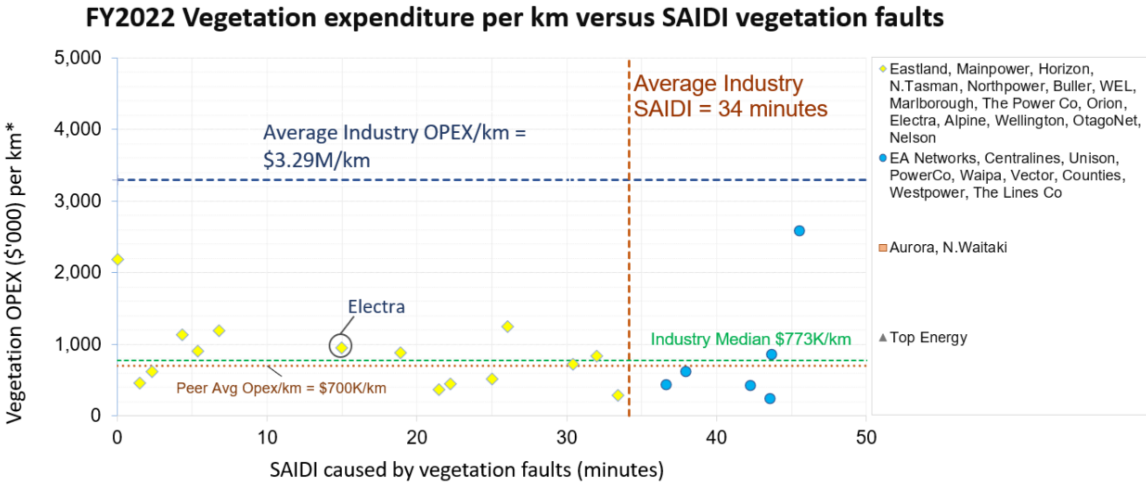
Out of the 14 third party interference incidents, 10 were caused by vehicle versus pole incidents, three due to the public felling trees while one due to an underground cable excavation fault. Figure 8-8 shows an extended duration incident involving a vehicle hitting a pole impacting SAIDI by 3.23 minutes. Risk mitigation strategies for such vehicle versus pole incidents include the identification of accident-prone areas and the location of such faults on our GIS. Liaison with NZTA, Council, Traffic Police and relevant authorities are ongoing.


**Figure 8-8: April 2022 vehicle-versus-pole incident at Sussex Street, Levin, impacting SAIDI by 3.23 minutes and affecting 211 consumers for 442 minutes**

### 8.3.2 Vegetation Faults

Expenditure on vegetation management has been increasing from $1.52M (FY2017) to $1.85M (FY2019) before moving gradually downwards to $1.49M in FY2022 (Section 5.12.1). The downward trend is a result of a reduction in reactive tree-trimming works when we moved from a responsive-based approach to a risk-based/proactive approach to systematically reduce tree-related faults.

The worsening SAIDI in FY2022 is caused by an increase in the number of vegetation outages due to a higher-than-average storm damage and rainfall where FY2022 had 53% more rainfall than the previous 20 years.




* Notes: 1 Overhead circuit (km) requiring vegetation management extracted from Information Disclosure Schedule 9c.
2 Averaged over 27 EDBs as two EDBs did not report circuit km for vegetation as at 15/9/2022.
3 Outliers excluded from the graph.

**Figure 8-9: FY2022 vegetation management expenditure per km versus SAIDI caused by vegetation faults**

Figure 8-9b portrays the industry's vegetation management operational expenditure per km of circuit requiring vegetation management versus SAIDI caused by vegetation faults for FY2022. For vegetation and faults, the peer group average is showing lower expenditure ($700K/km) but the measure per km disadvantages Electra, and it takes many years of systematic tree trimming and high removal rates to optimise costs. However, our expenditure of $0.96M per km is 71% below the industry average of $3.29M per km and slightly above the industry's median of $0.77M per km.

The expenditure on vegetation management has resulted in controlling SAIDI due to vegetation faults over the years apart from adverse weather effects. The SAIDI value for vegetation faults in FY2022 (15 minutes) is also 56% below the industry average of 34 minutes.

Conductors are affected by vegetation situated near the line - in an area called the Growth Limit Zone (GLZ) as defined by the Electricity (Hazards from Trees) Regulations 2003. As indicated in Figure 8-10a, Electra has enhanced our fault investigation strategy by classifying the cause based on the location of vegetation affecting our networks.

Over a four-year period (FY2019 to FY2022), 61% of the number of vegetation interruptions are caused by branches/trees outside the GLZ (Figure 8-10a) and these interruptions resulted in SAIDI being impacted by 21 minutes (71%) over the four years (Figure 8-10b). FY2022 vegetation SAIDI was 15 minutes where 11 minutes resulted from vegetation outside GLZ. With the high SAIDI impact, Electra has embarked on a strategy to target the vegetation located outside the GLZ to increase network reliability in vegetation fault-prone areas, where we proactively serve hazard warning notices to landowners for trees which pose a high risk to our overhead lines as elaborated in Section 5.12. Such a strategy will see the continued downward trend of our vegetation interruptions. Most tree-owners are agreeable to high-risk trees being removed (at Electra's costs). The notification letter outlines the risk to the conductors and liabilities from our legal counsel to add leverage. Unfortunately, we do not have the legal right to intervene based on the current tree regulations until post-failure of the tree.

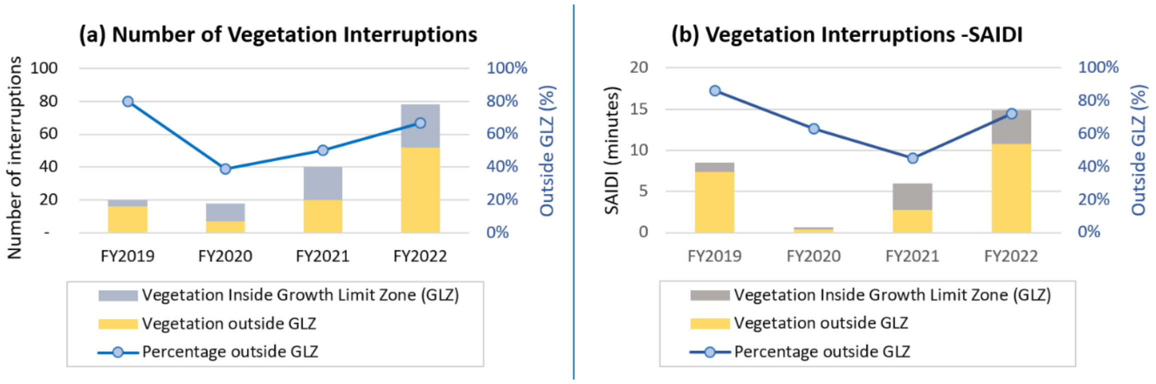



**Figure 8-10: FY2019 to FY2021 - Vegetation interruptions inside and outside GLZ (a) Number of interruptions; (b) SAIDI vegetation**

The number of interruptions caused by vegetation in relation to gust speed-direction is depicted in Figure 8-18 together with a discussion on weather-related interruptions (Section 8.3.5).

## 8.3.3 Defective Equipment

As portrayed in Figure 8-11a, the highest number of defective equipment incidents over FY2020 to FY2022 are caused by DDOs or drop-out fuses [55 faults contributing 31% of equipment faults], followed by transformers [38 faults, 21%] and conductor faults [23 faults, 13%]. The remainder of the faults are caused by connectors, cable/joints, crossarms/poles, jumpers, switchgear, arresters and failed protection.

Figure 8-11b shows the SAIDI impact for the defective equipment interruptions, the highest being due to conductors [11 SAIDI minutes, 22%], followed by cable faults including joints (16%), jumpers including connectors and connectors (both at 11%). Renewal programmes and maintenance activities are undertaken to address and resolve such faults particularly with the increase in the incidences of jumper connection and cable termination faults.

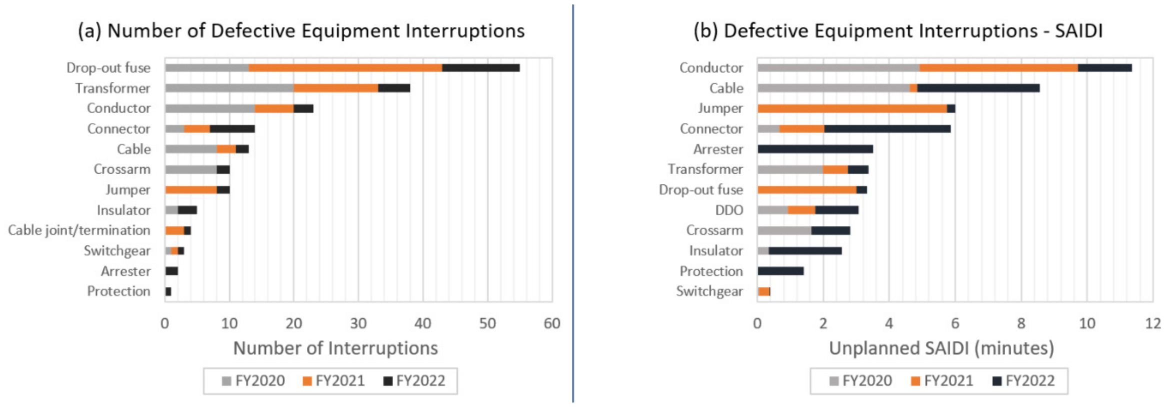



**Figure 8-11: FY2020 to FY2022 Defective Equipment (a) Number of Interruptions; (b) SAIDI impact**

Our condition-based risk assessment inspections have been extended to include overhead line inspections. The installation of FPIs, trip savers and automation of ground mount switchgears (described in Section 4.6) will increase reliability on our network.

**Figure 8-12: Installation of Golf Road automation switchgear in July 2021**

Over FY2017 to FY2022, our performance is benchmarked with other EDBs in the following graphs of Figure 8-13 where SAIDI, SAIDI percentage (over total interruptions) and reliability/renewal expenditure parameters are compared with the industrial average. As demonstrated in the said graphs, SAIDI/SAIDI percentage is below or close to the industrial average except for FY2018 where a latent protection error resulted in cascade tripping impacting SAIDI by 21 minutes[49].

Our reliability and renewal expenditure per circuit kilometre indicates that we are spending above the industry average to address defective equipment faults as reflected in our combined CAPEX/OPEX replacement and renewal of assets plus OPEX reliability expenditure[50].

[49] Electra Information Disclosure FY2018. Subsequent expert enquiry and re-engineering of protection settings have addressed protection setting issues.
[50] This review relates to Commerce Commission's observations in relation to defective equipment interruptions in the publication "Reporting of asset management practices by EDBs", July 2021

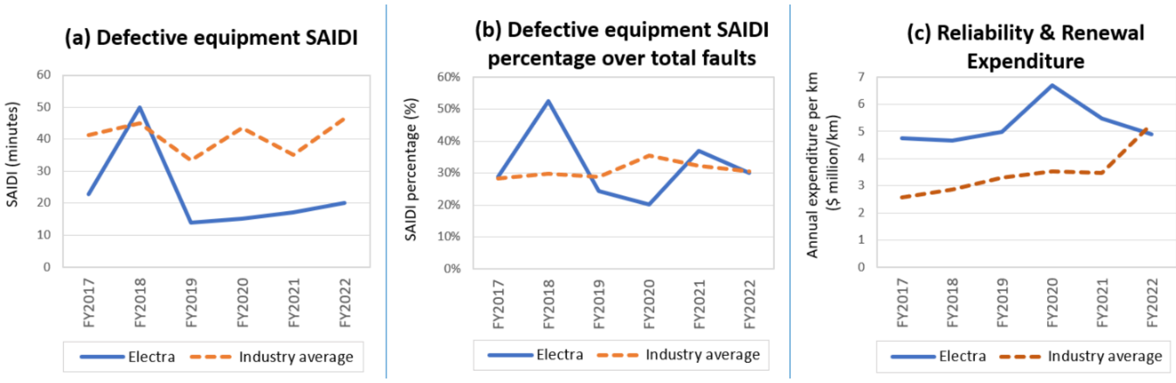



**Figure 8-13: EDB Benchmarking for Defective Equipment Interruptions: (a) SAIDI; (b) SAIDI as a proportion of total interruptions; (c) Expenditure in relation with defective equipment**

Figure 8-14 displays the analysis of Repex/km averaged over FY2020 to FY2022 against SAIDI for defective equipment. The analysis places Electra in the low SAIDI - high-cost quadrant indicating that expenditure/km is above the industry average but achieving a lower SAIDI (for defective equipment) of 15 minutes - 58% below industry average. This result suggests Electra is making investments in asset expenditure to improve or replace our assets to ensure they remain safe and reliable for our consumers.

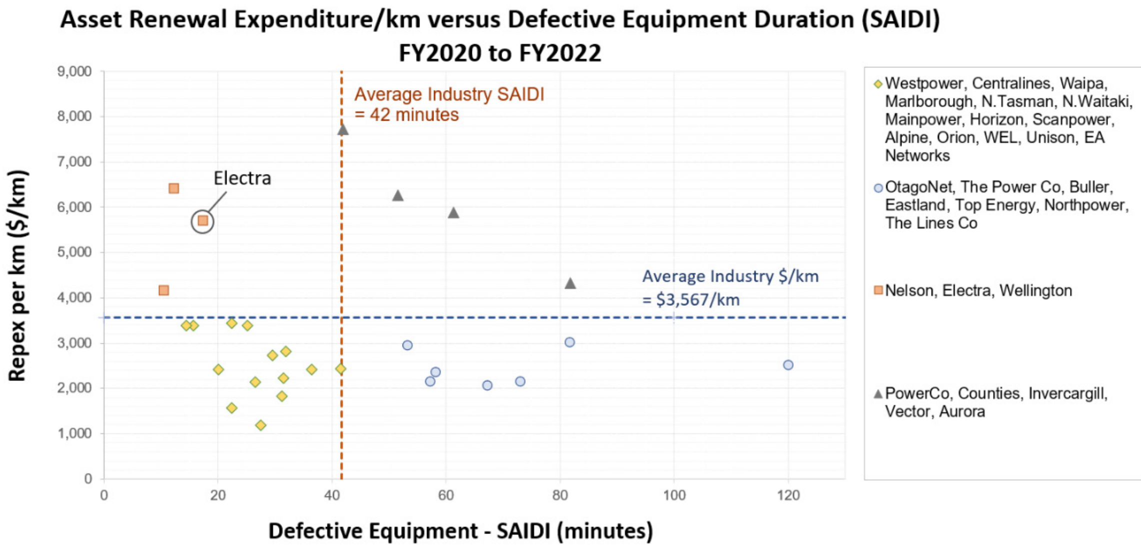



**Figure 8-14: EDB benchmarking of replacement expenditure (Repex) per kilometre against SAIDI for defective equipment - indicators averaged over FY2020 to FY2022**

## 8.3.4 Unknown interruptions

The unknown cause is selected when there is insufficient evidence to satisfy the criteria for a known cause, after appropriate fault investigation and line patrols had been conducted. Figure 8-15a shows the trend of the number of unknown interruptions and associated SAIDI in Electra's network. Benchmarking SAIDI and SAIFI for unknown interruptions (Figure 8-15b), the SAIDI-SAIFI percentages for FY2016-FY2019 were below or similar with industry parameters except for FY2020-FY2021. The increase in the number of unknown interruptions in FY2020 was 118, due to the change of categorisation of outages within the new Milsoft ADMS system. The process for the classification has been reviewed, well-defined procedures established, control room personnel trained and a post-fault senior supervisor investigating all unknown faults, resulting in the decreasing trend of unknown outages and their SAIDI since FY2020. Since his appointment two years ago, the post-fault investigator has identified the causes of 70 out or 80 faults which were initially termed "unknown".

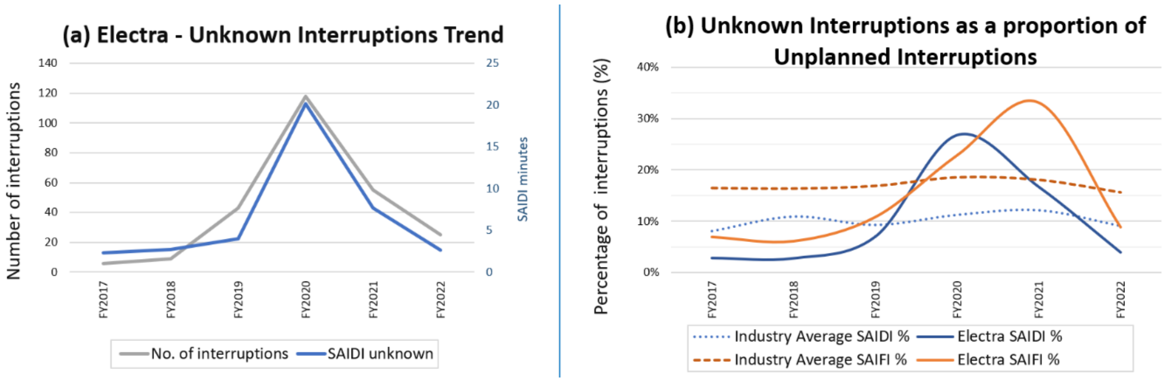



**Figure 8-15: FY2016 to FY2022: (a) Unknown interruptions frequency and SAIDI; (b) Benchmarking of unknown interruptions as a proportion of all unplanned interruptions**

Some of causes of such faults investigated included were due to wildlife and efforts have been made to install bird divertors or HV tape on conductors where birds have been frequenting the area.

**Figure 8-16: (a) Bird strikes causing faults on Levin West-Foxton 33kV line; (b) HV taping at 33kV conductors; (c) Bird divertors along Waihou Road line.**

The correlation of unknown faults to wind gust speed/direction and the number of unknown interruptions are depicted in Figure 8-18.

## 8.3.5 Asset Management System Enhancements

With the deployment of ADMS, Electra has introduced additional "cause" and equipment codes to enhance information integrity and data accuracy. Discrepancies such as doubled-up outages have been resolved and fault crew trained on the identification of the cause of faults and correct classification.

The review of SMS No. 56949 "Public Safety Network Operating Procedures" details line patrols and post fault investigation reporting. New cause codes introduced in the ADMS system include suspected causes of fault, vegetation outside the growth limit zone, wind-blown debris, and tree-fall zones. SCADA functionality and control room operations are continually being improved (Figure 8-17) with upgraded dashboards for monitoring of interruptions and demand.

A new process has also been established for the allocation of planned SAIDI minutes and frequency SAIFI to meet reliability targets. The purpose of this document is to specify the processes and allocate responsibilities to ensure planned reliability targets are met yearly and understood by the concerned parties.

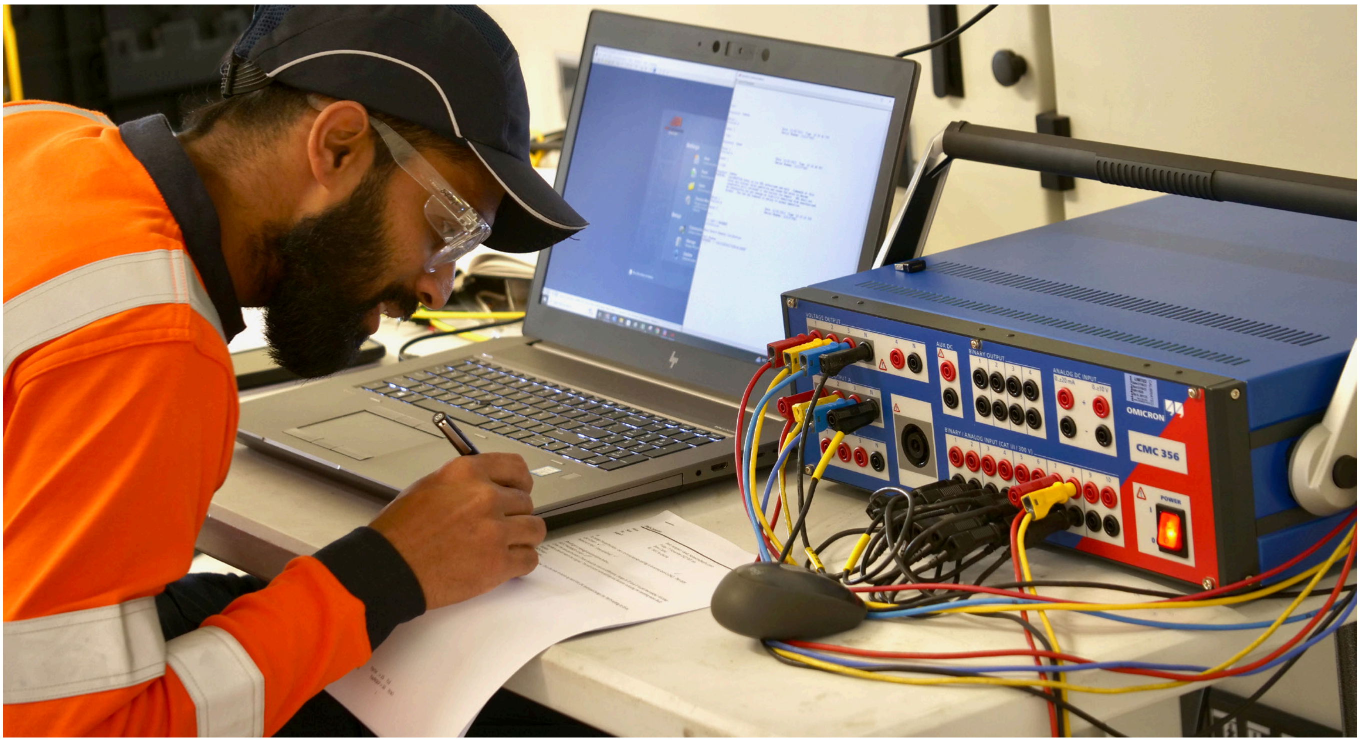
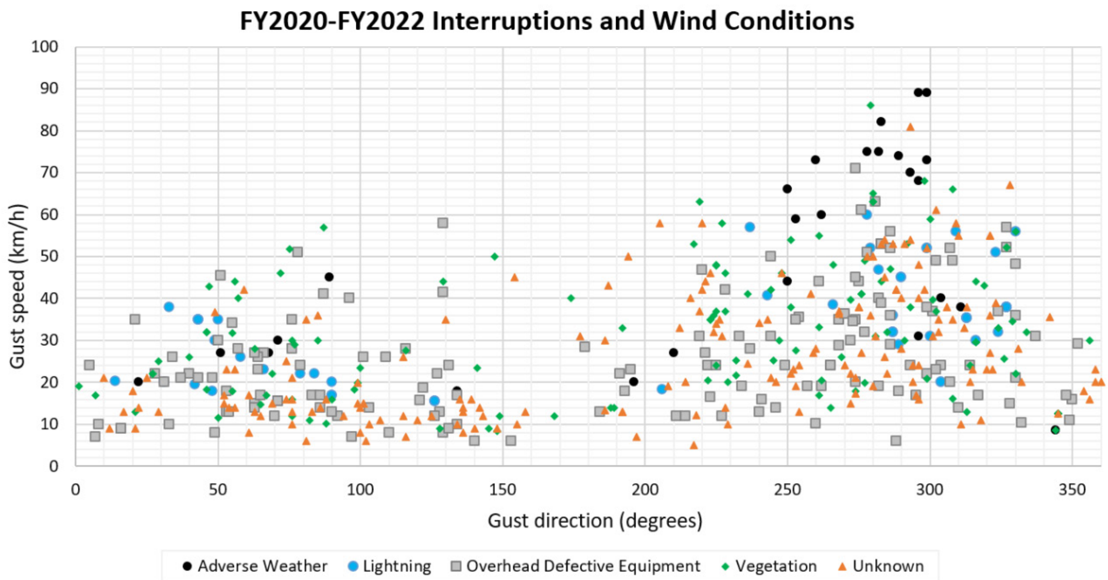


**Figure 8-17: Improvement of control monitoring systems**

As NIWA data was available hourly only for Levin weather station (wind gust, rain and temperature indicators), Electra has installed fifteen weather stations at key locations so wind gust speed and wind direction can be recorded and has begun integrating the information into interruptions from September 2021. As the terrain[51] affects wind speeds for instance, the gust speed increases as it passes over or between hills, decreases as it passes over rougher terrain and accelerates over open and flat expanses of land or water, the locations of these weather station are being assessed in relation to fault-prone areas. This initiative was completed in September 2022.

Studies into the effects of gust conditions (speed and direction) on weather-related causes are shown on Figure 8-18 for a total of 530 interruptions (in 317 fault days) between FY2020 to FY2022. The causes of these interruptions include adverse weather, lightning, vegetation, overhead defective equipment and unknown causes.




[51] The Authority on Sustainable Buildings, https://www.level.org.nz/site-analysis/wind/

| Classification | Gust Speed (km/h) | | | | | | | | Total | Gust Direction | | | | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | < 20 | 21-30 | 31-40 | 41-50 | 51-60 | 61-70 | 71-80 | > 80 | Outages | N | NE | E | SE | S | SW | W | NW | Outages |
| Adverse Weather | 6 | 5 | 3 | 2 | 4 | 4 | 4 | 2 | 30 | 2 | 2 | 3 | 2 | 1 | 1 | 10 | 9 | 30 |
| Overhead Defective Equipment | 75 | 38 | 18 | 8 | 8 | 1 | 1 | 0 | 149 | 10 | 24 | 19 | 15 | 5 | 18 | 35 | 23 | 149 |
| Lightning | 23 | 11 | 14 | 5 | 4 | 0 | 0 | 0 | 57 | 1 | 12 | 5 | 3 | 0 | 3 | 12 | 21 | 57 |
| Unknown | 89 | 32 | 26 | 15 | 6 | 2 | 0 | 1 | 171 | 13 | 15 | 23 | 18 | 9 | 23 | 35 | 35 | 171 |
| Vegetation | 60 | 16 | 19 | 16 | 8 | 3 | 0 | 1 | 123 | 10 | 16 | 15 | 8 | 5 | 20 | 27 | 22 | 123 |
| **Total:** | 253 | 102 | 80 | 46 | 30 | 10 | 5 | 4 | 530 | 36 | 69 | 65 | 46 | 20 | 65 | 119 | 110 | 530 |

**Figure 8-18: FY2020-FY2022 Weather-related interruptions versus gust speed and direction**

To study the effects of weather on the above interruptions, the NIWA wind directions were classified into the following sectors: N (-22.5 to 22.5), NE (22.5 to 67.5), E (67.5 to 112.5), SE (112.5 to 157.5), S (157.5 to 202.5), SW (202.5 to 247.5), W (247.5 to 292.5) and NW (292.5 to 337.5). The number of interruptions or faults versus wind gust speed-direction are displayed in the table above (Figure 8-18) and the related faults per day shown in Figure 8-19. Fault clusters are prevalent for wind gust speeds above 20km/h in the majority when westerlies, north-westerlies and south-westerlies prevail.

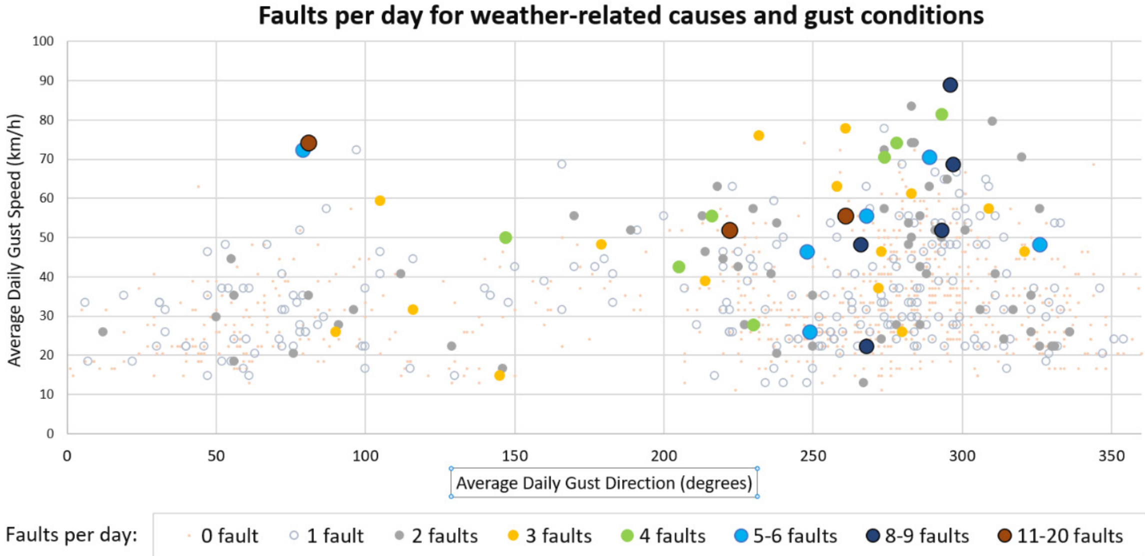



**Figure 8-19: FY2020-FY2022 Number of daily faults versus gust conditions for weather related causes**

The proportion of days with faults versus wind gust speeds and direction are shown in Figure 8-20. As the wind gust speeds increase (Figure 8-20a) from less than 20 km/h to speeds over 80km/h, the percentage of days-with-faults also increased from 21% to 100%.

When wind gusts' directions were analysed, Figure 8-20b shows the highest proportion of days-with-faults occur when easterlies prevail (41%) followed by south-easterlies/southerlies (31%) while the highest number of faults that could be affected by weather occurred with westerlies (189 faults) and north-westerlies (146 faults).

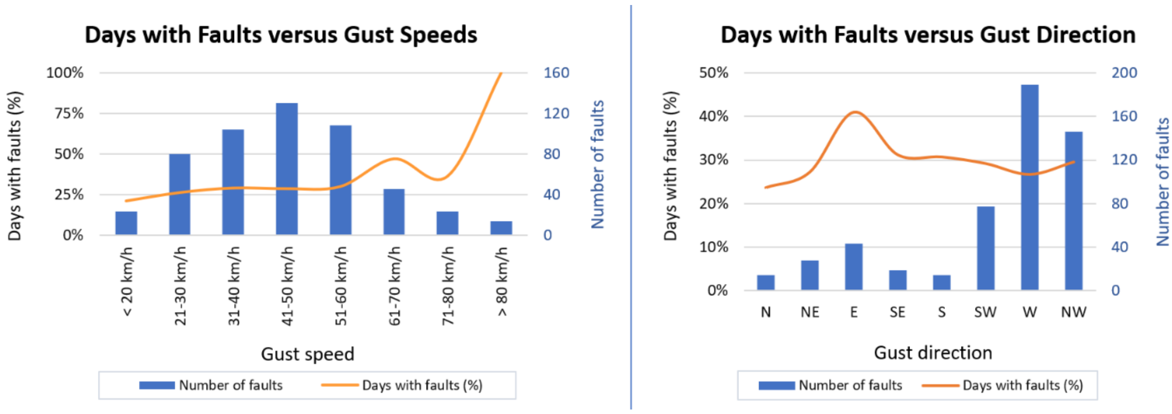



**Figure 8-20: FY2020-FY2022 Proportion of fault days versus (a) gust speed and (b) gust direction**

Precipitation and the difference in daily temperatures were also analysed. The daily precipitation rather than the hourly data was selected as the rainfall in the days before the event is deemed to have a greater impact as it takes some time for the water to permeate the asset. Temperature difference was derived as extreme temperature difference before the event might have triggered the fault. Based on the information from the Levin weather station, the precipitation and temperature data exhibited a weak correlation to the number of weather faults.

However, changes in the climate will bring greater risk of trees knocking out our overhead lines or damaging critical network infrastructure. If these risks are not mitigated, adverse weather conditions will not only impose a significant impact on network reliability and asset performance but will present risk to the safety of our consumers, staff and contractors. To prepare for this eventuality, we are integrating network and asset management practices to employ risk-based, data-driven processes where we have installed sixteen weather stations at various strategic locations across our network this financial year (Figure 8-21). The weather information together with asset health information will provide further insight into the effects of weather on interruptions. The analysis will enhance our fault prediction and investigation processes and provide certainty and consistency to the accurate categorisation of interruptions.

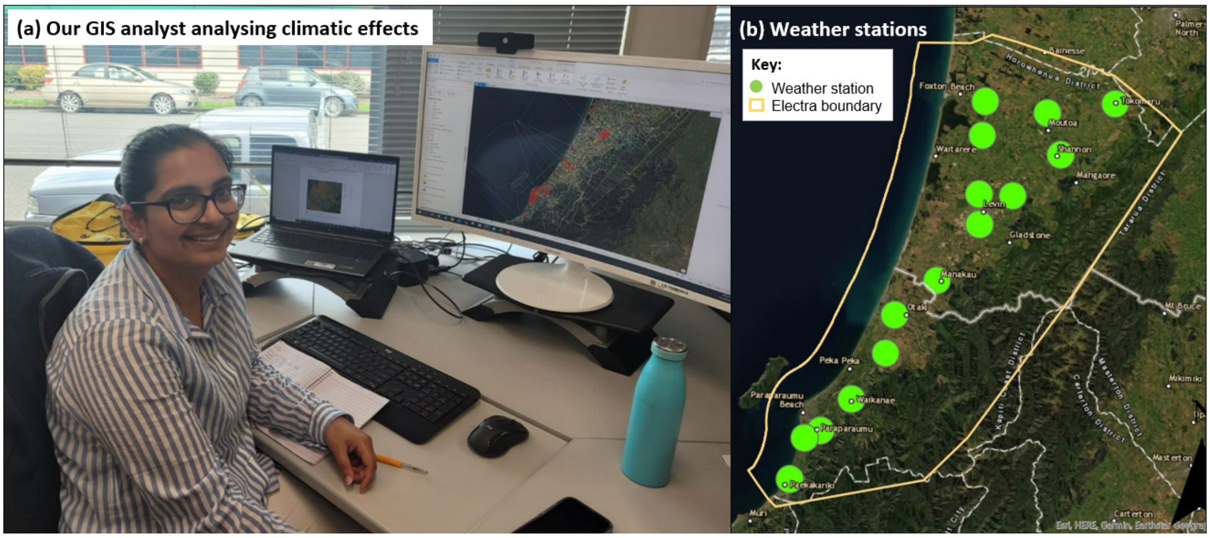



**Figure 8-21: (a) Monitoring the climatic effects on our network; (b) Weather station sites**

## 8.4 Performance measures

Electra's actual performance against target performance for the FY2022 year for key asset and financial indicators follow:

| Attribute | Measure | FY2022 target | FY2022 actual | Comment |
|---|---|---|---|---|
| Industry performance | Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022 and subsequent amendments | Compliant | Compliant except in minor risk preparedness sectors[52] | AMP assessed as generally compliant. |
| Energy delivery efficiency | Load factor (units entering network/maximum demand * hours in year) | 50% | 48% | Slightly off the target by 2%. |
| | Loss ratio (units lost / units entering network) | 7.3% | 8.0% | Non-compliant by 0.7%. A Losses Improvement Study has been conducted to determine the increase in losses. |
| | Capacity utilisation (maximum demand/installed transformer capacity) | 31% | 31% | Compliant. |
| Financial efficiency | Capital expenditure on assets (CAPEX) per:<br>-total circuit length (km)<br>-connection point | Increase within 5% of previous year | $5,737 (6% decrease)<br>$294 (6% decrease) | Compliant – decrease in CAPEX parameters. |
| | Operational expenditure (OPEX) per:<br>-total circuit length (km)<br>-connection point | Increase within 5% of previous year | $5,884 (2% increase)<br>$301 (2% increase) | Compliant – increase within 5% of previous indicators. |

[52] *Commerce Commission (2019), AMP Review of EDB Risk Preparedness*

### 8.4.1 **Load factor trends**

Figure 8-22 illustrates the historical trends for our load factor, derived from the energy (GWh) entering our network and maximum demand (MW). Our load factor in FY2022 is 48% a slight decrease of 2% from FY2021. The low load factor is attributed to a historical legacy to over-design for system growth. The load factor could be affected by a fall in energy (GWh) usage in FY2022, an effect from the Covid-19 pandemic. The load factor is expected to rise by 1% annually in the coming years aligned with the forecasted annual increase of 1% and 2% of our consumption levels and maximum demand respectively.

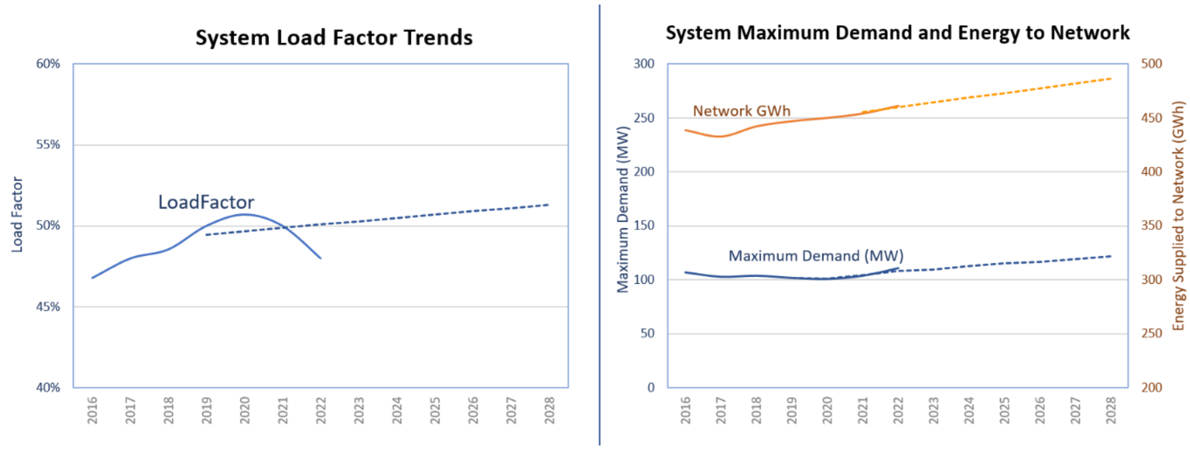



**Figure 8-22: System load factor historical trends and forecast**

### 8.4.2 **Capacity utilisation trends**

Figure 8-23 shows the industry's distribution transformer capacity utilisation against network load density. Electra sits well above the line of best fit at 32% utilisation and we use this relationship to set our utilisation target of above 30%.

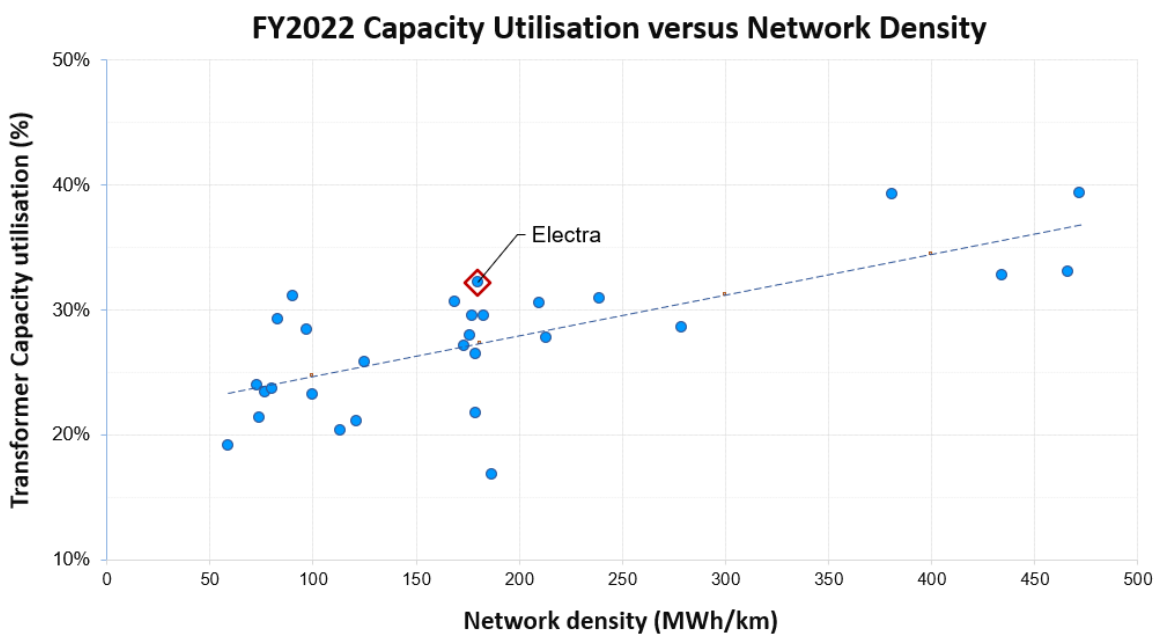



**Figure 8-23: FY2022 transformer capacity utilisation versus network density**

### 8.4.3 **Loss ratio**

Network losses decreased from 7.7% in FY2020 to 7.3% in FY2021 and then increased to 8% in FY2022. Figure 8-24 shows the historical trends for our losses and system GWh from FY2015 to FY2022 as well as our forecasts until FY2028 where the loss ratio is forecast to reduce by 0.5% annually with an increase in system GWh.

Electra commenced a Power Loss Reduction initiative in April 2021 to further investigate our technical and non-technical losses with the objective to reduce these losses. Technical losses were recalculated using SinCal where the losses at the northern and southern networks were determined at 21.4 GWh or 4.78%. The projected non-technical loss on the network was 3.0% or 13.6 GWh and a billing discrepancy by retailers of less than 1% of Electra customers has also been calculated. Further improvement of the analysis will be enhanced with the installation of zone substation power quality (PQ) meters at the 11kV bus of all zone substations so technical losses can be accurately recorded. PQ meters on the LV network have also been installed to verify HV and LV loss calculations.

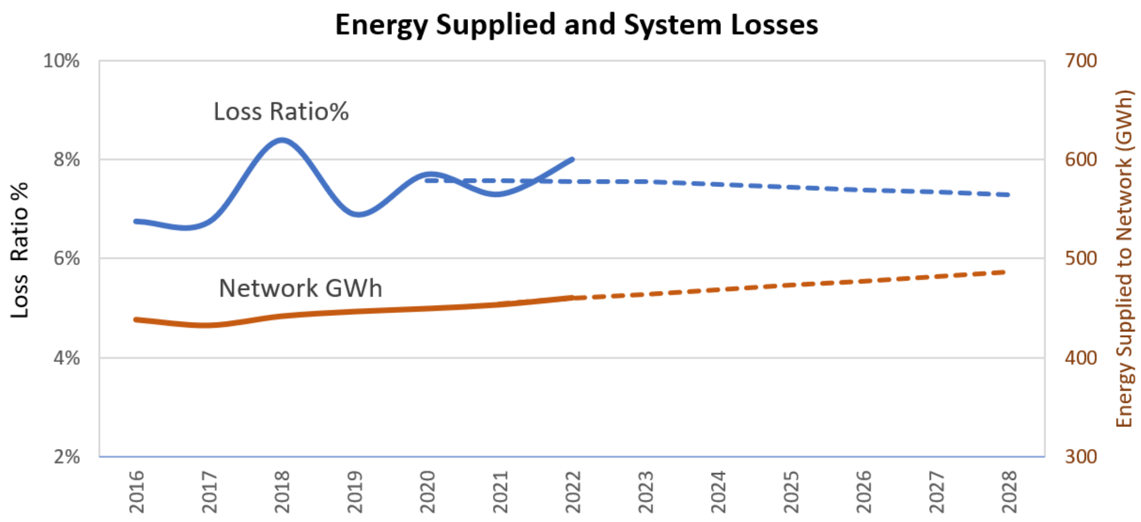



**Figure 8-24: System losses historical trends and forecasts**

## 8.4.4 **Financial effectiveness**

To examine our OPEX and CAPEX spend, Electra is compared with its peer group of six networks based on the Commerce Commission's medium regional grouping (detailed in Section 3.6). Within the peer group, our financial performance for FY2022 is examined in the following sub-sections.

### 8.4.4.1 **Revenue per customer**

The revenue ratio per customer for FY2022 shows Electra has the *lowest* revenue/ICP ratio in the country:

- Line charge revenue/ICP (Figure 8-25a), at $828 is the lowest compared with the peer group and industry averages of $1,134 and $1,283 respectively.

Customers tend to see the cost per kWh on their bills and therefore may not see us as especially low-cost due to a comparatively higher cost per kWh with the lowered regional consumption in FY2022 with the higher residential customer base.

Figure 8-25b is the graph of revenue per customer from FY2016 to FY2022, showing our revenue is well below the peer group and industrial average.

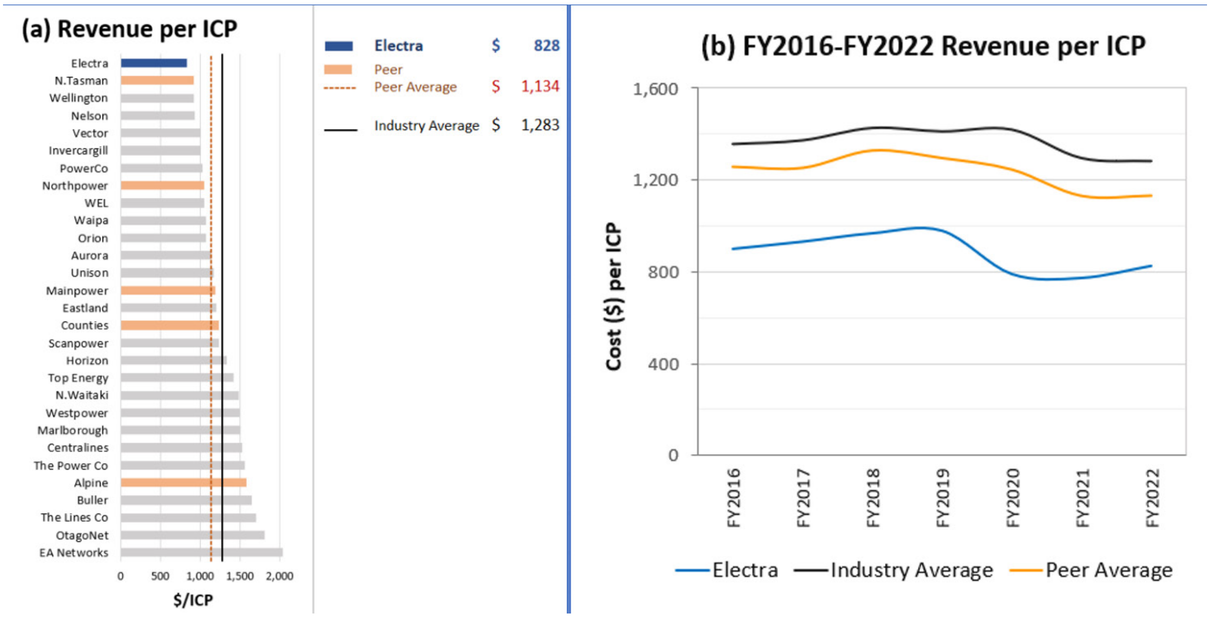



**Figure 8-25: (a) FY2022 Line charge revenue per ICP; (b) FY2016 to FY2022 Revenue per ICP**

### 8.4.4.2 **Operational Expenses**

The ratio measures in Figure 8-26a and Figure 8-26b show Electra is below both the peer group and industry averages:

- OPEX/ICP at $301 is the *second lowest* in the group below the peer and industry averages of $439 and $470 respectively (Figure 8-26a)
- OPEX/GWh at $32.65K is slightly above the industry average of $32.07K (Figure 8-26b), where our operational expenses is required do carry out important maintenance and renewal work.

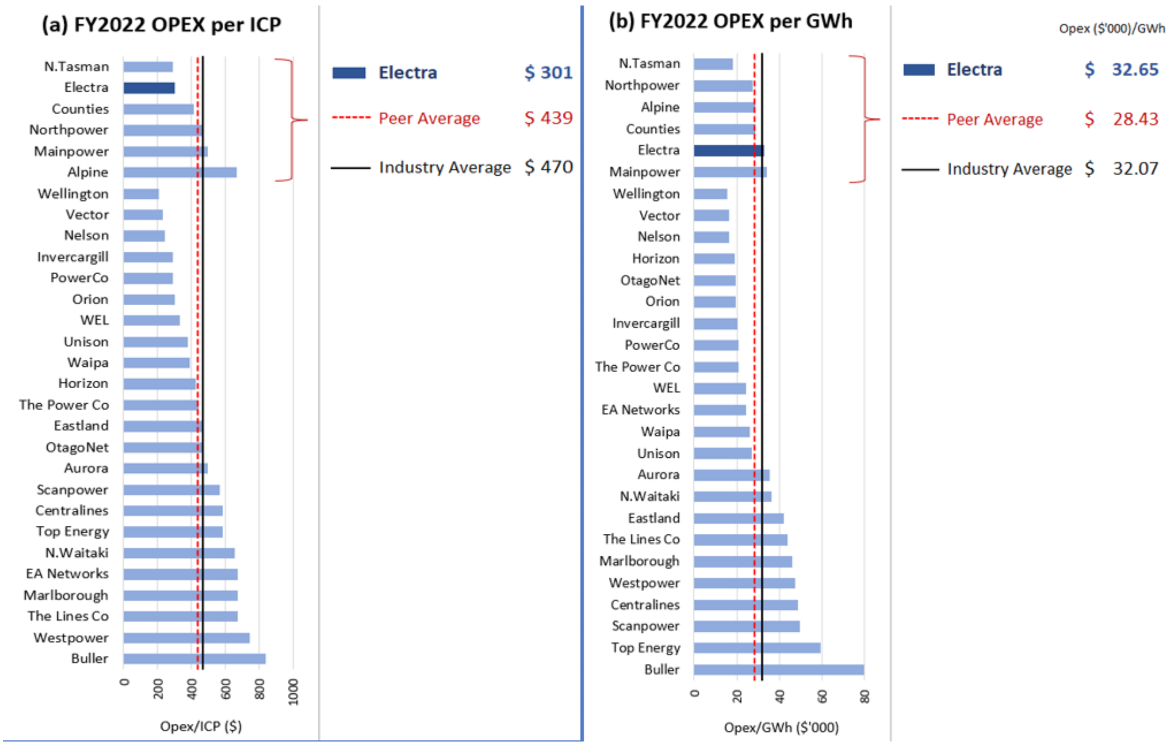



**Figure 8-26: (a) FY2022 OPEX per ICP; (b) 2022 Opex per GWh**

Using econometric modelling in Figure 8-27, the expected OPEX is calculated from FY2020 to FY2022 OPEX expenditure with variables of line length and transformer capacity. As shown in the chart, our FY2022 OPEX is below the regression line of EDBs' expected OPEX, demonstrating effective spending by Electra.

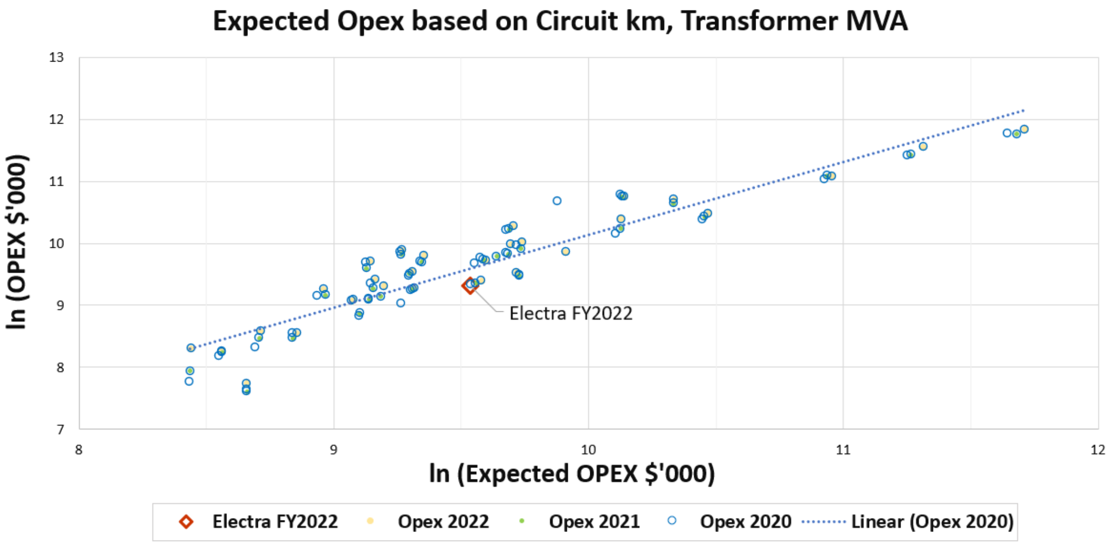



**Figure 8-27: Expected Opex FY2020 to FY2022**

To study the operational expenses further, the OPEX per km of total circuit length is compared to reliability indicator SAIDI (unplanned) for FY2022 as shown in Figure 8-28 and compared with similar electricity distribution businesses (EDBs) in New Zealand. Electra is within a group of eight EDBs whose average OPEX/km is over the industry average of $4,868 but below the unplanned SAIDI average of 192 minutes.

The use of a per kilometre (km) measure does not favour Electra due to the relatively short network (FY2022 at 2,354km) resulting in a higher measure as compared against the peer group (4,198km) and industry (5,239km) averages (Figure 8-32b).

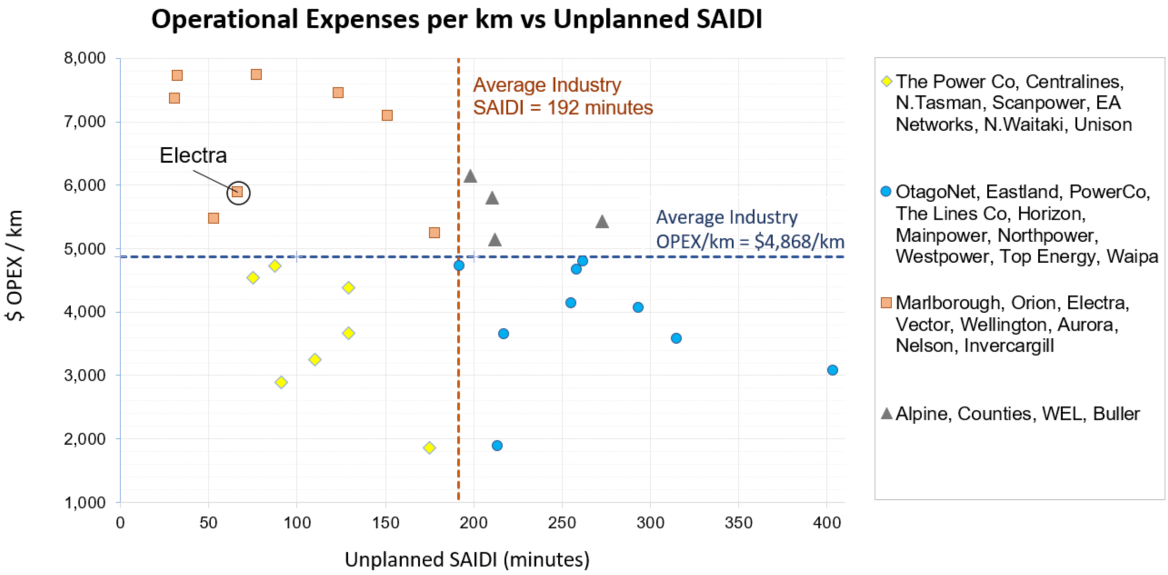



**Figure 8-28: Operational expenses per circuit length (km) versus unplanned SAIDI for FY2022**

Figure 8-29 compares the FY2022 OPEX per ICP versus unplanned SAIDI for all EDBs. Electra is one of nine EDBs in the quadrant whose OPEX/ICP and unplanned SAIDI are below the industry averages of $470 and 192 minutes respectively. Our OPEX/ICP at $294 is 31% below the industry average while unplanned SAIDI (46 minutes) is 58% below the average.

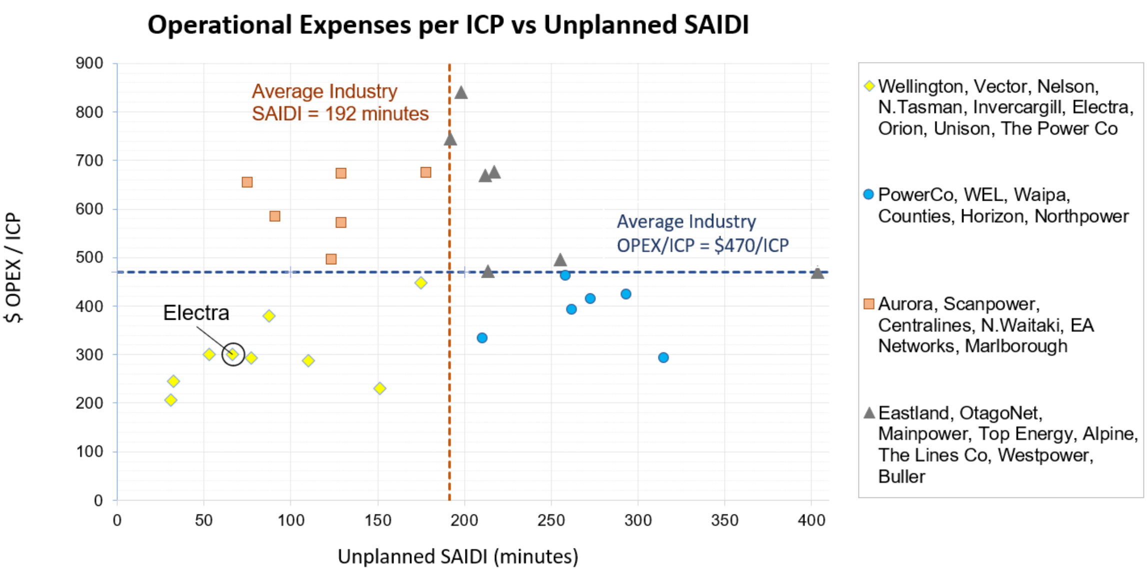



**Figure 8-29: Operational expenses per ICP versus unplanned SAIDI for FY2022**

Our annual survey results (Section 3.10.3) suggest customers are satisfied with their current levels of reliability and the price of delivering the service. This view is supported by our position in the lowest cost (revenue per ICP) for FY2022 versus the low SAIDI quadrant depicted in Figure 8-30. SAIDI C or unplanned SAIDI is fourth lowest in FY2022.

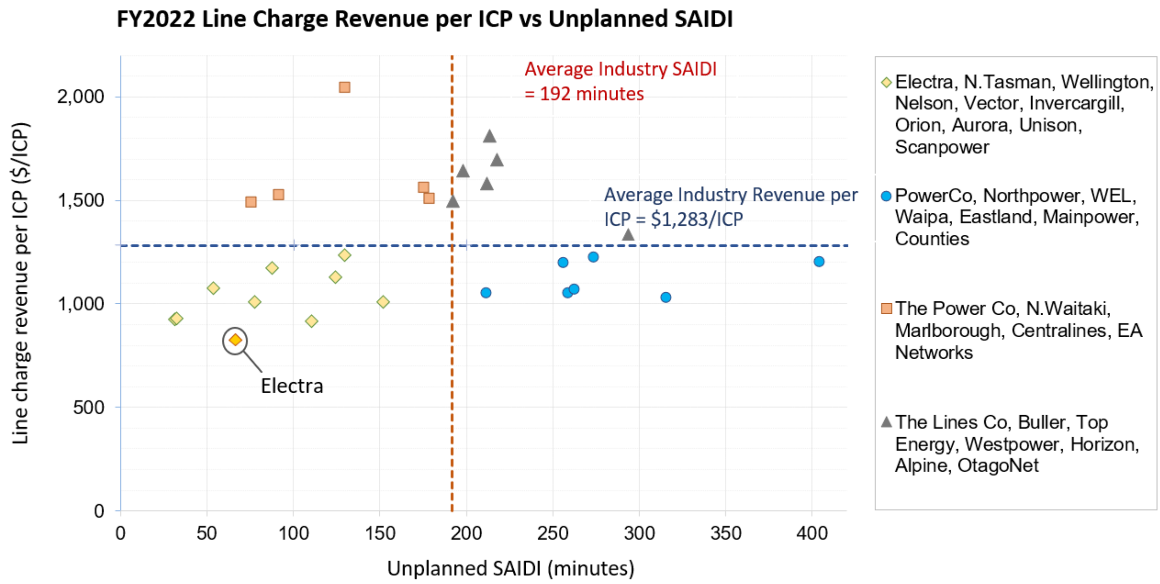



**Figure 8-30: FY2022 Line charge revenue per ICP versus unplanned SAIDI minutes**

These analyses suggest we are optimising our operational costs and pricing methodology to meet our customer needs and targeted service levels.

### 8.4.4.3 **Asset Capital Expenditure**

Capital expenditure on assets (excluding financing) shows Electra's asset CAPEX is below the peer group and industry averages:

- Asset CAPEX/ICP at $294 is also the second lowest within the peer group below the peer and industry averages of $640 and $594 respectively (Figure 8-31a)
- Asset CAPEX/km at $5,737 is in the fourth lowest in the peer group, and below both the peer average ($7,154) and industry average ($6,509) as shown in Figure 8-31b

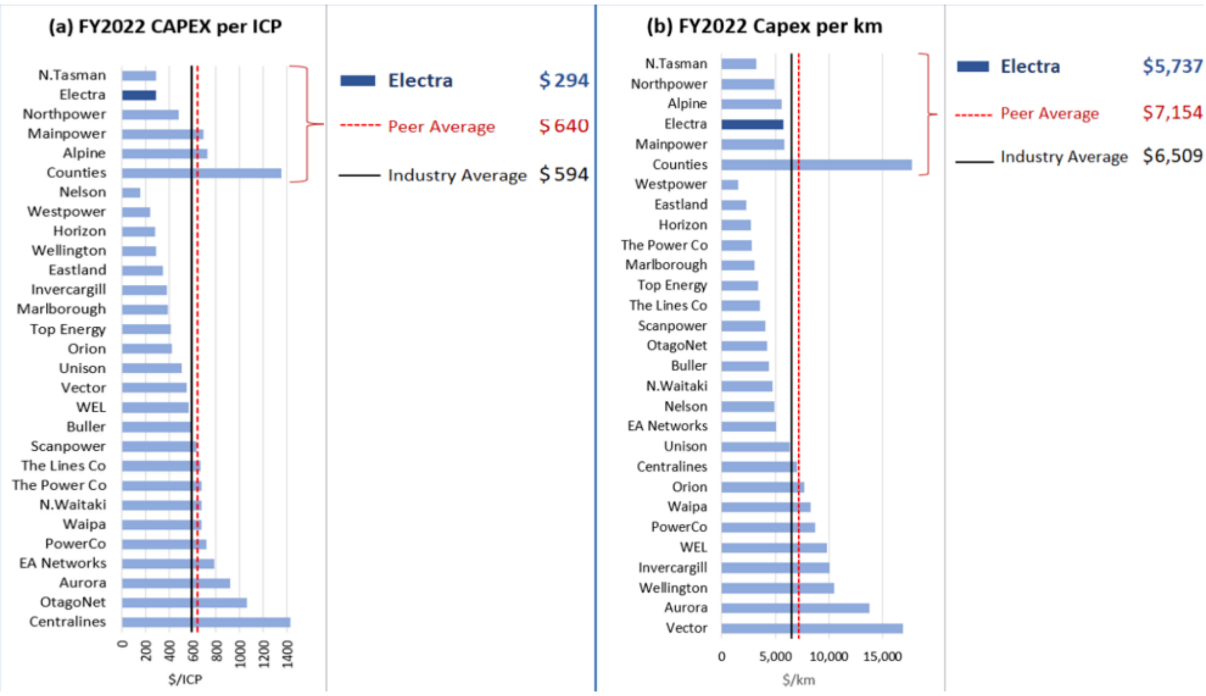



**Figure 8-31: FY2022 Asset capital expenditure or Asset CAPEX (a) per ICP; (b) per km**

Asset Capex includes both growth CAPEX and Replacement Capex Growth (Figure 8-32a) varies between EDBs and renewal or replacement Capex depends on the age of assets on the network, purchasing and maintenance decisions. Low levels of Capex will impact safety and reliability.

Though Electra has a system growth budget lower than its peers, a period of investment in the renewal and replacement (Repex) of infrastructure and transmission services has cumulated in a higher Repex per km as shown in Figure 8-32b.

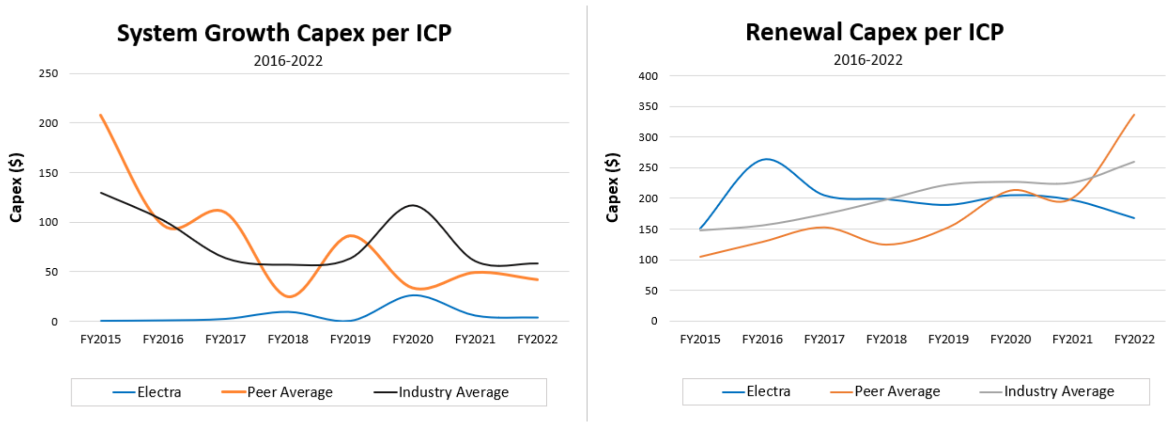



**Figure 8-32: FY2015 to FY2022 (a) Renewal and replacement expenditure per circuit km; (b) Total circuit length (km)**

The expenditure is necessary to replace infrastructure built between the 60s and 70s to provide the security and reliability to customers.

## 8.4.4.4 System operations, network and business support operational expenditure

From FY2021 to FY2022, system operations and network support (SONS) costs increased by 44% while business support costs decreased by 13%. With new systems and studies being commissioned such as the EAM (Mahi Tahi), ISO 55001 and Huringa Pūngao energy transformation initiatives, our business support costs have escalated to meet industry challenges and improve efficiencies but In comparison with our peers, our SONS operational expenses are below the peer average by 30% and well below the industry average by 42% as shown in Figure 8-33a. For business support costs (Figure 8-33b), these are also below the peer group and industry averages by 37% and 51% respectively.

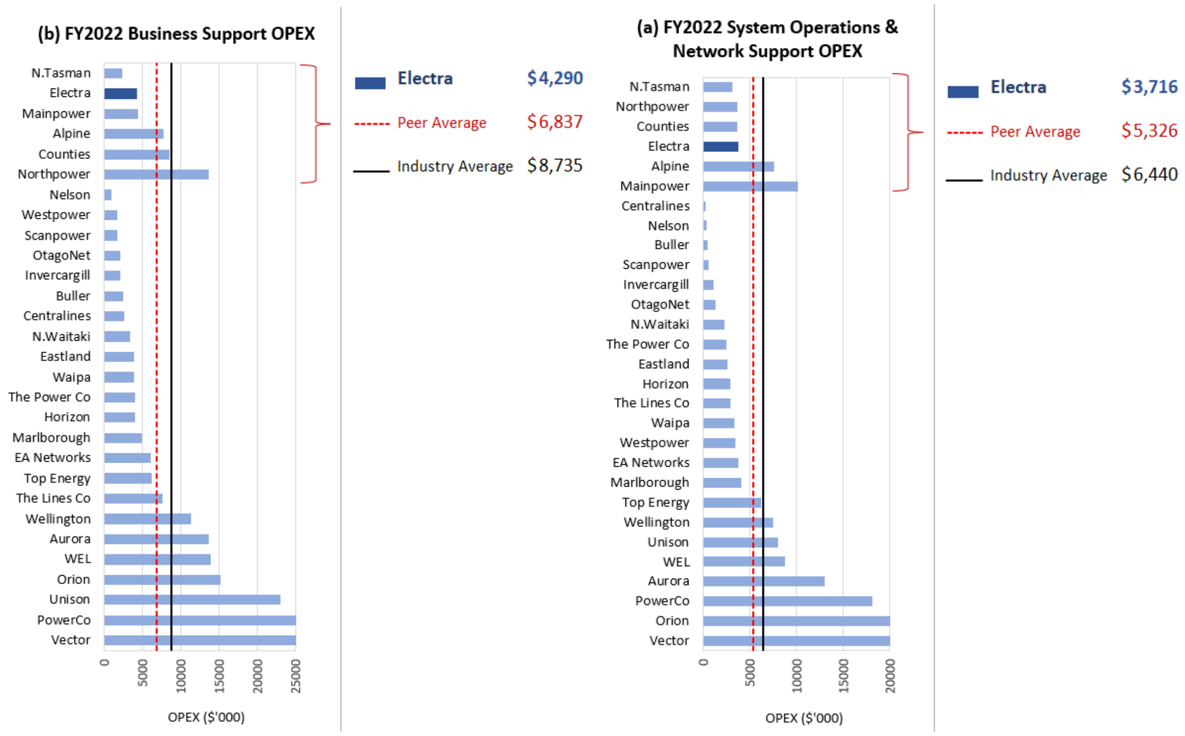



**Figure 8-33: FY2022 Non-network support OPEX: (a) System operations and network support; (b) Business support.**

## 8.5 Asset data and management maturity assessment

An asset data maturity assessment was carried out in November 2021 as a precursor to the implementation of TAG our Enterprise Asset Management System described in Section 8.7. The current maturity of asset information processes and the state of the Electra's information was evaluated in preparation for migration to TAG. Structures, processes, and tools were reviewed to examine how they will support data quality and enable ongoing asset information governance. The assessment found that limited systems were in place then but Electra was developing solutions to address the data and information requirements. The implementation of TAG is on course to provide a powerful platform for asset management through improved asset information as detailed in Section 8.7. To ensure our objectives are achieved, the expected benefits are enabled and supported through a change management process. Our ISO 55001 roadmap and TAG implementation will be the catalysts for improvement of our data and information processes.

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 the maturity of EDB asset management. Key asset managers undertook the assessment based on Commerce Commission's set of 31 questions and following EEA guidelines[53]. With our asset management project Mahi Tahi and other similar initiatives implemented, the team assessed our performance at Asset maturity level 2 or the developing stage for most categories, while Asset Management System, legal and auditing categories have reached compliance levels as shown in Figure 8-34**.** The detailed report on Asset Management Maturity (Schedule 13) is included in Appendix 8.

[53] EEA Guide, "Asset Management Maturity Assessment Tool", 2014s

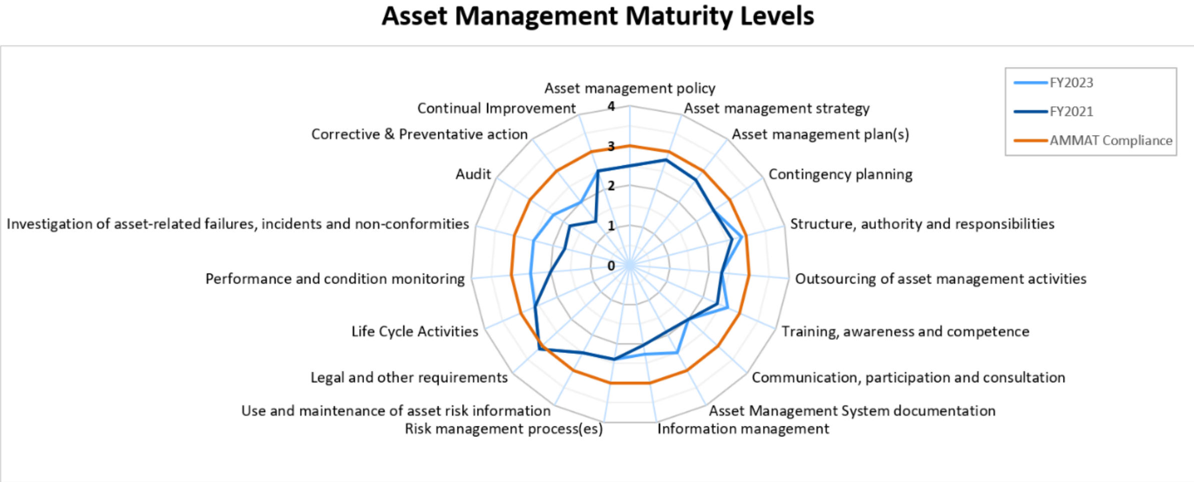



**Figure 8-34: AMMAT scores for FY2021 and FY2023**

Significant aspects Electra wishes to improve in the short term are:

| Practice cluster | Proposed improvements |
|---|---|
| Information management | Assurance of data held is of quality, accuracy and is consistency. Review of controls where these are regularly reviewed and improved where necessary. |
| Communication, participation and consultation | Improvement of team communications with the use of selected performance reports and management feedback on improvement targets. |
| Risk management processes | Documentation and application of the identification and assessment of asset related risk integrated across the asset lifecycle phases. |
| Corrective and preventive action | Mechanisms to be effectively put in place for the systematic instigation of preventive and corrective actions to address root causes of non-compliance or incidents identified by investigations, compliance evaluation or audit. |

The ISO55001 road map drawn to sequence the above improvements is included in Figure 8-35.

## 8.6 ISO 55001 Roadmap

Electra's electricity distribution activities depend on effective asset management to assure the safety and reliability of its services and the needs of the business and its stakeholders continue to be met at the lowest cost. Modern asset management calls for the consolidation of an asset management system to ensure alignment of asset management with our strategy to enable asset management activities to be controlled and continually improved.

The Covaris ISO 55000 2020 review[54] of Electra's asset management system described Electra as a competent asset manager with extensive strengths where the team has good understanding of future project requirements, is supported by experienced people, and there is excellent senior leadership focus from Board level down on asset management services delivery.

We have identified that bringing our asset management system into alignment with the international standard ISO 55001: 2014 would be beneficial in the following ways:

- Create a greater level of assurance in the effectiveness of network management
- Improve the consistency and discipline with which asset management processes are implemented
- Manage the risks associated with staff turnover in an increasingly uncertain labour market
- Prepare the company for possible changes in the regulatory environment
- Improve monitoring and evaluation of performance
- Enable improvements to be better targeted and more effectively demonstrate value.

We have commenced the development of our ISO 55001 Roadmap to align our asset management system with the requirements of ISO 55001 over a three-year period as shown in Figure 8-35 where seven workstreams have been identified.

[54] Covaris ISO 55001 Review, July 2020

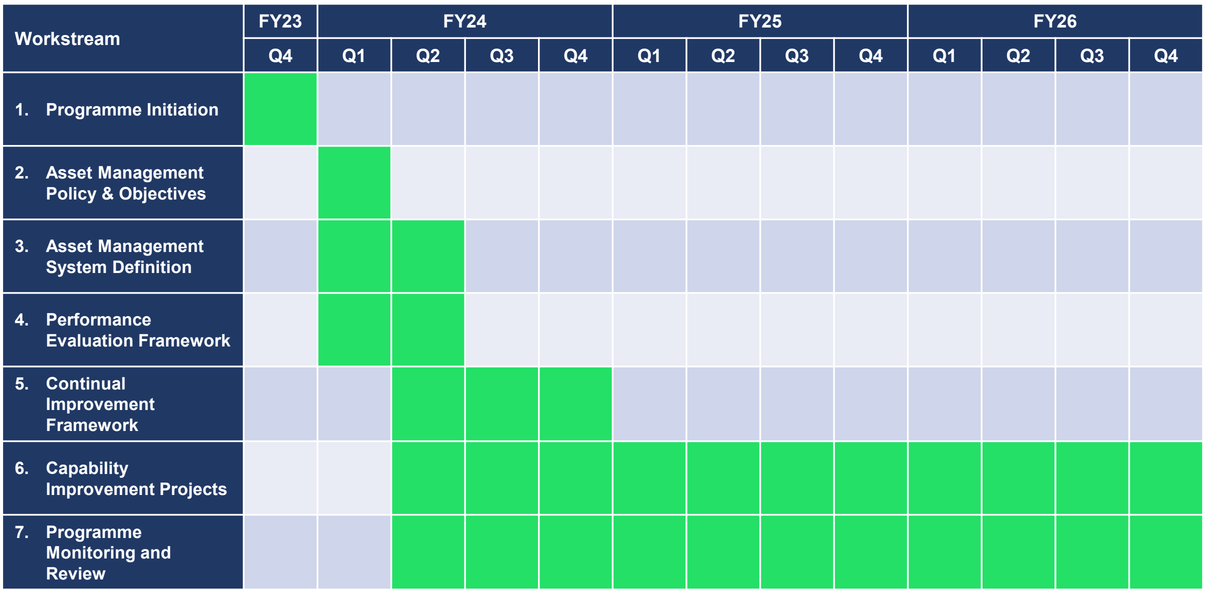



**Figure 8-35: ISO 55001 Roadmap**

An overview of each of the workstreams follow:

- **Programme Initiation:** The programme governance structure and plan as well as resource plan are developed
- **Asset management policy and objectives:** This workstream will ensure processes for forming, reviewing and communicating asset management policy and objectives are consistent, appropriate and well-defined. It will also consolidate asset management objectives and key performance indicators
- **Asset management system definition:** This workstream will document a clear description of the asset management system with reference to ISO 55001 requirements to ensure understanding of functions to support achievement of objectives and identify gaps
- **Performance Evaluation Framework:** Centralised performance evaluation processes for the asset management system will be developed including a performance measurement system, an internal audit programme, and a management review procedure. The performance evaluation framework will provide definitive information relating to the performance of assets while the asset management system will support decision-making
- **Continual Improvement Framework:** This workstream will establish a centralised continual improvement framework for the asset management system that will enable corrective actions and continual improvement opportunities to be registered and tracked through their lifecycle. The framework will ensure that available resources are consistently allocated to the most valuable risk control activity and that improvement actions taken are effective
- **Capability Improvement Projects:** Gaps identified through the completion of earlier workstreams will be addressed through focused capability improvement projects delivered through a standardised and lightweight project management framework
- **Programme Monitoring and Review:** The overall work programme will be subject to quarterly monitoring and review to evaluate performance, identify and control risks. Programme KPIs will be determined, including self-assessment of maturity against the AMMAT framework and progress against target on key workstreams and capability improvement projects.

## 8.7 Enterprise Asset Management System and Process Improvements

The launch of the EAM system, The Asset Guardian system (TAG), is set for a go-live during FY24. As part of Electra's ISO 55000 alignment initiative, TAG will result in the improvement of our asset management maturity or AMMAT[55] scores and we envision that all elements supported by EAM will significantly improve with the delivery of these process changes in Electra. These consequential improvements will form the basis for reducing our business risks related to public safety, loss of data, ineffective contract management, and non-compliance of reliability targets.

This initiative enables Electra's group strategy to improve operational efficiency, place the customer at the center, invest for the future, develop our people, and keep safe, as well as grow our business with a future focus. We made the conscious decision to prioritise the change such that it makes maximum impact on people, process, and data.

[55] *Schedule 13 Report on Asset Management Maturity, Electra AMP FY2021*

## 8.7.1 Mahi Tahi Programme

With the adoption of TAG, Electra is implementing the Mahi Tahi ("co-operate, teamwork, collaborate") programme with the vision "to connect and empower people to one Electra enabled by industry-leading technology"(Figure 8-36). During FY2024, we aim to transform our business to significantly improve operational efficiency and achieve excellence in our operations, using an all-Microsoft solution for finance, job planning, management, and asset management.

| Programme Mahi Tahi Vision | Programme Mahi Tahi Mission |
|---|---|
| *"To connect and empower people to one Electra enabled by industry leading technology"* | 1 Transform our business from a people, process and systems perspective<br>2 Build commitment, connection, confidence and transparency among our people to work as one team<br>3 Improve customer experiences<br>4 Create operational efficiency<br>5 Enable fact-based decision-making<br>6 Seamless and accurate one source of accurate truth |


Note: Key words from the programme vision alignment workshop held on June 2021

**Figure 8-36: Mahi Tahi vision and mission**

## 8.7.2 Continual Process Improvement

The continual improvement of our processes includes the following activities:

- **Process Alignment:** A lean processing approach supported by Boxfishâ Lean Methodology enables the business to understand waste and discuss frustrations with the current processes where areas for improvement are identified in the new system
- **Data Modelling:** Our data maturity was assessed alongside development of existing and future data models while an asset hierarchy prototype was modelled in the new system through a series of key work processes. This phase was crucial to allow the team to see how the data and process would interact and operate together giving the team confidence
- **Remediation:** Following on from the data modelling phase, a data remediation plan was put in place to ensure data would be highly effective at go-live as it would be this data set that would be utilised for user acceptance testing. Significant time and thought leadership across the business and consultant partners was utilised to create both the asset hierarchy, current and future data model and the linking of historic data sets into one data set to ensure the system will work from day one
- **Agile approach:** Adopting an agile approach to iterate and improve of design solutions through high collaboration with business users, understanding the opportunities for improvement throughout the Lean workstream, which was actively considered and incorporated into the design and build phases.

An example of one of our improvement processes is the planned maintenance process, mapped out in Figure 8-37. This process includes mapping out the current (Figure 8-37a) and future states (Figure 8-37b) where activities of planned inspections, maintenance scheduling and the monitoring of planned SAIDI and SAIFI are recorded.

Besides the planned maintenance process, other processes that are being developed for improvement or under implementation include:

- Unplanned maintenance
- Work order management
- Third party services covering new connections, vegetation management, disconnection and reconnections, cable location services, community lighting
- Asset renewal and replacement including pillar, fixed assets and equipment
- Disposal of assets.

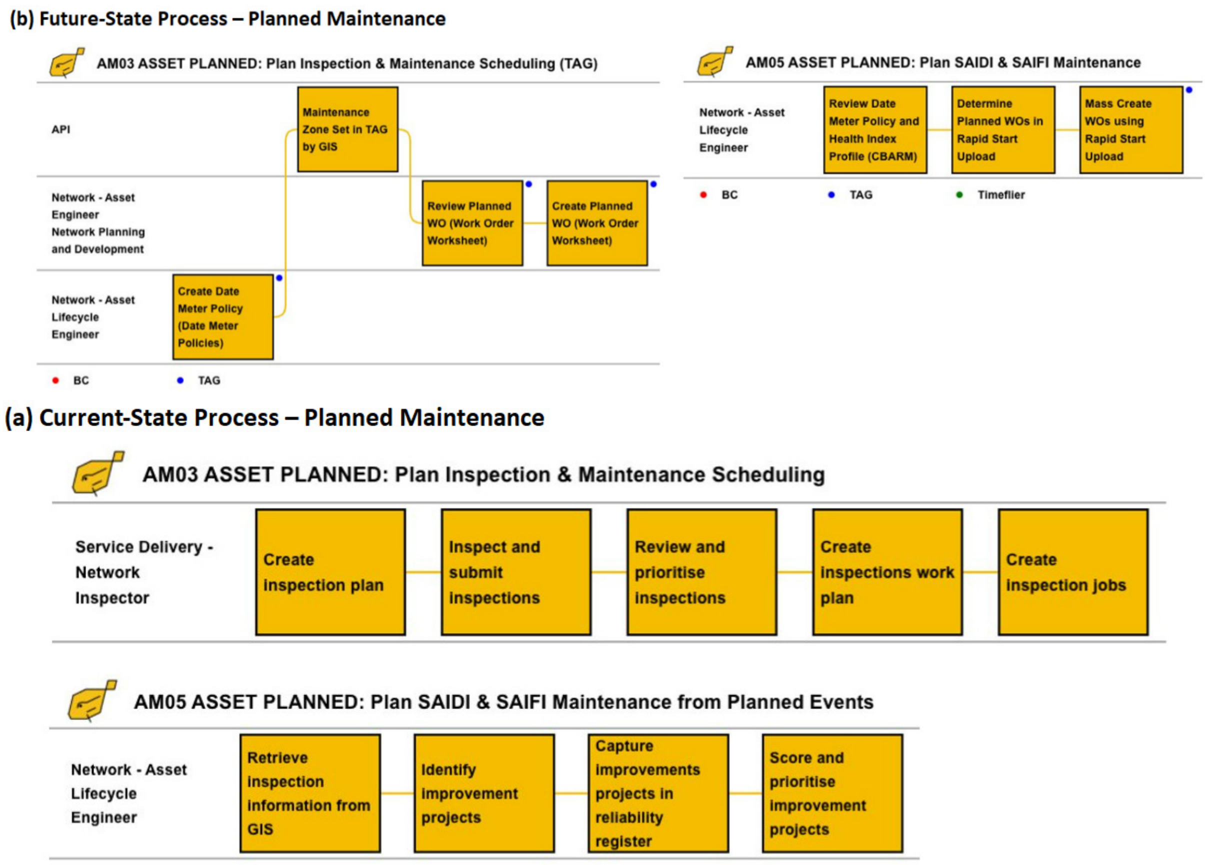



**Figure 8-37: Planned maintenance process improvement: (a) Current-state, and (b) Future-state processes**

## 8.7.3 Project Outcomes and Achievements

We sought outcomes that meet our strategic objectives and addressed the risks encountered in technology change including:

- Benchmarking and embracing world class asset management practices to continuously raise the maturity of our asset data
- Streamlining current business processes by combining a lean approach to remove inefficiencies to an optimum state, then enabled by a new asset management system
- Actively engaging stakeholders across the business early in the initiative into lean workshops to create buy-in and ownership of the change
- Adopting an agile approach to iterate on solution design through high collaboration with business users
- Using key external consultants to work alongside the business to “fill the gaps” and partner with the teams, to support both their learning and the project delivery
- Understanding the opportunities for improvement throughout the Lean workstream, which was actively considered and incorporated into the design and build phases
- Bringing in external change management resources to assist the People and Capability team in delivering change management across all phases.

The methodical, investigative approach undertaken focused on our people inside the business resulting in an increased collective understanding of the business and buy-in to the change. The approach significantly reduced project stress, while supporting the team delivering the project. The approach of focusing on aiding Electra’s people, supporting them with a high level of autonomy and support has meant external issues that could have delayed the project have not derailed the project as a result of the high level of internal engagement. Such engagement was evidenced by our teams shielding from August 2021, the project moving online, with minimal project delays and project efficiency increasing. User acceptance testing, end to end testing and training commenced in July 2022 and the new system will be commissioned in March 2023.

By sharing more accurate and timely information across our business using ‘one source of truth’ and streamlining our processes and tasks, we *can* focus on our customer-centric strategy by providing a better experience for our customers.

## 8.8 Asset Information System Improvements

Over recent years, Electra have been investing in data warehousing and analysis solutions and capability to enable the gathering and analysis of both structured and unstructured event and time series data.

The solutions currently utilised are:

- **Grafana:** A multi-platform open-source analytics and interactive visualization web application
- **iHistorian:** Software solution that collects industrial time-series and A&E data at very high speed
- **Influx DB:** A data solution capable of storing, analysing and displaying large amounts of time series data
- **PowerBI:** A business analytics service. It enables interactive visualisation and business intelligence capabilities
- **Splunk:** A solution capable of ingesting, storing and analysing large amounts of unstructured event-based data
- **FME:** A data manipulation, integration and automation platform. It enables the automated integration between unlike systems for the purposes of process enablement and optimisation.

The output of the above tools is used to improve decision-making by deriving insights from real time and historical datasets. Influx DB currently ingests data from our Maximum Demand Indicator IoT Sensors enabling the monitoring of the health of the asset. FME is a key capability within Electra as it is used extensively across the business.

### 8.8.1 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.

Some of the improvements included:

- Integration with the new EAM system, TAG, with process upgrades for the migration of data
- Automated customer notifications via multiple platforms (i.e. social media)
- Services to distributed workforce and remote offices
- Data scrubbing for all asset types covering overhead lines, cables, transformers, pillars.

Figure 8-38 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.

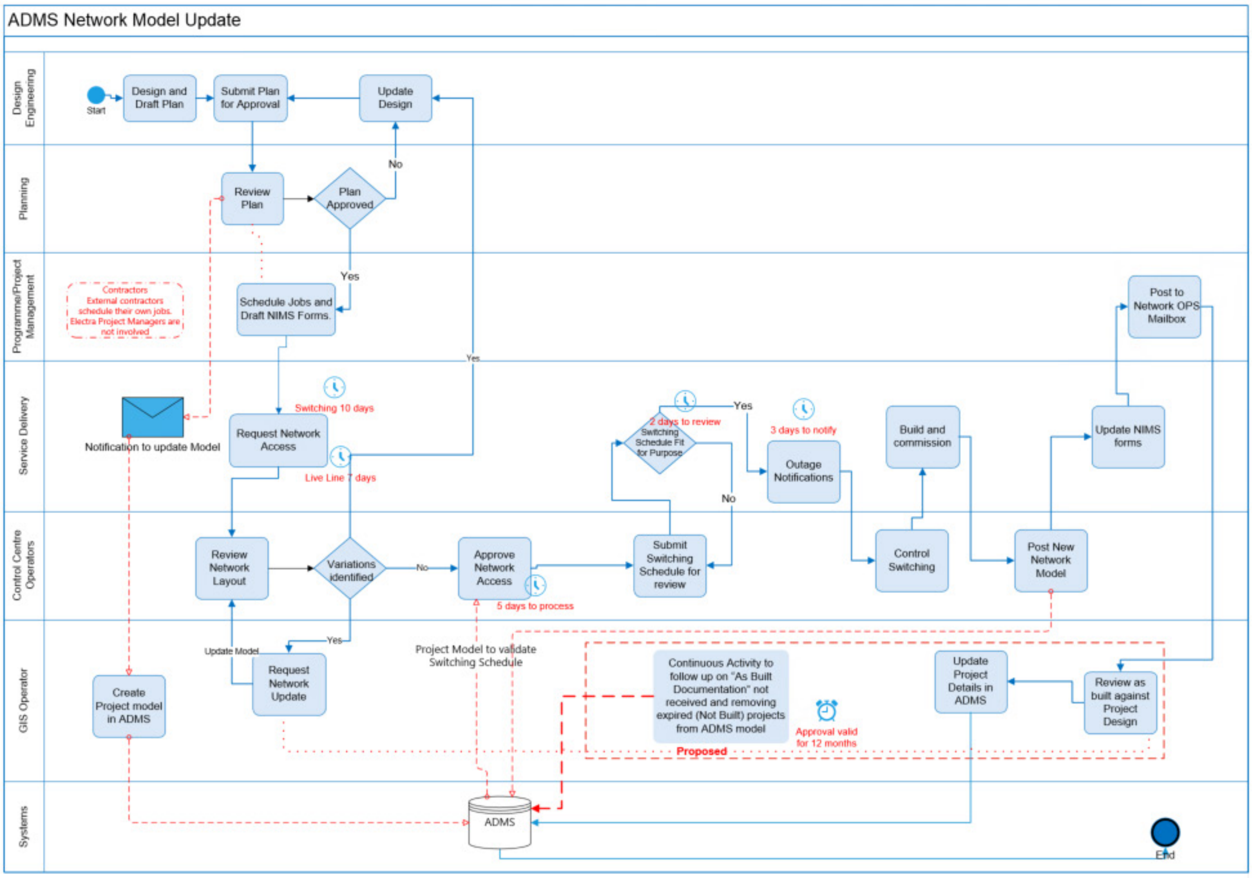



**Figure 8-38: ADMS network process improvement**

## 8.8.2 Improvement to Axos billing system

Electra switched to the Axos billing system in 2018 as the previous bespoke system had minimal support availability and limited features while Axos was well supported with a development roadmap.

The enhancements observed in the last year were:

- Introduction of registry manager to reduce data loading times with future options to maintain registry data
- Additional dashboard and visualisations to assist with revenue assurance
- Use of Axos data to calculate discount payments.

The road map for improvement includes improved automation of billing, and possible implementation of changes to unmetered billing.

## 8.8.3 Improvement to Network Data Accuracy

Processes are currently in place to ensure accurate data is used to manage our electrical network and distribution assets. We need good data to understand the condition of our network, forecast future demand and make good investment decisions. To achieve reliability, safety, sustainability and affordability goals, we are improving our network data processes by considering the following:

- Data modelling including future trends in the demands on the network are combined with analysis of energy trends to inform our strategy for the future
- Setting in place various asset management systems including the implementation of a secure solution which will consolidate SCADA, DERMS and Outage Management functions.

## 8.8.4 Inspections of 33/11kV structures and assets

Acoustic inspections have been being conducted at our substations. This year's November 2022 inspections saw nine substation structures being inspected with 19 total defects identified. Figure 8-39a shows the number of defects on various equipment. The inspection conducted in November 2022 at Levin East Zone Substation detected one cracked 33kV insulator on ABS 1011.


**Figure 8-39: Acoustic Inspection Defects**

Drone inspections continue to be conducted to expedite the inspection and condition-monitoring of our overhead assets in our efforts to meet our objectives for operational excellence. 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 Paekākāriki 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; in Section 5.2; the details are entered into the relevant CBARMM model (Section 5.1.1) and the asset condition updated.

## 8.8.5 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 3.13.7. 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 8-40. 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.

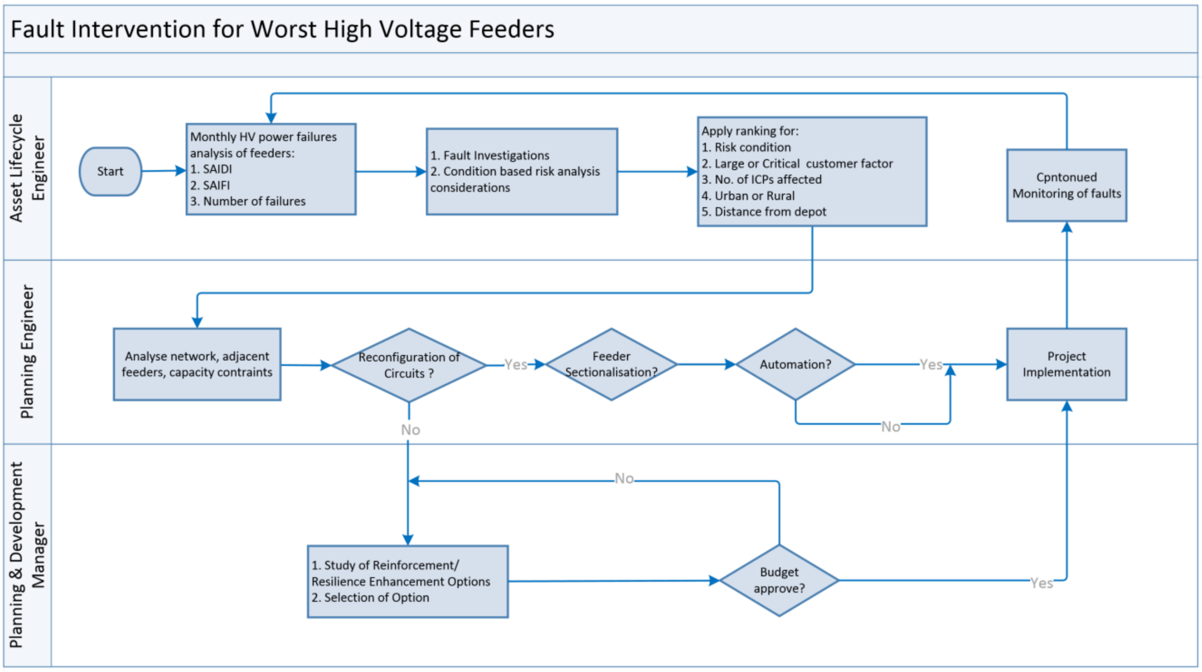



**Figure 8-40: Fault intervention process for worst 11kV distribution feeders**

## 8.8.6 Strategic vegetation management improvement process

Another asset improvement process is within our vegetation management. As discussed in Section 3.13.6, we have moved from a responsive to a proactive planned tree-trimming risk-based process depicted in Figure 8-41. 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.

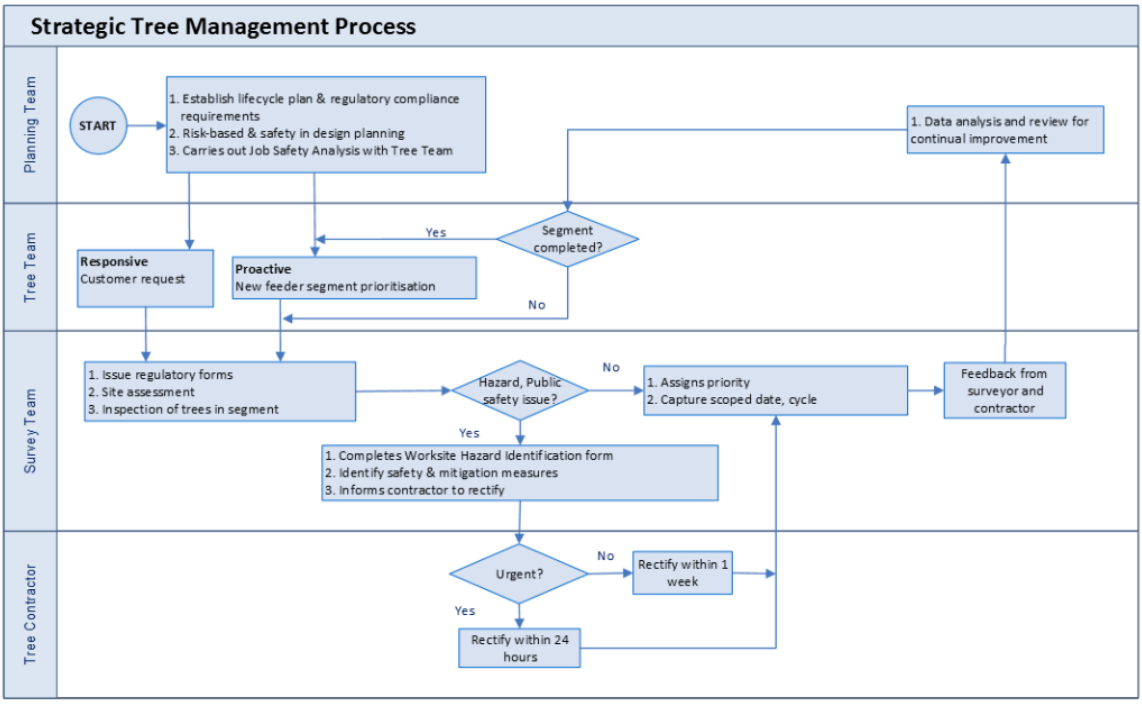



Figure 8-41: Tree-trimming planned process integration

# 9 APPENDICES

## 9.1 **List of Appendices**

## Appendix 1: Reconciliation of Asset Management Plan to Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022

The following table cross references the sections of this AMP to Attachment A of the Electricity Distribution Information Disclosure Determination 2012 (Targeted Review Tranche 1) Amendment Determination 2022 .

| 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, 1.1 Asset Management Plan Overview |
| 3.2 Details of the background and objectives of the EDB's asset management and planning processes; | 1 INTRODUCTION, 1.3 Company strategy, 1.3.1 Mission and vision, 1.3.2 Key strategies, 1.4 Asset management system, 1.5 Asset management framework, 3.2 Group business strategic objectives |
| 3.3 A purpose statement which- | 1.2 Purpose of the Asset Management Plan |
| 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, 1.13 Overview of documentation and controls, 1.1 Asset Management Plan Overview |
| 3.3.2 states the corporate mission or vision as it relates to asset management; | 1.3.1 Mission and vision |
| 3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB; | 1.5.1 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 | 1.5.2 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; | 1.5.3 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; | 1.6 Planning period |
| 3.5 The date that it was approved by the directors; | 1.7 Board approval |
| 3.6 A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates- | 1.8 Stakeholder interests |
| 3.6.1 how the interests of stakeholders are identified | 1.8.1 Stakeholder interests and how they are identified |
| 3.6.2 what these interests are; | 1.8.2 Linking stakeholder interests to asset management practices |
| 3.6.3 how these interests are accommodated in asset management practices; and | 1.8.2 Linking stakeholder interests to asset management practices |
| 3.6.4 how conflicting interests are managed; | 1.8.3 Managing conflicting stakeholder interests, 3.12 Translating stakeholder needs into service levels |
| 3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including- | 1.1 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; | 1.10.1 Summary of roles, delegated authorities and reporting |

| Determination Clause (Attachment A of Determination*) | AMP Section(s) |
|---|---|
| 3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and | 1.10.1 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; | 1.10.2 Use of external contractors and advisers |
| 3.8 All significant assumptions- | 1.15 Significant assumptions, 1.15.1 Causes of possible material differences, 1.15.2 Financial forecasts, 1.15.3 Limitations of this AMP |
| 3.8.1 quantified where possible; | 1.15 Significant assumptions |
| 3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including- | 1.15 Significant assumptions |
| 3.8.3 a description of changes proposed where the information is not based on the EDB's existing business; | Not applicable |
| 3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and | 1.1.1 Challenges, areas and dimensions of uncertainty, 1.15 Significant assumptions, 1.1 Asset Management Plan Overview, 1.9 Climate change and decarbonisation |
| 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 Sch | 1.15.2 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; | 1.15.1 Causes of possible material differences |
| 3.10 An overview of asset management strategy and delivery; | 1.4.1 Asset management policy, 1.4.2 Asset management strategy |
| 3.11 An overview of systems and information management data; | 1.11 Asset management systems and information management |
| 3.11.1 To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe- | |
| the processes used to identify asset management data requirements that cover the whole of life cycle of the assets; | 1.12 Overview of key lifecycle processes<br><br>5.1 Asset lifecycle management |
| the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets; | 1.11 Asset management systems and information management<br><br>5.2 Management of our assets<br><br>8.6 ISO 55001 Roadmap |
| the systems and controls to ensure the quality and accuracy of asset management information; | 1.11.1 Data integrity<br><br>1.13 Overview of documentation and controls |
| the extent to which these systems, processes and controls are integrated; | 6.2.2 Our ICT assets<br><br>8.3.5 Asset Management System Enhancements<br><br>8.8 Asset Information System Improvements |
| how asset management data informs the models that an EDB develops and uses to assess asset health; and | As per clause 2.6.1A(1) of the Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022, these subclauses clauses do not apply in respect of the AMP required to be disclosed before the start of the disclosure year 2024 (publicly disclosed by 31 March 2023). |
| how the outputs of these models are used in developing capital expenditure projections. | |

| Determination Clause (Attachment A of Determination*) | AMP Section(s) |
|---|---|
| 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; | 1.11.1 Data integrity |
| 3.13 A description of the processes used within the EDB for- | . |
| 3.13.1 managing routine asset inspections and network maintenance; | 1.12 Overview of key lifecycle processes, 1.12.1 Routine inspections, 1.12.2 Maintenance drivers |
| 3.13.2 planning and implementing network development projects; and | 1.12.3 Development of project drivers |
| 3.13.3 measuring network performance; | 1.12.4 Measuring performance, 3 SERVICE LEVELS |
| 3.14 An overview of asset management documentation, controls and review processes. | 1.13 Overview of documentation and controls |
| 3.15 An overview of communication and participation processes; | 1.14 Overview of communication processes |
| 3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and | 1.15.2 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. | EXECUTIVE SUMMARY, 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 |
| 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).<br>The AMP must identify the supply security provided at individu | 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. | 5.1 Secondary systems |

| Determination Clause (Attachment A of Determination*) | AMP Section(s) |
|---|---|
| 4.3 If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network. | 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. | 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 f | 3 SERVICE LEVELS |
| 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. | 3.3 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 | 3.3 Primary customer service levels, 3.4 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. | 3.5 Asset performance levels, 8.2 Network reliability performance, 8.3 Review of Commerce Commission's reliability target areas and asset information, 8.5 Asset data and management maturity assessment |
| 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 | 1.8.1 Stakeholder interests and how they are identified, 1.8.2 Linking stakeholder interests to asset management practices, 3.3.2 Justification for reliability targets, 3.8 Regulatory compliance levels, 3.1 Justification for service levels, 3.12 Translating stakeholder needs into service levels |
| 9. Targets should be compared to historic values where available to provide context and scale to the reader. | 3 SERVICE LEVELS, 8.2 Network reliability performance, 8.3 Review of Commerce Commission's reliability target areas and asset information, 8.4 Performance measures |
| 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. | 1.1.1 Challenges, areas and dimensions of uncertainty, 1.15.1 Causes of possible material differences, 1.15.2 Financial forecasts, 1.15.3 Limitations of this AMP, 3.6 Financial efficiency, 4.5 Flexibility Solutions, 4.6 Huringa Pūngao Energy Transformation Update |

| Determination Clause (Attachment A of Determination*) | AMP Section(s) |
|---|---|
| 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; | 3.13 Tactical programmes, 4.3 Development policies, standards and methods, 8.5 Asset data and management maturity assessment, 8.7 Enterprise Asset Management System and Process Improvements, 8.8 Asset Information System Improvements |
| 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, 4.3.6 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, 4.8 Demand forecasts, 4.8.2 Approach to system demand forecasts |
| 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; | 1.1.4 Forecasting and understanding the future, 4.8 Demand forecasts, 4.8.1 Approach to system 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, | 4.9.4 Zone substation demand forecasts, 4.9.3 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 | 1.1.1 Challenges, areas and dimensions of uncertainty, 1.1.2 Regional Development, 4.4 Known constraints, 4.7 Huringa Pūngao Energy Transformation Update |
| 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; | 1.1.1 Challenges, areas and dimensions of uncertainty, 4.3.4 Impact of distributed generation, 4.5 Flexibility Solutions, 4.7 Huringa Pūngao Energy Transformation Update |
| 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- | 1.1.2 Regional Development, 4.3.5 Options for meeting or managing demand, 4.7 Huringa Pūngao Energy Transformation Update, 4.3.6 Development Prioritisation, 4.14 Development projects |
| 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; | 4.1 Development context, 4.2 Development criteria, 4.3 Development policies, standards and methods, 4.14 Development projects |
| 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 | 4.14 Development projects |

| Determination Clause (Attachment A of Determination*) | AMP Section(s) |
|---|---|
| 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, 4.3.3 Policies on embedded generation, 4.5 Distributed generation assessment, 4.6 Flexibility Solutions |
| 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; | 4.10.1 Development projects for FY2024 year |
| 11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and | 4.10.2 Development projects for FY2025 to FY2028 |
| 11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period; | 4.10.3 Development projects for FY2029 to FY2033 |
| 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, 4.5 Distributed generation assessment |
| 11.12 A description of the EDB's policies on non-network solutions, including- | 4.3.4 Options for meeting or managing demand, 4.6 Flexibility Solutions, 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 | 4.3.4 Options for meeting or managing demand, 4.10 Emerging technology and initiatives, 4.6 Flexibility Solutions |
| 11.12.2 the potential for non-network solutions to address network problems or constraints. | 4.3.4 Options for meeting or managing demand, 4.10 Emerging technology and initiatives, 4.6 Flexibility Solutions, 4.7 Huringa Pūngao Energy Transformation Update, 6.2 Non-network ICT strategy, 8.8 Asset Information System Improvements |
| 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 |
| 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, 5.1 Asset 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, 5.13 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, 5.1 Asset 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 asset | 5 LIFECYCLE MANAGEMENT, 5.1 Asset lifecycle management, 5.1.1 Condition-based asset risk management, 5.1.2 Safety in design |

| Determination Clause (Attachment A of Determination*) | AMP Section(s) |
|---|---|
| 12.3.2 a description of innovations that have deferred asset replacements; | 3.13 Tactical programmes, 4.3.5 Options for meeting or managing demand, 4.5.7 |
| 12.3.3 a description of the projects currently underway or planned for the next 12 months; | 5 LIFECYCLE MANAGEMENT, 5.13 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, 5.13 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, 5.13 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, 5.13 Summary of inspections and maintenance |
| 12.5 Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of: | As per clause 2.6.1A(1) of the Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022, these clauses do not apply in respect of the AMP required to be disclosed before the start of the disclosure year 2024 (publicly disclosed by 31 March 2023). |
| 12.5.1 the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and | |
| 12.5.2 the rationale for using the approach for each asset category | |
| 12.6 Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance. | |
| 12.7 The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB used to inform these expenditure projections. | |
| 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, 6.2.2 Our ICT 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 | 6.1 Summary of non-network assets, 6.2.4 ICT forecast |
| 13.4 a description of material maintenance and renewal projects (where known) planned for the next five years. | 6.1 Summary of non-network assets, 6.2.4 ICT 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; | 5.1.1 Condition-based asset risk management, 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, 7.2.7 Natural disaster risks, 7.4 Resilience framework, 7.4.1 High Impact Low Probability (HILP) Events |
| 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, 7.4.2 Emergency response and contingency planning, 7.4.3 Emergency response plans, 7.4.4 Resilience planning for risk preparedness |
| 14.4 Details of emergency response and contingency plans. | 7.3 Mitigating network vulnerabilities, 7.4.2 Emergency response and contingency planning, 7.4.3 Emergency response plans, 7.4.4 Resilience planning for risk preparedness |

| Determination Clause (Attachment A of Determination*) | AMP Section(s) |
|---|---|
| 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, 8.3.11, 8.4.4 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 Review of Commerce Commission's reliability target areas and asset information, 8.3.11, 8.4 Performance measures |
| 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. | 8.5 Asset data and management maturity assessment, 8.6 ISO 55001 Roadmap, 8.7 Enterprise Asset Management System and Process Improvements |
| 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. | 3.13 Tactical programmes, 4.7 Emerging technology and initiatives, 4.5.7, 8.5 Asset data and management maturity assessment, 8.6 ISO 55001 Roadmap, 8.7 Enterprise Asset Management System and Process Improvements, 8.8 Asset Information System Improvements |
| 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 | 1.13 Overview of documentation and controls, 5.14 Our employees, 5.15 Resourcing policy and strategy, Appendix 1 Reconciliation of Asset Management Plan to Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022 |
| 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans. | 1.13 Overview of documentation and controls, 1.1 Accountabilities for asset management, 1.10.1 Summary of roles, delegated authorities and reporting, 1.10.2 Use of external contractors and advisers, 5.14 Our employees, 5.15 Resourcing policy and strategy |
| 17. AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1 - 17.7 below: | As per clause 2.6.1A(2)(a) of the Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022 we intend to publicly disclose the information required in the clause below in a separate document by 30 June 2023. |
| 17.1 a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's process and communications in respect of planned interruptions and unplanned interruptions; | |
| 17.2 a description of the EDB's practices for monitoring voltage, including: | |
| 17.2.1 the EDB's practices for monitoring voltage quality on its low voltage network; | |
| 17.2.2 work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010; | |
| 17.2.3 how the EDB responds to and reports on voltage quality issues when the EDB indetifies them, or when they are raised by a stakeholder; | |
| 17.2.4 how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and | |
| 17.2.5 any plans for improvements to any of the practices outlinned at clauses 17.2.1 – 17.2.4 above; | |
| 17.3 a description of the EDB's customer practices, including: | |
| 17.3.1 the EDB's customer engagement protocols and customer service measures — including customer satisfaction with the EDB's supply of electricity distribution services; | |

| Determination Clause (Attachment A of Determination*) | AMP Section(s) |
|---|---|
| 17.3.2 the EDB's approach to planning and managing customer compliant resolution; | |
| 17.4 a description of the EDB's practices for connecting consumers, including: | |
| 17.4.1 the EDB's approach to planning and management of- | |
| (a) connecting new consumers (offtake and injection connections), and overcoming encountered issues; and | |
| (b) alterations to exisitng connections (offtake and injection connections); | |
| 17.4.2 how the EDB is seeking to minimise the cost to consumers of new or altered connections; | |
| 17.4.3 the EDB's approach to planning and managing communications with consumers about new or altered connections; and | |
| 17.4.4 commonly encountered delays and potential timeframes for different connections. | |
| 17.5 A description of the following: | |
| 17.5.1 how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: | |
| (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity; | |
| (b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account; | |
| (c) how the EDB takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and | |
| 17.5.2 how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity; | |
| 17.6 a description of the following: | |
| 17.6.1 any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials; | |
| 17.6.2 the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers; | |
| 17.6.3 how the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices; | |
| 17.6.4 how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and | |
| 17.6.5 the types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information. | |
| 17.7 For the purpose of disclosing the information required under clauses 17.6.1 – 17.6.5 above, an EDB is not required to include commercially sensitive or confidential information. | |

## Appendix 2: Schedule 11a - Report on Forecast Capital Expenditure

| | |
|---|---|
| *Company Name* | Electra Ltd |
| *AMP Planning Period* | 1 April 2023 – 31 March 2033 |

### 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* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | | | | | | | | | | | | |
| 8 | for year ended | **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** | **31 Mar 32** | **31 Mar 33** |
| 9 | **11a(i): Expenditure on Assets Forecast** | **$000 (in nominal dollars)** | | | | | | | | | | |
| 10 | Consumer connection | 400 | 443 | 456 | 470 | 484 | 499 | 514 | 529 | 545 | 561 | 578 |
| 11 | System growth | 100 | 2,410 | 3,142 | 2,493 | 4,980 | 6,538 | 6,540 | 7,916 | 8,477 | 7,285 | 7,505 |
| 12 | Asset replacement and renewal | 9,429 | 9,992 | 10,147 | 13,975 | 12,003 | 12,911 | 11,565 | 13,315 | 13,213 | 14,969 | 15,436 |
| 13 | Asset relocations | - | - | - | - | - | - | - | - | - | - | - |
| 14 | Reliability, safety and environment: | | | | | | | | | | | |
| 15 | Quality of supply | 2,575 | 4,122 | 4,357 | 3,825 | 6,347 | 5,546 | 5,532 | 5,011 | 5,218 | 5,005 | 5,157 |
| 16 | Legislative and regulatory | 650 | 559 | 628 | 424 | 382 | 675 | - | - | - | - | - |
| 17 | Other reliability, safety and environment | 620 | 755 | 435 | 448 | 688 | 346 | 270 | 278 | 286 | 295 | 304 |
| 18 | **Total reliability, safety and environment** | 3,845 | 5,436 | 5,420 | 4,698 | 7,417 | 6,567 | 5,801 | 5,288 | 5,504 | 5,300 | 5,461 |
| 19 | **Expenditure on network assets** | 13,774 | 18,280 | 19,165 | 21,636 | 24,884 | 26,515 | 24,420 | 27,048 | 27,739 | 28,114 | 28,980 |
| 20 | Expenditure on non-network assets | 3,229 | 6,820 | 9,112 | 5,747 | 1,930 | 1,283 | 2,510 | 1,272 | 1,414 | 1,463 | 1,507 |
| 21 | **Expenditure on assets** | 17,003 | 25,100 | 28,277 | 27,382 | 26,815 | 27,798 | 26,930 | 28,320 | 29,153 | 29,578 | 30,487 |
| 23 | *plus* Cost of financing | 90 | 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 |
| 27 | **Capital expenditure forecast** | 17,213 | 25,310 | 28,487 | 27,592 | 27,025 | 28,008 | 27,140 | 28,530 | 29,363 | 29,788 | 30,697 |
| 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 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** | **31 Mar 32** | **31 Mar 33** |
| 32 | | **$000 (in constant prices)** | | | | | | | | | | |
| 33 | Consumer connection | 400 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 | 443 |
| 34 | System growth | - | 2,410 | 3,050 | 2,350 | 4,557 | 5,809 | 5,641 | 6,629 | 6,892 | 5,750 | 5,752 |
| 35 | Asset replacement and renewal | 9,429 | 9,992 | 9,852 | 13,172 | 10,985 | 11,472 | 9,976 | 11,151 | 10,744 | 11,817 | 11,830 |
| 36 | Asset relocations | - | - | - | - | - | - | - | - | - | - | - |
| 37 | Reliability, safety and environment: | | | | | | | | | | | |
| 38 | Quality of supply | 2,575 | 4,122 | 4,230 | 3,606 | 5,808 | 4,927 | 4,772 | 4,196 | 4,243 | 3,951 | 3,952 |
| 39 | Legislative and regulatory | 650 | 559 | 610 | 400 | 350 | 600 | - | - | - | - | - |
| 40 | Other reliability, safety and environment | 620 | 755 | 422 | 422 | 629 | 308 | 233 | 233 | 233 | 233 | 233 |
| 41 | **Total reliability, safety and environment** | 3,845 | 5,436 | 5,262 | 4,428 | 6,788 | 5,835 | 5,004 | 4,429 | 4,475 | 4,184 | 4,185 |
| 42 | **Expenditure on network assets** | 13,674 | 18,280 | 18,607 | 20,394 | 22,773 | 23,558 | 21,065 | 22,652 | 22,554 | 22,194 | 22,211 |
| 43 | Expenditure on non-network assets | 3,229 | 6,820 | 8,847 | 5,417 | 1,767 | 1,140 | 2,165 | 1,065 | 1,150 | 1,155 | 1,155 |
| 44 | **Expenditure on assets** | 16,903 | 25,100 | 27,454 | 25,810 | 24,539 | 24,698 | 23,230 | 23,717 | 23,704 | 23,349 | 23,366 |
| 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 | | | | | | | | | | | | |

| | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 | CY+6 | CY+7 | CY+8 | CY+9 | CY+10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| for year ended | 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 | 31 Mar 32 | 31 Mar 33 |
| **Difference between nominal and constant price forecasts** | $000 | | | | | | | | | | |
| Consumer connection | - | - | 13 | 27 | 41 | 56 | 71 | 86 | 102 | 118 | 135 |
| System growth | 100 | - | 92 | 143 | 423 | 729 | 899 | 1,286 | 1,584 | 1,534 | 1,753 |
| Asset replacement and renewal | - | - | 296 | 802 | 1,019 | 1,440 | 1,589 | 2,164 | 2,470 | 3,152 | 3,606 |
| Asset relocations | - | - | - | - | - | - | - | - | - | - | - |
| Reliability, safety and environment: | | | | | | | | | | | |
| Quality of supply | - | - | 127 | 220 | 539 | 618 | 760 | 814 | 975 | 1,054 | 1,205 |
| Legislative and regulatory | - | - | 18 | 24 | 32 | 75 | - | - | - | - | - |
| Other reliability, safety and environment | - | - | 13 | 26 | 58 | 39 | 37 | 45 | 53 | 62 | 71 |
| **Total reliability, safety and environment** | - | - | 158 | 270 | 629 | 732 | 797 | 859 | 1,029 | 1,116 | 1,276 |
| **Expenditure on network assets** | 100 | - | 558 | 1,242 | 2,112 | 2,957 | 3,355 | 4,396 | 5,185 | 5,921 | 6,769 |
| Expenditure on non-network assets | - | - | 265 | 330 | 164 | 143 | 345 | 207 | 264 | 308 | 352 |
| **Expenditure on assets** | 100 | - | 824 | 1,572 | 2,275 | 3,100 | 3,700 | 4,602 | 5,449 | 6,229 | 7,121 |

## 11a(ii): Consumer Connection

| | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|
| for year ended | 31 Mar 23 | 31 Mar 24 | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 |
| *Consumer types defined by EDB** | $000 (in constant prices) | | | | | |
| All | 400 | 443 | 443 | 443 | 443 | 443 |
| [EDB consumer type] | | | | | | |
| [EDB consumer type] | | | | | | |
| [EDB consumer type] | | | | | | |
| **include additional rows if needed* | | | | | | |
| **Consumer connection expenditure** | 400 | 443 | 443 | 443 | 443 | 443 |
| *less* Capital contributions funding consumer connection | | | | | | |
| **Consumer connection less capital contributions** | 400 | 443 | 443 | 443 | 443 | 443 |

## 11a(iii): System Growth

| | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|
| Subtransmission | - | - | - | - | - | 554 |
| Zone substations | - | 250 | - | - | - | - |
| Distribution and LV lines | - | - | - | - | 617 | 639 |
| Distribution and LV cables | 100 | 2,160 | 3,050 | 2,350 | 3,323 | 3,977 |
| Distribution substations and transformers | - | - | - | - | 617 | 639 |
| Distribution switchgear | - | - | - | - | - | - |
| Other network assets | - | - | - | - | - | - |
| **System growth expenditure** | 100 | 2,410 | 3,050 | 2,350 | 4,557 | 5,809 |
| *less* Capital contributions funding system growth | | | | | | |
| **System growth less capital contributions** | 100 | 2,410 | 3,050 | 2,350 | 4,557 | 5,809 |

## 11a(iv): Asset Replacement and Renewal

| | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|
| for year ended | 31 Mar 23 | 31 Mar 24 | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 |
| | $000 (in constant prices) | | | | | |
| Subtransmission | 590 | 654 | 875 | 2,205 | 2,205 | 2,205 |
| Zone substations | 1,710 | 2,765 | 2,475 | 3,751 | 150 | 150 |
| Distribution and LV lines | 4,967 | 3,950 | 3,628 | 4,427 | 5,020 | 5,541 |
| Distribution and LV cables | 580 | 787 | 724 | 724 | 1,236 | 1,168 |
| Distribution substations and transformers | 787 | 927 | 1,109 | 1,109 | 1,417 | 1,428 |
| Distribution switchgear | 130 | 177 | 237 | 237 | 237 | 259 |
| Other network assets | 665 | 731 | 803 | 720 | 720 | 720 |
| **Asset replacement and renewal expenditure** | 9,429 | 9,992 | 9,852 | 13,172 | 10,985 | 11,472 |
| *less* Capital contributions funding asset replacement and renewal | | | | | | |
| **Asset replacement and renewal less capital contributions** | 9,429 | 9,992 | 9,852 | 13,172 | 10,985 | 11,472 |

## 11a(v): Asset Relocations

| | for year ended | Current Year CY<br>31 Mar 23 | CY+1<br>31 Mar 24 | CY+2<br>31 Mar 25 | CY+3<br>31 Mar 26 | CY+4<br>31 Mar 27 | CY+5<br>31 Mar 28 |
|---|---|---|---|---|---|---|---|
| *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

| | for year ended | Current Year CY<br>31 Mar 23 | CY+1<br>31 Mar 24 | CY+2<br>31 Mar 25 | CY+3<br>31 Mar 26 | CY+4<br>31 Mar 27 | CY+5<br>31 Mar 28 |
|---|---|---|---|---|---|---|---|
| *Project or programme** | | **$000 (in constant prices)** | | | | | |
| Protection Work | | 650 | 1,502 | 804 | 915 | 554 | 665 |
| Improving Network Interconnectivity | | 405 | 665 | 1,521 | 286 | 1,467 | 652 |
| Network Automation and Sectionalisation | | 860 | 1,361 | 1,361 | 1,861 | 1,361 | 1,361 |
| Fault Locator | | 290 | 344 | 294 | 294 | 119 | 119 |
| Condition Monitoring | | 370 | 250 | 250 | 250 | 250 | - |
| Decarbonisation impact | | - | - | - | - | 2,057 | 2,130 |
| **include additional rows if needed* | | | | | | | |
| All other projects or programmes - quality of supply | | | | | | | |
| **Quality of supply expenditure** | | 2,575 | 4,122 | 4,230 | 3,606 | 5,808 | 4,927 |
| *less* Capital contributions funding quality of supply | | | | | | | |
| **Quality of supply less capital contributions** | | 2,575 | 4,122 | 4,230 | 3,606 | 5,808 | 4,927 |

## 11a(vii): Legislative and Regulatory

| | for year ended | Current Year CY<br>31 Mar 23 | CY+1<br>31 Mar 24 | CY+2<br>31 Mar 25 | CY+3<br>31 Mar 26 | CY+4<br>31 Mar 27 | CY+5<br>31 Mar 28 |
|---|---|---|---|---|---|---|---|
| *Project or programme** | | **$000 (in constant prices)** | | | | | |
| Seismic Strengthening | | 650 | 559 | 610 | 400 | 350 | 600 |
| [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** | | 650 | 559 | 610 | 400 | 350 | 600 |
| *less* Capital contributions funding legislative and regulatory | | | | | | | |
| **Legislative and regulatory less capital contributions** | | 650 | 559 | 610 | 400 | 350 | 600 |

| Row | | Current Year CY<br>31 Mar 23 | CY+1<br>31 Mar 24 | CY+2<br>31 Mar 25 | CY+3<br>31 Mar 26 | CY+4<br>31 Mar 27 | CY+5<br>31 Mar 28 |
|---|---|---|---|---|---|---|---|
| 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 | 277 | 222 | 222 | 139 | 122 |
| 155 | Replacement of Deck Transformers | - | 111 | - | - | - | - |
| 156 | Replacement of Pitchfilled Potheads | 90 | 90 | 90 | 90 | 75 | 75 |
| 157 | Steel Link Pillar Removal | 205 | 277 | 111 | 111 | 111 | 111 |
| 158 | **include additional rows if needed* | | | | | | |
| 159 | All other projects or programmes - other reliability, safety and environment | | | | | | |
| 160 | **Other reliability, safety and environment expenditure** | 620 | 755 | 422 | 422 | 629 | 308 |
| 161 | *less* Capital contributions funding other reliability, safety and environment | | | | | | |
| 162 | **Other reliability, safety and environment less capital contributions** | 620 | 755 | 422 | 422 | 629 | 308 |
| 163 | | | | | | | |

| Row | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|
| 164 | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
| 165 | for year ended | 31 Mar 23 | 31 Mar 24 | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 |
| 166 | **11a(ix): Non-Network Assets** | | | | | | |
| 167 | **Routine expenditure** | | | | | | |
| 168 | *Project or programme** | $000 (in constant prices) | | | | | |
| 169 | Office buildings, depots & workshops | 245 | 4,245 | 4,235 | 2,130 | 80 | 85 |
| 170 | Office furniture, fittings and equipment incl. PPE | 50 | 25 | 25 | 25 | 25 | 25 |
| 171 | Tools, plant & other machinery | 420 | 520 | 350 | 350 | 350 | 350 |
| 172 | Motor Vehicles | - | 600 | 1,067 | 1,067 | 467 | - |
| 173 | ICT | 1,969 | 995 | 935 | 560 | 560 | 475 |
| 174 | IoT | 545 | 435 | 2,235 | 1,285 | 285 | 205 |
| 175 | **include additional rows if needed* | | | | | | |
| 176 | All other projects or programmes - routine expenditure | | | | | | |
| 177 | **Routine expenditure** | 3,229 | 6,820 | 8,847 | 5,417 | 1,767 | 1,140 |
| 178 | **Atypical expenditure** | | | | | | |
| 179 | *Project or programme** | | | | | | |
| 180 | Included above | | | | | | |
| 181 | | | | | | | |
| 183 | | | | | | | |
| 184 | | | | | | | |
| 185 | | | | | | | |
| 186 | **include additional rows if needed* | | | | | | |
| 187 | All other projects or programmes - atypical expenditure | | | | | | |
| 188 | **Atypical expenditure** | - | - | - | - | - | - |
| 189 | | | | | | | |
| 190 | **Expenditure on non-network assets** | 3,229 | 6,820 | 8,847 | 5,417 | 1,767 | 1,140 |

## Appendix 3: Schedule 11b - Report on Forecast Operational Expenditure

Company Name: Electra Ltd
AMP Planning Period: 1 April 2023 – 31 March 2033

### 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 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 | 31 Mar 32 | 31 Mar 33 |
| 9 | **Operational Expenditure Forecast** | **$000 (in nominal dollars)** | | | | | | | | | | |
| 10 | Service interruptions and emergencies | 1,973 | 2,186 | 2,265 | 2,272 | 2,340 | 2,410 | 2,444 | 2,518 | 2,593 | 2,671 | 2,751 |
| 11 | Vegetation management | 1,610 | 1,784 | 1,837 | 1,893 | 1,949 | 1,896 | 1,952 | 2,011 | 2,071 | 2,133 | 2,197 |
| 12 | Routine and corrective maintenance and inspection | 1,533 | 1,969 | 1,915 | 1,973 | 1,885 | 1,941 | 1,792 | 1,773 | 1,826 | 1,880 | 1,937 |
| 13 | Asset replacement and renewal | 555 | 565 | 582 | 599 | 2,606 | 2,855 | 3,193 | 3,364 | 3,566 | 3,776 | 3,996 |
| 14 | **Network Opex** | 5,671 | 6,504 | 6,600 | 6,737 | 8,780 | 9,102 | 9,381 | 9,666 | 10,056 | 10,461 | 10,881 |
| 15 | System operations and network support | 7,546 | 8,857 | 9,242 | 9,527 | 9,813 | 10,108 | 10,411 | 10,723 | 11,045 | 11,376 | 11,717 |
| 16 | Business support | 5,543 | 5,334 | 5,903 | 6,471 | 6,665 | 6,865 | 7,071 | 7,283 | 7,501 | 7,726 | 7,958 |
| 17 | **Non-network opex** | 13,089 | 14,191 | 15,145 | 15,998 | 16,478 | 16,972 | 17,481 | 18,006 | 18,546 | 19,102 | 19,675 |
| 18 | **Operational expenditure** | 18,760 | 20,696 | 21,745 | 22,735 | 25,258 | 26,074 | 26,862 | 27,671 | 28,602 | 29,563 | 30,557 |
| 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 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 | 31 Mar 32 | 31 Mar 33 |
| 21 | | **$000 (in constant prices)** | | | | | | | | | | |
| 22 | Service interruptions and emergencies | 1,973 | 2,186 | 2,199 | 2,142 | 2,142 | 2,142 | 2,108 | 2,108 | 2,108 | 2,108 | 2,108 |
| 23 | Vegetation management | 1,610 | 1,784 | 1,784 | 1,784 | 1,784 | 1,684 | 1,684 | 1,684 | 1,684 | 1,684 | 1,684 |
| 24 | Routine and corrective maintenance and inspection | 1,533 | 1,969 | 1,859 | 1,859 | 1,725 | 1,725 | 1,545 | 1,484 | 1,484 | 1,484 | 1,484 |
| 25 | Asset replacement and renewal | 555 | 565 | 565 | 565 | 2,385 | 2,536 | 2,754 | 2,818 | 2,899 | 2,981 | 3,063 |
| 26 | **Network Opex** | 5,671 | 6,504 | 6,407 | 6,350 | 8,035 | 8,087 | 8,092 | 8,095 | 8,176 | 8,258 | 8,340 |
| 27 | System operations and network support | 7,546 | 8,558 | 8,652 | 8,660 | 8,660 | 8,660 | 8,660 | 8,660 | 8,660 | 8,660 | 8,660 |
| 28 | Business support | 5,543 | 5,154 | 5,527 | 5,881 | 5,881 | 5,881 | 5,881 | 5,881 | 5,881 | 5,881 | 5,881 |
| 29 | **Non-network opex** | 13,089 | 13,712 | 14,179 | 14,541 | 14,541 | 14,541 | 14,541 | 14,541 | 14,541 | 14,541 | 14,541 |
| 30 | **Operational expenditure** | 18,760 | 20,216 | 20,587 | 20,891 | 22,576 | 22,629 | 22,634 | 22,636 | 22,718 | 22,799 | 22,881 |
| 31 | **Subcomponents of operational expenditure (where known)** | | | | | | | | | | | |
| 32 | 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* | | | | | | | | | | | |
| 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 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 | 31 Mar 32 | 31 Mar 33 |
| 41 | **Difference between nominal and real forecasts** | **$000** | | | | | | | | | | |
| 42 | Service interruptions and emergencies | - | - | 66 | 130 | 199 | 269 | 336 | 409 | 485 | 562 | 643 |
| 43 | Vegetation management | - | - | 54 | 109 | 165 | 211 | 268 | 327 | 387 | 449 | 513 |
| 44 | Routine and corrective maintenance and inspection | - | - | 56 | 113 | 160 | 216 | 246 | 288 | 341 | 396 | 452 |
| 45 | Asset replacement and renewal | - | - | 17 | 34 | 221 | 318 | 439 | 547 | 666 | 795 | 933 |
| 46 | **Network Opex** | - | - | 192 | 387 | 745 | 1,015 | 1,289 | 1,571 | 1,880 | 2,203 | 2,542 |
| 47 | System operations and network support | - | 300 | 589 | 867 | 1,153 | 1,448 | 1,751 | 2,063 | 2,385 | 2,716 | 3,057 |
| 48 | Business support | - | 180 | 376 | 589 | 783 | 983 | 1,189 | 1,401 | 1,620 | 1,845 | 2,077 |
| 49 | **Non-network opex** | - | 480 | 966 | 1,457 | 1,936 | 2,431 | 2,940 | 3,464 | 4,005 | 4,561 | 5,134 |
| 50 | **Operational expenditure** | - | 480 | 1,158 | 1,843 | 2,682 | 3,446 | 4,229 | 5,035 | 5,884 | 6,764 | 7,676 |

## 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,

| sch ref | | | | | Asset condition at start of planning period (percentage of units by grade) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Voltage | Asset category | Asset class | Units | H1 | H2 | H3 | H4 | H5 | Grade unknown | Data accuracy (1–4) | % of asset forecast to be replaced in next 5 years |
| 10 | All | Overhead Line | Concrete poles / steel structure | No. | | | 2.30% | 92.70% | 5.00% | | 3 | 2.50% |
| 11 | All | Overhead Line | Wood poles | No. | | | 40.00% | 60.00% | | - | 2 | 45.00% |
| 12 | All | Overhead Line | Other pole types | No. | | | | | | | N/A | |
| 13 | HV | Subtransmission Line | Subtransmission OH up to 66kV conductor | km | | | 9.50% | 87.90% | 2.60% | | 4 | 10.00% |
| 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. | | | | 90.00% | 10.00% | | 4 | - |
| 28 | HV | Zone substation switchgear | 33kV Switch (Ground Mounted) | No. | | | | | | | N/A | |
| 29 | HV | Zone substation switchgear | 33kV Switch (Pole Mounted) | No. | | | 75.50% | 15.00% | 9.50% | | 3 | - |
| 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. | | | | 89.50% | 10.50% | | 4 | 10.52% |
| 40 | HV | Distribution Line | Distribution OH Open Wire Conductor | km | | | 7.00% | 83.40% | 9.60% | | 3 | 7.20% |
| 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 | | - | | 91.20% | 8.80% | | 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% | 77.50% | 20.00% | | 4 | 2.50% |
| 47 | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (Indoor) | No. | | | 5.12% | 76.88% | 18.00% | | 4 | 5.20% |
| 48 | HV | Distribution switchgear | 3.3/6.6/11/22kV Switches and fuses (pole mounted) | No. | | | 3.50% | 90.50% | 6.00% | | 3 | 4.50% |
| 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. | | | 6.00% | 88.50% | 5.50% | | 3 | 6.50% |
| 51 | HV | Distribution Transformer | Pole Mounted Transformer | No. | | | 4.00% | 74.00% | 22.00% | | 4 | 5.00% |
| 52 | HV | Distribution Transformer | Ground Mounted Transformer | No. | | | 4.00% | 55.00% | 41.00% | | 4 | 4.00% |
| 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 | | | 4.00% | - | 2.30% | 93.70% | 2 | 4.00% |
| 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. | | 2.00% | 18.00% | 3.50% | 74.00% | | 3 | 24.00% |
| 59 | All | Protection | Protection relays (electromechanical, solid state and numeric) | No. | | | 10.00% | 55.00% | 35.00% | | 4 | 15.00% |
| 60 | All | SCADA and communications | SCADA and communications equipment operating as a single syste | 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 2023 – 31 March 2033**

### 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 | 5.3 | 5 | N-1 | 6 | 105% | 5 | 109% | Other | Load managed by feeder reconfiguration and transfer to other zone feeders. |
| 10 | Foxton | 7.3 | 23 | N-1 | 4 | 32% | 23 | 39% | No constraint within +5 years | |
| 11 | Levin West | 14.0 | 23 | N-1 | 12 | 61% | 23 | 69% | No constraint within +5 years | |
| 12 | Levin East | 15.4 | 23 | N-1 | 12 | 67% | 23 | 76% | No constraint within +5 years | |
| 13 | Otaki | 13.2 | 23 | N-1 | 4 | 57% | 23 | 67% | No constraint within +5 years | |
| 14 | Waikanae | 17.0 | 23 | N-1 | 12 | 74% | 23 | 85% | No constraint within +5 years | |
| 15 | Paraparaumu East* | 13.7 | 23 | N-1 | 16 | 60% | 23 | 69% | No constraint within +5 years | |
| 16 | Paraparaumu West | 13.1 | 23 | N-1 | 8 | 57% | 23 | 66% | No constraint within +5 years | |
| 17 | Raumati | 10.3 | 23 | N-1 | 12 | 45% | 23 | 51% | No constraint within +5 years | |
| 18 | Paekakariki | 3.1 | - | 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*

* Paraparaumu renamed to Paraparaumu East

## Appendix 6: Schedule 12c – Report on Forecast Network Demand

Company Name: Electra Ltd
AMP Planning Period: 1 April 2023 – 31 March 2033

### SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

| sch ref | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|
| 7 | **12c(i): Consumer Connections** | | | | | | |
| 8 | *Number of ICPs connected 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 23 | 31 Mar 24 | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 |
| 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 | 120 | 130 | 140 | 150 | 160 | 170 |
| 21 | Capacity of distributed generation installed in year (MVA) | 0.6 | 0.6 | 0.6 | 0.6 | 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 23 | 31 Mar 24 | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 |
| 25 | GXP demand | 81 | 82 | 86 | 88 | 90 | 92 |
| 26 | *plus* Distributed generation output at HV and above | 26 | 27 | 27 | 27 | 27 | 27 |
| 27 | **Maximum coincident system demand** | 108 | 109 | 113 | 115 | 117 | 119 |
| 28 | *less* Net transfers to (from) other EDBs at HV and above | | | | | | |
| 29 | **Demand on system for supply to consumers' connection points** | 108 | 109 | 113 | 115 | 117 | 119 |
| 30 | **Electricity volumes carried (GWh)** | | | | | | |
| 31 | Electricity supplied from GXPs | 403 | 407 | 411 | 416 | 419 | 423 |
| 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** | 464 | 469 | 473 | 478 | 482 | 486 |
| 36 | *less* Total energy delivered to ICPs | 429 | 434 | 438 | 442 | 447 | 451 |
| 37 | **Losses** | 35 | 35 | 35 | 35 | 35 | 36 |
| 38 | | | | | | | |
| 39 | **Load factor** | 49% | 49% | 48% | 47% | 47% | 47% |
| 40 | **Loss ratio** | 7.6% | 7.5% | 7.4% | 7.4% | 7.3% | 7.3% |

## Appendix 7: Schedule 12d – Report Forecast Interruptions and Duration

| | |
|---|---|
| *Company Name* | Electra Ltd |
| *AMP Planning Period* | 1 April 2023 – 31 March 2033 |
| *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* |
|---|---|---|---|---|---|---|---|
| *8* | | | | | | | |
| *9* | for year ended | **31 Mar 23** | **31 Mar 24** | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** | **31 Mar 28** |
| *10* | **SAIDI** | | | | | | |
| *11* | Class B (planned interruptions on the network) | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| *12* | Class C (unplanned interruptions on the network) | 63.0 | 63.0 | 63.0 | 63.0 | 63.0 | 63.0 |
| *13* | **SAIFI** | | | | | | |
| *14* | Class B (planned interruptions on the network) | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| *15* | Class C (unplanned interruptions on the network) | 1.58 | 1.58 | 1.58 | 1.58 | 1.58 | 1.58 |

## Appendix 8: Schedule 13 – Report on Asset Management Maturity

| | |
|---|---|
| *Company Name* | Electra Ltd |
| *AMP Planning Period* | 1 April 2023 – 31 March 2033 |
| *Asset Management Standard Applied* | ISO 55000 |

**SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY**

This schedule requires information on the EDB'S self-assessment of the maturity

| Question No. | Function | Question | Score | Evidence—Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 3 | Asset management policy | To what extent has an asset management policy been documented, authorised and communicated? | 2.5 | A specific Asset Management Policy was prepared and signed off by the Board of Directors in the 2012/13 year. It has been included as part of both the Network and Group Strategic Plans.Electra's Strategic Plan was examined,it embodies good line-of-sight, and includes SWOT and PESTLE analyses. | 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 | The strategic plan and the AMP clearly embody a cohesive set of strategies that link to the goal areas. | 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 | Top management. The organisation's strategic planning team. The management team that has overall | The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, |
| 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 | The strategy for each asset class described in Chapter 6 of the AMP explicitly considers condition, age and systemic issues. Refer to Q26 below. | 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 | 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 | Chapter 6 of the AMP clearly shows that the condition and life cycle of major asset classes are considered. There is direct line-of-sight from the asset age and condition to the policies, the management tactics and the resulting work program. | 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 | The organisation's asset management plan(s). |

| | |
|---|---|
| *Company Name* | Electra Ltd |
| *AMP Planning Period* | 1 April 2023 – 31 March 2033 |
| *Asset Management Standard Applied* | ISO 55000 |

**SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)**

| Question No. | Function | Question | Score | Evidence—Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 27 | Asset management plan(s) | How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery? | 2.7 | | 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 | Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication. |
| 29 | Asset management plan(s) | How are designated responsibilities for delivery of asset plan actions documented? | 2.5 | Chapter 1.10 of the AMP documents the responsibilities for AM. | 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 | 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<br><br>(Note this is about resources and enabling support) | 2.7 | Refer to Q40 also. | 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 | The management team with overall responsibility for the asset management system. Operations, maintenance and | 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 | 2.5 | Electra has various guidelines for Escalation Of Events and Major Network Events that define escalation actions, key roles and communication requirements. Evidence of supply restoration after the November 2016 earthquake was examined, noting repairs. | 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 | The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. | The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers. |

| | |
|---|---|
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**SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)**

| Question No. | Function | Question | Score | Evidence—Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 37 | Structure, authority and responsibilities | What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset | 3 | Chapter 1.10 of the AMP shows the current structure, demonstrating alignment to the asset life cycle. | 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 | Top management. People with management responsibility for the delivery of asset management policy, | Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their |
| 40 | Structure, authority and responsibilities | What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management? | 3 | A sucession planning model and a talent matrix were examined (HRs database), however this stops short of a specific numbers of each staff category required over the timeframe.For asset mangagemnt work a process is established and followed by | 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 | Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate |
| 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 | There is a fortnightly Progress To Plan meeting to ensure that works are completed to target. There is also a monthly Lines business unit meeting that includes field staff that deals with operational issues (eg. issuing of latest schematics), safety, quality and some works | 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 | 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 |
| 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 | 2.3 | The Undergound Line Construction Standard was examined. | 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 | Top management. The management team that has overall responsibility for asset management. The manager(s) | 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 |

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**SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)**

| Question No. | Function | Question | Score | Evidence—Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 48 | Training, awareness and competence | How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management | 3 | KPA Review documents for the Contract Supervisor and for the Field Staff were inspected. These clearly link performance requirements to Electra's values and specific competency requirements. The documents inspected were drafts, and show evidence of | 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 | Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy | 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 |
| 49 | Training, awareness and competence | How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies? | 2.5 | The Competency Framework (on HR's database) was inspected. | 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 | Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy | Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the |
| 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, | 2.5 | Refer to Q48. The KPA Review documents for the Contract Supervisor and for the Field Staff inspected clearly link performance requirements to Electra's values and specific job competencies, and then assess actual performance against those values and | 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 | Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and | Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework |

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**SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)**

| Question No. | Function | Question | Score | Evidence—Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 53 | Communication, participation and consultation | How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers? | 2 | Refer to Q42. This meeting ensures that the importance of the works program staying on time and on budget is clearly emphasised. Operational "red flag" issues are communicated to all staff and contractors via a Network Group Advisory Notice (NGAN #64 was inspected, and demonstrated a high level of document control) | 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 | Top management and senior management representative(s), employee's representative(s), employee's trade union 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 |
| 59 | Asset Management System documentation | What documentation has the organisation established to describe the main elements of its asset management system and interactions between them? | 2.5 | A lean process forum has been undertaken with all relavent employees to outline existing AM procedures and highlight areas of possible improvement. This has produced streamlined future state processes that Electra is currently working towards | 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 | The management team that has overall responsibility for asset management. Managers engaged in asset management | 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 | In regard to critical or dangerous situations, Network Group Advisory Notice #64A advising of potentially dangerous substation, and NGAN #64B advising of remediation were inspected. In conjunction with Q59, areas of interest have been highlighted through the | Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the<br><br>The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT | The organisation's strategic planning team. The management team that has overall responsibility for | 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. |
| 63 | Information management | How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent? | 2 | A Data Quality report has been created to identify, categorise and prioritise missing or incorrect asset information. Information is corrected or populated according to its priority or operational impact. | The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale.<br><br>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. |

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**SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)**

| Question No. | Function | Question | Score | Evidence—Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 64 | Information management | How has the organisation's ensured its asset management information system is relevant to its needs? | 2.5 | Electra is currently implementing an Enterprise Asset Management (EAM) software package to capture all relavent asset information is avaliable from a single source. See Q59 for information about highlighting of relavent information. | 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 | The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of |
| 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 PSMS Policy was examined, and it is noted that this policy references a wide range of policies aimed at ensuring conformance and minimising risks at the design, construction, commissioning and operating phases of the asset life cycle. The PSMS Internal Audit and | 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 | The top management team in conjunction with the organisation's senior risk management representatives. There | The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. |
| 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 | The TELARC Revalidation of January 2019 included an assessment of 2 contractors skills and competencies, and noted that Electra has also performed further contractor competency audits. | 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). | The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able |
| 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 | 3.1 | Electra uses Comply With to maximise its legal and regulatory compliance. Electra completed 2018 Comply With survey with wider scope and tighter compliance. | In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are | Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team | The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is |

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**SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)**

| Question No. | Function | Question | Score | Evidence—Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 88 | Life Cycle Activities | How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, | 2.6 | Electra has Standards for design and construction of works to minimise non-conformance. A wide range of operating policies ensure compliant operation.Electra's standards closely follow the Powerco standards to help lower costs for suppliers, | 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 | Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. | Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, |
| 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 | 2.6 | The Underground Line Construction Standard was examined. | 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 | Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the | Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation |
| 95 | Performance and condition monitoring | How does the organisation measure the performance and condition of its assets? | 2.5 | The first step in managing asset performance is through the use of design and construction standards, material specifications and auditing of completed works. Electra is actively installing new monitoring equipment to existing assets to better understand fleet | 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 | A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision- | Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring |
| 99 | Investigation of asset-related failures, incidents and nonconformities | How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances | 2.5 | NGAN's 64A and 64B (Totara St transformer station safety issue) were examined. The Process For Investigation Of Network Incidents Involving Public Safety was examined. Use of the incident reporting platform Vault has lead to chains of responsibility for reporting and | 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 | The organisation's safety and environment management team. The team with overall responsibility for the | Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. |

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## SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

| Question No. | Function | Question | Score | Evidence—Summary | Why | Who | Record/documented Information |
|---|---|---|---|---|---|---|---|
| 105 | Audit | What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))? | 2.3 | The PSMS Internal Audit and the TELARC Revalidation have been inspected. The AMMAT was refreshed in January 2017. Various consultants have been engaged to assess various aspects of Electra's AM activity, and recommend improvements. | 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 | 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 |
| 109 | Corrective & Preventative action | How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance? | 2 | The Undergound Line Construction Standard was examined. The Process For Investigation Of Network Incidents Involving Public Safety from the PSMS was examined. | 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 | The management team responsible for its asset management procedure(s). The team with overall responsibility for the | Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement |
| 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 | 2.3 | The memo from GM Lines Business in December 2016 includes a commitment to investigate several safety, reliability and resiliance improvements within the existing cost base. | 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 | The top management of the organisation. The manager/team responsible for managing the organisation's asset | Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) |
| 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 | Presence of external contractors was noted on various occassions. Attendance of Electra staff at industry events has been observed. Comparative analysis work was examined. | One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all | The top management of the organisation. The manager/team responsible for managing the organisation's asset | Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence |

Company Name: Electra Limited
For Year Ended 31 March 2023

**Schedule 14a Mandatory Explanatory Notes on Forecast Information**

**In this Schedule, clause references are to the Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022 –**

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

   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)*

1. 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)*

2. 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.

**CERTIFICATION FOR YEAR-BEGINNING DISCLOSURE - ASSET MANAGEMENT PLAN CLAUSE 2.9.1**

We, Shelly Anne Mitchell-Jenkins and Stephen Robert Armstrong, 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** **Date** 24/2/23

**Stephen Robert Armstrong - Director** **Date** 24/2/23.

## 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 |
| CBARMM | Condition-Based Asset Risk Management Model (CBARMM) |
| CBD | Central Business District |
| $CO_2e$ | Represents an amount of a greenhouse gas (GHG) whose atmospheric impact has been standardized to that of one unit mass of carbon dioxide ($CO_2$), based on the global warming potential (GWP) of the gas. |
| 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 |
| DERMS | Distributed Energy Resource Management System |
| 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. |

| Term | Description |
|---|---|
| High voltage | Voltage exceeding 1,000 volts, generally 11,000 volts (known as 11kV) |
| HILP | High Impact Low Probability |
| 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 |
| $MtCO_2e$ | Abbreviation of a million tonnes of carbon dioxide equivalent (see also $CO_2e$) |
| MVA | megavolt amp |
| MW | megawatt |
| MWh | megawatt hour (one million watt hour) |
| N-1 Security | A load is said to have N-1 security if for the loss of any one item of equipment supply to that load is not interrupted or can be restored in the time taken to switch to alternate supplies. |
| NIMs | A Network Information Management System which contains geospatial information for all assets including asset description, location, age, electrical attributes, etc. |
| OC | Overcurrent |
| OCPI | Open charge point interphase |
| OCPP | Open charge point protocol |
| ODRC | Optimised Depreciated Replacement Cost. |
| ODV | Optimised Deprival Value. |
| ONAF | Oil Natural Air Forced |
| ONAN | Oil Natural Air Natural |
| OPEX | Operational Expenditure an ongoing expense for running a business e.g. rent, power. wages |
| OT | Operations technology, which means digital technology used for process control, protection of machinery and assurance of product quality |
| PILC | Paper-insulated, lead-covered - a type of cable insulation. |
| PPM | Parts per million |
| 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. |
| RS | Relative saturation |

| Term | Description |
|---|---|
| RTU | Remote Terminal Unit |
| SAIDI | System Average Interruption Duration Index is the average total duration of interruptions per connected customer |
| SAIFI | System Average Interruption Frequency Index is the average number of interruptions per connected customers |
| SCADA | Electra's computerized System Control and Data Acquisition System being the primary tool for monitoring and controlling access and switching operations for Electra's Network. |
| SCI | Statement of Corporate Intent |
| 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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