ASSET MANAGEMENT PLAN UPDATE

2022/2032

CONTENTS

MESSAGE FROM THE CHIEF EXECUTIVE

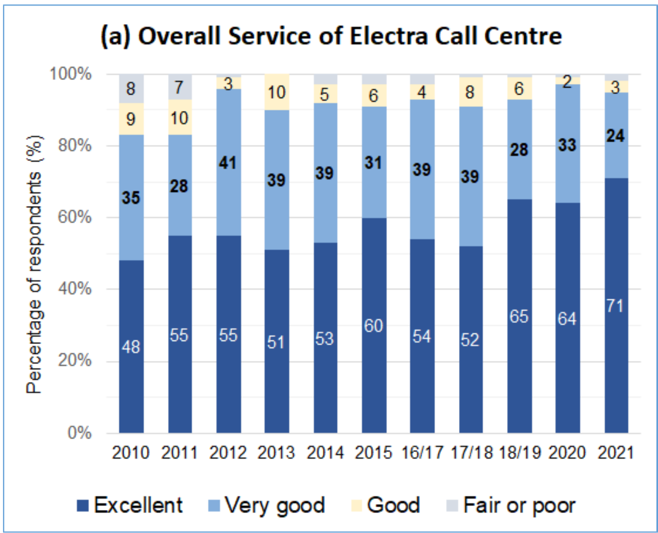
It gives me great pleasure to present Electra's Asset Management Plan (AMP) Update for 2022 to 2032. This AMP Update is a companion to our comprehensive Asset Management Plan published in March 2021.

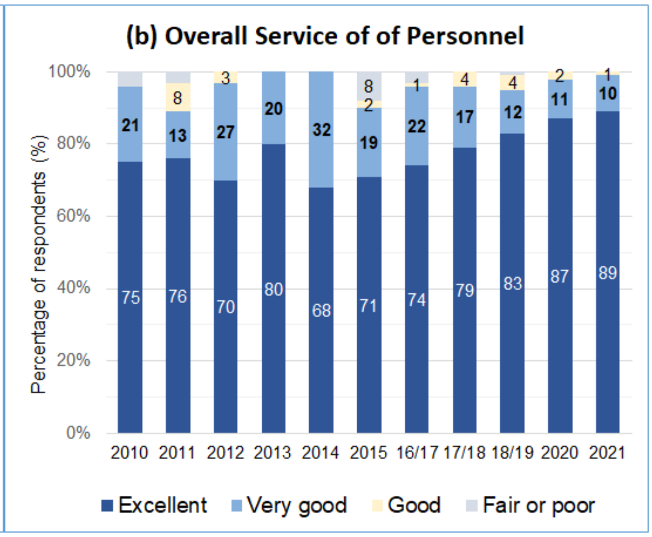
Despite the challenges that the pandemic has presented, Electra has responded well by adapting work practices to safely deliver the essential services and AMP programme.

Electra has made excellent progress on the delivery of the focus areas identified in the previous year 2021 Asset Management Plan (AMP) and Electra Group Strategic goals with the focus on improved customer service, initiatives to reach the zero-harm target and maintain our mix of high reliability and cost-conscious operation.

- **Strategic Objective: Focus on Customers**

It is pleasing to note that the 2021 customer survey has reported the highest level of satisfaction achieved by both the Call Centre and our service personnel over the past ten years as shown in the following graphs. I expect this reflects our focus on communication with our customers, investment in outage systems and staff development programmes.





During the year, Electra worked with the Electricity Authority, Commerce Commission, MBIE and electricity retailers in the creation of the Consumer Care Guidelines to ensure that safeguards are in place for vulnerable customers' access to electricity. Electra was one of only four Distributors to participate in the process, as 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 the Electra Board of Directors. This has been made possible by a comprehensive training programme to develop our workforce with increased competencies and career pathways to reflect and promote our values: Safe, Professional, Accountable, Integrity, and Respect.

- **Strategic Objective: High Reliability and cost-conscious operation**

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

This analysis concludes the following:

Measure for period from financial years 2017 to 2021	Position within peer group	Position within overall industry
Line charges/costs per customer	Best (lowest)	Best (lowest)
OPEX per customer	Best (lowest)	Within lowest quartile (rank 6th)
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)	Within lowest quartile (rank 2nd)

- **Huringa Pūngao Energy Transformation initiative**

The Energy Transformation Roadmap or Huringa Pūngao initiative launched in July 2021 will ensure that Electra has a pathway to build the necessary capability and capacity to support New Zealand's decarbonisation efforts. By pursuing the roadmap, I am confident that Electra should be well on the way to demonstrating that it can be a competent distribution network operator and be fully engaged in facilitating consumers and other network users such as grid scale solar, to connect and trade across its network.

- **Mahi Tahi initiative**

Electra's new Enterprise Asset Management system was launched in June 2021 where The Asset Guardian or TAG was selected as the most appropriate solution - with the best fit for Electra based on company size, the ease of implementation and adoption from a change management perspective as well as the stage of our asset maturity journey. With the adoption of TAG, Electra has launched the Mahi Tahi programme, to "co-operate, teamwork, collaborate" – bringing together all business areas with the vision "to connect and empower people to one Electra enabled by industry leading technology" transforming the business by improving operational efficiency and excellence.

Mahi Tahi will deliver a world class technology solution to our business. By sharing more accurate and timely information across our business ('one source of truth') and streamlining our processes and tasks, we can focus on providing better experiences for our customers. Mahi Tahi will ultimately make our work more enjoyable by removing bottlenecks and eliminating manual rework and work arounds, allowing Electra to focus on the meaningful services that make a difference to the customers we serve.

OUTLOOK

Major infrastructure projects such as the Kāpiti Expressway and Transmission Gully roading projects continue to stimulate regional growth and create economic opportunities. Having lagged Kāpiti for several years, the Horowhenua region is beginning to emerge as a strong performer with most economic indicators outperforming the national average in the year ended 31 December 2020.

The combination of affordability, location, and government investment in roading to the greater Wellington region is making the Kāpiti and Horowhenua region an attractive place to live, work and play. The maximum coincident winter demand recorded in June 2021 was 107.4 MW, the highest increase of 3.3% as compared to previous years' increase at about 3% annually.

Based on the Huringa Pūngao Energy Transformation report, there are two scenarios for future uncontrolled and controlled demand and the low and high demand forecasts are 1.4% and 2.6% respectively. Scenario analysis evaluates the network impact of electrification to consider the risks and benefits to the network.

With significant regional growth, these are exciting times for Electra as we prepare for Huringa Pūngao or Energy Transformation trials coupled with DER initiatives and cost reflective pricing. Alternatives to poles and wires are being considered. Access to low voltage data remains a necessity with TAG/ERP implementation for better planning and operational efficiency. Challenges that persist are access to low voltage data, accessing talent and rising costs. Climate change, regulatory changes and ongoing economic impact of Covid-19 are all significant considerations that have been highlighted in the Risk Management Section. These risks are managed in the company risk register, alongside traditional non-network risks such as cyber dangers, seismic threats and terrorism.

Key work streams going forward follow:

- Implement the improvement initiatives identified through detailed audit, to align Electra's policies, processes, and practises with ISO 55000 asset management framework. This will be a multiyear strategic project. EAM system implementation (Mahi Tahi project) is one of the first steps identified per the roadmap of improvements.
- Implement Mahi Tahi process improvement based on the lean methodology to align business to ISO 55000 practices for improved asset management maturity.
- Implement Huringa Pūngao Electricity Transformation Roadmap to guide the company response to the challenges and opportunities of the electrification of transport sector.
- Continue to improve performance, manage risk and optimise costs, with a view to improve customer experience.
- Implement strategy for transition to a transactive network while maintaining watching brief on DERMS and participation in industry working groups
- Enhancing evidence-based investment decisions with risk and criticality dimensions to quantify and prioritise investments
- Enhancing and supporting sustainability, climate change and renewables initiatives.

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

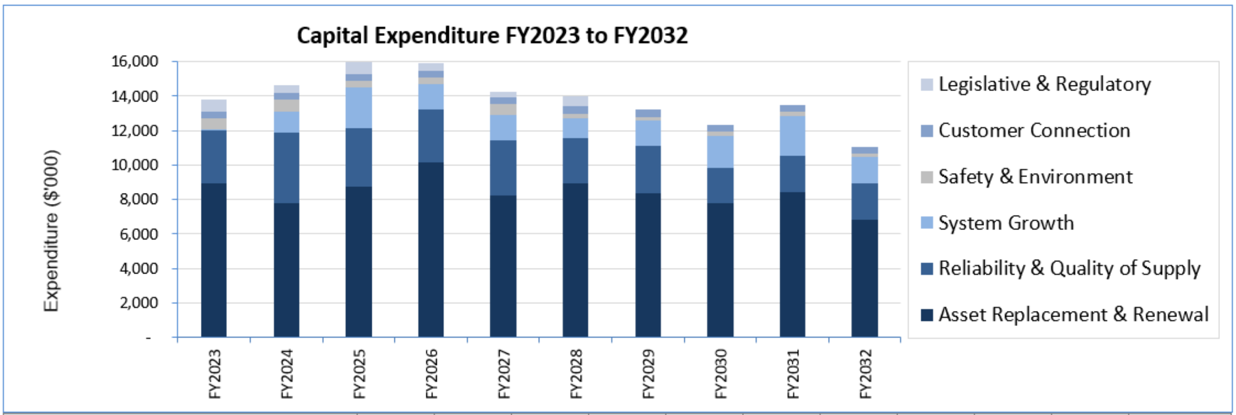
MATERIAL PROJECTS

In deriving the programmes for network development, system growth and renewal (Section 3), Electra optimises expenditure to consider demand growth, existing network conditions and capacity, customer input and service levels for reliability, quality, and safety. The significant programmes for the planning period include the following projects:

PROGRAMME	MAIN DRIVER	PROPOSED TIMING
NETWORK PROJECTS		
Automation of 11kV Ground-mounted switchgear	Quality	FY2023-FY2032
Foxton-Levin West 33kV Aluminium to Butterfly upgrade	Growth	FY2028-FY2030
Foxton-Shannon Road 11kV upgrade to Aluminium	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 and 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
NETWORK PROJECTS		
ISO 550000 - Mahi Tahi Strategic Process Improvement		
Huringa Pūngao Electricity Transformation Roadmap		

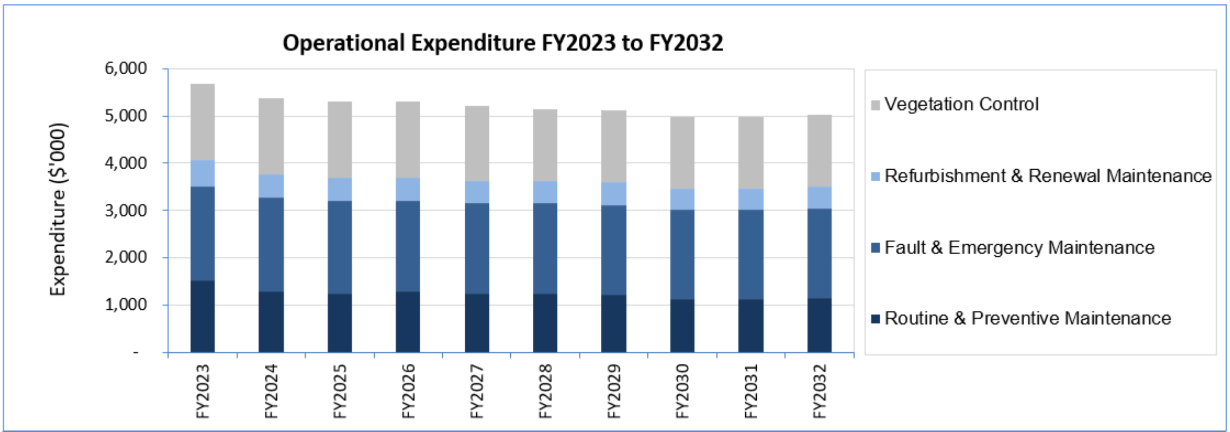
FORECAST EXPENDITURE

Projected capital expenditure drivers over the next 10 years are expected to be 61% for renewal and replacement work, 20% for reliability or supply quality, 11% for system growth and 8% for legislative, safety and environmental requirements. Capital costs (depicted in Figure A) are expected to average $13.9M per year over the next 10 years while operational costs (Figure B) are expected to average $5.2M per year over the same period. Electra has the flexibility to adjust this investment if growth accelerates beyond our expectations. The expenditure forecasts are based on 2021 constant New Zealand dollars.



Capital Expenditure (Current $'000)	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	*Average %*
Asset Replacement & Renewal	8,929	7,772	8,753	10,171	8,268	8,961	8,396	7,766	8,416	6,852	*61%*
Reliability & Quality of Supply	3,075	4,100	3,380	3,055	3,150	2,625	2,705	2,055	2,105	2,105	*20%*
System Growth	100	1,250	2,350	1,470	1,500	1,125	1,500	1,900	2,350	1,500	*11%*
Safety & Environment	620	690	390	390	605	285	210	210	210	210	*3%*
Customer Connection	400	400	400	400	400	400	400	400	400	400	*3%*
Legislative & Regulatory	650	450	700	400	350	600	-	-	-	-	*2%*
Total (CAPEX) :	**13,774**	**14,662**	**15,973**	**15,886**	**14,273**	**13,996**	**13,211**	**12,331**	**13,481**	**11,067**	***100%***

Figure A: Projected Capital Expenditure from FY2023 to FY2032



Operations & Maintenance (Current $'000)	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	*Average %*
Routine & Preventive Maintenance	1,533	1,293	1,243	1,283	1,243	1,243	1,214	1,119	1,119	1,159	*24%*
Fault & Emergency Maintenance	1,973	1,973	1,973	1,921	1,921	1,921	1,891	1,891	1,891	1,891	*37%*
Refurbishment & Renewal Maintenance	555	495	480	495	450	450	495	450	450	450	*9%*
Vegetation Control	1,610	1,610	1,610	1,610	1,610	1,520	1,520	1,520	1,520	1,520	*30%*
Total (OPEX) :	**5,671**	**5,371**	**5,306**	**5,309**	**5,224**	**5,134**	**5,120**	**4,980**	**4,980**	**5,020**	***100%***

Figure B: Projected OPEX from FY2023 to FY2032

Electra's AMP Update 2022 together with our comprehensive AMP 2021 are important and evolving documents for which your feedback is welcomed. Our General Manager – Lines Business and I would be happy to hear from you.

Kind regards

Neil Simmonds

Chief Executive

INTRODUCTION

1. INTRODUCTION

In March 2021, Electra published a comprehensive Asset Management Plan 2021-2031 (AMP 2021) available on our website. This AMP Update 2022 provides our customers and stakeholders with the material changes and updates to our asset management planning since our AMP 2021 was published.

The Commerce Commission allows an AMP update as per Clause 2.6.3 of the Electricity Distribution Information Disclosure Determination 2012, which requires Electra to complete and publicly disclose an update before 1 April 2022 while Clause 2.6.5 requires any material changes to asset management practices, network development and lifecycle asset management plans in the AMP 2021 be disclosed. Clause 2.6.6 requires that the following schedules be included, and these are provided in the Appendices:

- (a) the Report on Forecast Capital Expenditure in Schedule 11a;
- (b) the Report on Forecast Operational Expenditure in Schedule 11b;
- (c) the Report on Asset Condition in Schedule 12a;
- (d) the Report on Forecast Capacity in Schedule 12b;
- (e) the Report on Forecast Network Demand in Schedule 12c;
- (f) the Report on Forecast Interruptions and Duration in Schedule 12d.

This AMP Update 2022 covers our updated network strategies, works delivery, programme of work and expenditure forecasts for the next 10 years from 1 April 2022 to 31 March 2032. This AMP Update 2022 shall be read in conjunction with the AMP 2021.

This AMP Update also contains our customer expectations from our 2021 survey in the next section (Section 2), our service levels (Section 3), the material updates to our network development, lifecycle management and non-network plans (Sections 6 to 8), risk management (section 9) as well as an evaluation of our performance in Section 4.

Section 5 describes our asset management practice performance improvements with the launching of our Mahi Tahi initiative TAG, the Enterprise Asset Management System.

Flexibility solutions including the Huringa Pūngao Electricity Transformation Roadmap is described in Section 6.3. |

Section 8 includes a review of our reliability performance and asset management practices in response to the Commerce Commission's publication "Reporting of asset management practices by EDBs" released on 26/7/2021.

Besides engaging with the Commerce Commission on the AMP and the impact of decarbonisation on electricity line services, Electra is engaging with the Electricity Authority on Consumer Care Guidelines as highlighted in the Executive Summary.

2. CUSTOMER EXPECTATIONS

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 we gauge customer expectations by conducting yearly Customer Service Surveys since the late 1990s. The 2021 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. A total of 300 respondents were interviewed where 200 were residential householders and 100 commercial end-users. The 2021 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.

2.1 Fault resolution and service delivery

We interviewed customers who had contacted the Call Centre and 95% of faulted customers rated the service as 'excellent' or 'very good'. This year depicts the highest level of satisfaction achieved by the Call Centre over the past eleven years as shown Figure 2-1a.

Similarly, 99% of faulted customers who experienced a call from a service person, rated the service as 'excellent' or 'very good'. The results reveal that the level of excellence has continued its upward trend and is also at its highest reading (Figure 2-1b).

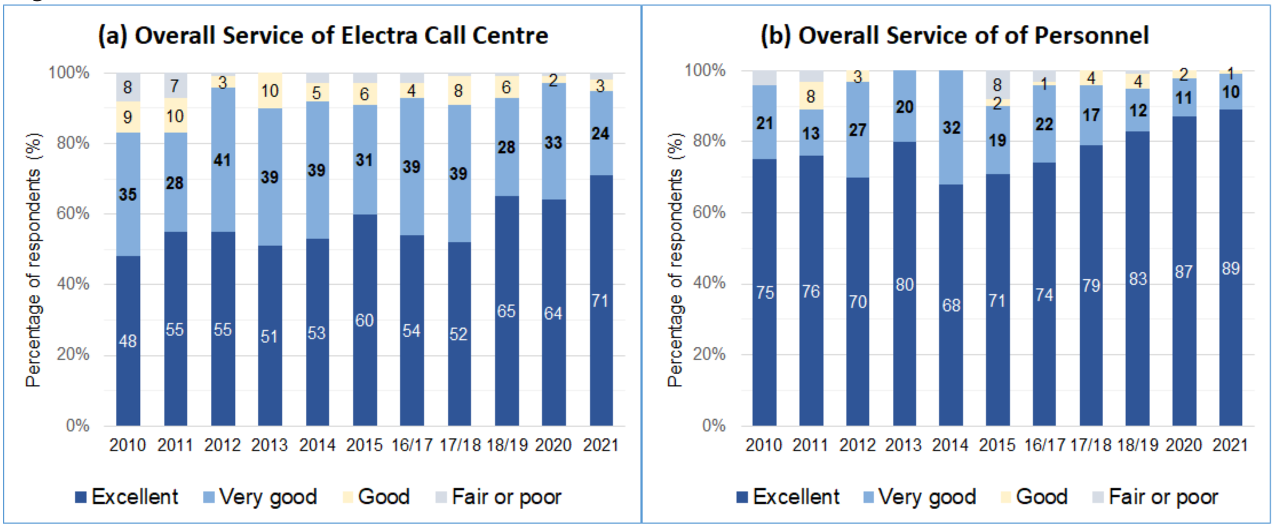


Figure 2-1: Overall services of: (a) Electra Call Centre, and (b) Service personnel

2.2 Customer Engagement Campaign

Electra asked customers on our reach-out campaign 'Money for Jam' where Electra encouraged customers to seek out the best electricity plan with their retailer and to use the 'Powerswitch' website. As shown in Figure 2-2, 22% of the total respondents stated that they could recall the campaign, after prompting. The research participants were then asked whether they had heard of and, used 'Powerswitch'. 48% of the total respondents interviewed stated that they had heard of 'Powerswitch' but not necessarily as a direct result of the campaign while 16% indicated that they had used or referred to 'Powerswitch'.

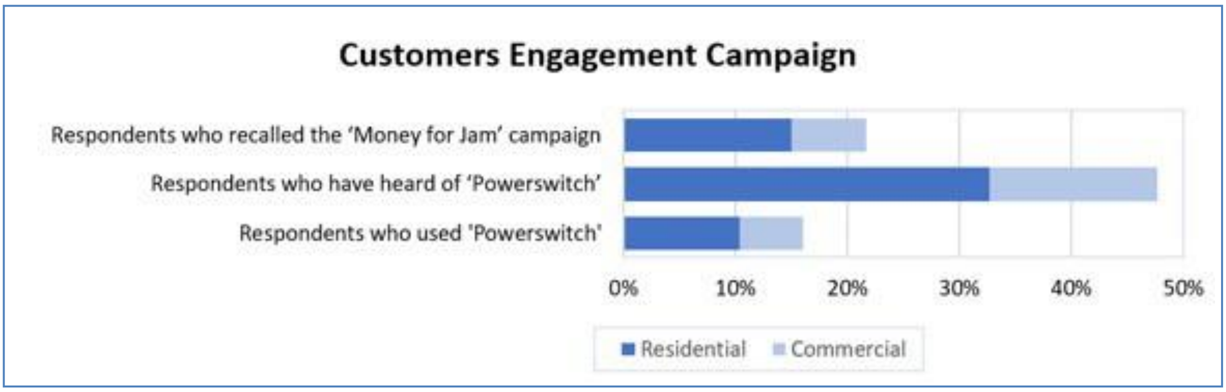


Figure 2-2: (a) Preferred customer communication channels during a fault and (b) Sources of contact information

2.3 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’. 94% of participants indicated they were either ‘very’ or ‘quite satisfied’ with the reliability of electricity supply as shown in Figure 2-3a. Only six respondents (2%) stated they were ‘dissatisfied’ with the reliability of supply. These respondents were asked whether they would be prepared to pay more for a more reliable supply of electricity. All six indicated that they would not be prepared to do so. Their rationale follows:

> *“If you pay your bill on time, you should get the service you have paid for. The expectation is that it should be reliable.”*
>
> *“We have always had a reliable service. You expect it. It has always been that way. I am not aware of any reason why it should change.”*
>
> *“The price of electricity goes up, not down, so the level of service should be maintained.”*
>
> *“I have heard that electricity is expensive in NZ compared to other countries. It should, therefore, be reliable.”*
>
> *“I wouldn’t be prepared to pay more for it. We pay enough now.”*
>
> *“No, I don’t think that is a good move. Reliable power should be available and affordable for everyone. It is an essential service that we all need.”*

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

Respondents were then asked this question (Figure 2-3b): *“Would you be prepared to have slightly more power cuts, if it meant your electricity bill was a bit lower?”*

16% of the total respondents interviewed indicated that they might be prepared to consider this trade-off. Such a consideration was notably lower among respondents from the Electra list sample, presumably because many of them had experienced the inconvenience of August 2021 Transpower outage.

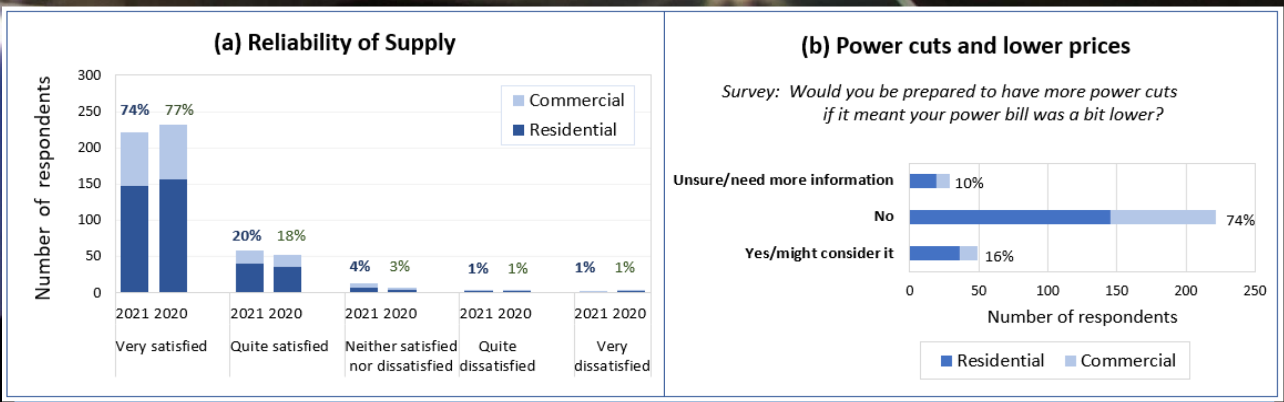


Figure 2-3: Satisfaction responses on supply reliability

As in previous surveys, the respondents were asked: “If you could ask, or tell, the Chief Executive of Electra anything at all, what would it be?”

Tell us about the future of electricity/energy; what is your view of where it is headed (wind farms, solar energy, new/emerging energy forms)?
Electra should adopt a higher profile/up its marketing
Tell us about Electra's support for/good work in the community
The rebate/discount/dividend is important/appreciated

This survey indicates that overall, our customers are satisfied with network reliability. It indicates that Electra is not over-investing in the network and we remain customer-centric, meeting our customer needs and retaining relatively low costs to maintain reliability in the lowest quartile amongst EDBs.

2.4 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 2-4 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 that our customer-centric strategy is paying off.

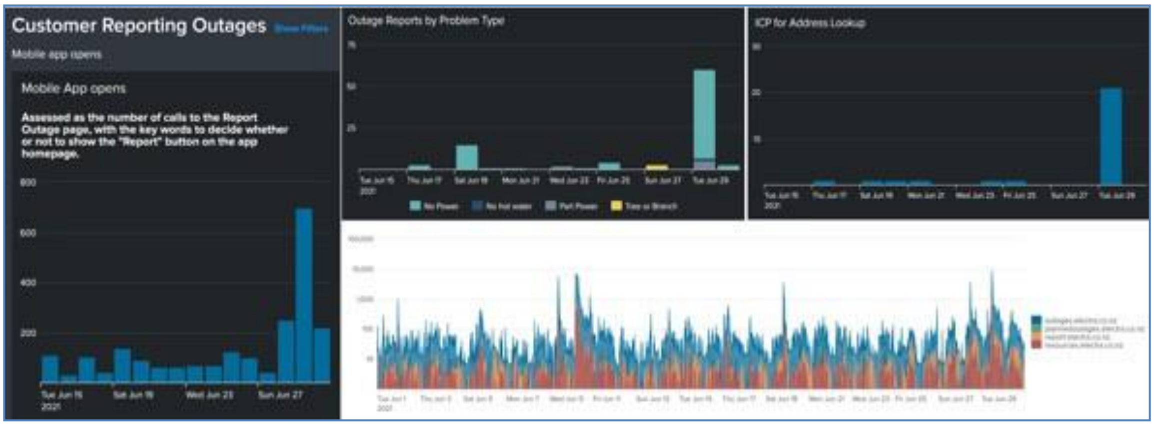


Figure 2-4: Splunk dashboard monitoring the usage of our Electra mobile app

Our customer care operators actively use the dashboards that record and display load control information so that we can pro-actively aid and useful information to our customers when they contact us about hot water faults as demonstrated in Figure 2-5.

Figure 2-5: Customer care operator monitoring hot-water demand

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 2-6. This data set is analysed against the outages recorded in ADMS and we are observing good results in early notification of outages and assessing when the power is restored.

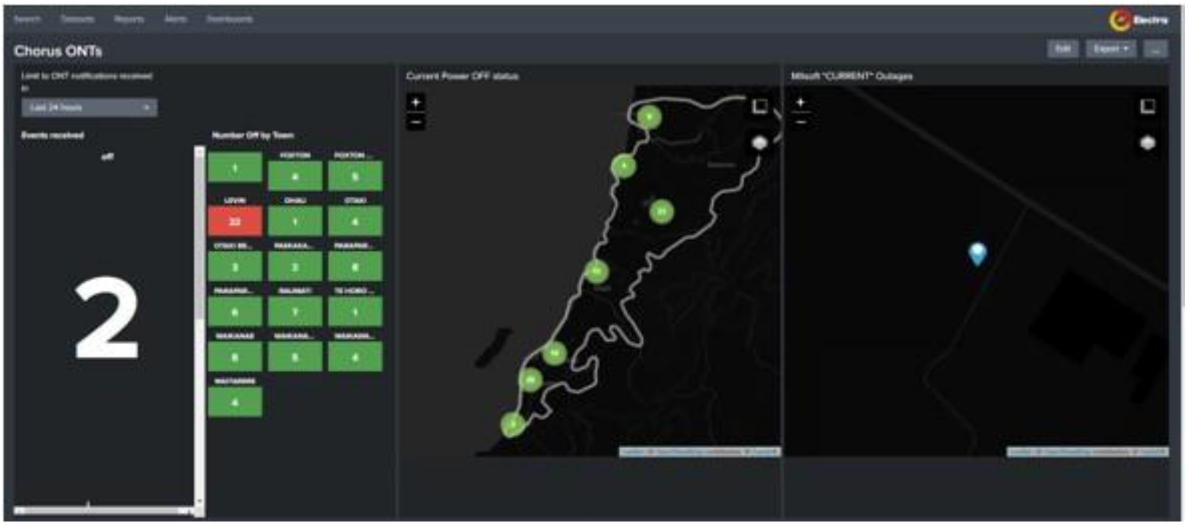


Figure 2-6: Splunk dashboard indicating power loss on Chorus optical fibre connections

Electra has also deployed over 100 power loss sensors (Figure 2-7a) that inform us when key customers lost power with another 150 units being rolled out in FY2021. 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 2-7). Other initiatives are detailed in Section 6.4.

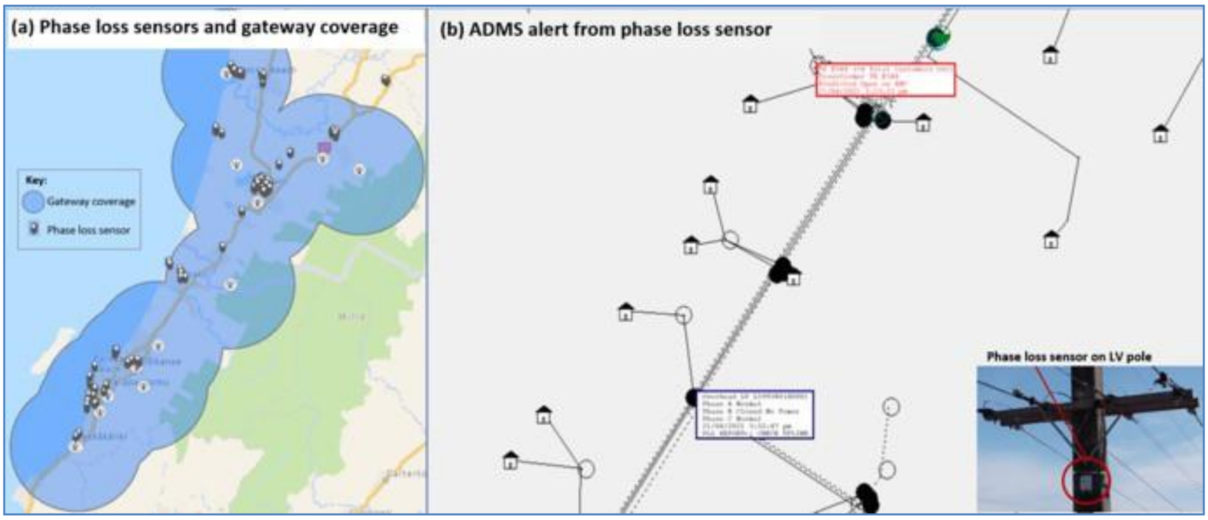


Figure 2-7: (a) Phase loss sensors and gateway coverage; (b) ADMS

SERVICE PERFORMANCE MEASURES AND TARGET

3. SERVICE PERFORMANCE MEASURES AND TARGETS

The section describes how we measure performances. Besides reliability, Electra monitors the performance of key services against a range of measures including financial efficiency, safety, environmental and legislative compliance.

3.1 Reliability Performance

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

MEASURE	ACTUAL (HISTORICAL)					PREVIOUS TARGET	NEW TARGET
	FY2017	FY2018	FY2019	FY2020	FY2021	FY2013-FY2021	FY2022-2027
SAIDI B (Planned)	17.13	26.73	32.32	19.50	28.39	15	20
SAIDI C (Unplanned)	79.23	95.00	57.00	75.40	45.93	68	63
SAIDI B & C	**96.90**	**121.73**	**89.33**	**94.94**	**74.32**	**83**	**83**
SAIFI B (Planned)	0.05	0.08	0.10	0.06	0.10	0.06	0.08
SAIFI C (Unplanned)	1.45	2.00	1.17	1.81	0.87	1.6	1.5
SAIFI B & C	**1.63**	**2.08**	**1.26**	**1.87**	**0.97**	**1.66**	**1.58**
CAIDI B (Planned)	342.60	321.21	323.20	313.37	286.77	250	250
CAIDI C (Unplanned)	54.64	47.58	48.72	41.75	52.61	42.5	42
CAIDI B & C	**59.45**	**58.53**	**70.90**	**50.80**	**76.46**	**50**	**52.5**

As shown in the above table, our reliability targets have been revised for the years FY2022 to FY2027, increasing SAIDI B to 20 minutes and decreasing SAIDI C to 63 minutes thereby maintaining SAIDI B&C at 83 minutes. Since FY2013, our regulatory asset base has grown from $143M to $209M and network circuit length increased by 75km. With the increasing demand from our customer base, the rise in planned network augmentation, renewal and maintenance activities had warranted the increase of SAIDI B which had not been changed since FY2013. With the launching of our EAM project, we are confident that the implementation of initiatives and enhanced processes will improve unplanned SAIDI (SAIDI C), so SAIDI C has been decreased from 68 to 63 minutes, thereby maintaining SAIDI B&C at 83 minutes. CAIDI B is maintained at 250 minutes while CAIDI C is reduced slightly to 42 minutes giving an overall CAIDI B&C to 52.5 minutes.

The total B&C SAIDI targets have been benchmarked with our peer group of eight networks based on network characteristics, network density and customer size (see Section 4.4.4). 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 4.2 and 4.3.

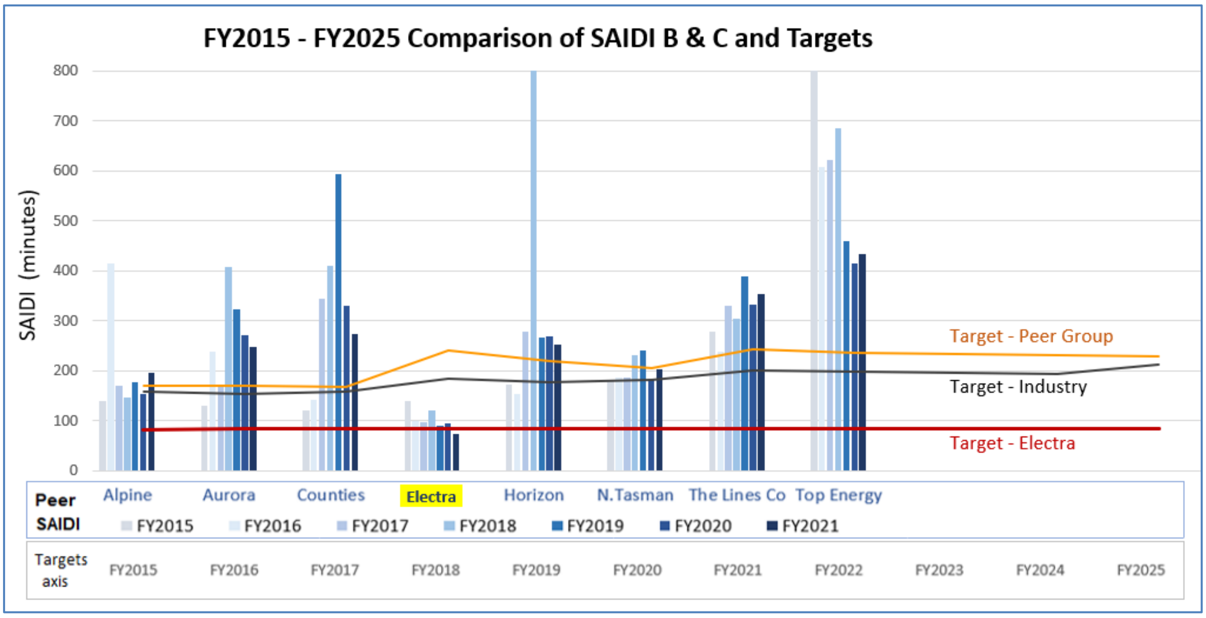


Figure 3-1: Peer comparison of unplanned and planned SAIDI (B+C SAIDI)

3.2 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
Load factor	49%	50%	51%	50%	50%	50%	50%	50%	50%	50%
Capacity utilisation	31%	30%	30%	31%	31%	31%	32%	32%	32%	32%
Network losses	8.4%	6.9%	7.7%	7.3%	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 5). Further details of the above are included in Section 4.4. Electra has commissioned a Power Losses Reduction Initiative to investigate technical losses which is described in Section 4.4.3.

3.3 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
	FY2019	FY2020	FY2021	
Capital expenditure on assets per total circuit length (km)	$5,065	$10,914	$6,119	Increase to be less than 5% of the previous year’s figures.
Capital expenditure on assets per connection point	$259	$561	$313	
Operational expenditure on assets per total circuit length (km)	$5,308	$5,603	$5,746	
Operational expenditure on assets per connection point	$271	$288	$294	

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

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

The trends in our operational (OPEX) and capital asset expenditure (CAPEX) per ICP and per circuit length (in km) are depicted in Figure 3-2. Electra aims to maintain its OPEX and CAPEX per ICP and per circuit length (km) within 5% of the previous year's figures.

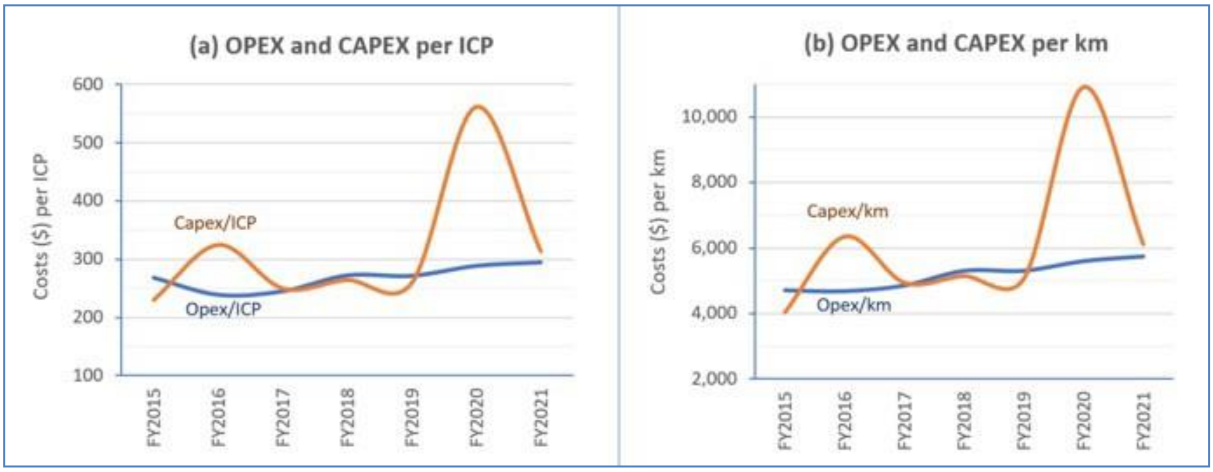


Figure 3-2: OPEX and CAPEX (a) per ICP, and (b) per circuit length (km)

The costs for both OPEX per ICP and per circuit kilometre increased by 2% and 3% respectively from FY2020 to FY2021. CAPEX per ICP and per circuit kilometre has both decreased by 44% from FY2020 to FY2021. 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 a low growth budget but had a 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.

Further evaluation of the above indicators is included in Section 4.4.4.

3.4 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.

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	FY2018	FY2019	FY2020	FY2021	TARGET AND FORECAST	PERFORMANCE MEASUREMENT
Public safety: safety of staff, contractors, and the public	Number of incidents	8	13	51	68	Zero harm	There were 870 proactive/ preventive actions including audit (internal and external), observation and meetings during the FY. High levels of compliance recorded.
Personnel safety	Lost Time Injury (LTI)	4	3	3	2	Zero LTI	Annual measurement
Environmental responsibility	Number of environmental incidents	0	0	0	0	Zero harm to the environment	SF6 Leak rate, transformer leak rate, zone transformers dissolved gas analysis

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. The increase in incidents from 2020 is attributed to the use of Vault software which allowed real-time reporting for public safety incidents.

Training was provided to all employees on reporting in Vault, increasing observations and incident-reporting. Vault has also been installed this financial year as an App on mobile phones which has made Vault even more accessible. Electra has invested in a comprehensive training and development programme to develop our workforce with increased competencies and career pathways. Details are elaborated in Section 5.14 of AMP 2021.

3.5 Regulatory performance levels

Electra's performance with legislative requirements is indicated in the following table:

Service criteria	Indicator	FY2019	FY2020	FY2021	Target and forecast	Performance measurement
Legislative requirements	Compliance with relevant regulations	98.7%	99.3%	98.7%	100% Compliance	Annual measurement, using ComplyWith system

3.5.1 Legislation compliance survey

The results of the Group Legislation Compliance Survey 2021, completed by 39 managers and key employees, were reviewed by the Risk and Audit Committee in August 2021. As per Figure 3-3, the survey covered 79 Acts/ regulations and overall compliance was rated high with 34 partial non-compliances where remedial actions are being undertaken to cover the following:

- Health and safety responsibilities
- Development of new work procedures to support working from home, security of loads and work that may involve asbestos
- Development of an information security management framework to classify and protect data
- Updating of Call Centre consumer information to ensure efficient contact processes.

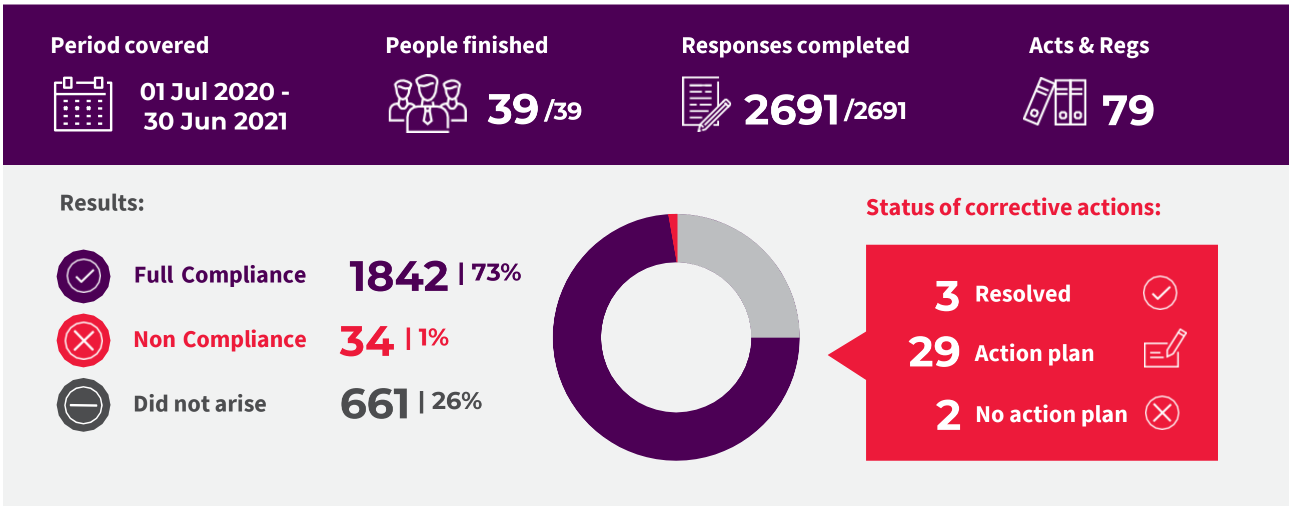


Figure 3-3: Summary of Electra's Legislation Compliance Report 2021

3.5.2 Survey participation

The survey continues to be well-supported with 100% completion and wide-ranging responses. All instances of partial non-compliance are being tracked through the Corrective Actions module in the ComplyWith system which enables on-going progress monitoring and reporting by managers until full resolution of compliance issues.

PERFORMANCE EVALUATION

4. PERFORMANCE EVALUATION

In this section, the information for the benchmarking of electricity distribution businesses or EDBs are extracted from the Commerce Commission's publications[1] while FY2021 indicators are extracted from the information disclosure publications from EDB as at 10-Sep-2021.

4.1 Works delivery performance

This section outlines Electra's progress against budgeted targets FY2021.

4.1.1 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	FY2021 TARGET ($000)	FY2021 ACTUAL ($000)	VARIANCE ($000)	VARIANCE (%)	REASONS FOR VARIANCES
Service interruptions and emergencies	1,859	1,611	-248	-13%	• Less than forecast due to less faults in the disclosure year, consistent with the improved SAIDI and SAIFI results • Number of faults caused by customers was consistent with prior years but mostly treated as capital expenditure
Vegetation management	1,608	1,552	-56	-3%	• No material variation
Routine and corrective maintenance and inspection	999	1,430	+431	+43%	• Additional inspections carried out for pillars from prior years • Additional maintenance work required on the 33kV Mangahao to Levin line comprising of insulator replacements • Priority pole-straightening work identified during the inspection process which was not included in the forecast
Asset replacement and renewal	312	685	+373	+119%	• Repairing ground-mounted transformers exceeded budget due to additional traffic management requirements • Replacement of Zone Substation tap changers and replacing cracked bushings
System operations and network support	3,901	3,187	-714	-18%	• Underspend attributed to greater capitalised salaries than forecast, combined with vacancies in positions in the Network team
Business support	4.439	4,926	+487	+11%	• Overspend predominantly due to IT support agreements being greater than forecast • Attributed to more emphasis on cloud-based products which is a subscription pricing model
Total	**13,118**	**13,391**	**+273**	**+2%**	• **No material variation**

Overall, our operational expenditure was $273K over forecast or 2% above the forecast and the variances within the main categories are depicted in Figure 4-1a.

Electra applies a materiality threshold of $100K to identify material projects.

[1] Commerce Commission, 4/2/2021, "Electricity distributers' information disclosure data 2013-2020.xlsm"

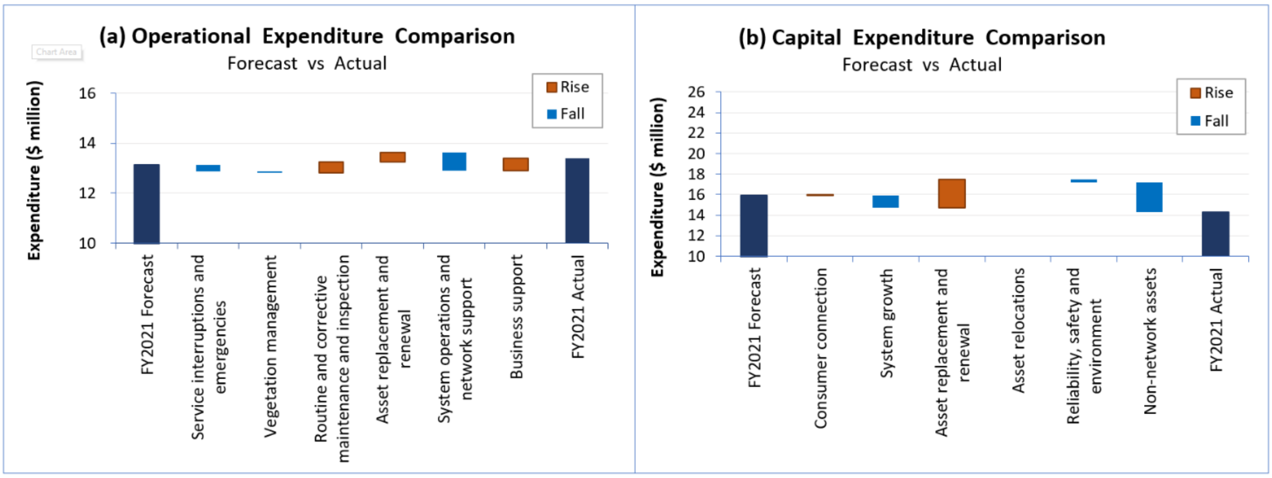


Figure 4-1: Variations between forecast and actual expenditures for: (a) Operational expenditure (OPEX), and (b) Capital expenditure (CAPEX)

4.1.2 Network development plan delivery

Overall expenditure on assets was $1.62M 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	FY2021 TARGET ($000)	FY2021 ACTUAL ($000)	VARIANCE ($000)	VARIANCE (%)	REASONS FOR VARIANCES
Consumer connection	95	114	+19	+21%	• No material variance
System growth	1,450	244	-1,206	-83%	• Deferment of the Kāpiti 11kV feeder project to July 2021 to incorporate an intelligent automation scheme to alleviate reliability concerns and look at a more permanent solution for load growth a few years later when the loading eventuates due to airport/ commercial developments
Asset replacement and renewal	6,217	8,981	+2,764	+44%	• Renewal expenditure exceeded forecast due to overhead line replacement projects exceeding forecast and projects carried over from the previous disclosure year • Unplanned carry-over of two large projects in March 2020 taking priority, due to the impact of the Covid-19 lock down
Reliability, safety, and environment	3,347	3,091	-256	-8%	• Part deferment of upgrading works for zone substation buildings to meet seismic requirements
Asset relocation	0	0	0	0%	• Nil
Non-network assets	4,773	1,828	-2,945	-62%	• Deferment of the Enterprise Asset Management (EAM) system, the upgrade of Microsoft Dynamics Nav 2015 to Business Central and purchase of heavy and light vehicles. • Lease of light vehicle fleet where most of this transition will occur in 2022 Any vehicles leased in the current disclosure year are included in the RAB consistent with the requirements of IFRS 16
Total Expenditure on Assets	**15,882**	**14,259**	**-1,623**	**-10%**	• **Differences as per reasons given above.**

Figure 4-1b shows the forecast, actual spend as well as variances for main categories.

4.2 Network reliability performance

4.2.1 Customer service performance (reliability)

Electra's actual performance against target performance for the FY2021 year for the key customer service attributes is shown in the following table.

ATTRIBUTE	MEASURE	FY2021 TARGET	FY2021 ACTUAL	COMMENT
Network reliability: planned outages	SAIDI B (minutes)	15	28.39	Lack of connection points for generation for 11kV reconductoring projects.
	SAIFI B	0.06	0.099	
	CAIDI B (minutes)	250	286.77	
Network reliability: unplanned outages	SAIDI C (minutes)	68	45.93	Compliant.
	SAIFI C	1.6	0.873	
	CAIDI C (minutes)	42.5	52.61	Lengthy unplanned outages due to vehicle-pole incidents.
Network reliability: planned & unplanned outages	SAIDI B&C (minutes)	83	74.32	Compliant.
	SAIFI B&C	1.66	0.97	Compliant
	CAIDI B&C (minutes)	50	76.46	Non-compliant due to lack of generation
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 4-2 with the reliability triangle comparing SAIDI against SAIFI for EDBs, averaged over a three-year period (FY2019 to FY2021[2]). Out of 29 EDBs, Electra is one of thirteen EDBs in the first quadrant below SAIDI, SAIFI and CAIDI industry averages of 216, 2.02 and 111 respectively. Electra is ranked fifth lowest for SAIDI (planned and unplanned) and ranked second best amongst 29 EDBs for CAIDI.

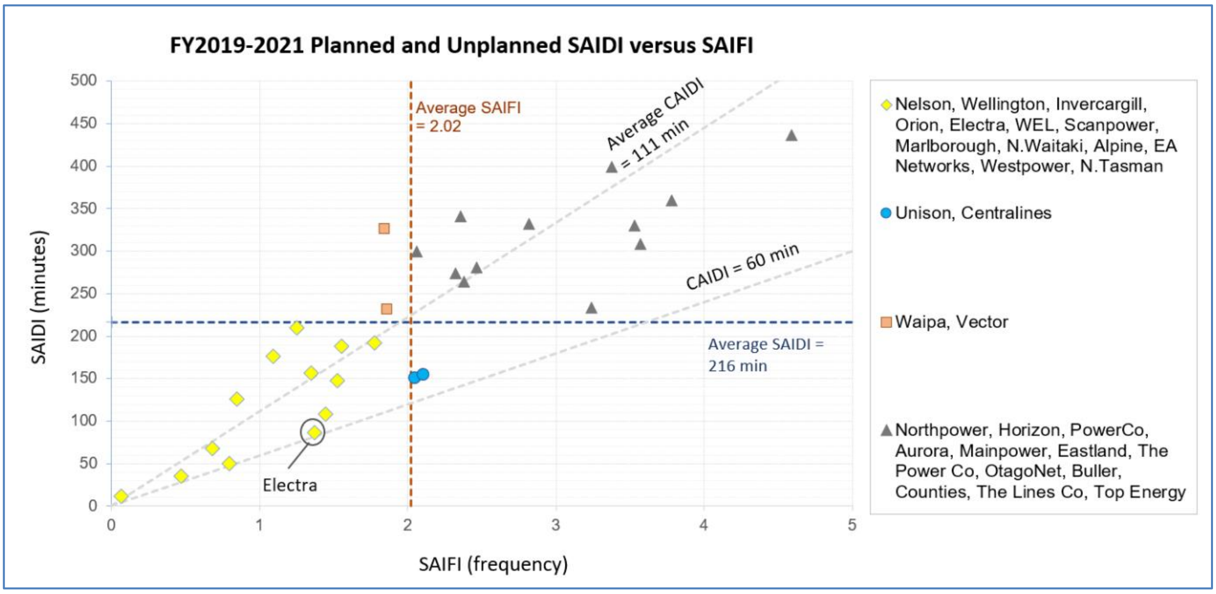


Figure 4-2: FY2020 to FY2021 SAIDI for planned B and unplanned C outages for EDBs

[2]FY2021 data is extracted from information disclosures from the relevant EDB's websites as at 10/9/2021.

4.2.2 Causes of faults

A cause analysis into our network reliability performance is depicted in Figure 4-4. The highest cause of faults impacting SAIDI in FY2021 (Figure 4-4a) is defective equipment (37%) followed by third party interference (21%), unknown (17%), vegetation (13%) and adverse weather (6%). A further investigation based on the frequency of causes or SAIFI (Figure 4-4b) gave the highest fault contributors as unknown (33%), defective equipment (29%), vegetation (13%), third party interference (12%) and adverse weather (8%). Other causes of faults include wildlife and lightning.

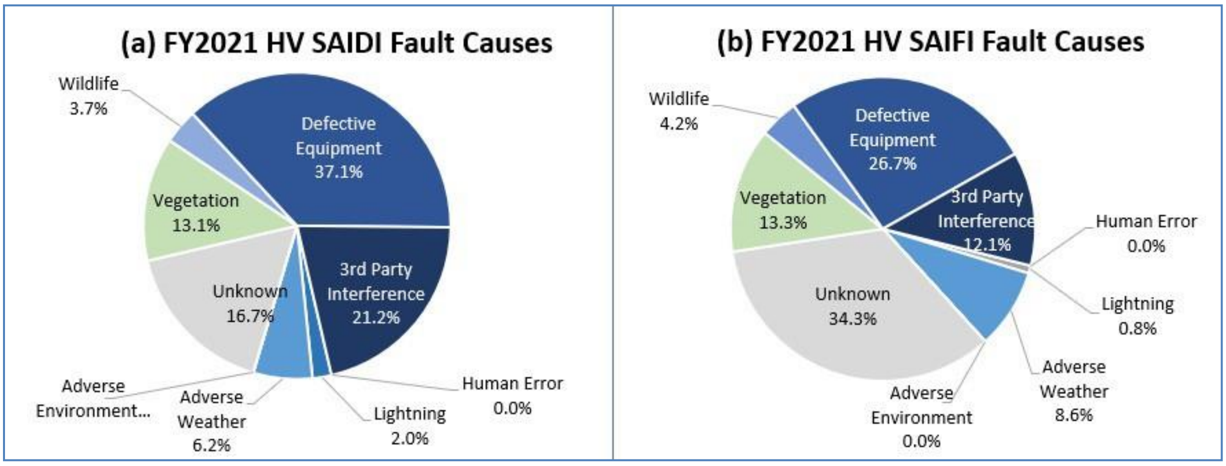


Figure 4-2: FY2020 to FY2021 SAIDI for planned B and unplanned C outages for EDBs

The SAIDI impact and the number of HV faults between FY2017 to FY2021 are also shown in Figure 4-4. The actual number of unplanned outages in FY2020 is 304 as reported in the last AMP and the number of faults has dropped to 245 in FY2021.

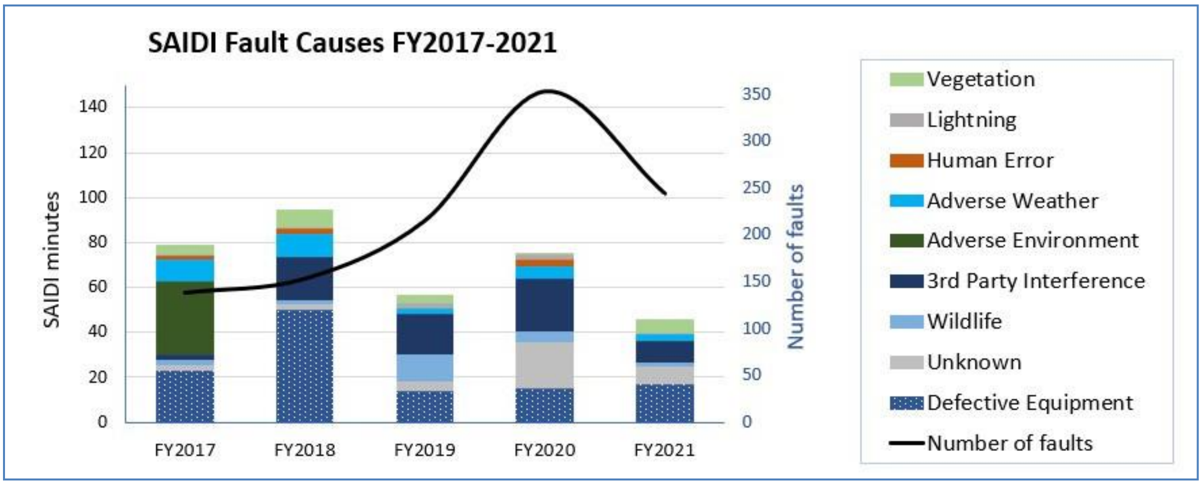


Figure 4-4: SAIDI and Number of HV faults from FY2017-FY2021

4.2.3 Restoration of faults

The information disclosure includes the performance indicator for faults restoration within a period of three hours. Figure 4-5b compares the performance of Electra against other EDBs from FY2020-FY2021 where our average performance of 74% is higher than the industry's median of 72%. Our performance between FY2017 to FY2021 is shown in Figure 4-5b 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 FY2021, 72% of faults were restored within three hours.

A Reliability Committee has been established and faults over 0.5 SAIDI minutes are scrutinised for extensive root-cause analysis to be conducted by the committee, where large customers may be affected or customers may be affected for an extended outage time. The analyses conducted have resulted in dropout fuses being replaced by TripSavers, switchgear automation and reinforcement projects - to be completed this year or the next financial year. There has been no 33kV faults with an "unknown" classification due to the criticality of the loss of supply.

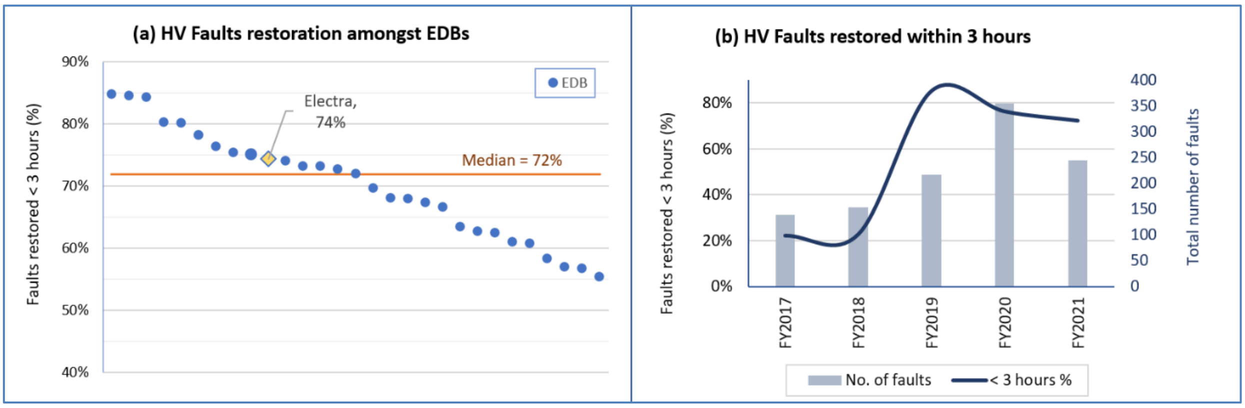


Figure 4-5: Faults restored within 3 hours: (a) EDB benchmarking from FY2020-FY2021, and (b) Electra FY2017-FY2021

Reliability investigation, root cause analysis and network resilience enhancement are continuously being reviewed and conducted and an average of $2.8M 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.

4.3 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[3] 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[4] though only Levin Station data was available. Some of the analyses undertaken are included in the following sub-sections.

4.3.1 Extended duration interruptions

This section evaluates "extended duration interruptions" where such interruptions stretch over three hours on the network. Figure 4-6 shows the trend of extended duration interruptions on our network trending downwards from FY2013 [13 outages, 15% of total unplanned interruptions] to FY2019 and slightly increasing to FY2021 with 68 or 28% of total unplanned interruptions. Comparing with other EDBs, the proportion of our extended duration interruptions is less or equal than the industry averages except from FY2015 to FY2016.

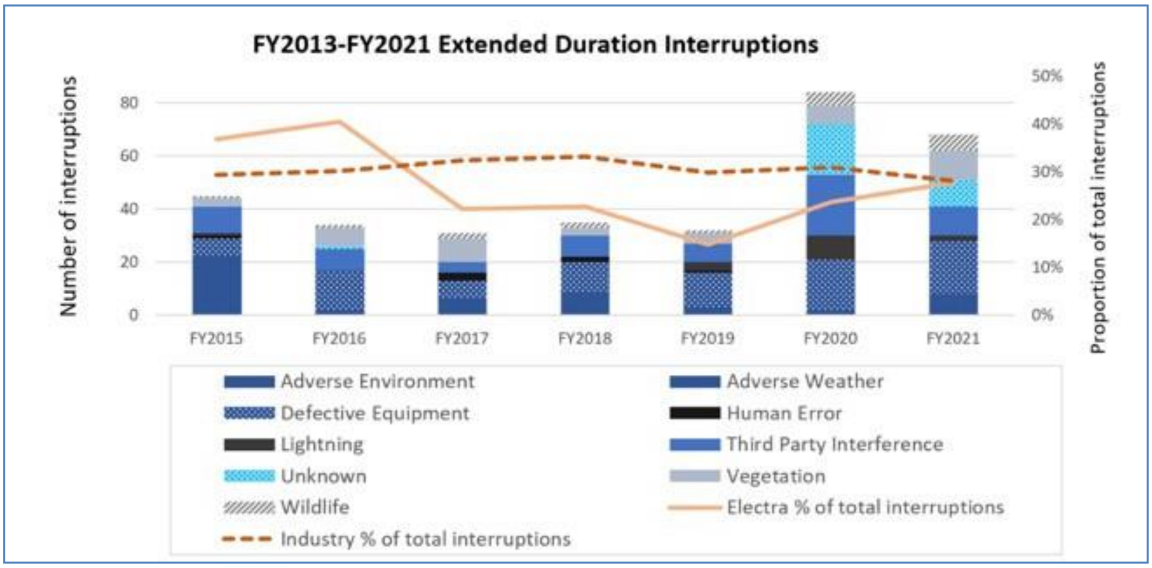


Figure 4-6: FY2013 to FY2021: Number of extended duration interruptions and proportion of total unplanned interruptions – comparison of Electra with Industry averages

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

Figure 4-7a further shows the SAIDI impact attributed to extended duration interruptions causes from FY2019 to FY2021. The total SAIDI from these interruptions was 47.5 minutes in FY2019; from FY2020 to FY2021, SAIDI decreased by 48% - from 42.8 minutes (FY2020) to 22.5 minutes (FY2021). In FY2021, the highest SAIDI impact of such interruptions as shown in Figure 4-7b is caused by third party interference (38% from 11 outages) followed by vegetation (18% from 11 outages), defective equipment (18% from 20 outages) and unknown causes (14% from 10 outages). Adverse weather, wildlife and lightning causes had a smaller SAIDI impact.

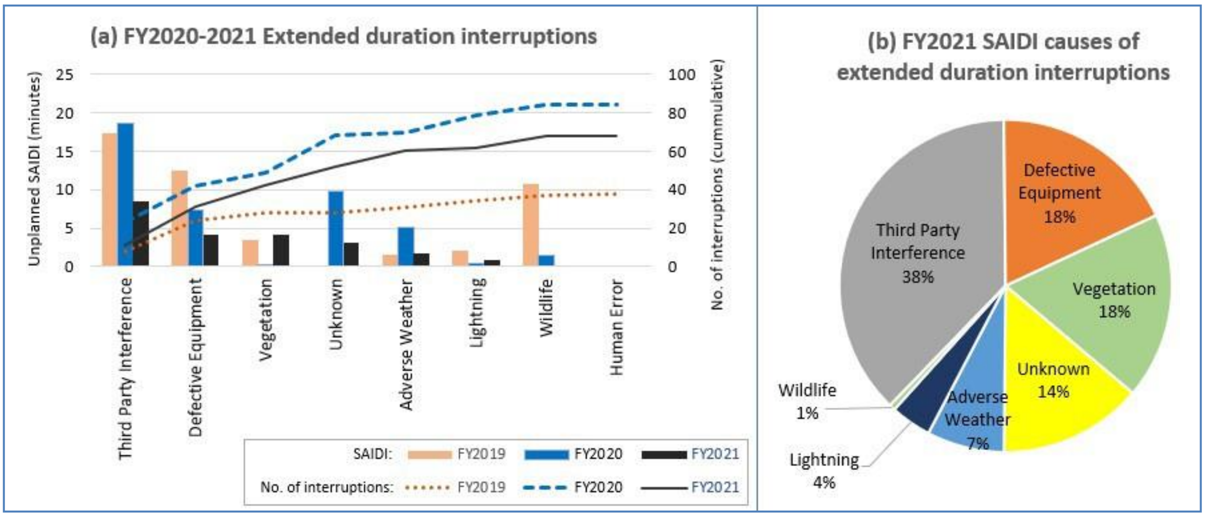


Figure 4-7: Extended duration interruptions (a) FY2019-FY2021: Causes for faults: SAIDI and cumulative number of interruptions; (b) FY2021 Causes - SAIDI.

Out of the 11 third party interference incidents, 10 were caused by vehicle versus pole incidents while one was due to an underground cable excavation fault. Figure 4-9 shows an extended duration incident involving a vehicle hitting a pole impacting SAIDI by 2.66 minutes and SAIFI by 0.026. 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.

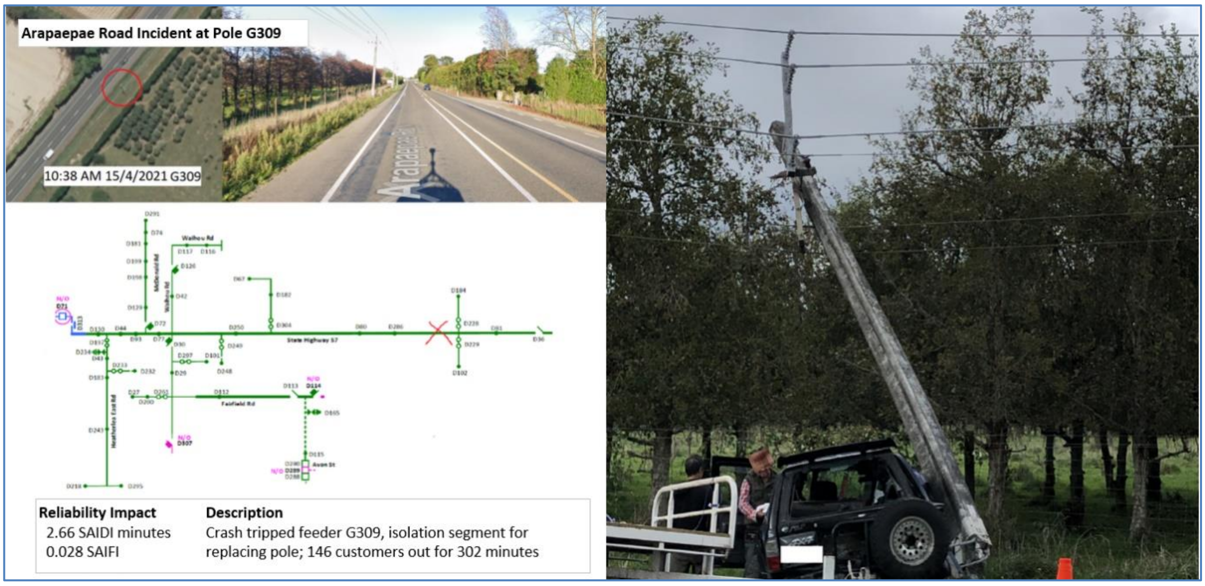


Figure 4-8: April 2021 vehicle-versus-pole incident impacting SAIDI by 2.66 minutes and affecting 215 consumers for 260 minutes

4.3.2 Vegetation Faults

Figure 4-9a shows that expenditure on vegetation management has been increasing from 1.27M (FY2016) to $1.85M (FY2019) before moving downwards to 1.55M in FY2021. 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 corresponding decreasing trend line is observed where vegetation SAIDI dropped from 8.7 minutes (FY2016) to 6 minutes in FY2021. Compared to other EDBs in the same industry, our SAIDI is consistently below the industry average (FY2017 to FY2021) as shown in Figure 4-9a, implying an efficient and effective strategy in vegetation control.

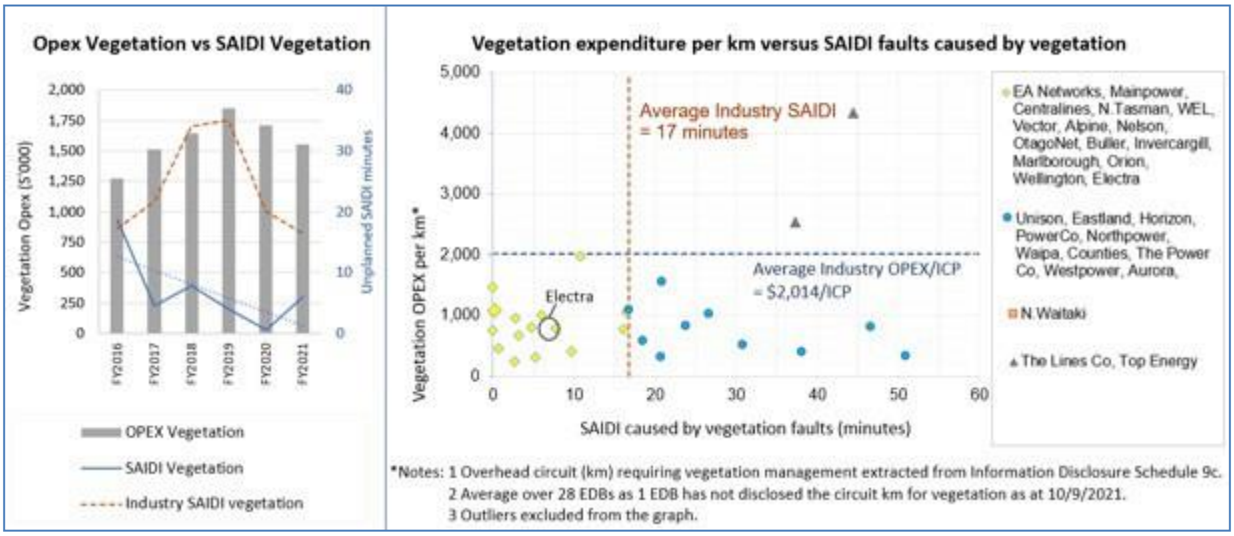


Figure 4-9: (a) Electra HV vegetation faults – SAIDI and OPEX, and (b) FY2021 vegetation management expenditure per km versus SAIDI caused by vegetation faults

Figure 4-9b portrays the industry's vegetation management operational expenditure per km of circuit requiring vegetation management versus SAIDI caused by vegetation faults for FY2021. Our expenditure of $998 per km is 50% below the industry average of $2,014 per km. The expenditure on vegetation management has resulted in the reduction of SAIDI due to vegetation faults over the years as indicated earlier (Figure 4-9a). The SAIDI value in FY2021 (6 minutes) is also 63% below the industry average of 16.3 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 4-10, Electra has enhanced our fault investigation strategy by classifying the cause based on the location of vegetation affecting our networks.

Over a three-year period (FY2019 to FY2021), 55% of the number of vegetation interruptions are caused by branches/trees outside the GLZ (Figure 4-10a) and these interruptions resulted in SAIDI being impacted by 10.5 minutes (69%) over the three years (Figure 4-10b). 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 hazard warning notices are being served to landowners for trees which pose a high risk to our overhead lines. Such a strategy will see the continued downward trend of our vegetation interruptions.

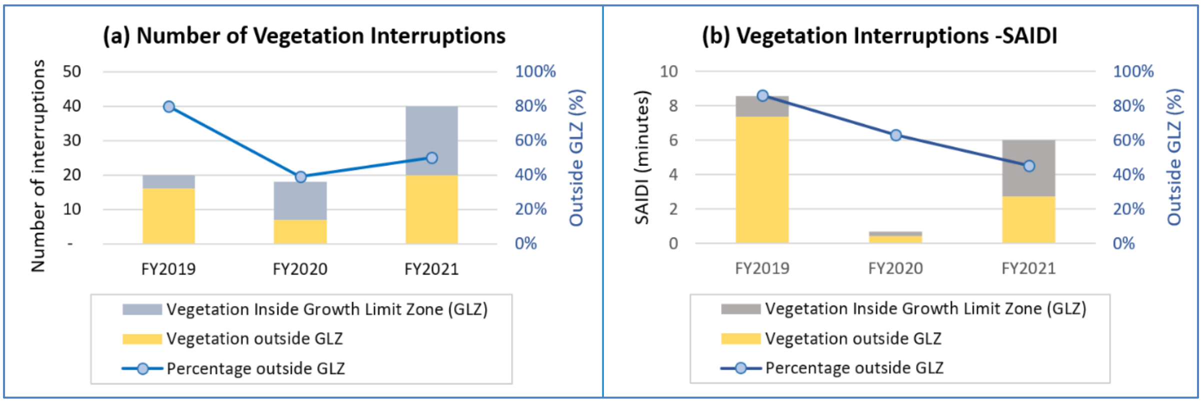


Figure 4-10: FY2019 to FY2021 - Vegetation interruptions (a) Number of interruptions; (b) SAIDI vegetation

The number of interruptions caused by vegetation in relation to gust speed-direction is depicted in Figure 4 -17 together with a discussion on weather-related interruptions (section 4.3.5).

4.3.3 Defective Equipment

As portrayed in Figure 4 -11a, the highest number of defective equipment incidents are caused by DDOs [58 faults contributing 27% of equipment faults], transformers [47 faults, 22%] and conductor faults [34 faults, 16%]. The remainder of the faults are caused by cable/joints, crossarms/poles, jumpers, connectors, insulators, switchgear, and LV installations.

Figure 4-11b shows the SAIDI impact for the defective equipment interruptions, the highest being due to conductors (37%), cables including joints (19%), jumpers including connectors (16%), switchgear including DDOs (14%), transformers (8%), poles/crossarms (8%) and insulators (5%); 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. Out of the 37% (17 SAIDI minutes) of defective equipment outages, 5.3 minutes were due to DDO overcurrent outages. Apart from DDO outages, most faults are caused by conductors, jumpers and terminations.

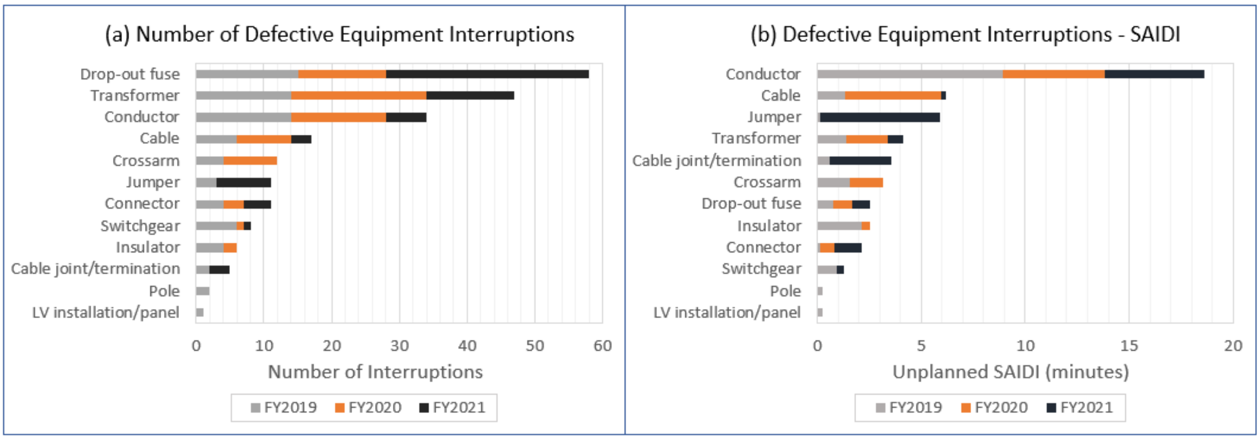


Figure 4-11: FY2019 to FY2021 Defective Equipment (a) Number of Interruptions; (b) SAIDI impact

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 6.4) will increase reliability on our network.

Figure 4-12: Installation of Golf Road automation switchgear in July 2021

Over FY2015 to FY2021, our performance is benchmarked with other EDBs in the following graphs of Figure 4-13 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 and 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[5].

[5] Electra Information Disclosure FY2016. Subsequent expert enquiry and re-engineering of protection settings have addressed protection setting issues.

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[6].

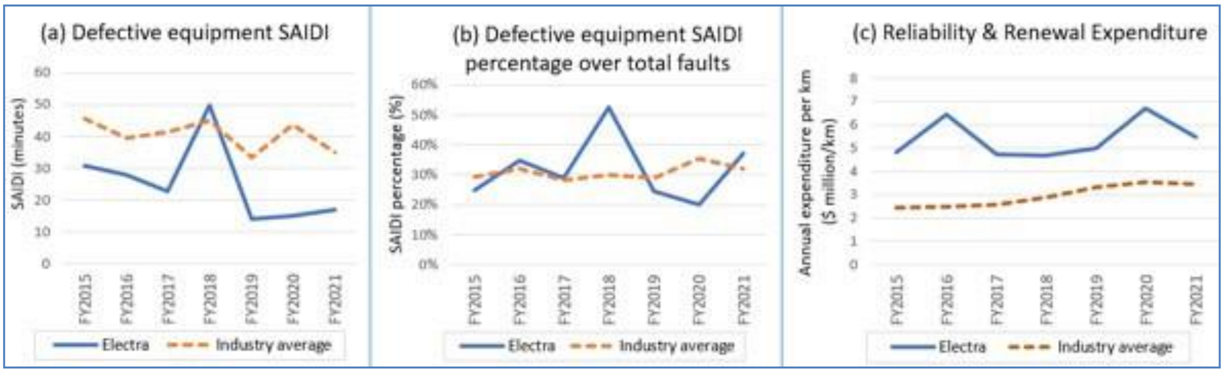


Figure 4-13: EDB Benchmarking for Defective Equipment Interruptions: (a) SAIDI; (b) SAIDI as a proportion of total interruptions; (c) Expenditure in relation with defective equipment

A further analysis of data averaged over FY2019 to FY2021 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 - 59% below industry average. This result suggests that Electra is making investments in asset expenditure to improve or replace their assets to ensure they remain safe and reliable for our consumers.

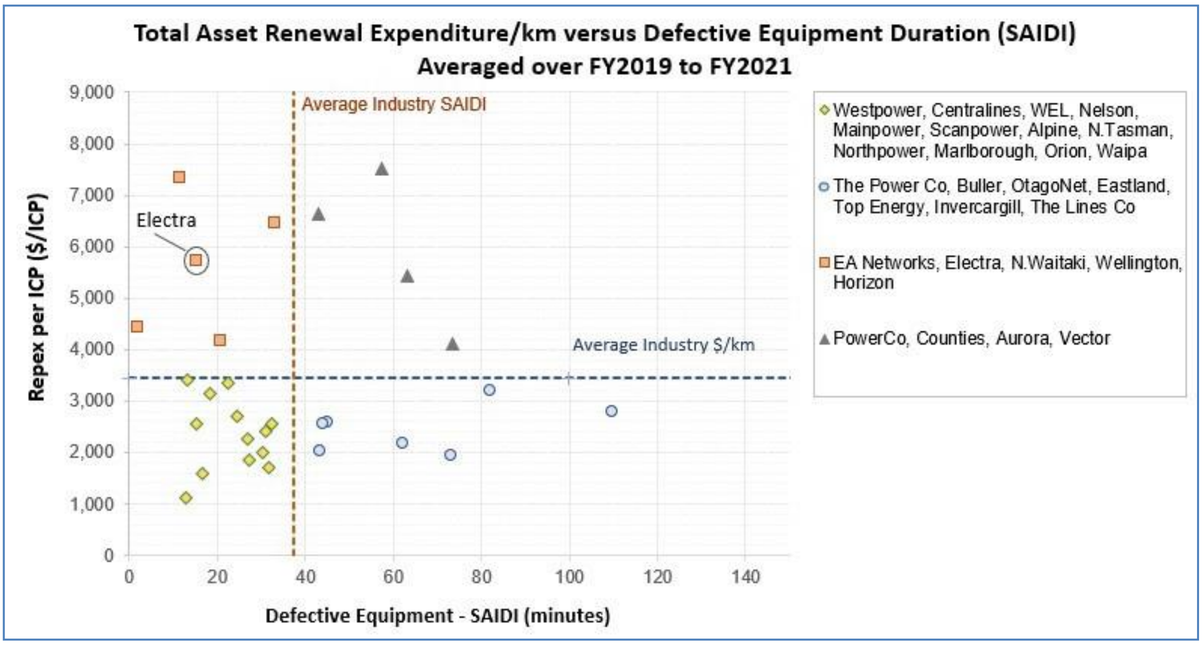


Figure 4-14: EDB benchmarking of replacement expenditure (Repex) per kilometre against SAIDI for defective equipment - indicators averaged over FY2019 to FY2021

[6] 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 .

4.3.4 Unknown interruptions

The unknown cause is selected when there is insufficient evidence to satisfy the criteria for a known cause even after appropriate fault investigation and line patrols had been conducted. Figure 4-15a shows the trend of the number and SAIDI of unknown interruptions in Electra's network. Benchmarking SAIDI and SAIFI for unknown interruptions (Figure 4-15b), the SAIDI-SAIFI percentages for FY2015-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 Reliability Committee set up recently has reviewed the process for the classification, established well defined procedures and control room personnel and technicians retrained on the classification of outage causes.

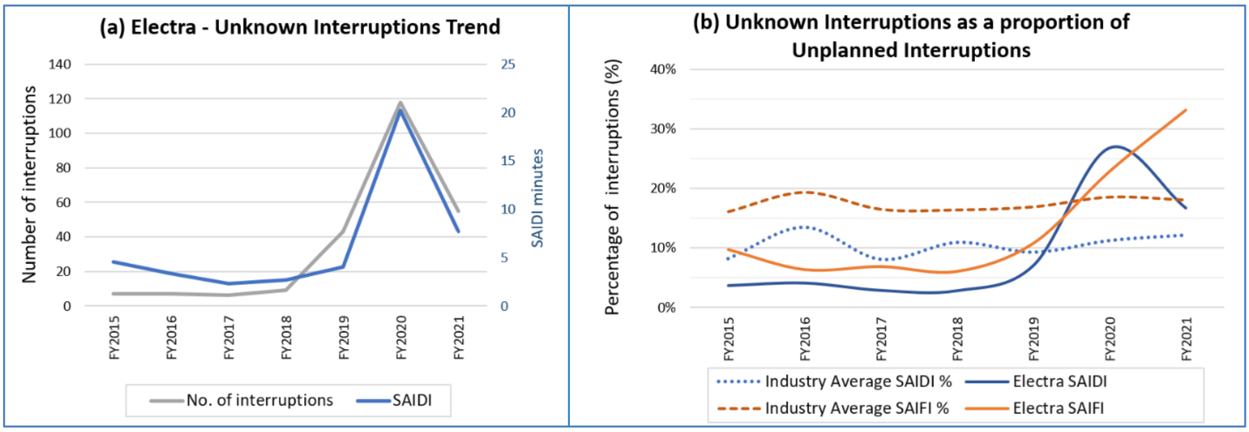


Figure 4-15: FY2015 to FY2021: (a) Unknown interruptions frequency and SAIDI; (b) Benchmarking of unknown interruptions as a proportion of all unplanned interruptions

The correlation of unknown faults to gust speed/direction and the number of unknown interruptions is depicted in Figure 4-17.

4.3.5 Asset Management System Enhancements

With the deployment of the 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 4-16) with upgraded dashboards for monitoring of interruptions and demand.

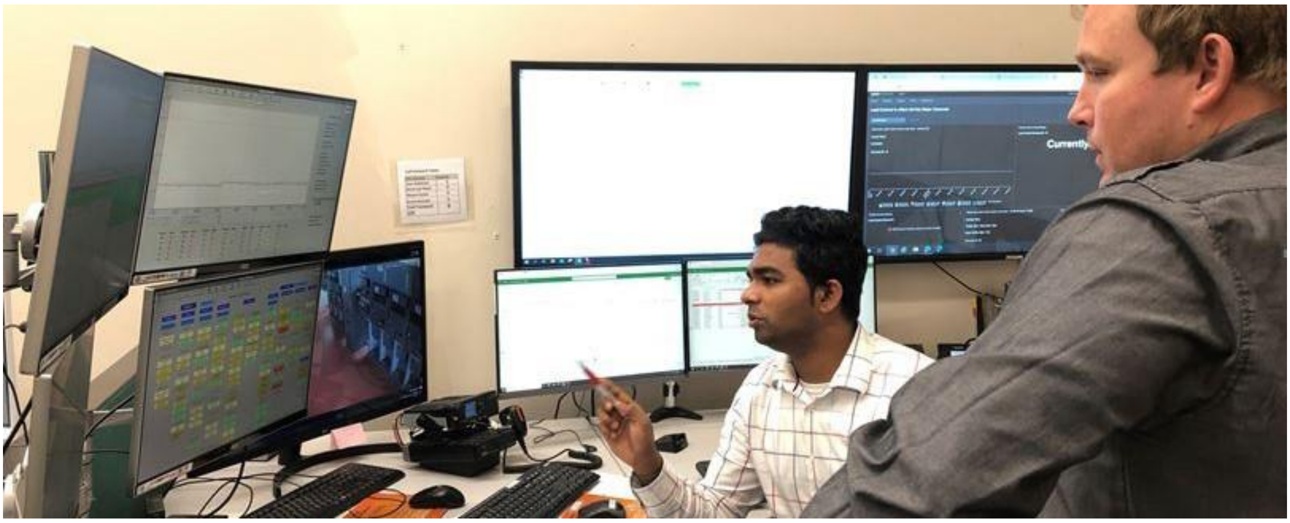
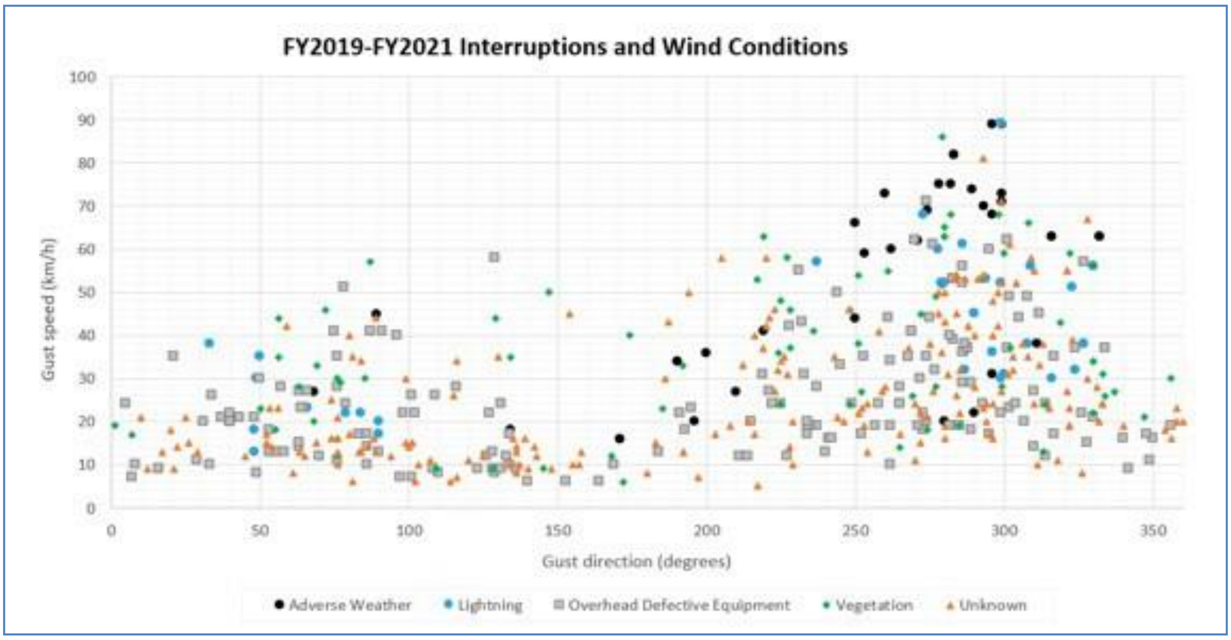


Figure 4-16: Improvement of control monitoring systems

As NIWA data included only Levin weather station, Electra will be installing fifteen weather stations at key locations so that gust speed, wind direction and the number of lightning strikes can be recorded and seamlessly integrated into their interruption reports. As the terrain[7] 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. The target completion date for this initiative is March 2022.

Studies into the effects of gust conditions (speed and direction) on weather-related causes are shown on Figure 4-17 for a total of 531 interruptions between FY2019 to FY2021. The causes of these interruptions include adverse weather, lightning, vegetation, overhead defective equipment, and unknown causes.



Classification	Gust Speed (km/h)								Total Outages	Gust Direction								Total Outages
	<20	21-30	31-40	41-50	51-60	61-70	71-80	>80		N	NE	E	SE	S	SW	W	NW	
Adverse Weather	6	5	3	3	7	9	5	2	40	0	0	2	1	6	2	15	14	40
Overhead Defective Equipment	90	39	24	10	9	1	1	0	174	12	26	23	16	6	23	42	26	174
Lightning	11	8	16	5	6	2	0	2	50	0	8	5	0	0	1	13	23	50
Unknown	97	39	29	17	7	2	1	1	193	12	13	27	21	9	24	39	48	193
Vegetation	20	14	16	10	10	3	0	1	74	4	5	11	5	5	9	19	16	74
Total:	224	105	88	45	39	17	7	6	531	28	52	68	43	26	59	128	127	531

Figure 4-17: FY2019-FY2021 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 gust speed-direction are displayed in the table above (Figure 4-17) and the related faults per day shown in Figure 4-18. Fault clusters are prevalent for gust speeds above 20km/h in the majority when easterlies, south-westerlies and north-westerlies prevail.

[7] The Authority on Sustainable Buildings, https://www.level.org.nz/site-analysis/wind/

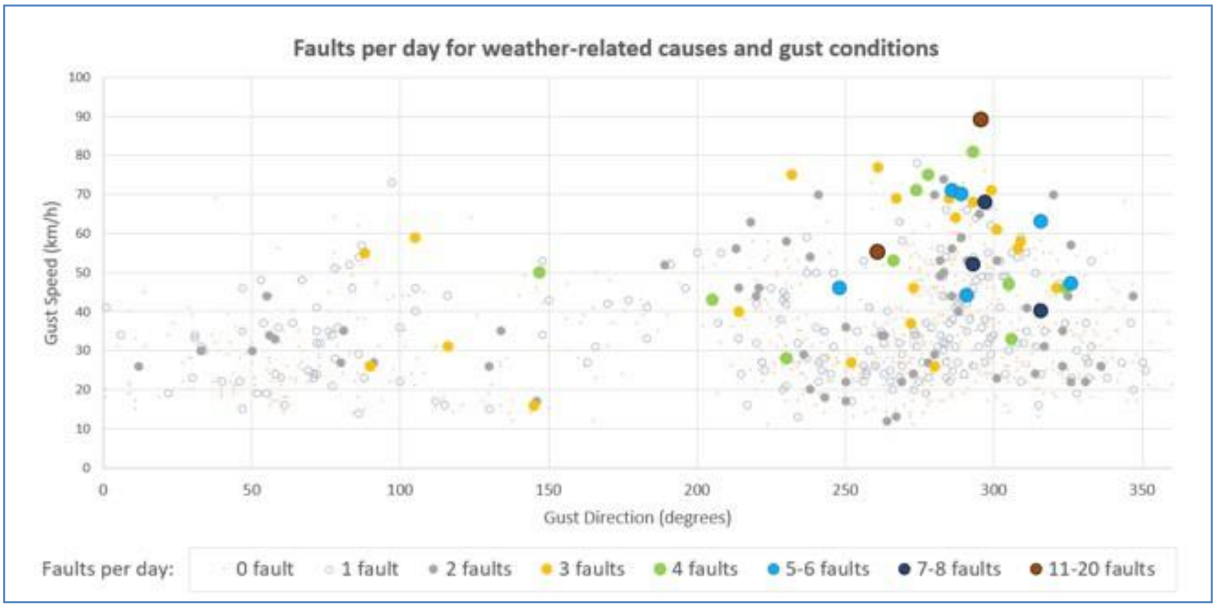


Figure 4-18: FY2019-FY2021 Number of daily faults versus gust conditions for weather related causes

The proportion of days with faults versus gust speeds and direction are shown in Figure 4-19. As the gust speeds increase (Figure 4-19a) from less than 20 km/h to speeds over 80km/h, the percentage of days-with-faults also increased from 21% to 100%.

When gusts' directions were analysed, Figure 4-19b shows that the highest proportion of days-with-faults occur when easterlies prevail (36%) followed by south-westerlies (32%) and north-westerlies also at 32%. The number of faults that could be affected by weather are also indicated.

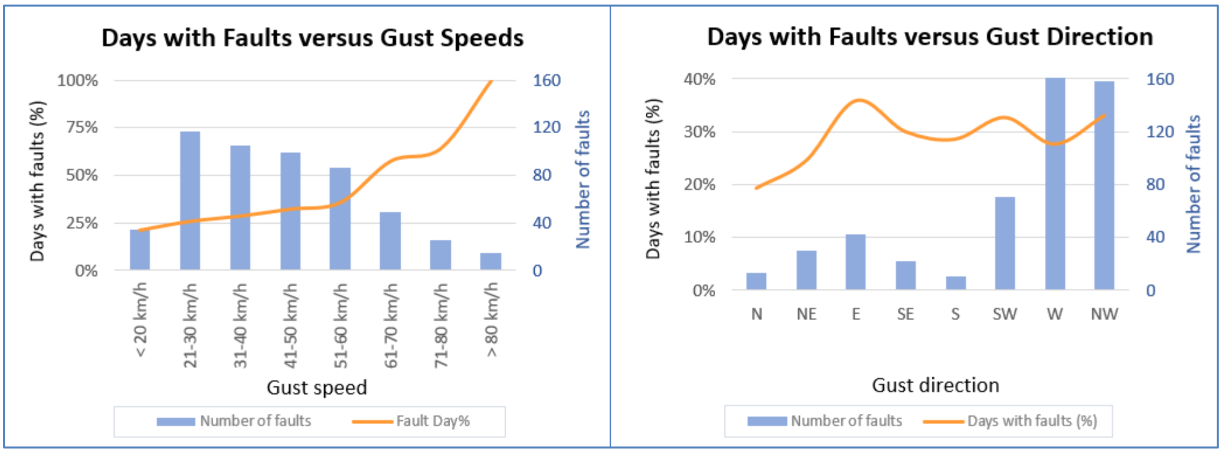


Figure 4-19: FY2019-FY2021 Proportion of fault days versus (a) gust speed and (b) gust direction

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 be 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 fifteen weather stations at various strategic locations across our network this financial year (Figure 4-20). The weather information (Figure 4-21), 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 4-21: b shows the dashboard for one of the weather stations commissioned and providing network teams with near real-time weather conditions.

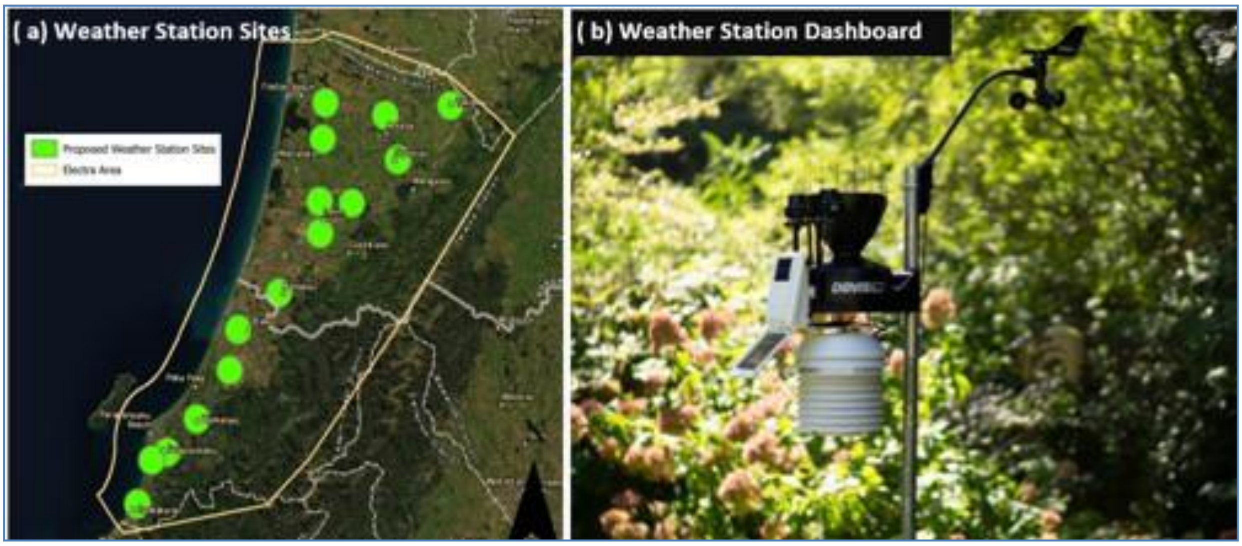


Figure 4-20: (a) Proposed location of weather stations; (b) Weather station installed at site

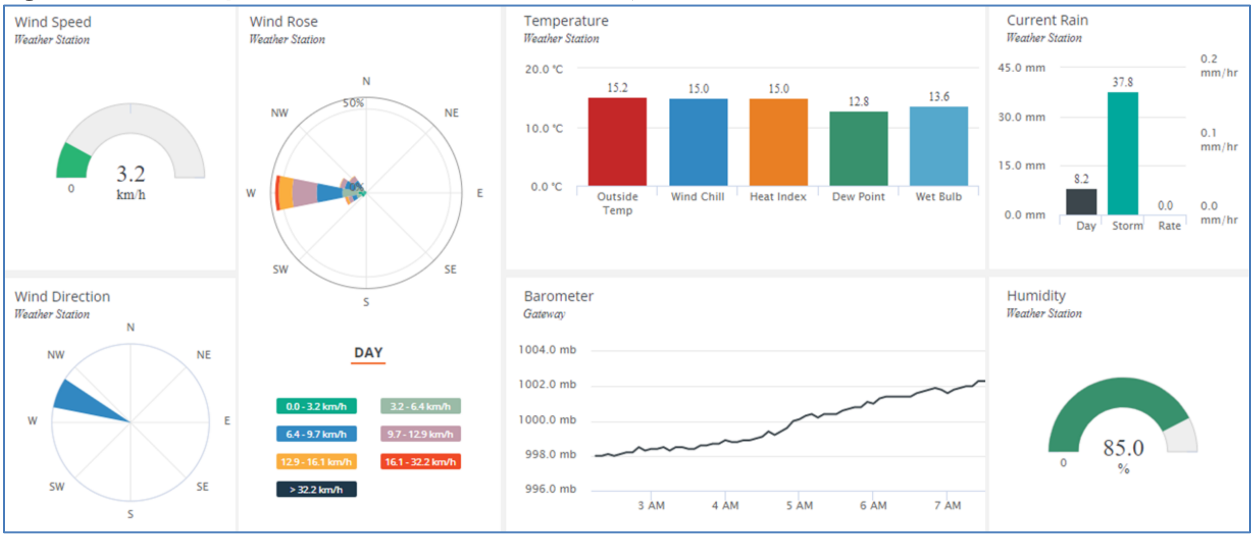


Figure 4-21: Weather station dashboard

4.4 Asset system performance

Electra's actual performance against target performance for the FY2021 year for key asset and financial indicators follow:

ATTRIBUTE	MEASURE	FY2021 TARGET	FY2021 ACTUAL	COMMENT
Industry performance	Electricity Distribution Information Disclosure Determination 2012 and subsequent amendments	Compliant	Compliant except in minor risk preparedness[8] sectors	AMP assessed as generally compliant.
Energy delivery efficiency	Load factor (units entering network/maximum demand * hours in year)	51%	50%	Slightly off the target by 1%.
	Loss ratio (units lost / units entering network)	7.4%	7.3%	Target achieved.
	Capacity utilisation (maximum demand/installed transformer capacity)	31%	31%	Target achieved.
Financial efficiency	Capital expenditure on assets (CAPEX) per: total circuit length (km) connection point	Increase within 5% of previous year	$6,119 $313	Compliant – significant decrease as compared to FY2020.
	Operational expenditure (OPEX) per: total circuit length (km) connection point	Increase within 5% of previous year	$5,746 (3% increase) $294 (2% increase)	Compliant - within 5% of previous indicators.

4.4.1 Load factor trends

Figure 4-22 illustrates the historical trends for our load factor, derived from the energy (GWh) entering our network and maximum demand (MW). Our load factor in FY2021 is 50% a slight decrease of 1% from FY2020, the low load factor is attributed to a historical legacy to over-design for system growth. The load factor is expected to rise by less than 1% annually in the coming years aligned with the forecasted annual increase of 1.1% and 0.7% of our consumption levels and maximum demand respectively. However, the load factor may be affected by a fall in energy (GWh) usage in FY2022, an effect from the Covid-19 pandemic.

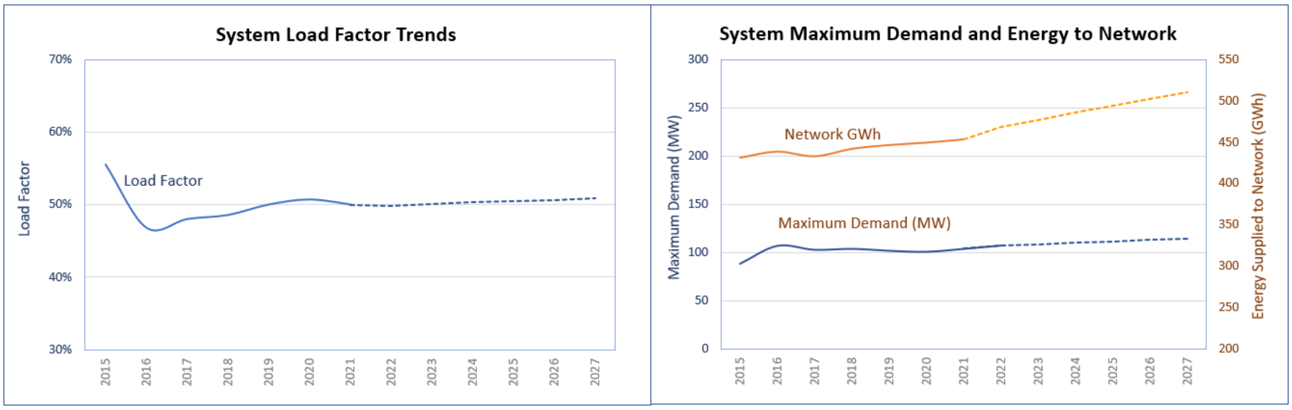


Figure 4-22: System load factor historical trends and forecast

[8] Commerce Commission (2019). AMP Review of EDB Risk Preparedness

4.4.2 Capacity utilisation trends

Figure 4-23 shows the industry's distribution transformer capacity utilisation against network load density. Electra sits well above the line of best fit at 31% utilisation and we use this relationship to set our utilisation target of above 30%.

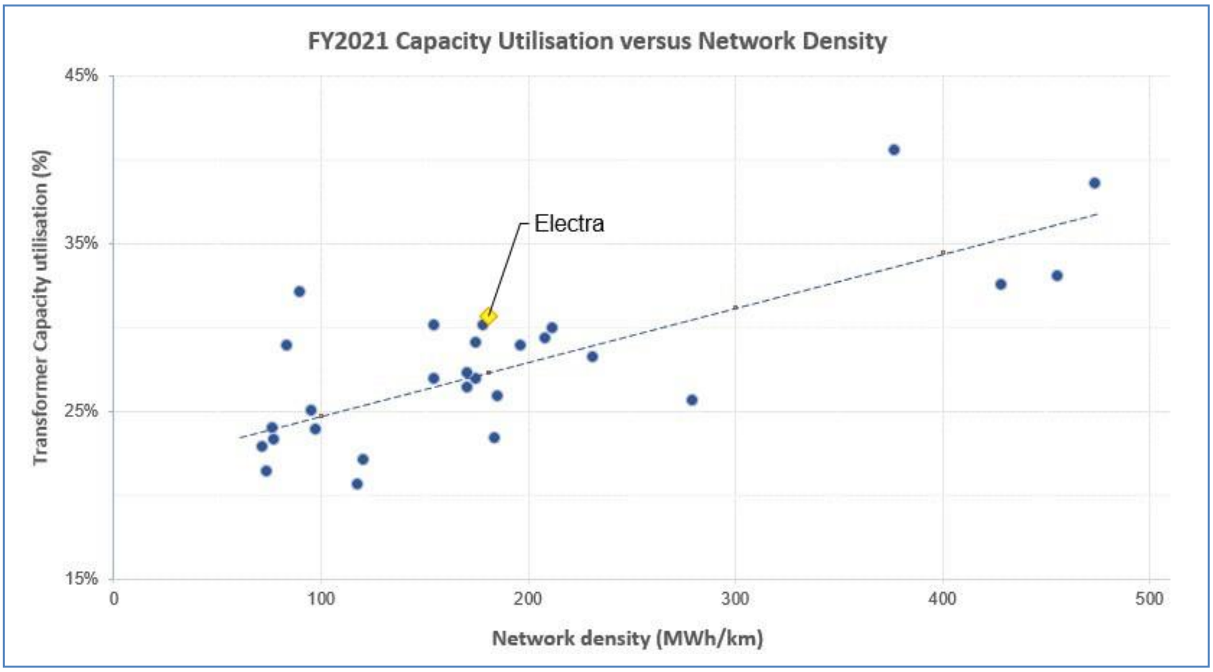


Figure 4-23: FY2021 transformer capacity utilisation versus network density

4.4.3 Loss ratio

Network losses fell from 7.7% in FY2020 to 7.3% in FY2021. Figure 4-24 shows the historical trends for our losses and system GWh from FY2010 to FY2021 as well as our forecasts until FY2027 where the loss ratio is forecasted to reduce by 0.5% annually with an increase in system GWh.

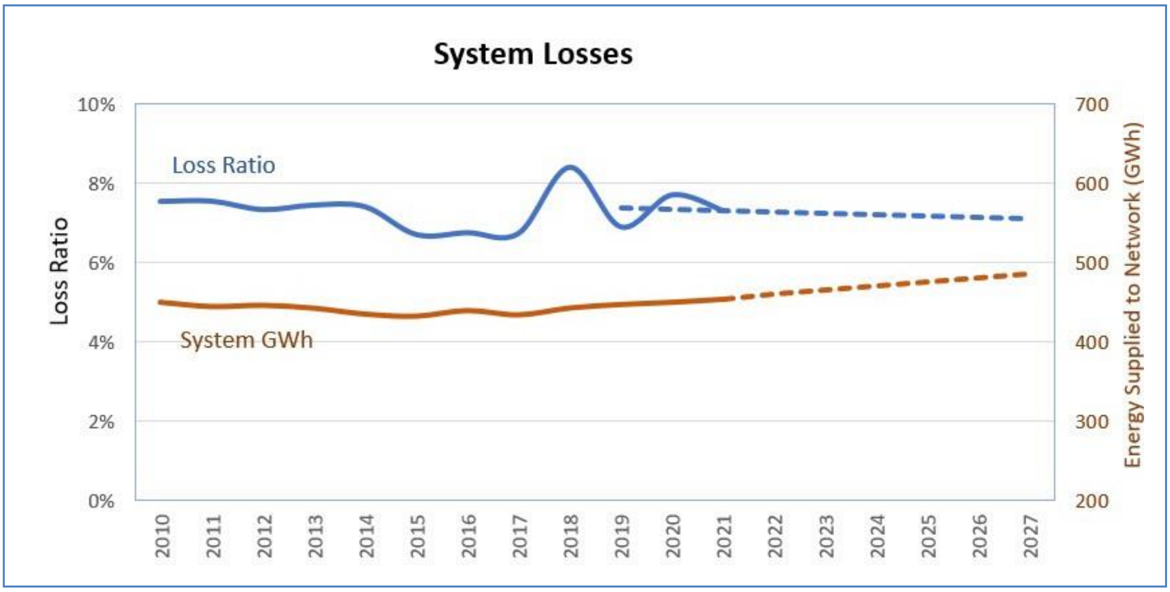


Figure 4-24: System losses historical trends and forecasts

The Power Loss Reduction initiative commenced in April 2021. 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 for all 11kV feeders so that technical losses can be accurately recorded. PQ meters on the LV network have also been installed to verify HV and LV loss calculations.

4.4.4 Financial effectiveness

To examine our OPEX and CAPEX, Electra is compared with its peer group[9] of eight networks based on network characteristics, network density and customer size; these networks include Alpine, Aurora, Counties Power, Horizon, Network Tasman, The Lines Co and Top Energy.

Within the peer group, our financial performances follow:

- OPEX/ICP at $294 is the second lowest in the group, within the first quartile as compared to the industry average of $427 and the peer median of $456 (Figure 4-25a)
- Asset CAPEX/ICP at $313 is the third lowest - within the first quartile as compared with the industry average of $542 and the peer median at $544 (Figure 4-25b)
- Asset CAPEX/km at $6,119 is in the third quartile and above both the peer median ($4,462) and industry average ($5,777) as per Figure 4-26a.
- Line charge revenue/ICP (Figure 4-26b), at $776 is the lowest compared with the peer median and industry average of $1,180 and $1,296 respectively.

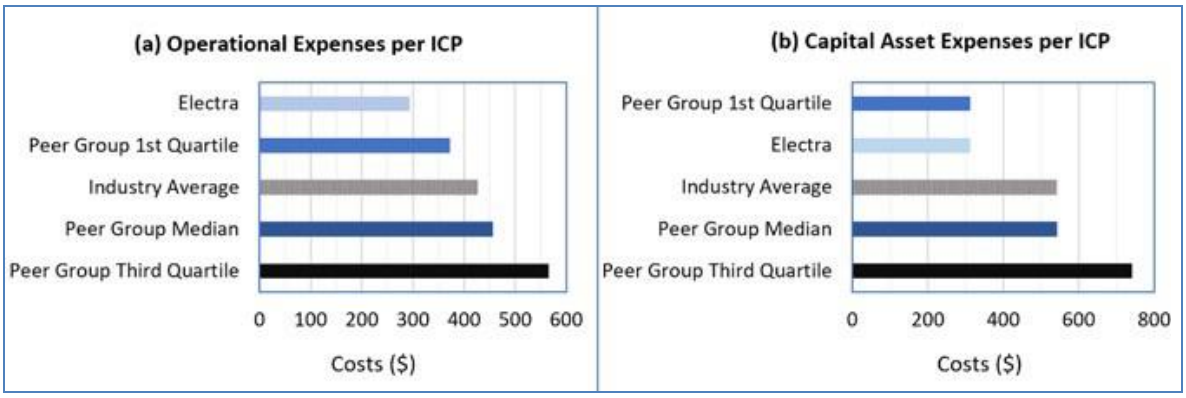


Figure 4-25: Peer group FY2021 OPEX and Asset CAPEX per ICP

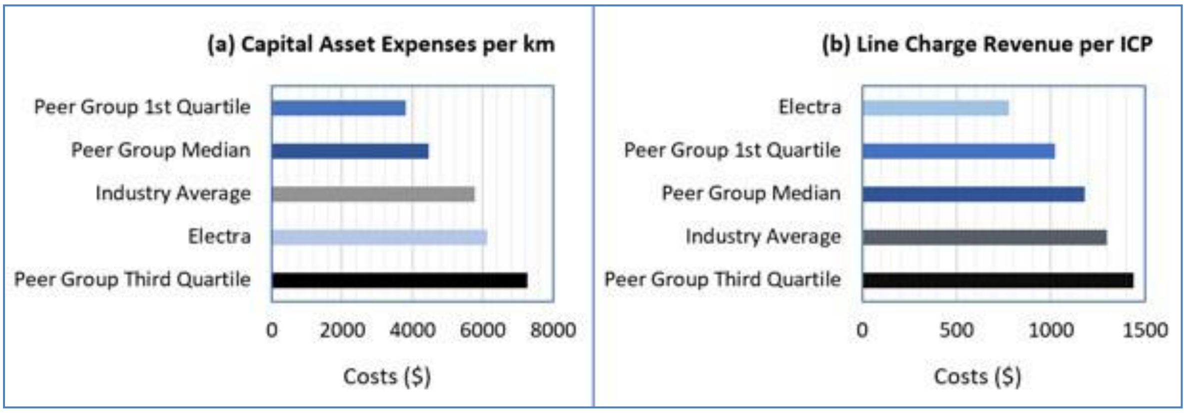


Figure 4-26: Peer group FY2021: (a) Asset expenditure per km, and (b) Line charge revenue per ICP

Though Electra has a low system growth budget lower than its peers, due to 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 4-27a. The expenditure is necessary to replace infrastructure built between the 60s and 70s to provide the security and reliability to customers.

Further the use of a per kilometre (km) measure does not favour Electra due to the relatively short network (FY2021 at 2,330km) as compared to the peer group (3,874km) and industry (5,380km) averages (Figure 4-27b).

[9] FY2021 data is extracted from Information Disclosure schedules from the relevant EDB's website.

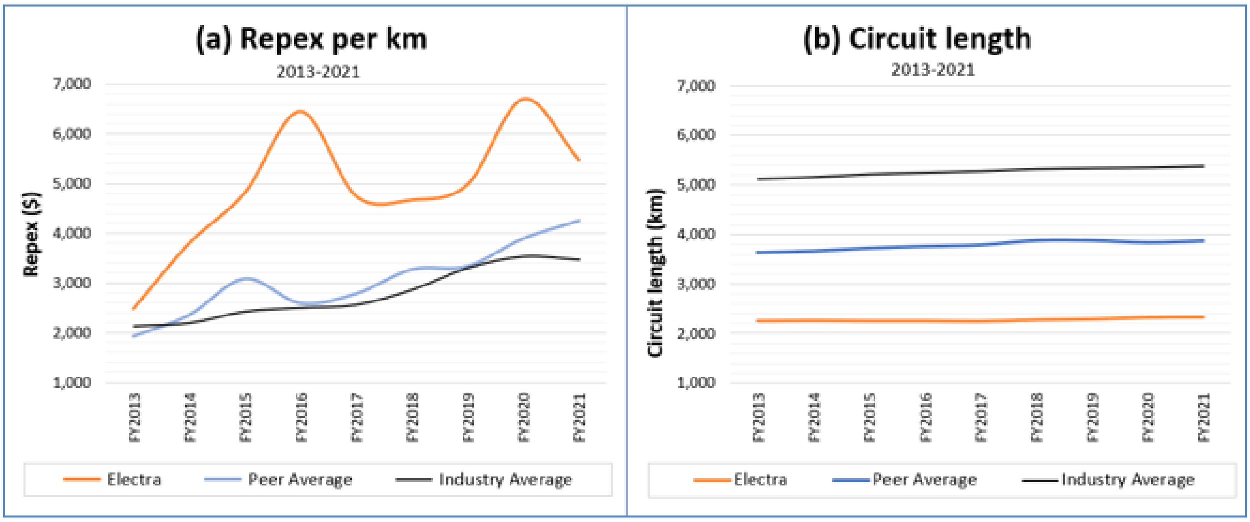


Figure 4-27: FY2013 to FY2021 (a) Renewal and replacement expenditure; (b) Total circuit length (km)

To study the operational expenses further, the OPEX per km of total circuit length is compared to reliability indicator SAIDI (unplanned) for FY2021 as shown in Figure 4-28 and compared with similar electricity distribution businesses (EDBs) in New Zealand. The input parameters are extracted from the FY2021 Information Disclosures for the relevant EDBs. Electra is within a group of nine EDBs whose average OPEX/km is over the industry average of $4,476 but below the unplanned SAIDI average of 110 minutes.

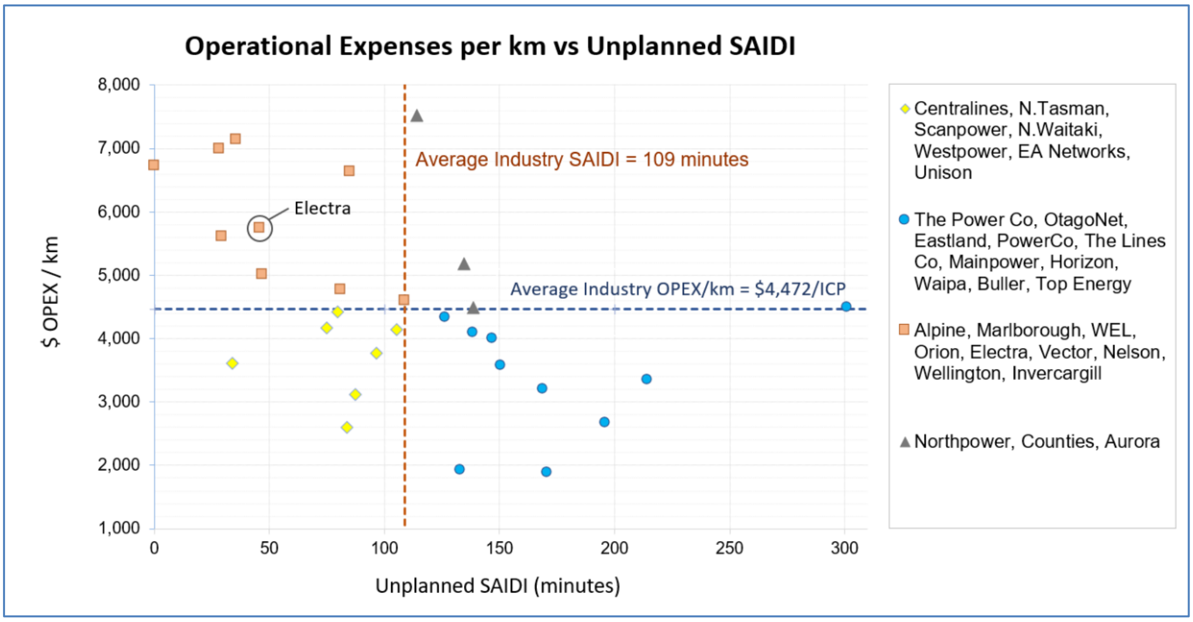


Figure 4-28: Operational expenses per circuit length (km) versus unplanned SAIDI for FY2021

Figure 4-29 compares the FY2021 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 $427 and 110 minutes respectively. Our OPEX/ICP at $294 is 31% below the industry average while unplanned SAIDI (46 minutes) is 58% below the average.

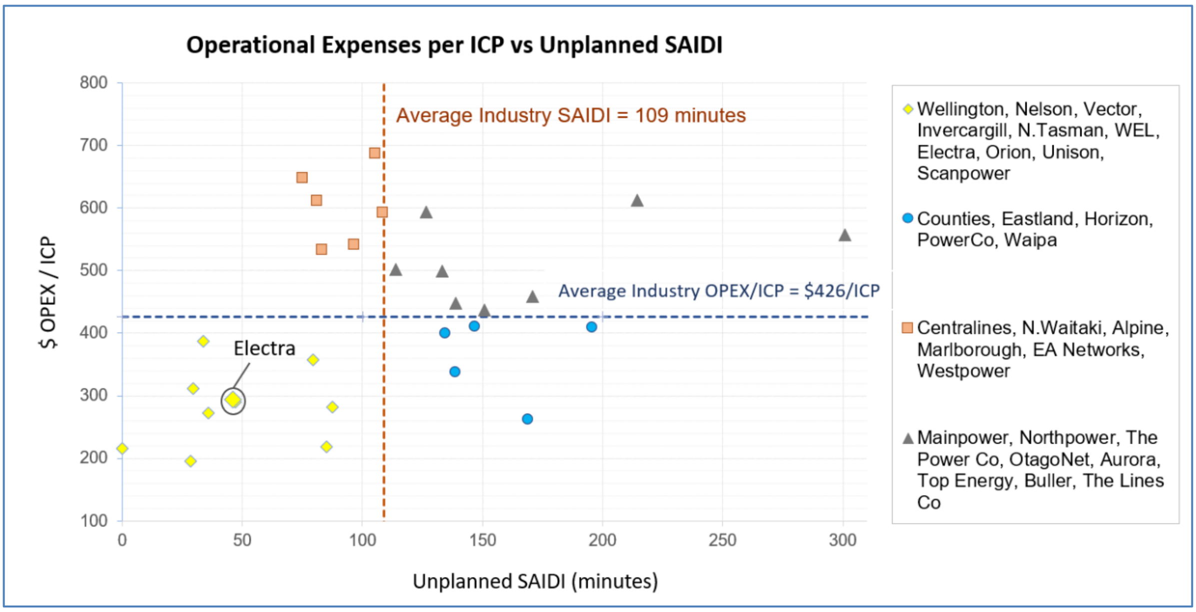


Figure 4-29: Operational expenses per ICP versus unplanned SAIDI for FY2021

Figure 4-30a displays the downward trend of our delivery costs or line charge revenue per ICP from FY2019 to FY2021. Further, our survey results (Sections 2.2 and Figure 4-30) suggest that 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 low cost (revenue per ICP) versus the low SAIDI quadrant depicted in Figure 4-30b.

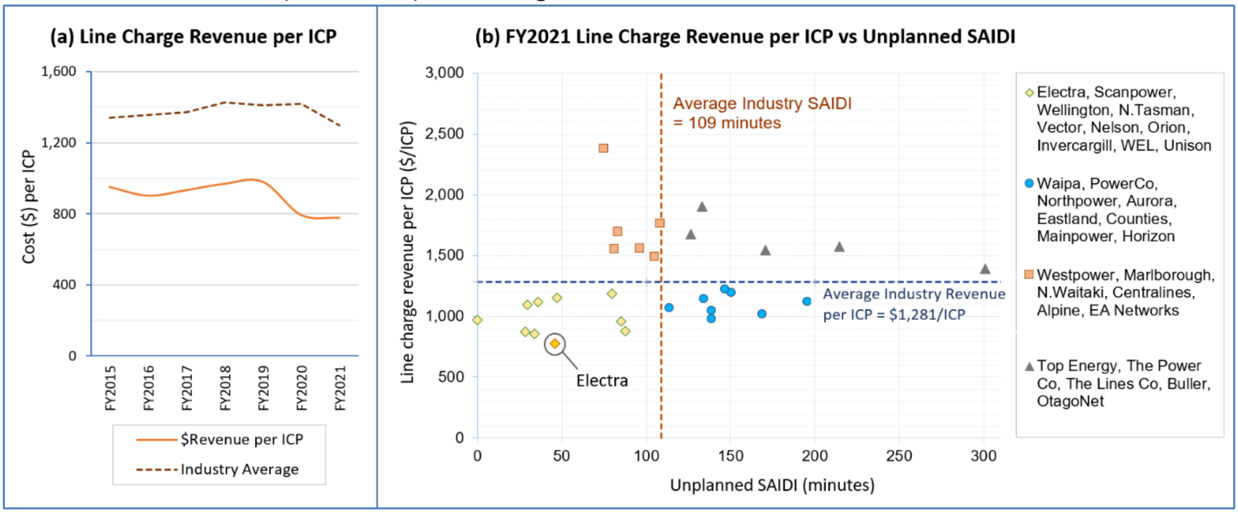


Figure 4-30: (a) Line charge revenue per ICP trend (b) FY2021 Line charge revenue per ICP versus unplanned SAIDI minutes

4.4.4.1 System operations, network, and business support expenditure

From FY2020 to FY2021, system operations and network support (SONS) costs increased by 9% while business support costs increased by 8%. In comparison with our peers, we are below the SONS median by 5% and well below (48%) the industry average as shown in Figure 4-31a. For business support costs (Figure 4-31b), these are also below the peer group median and industry average by 26% and 39% respectively.

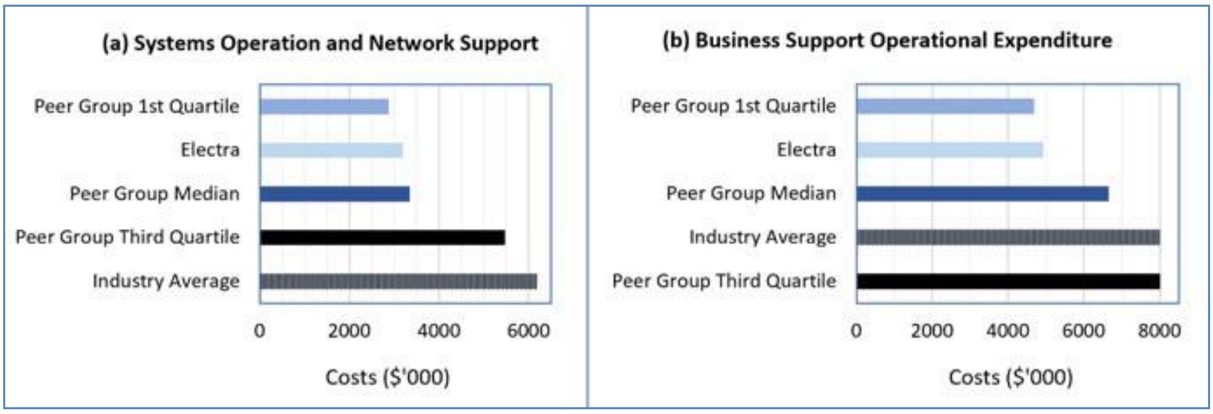


Figure 4-31: Peer group FY2021: (a) System operations and network support, and (b) Business support operating expenditure

ASSET MANAGEMENT PRACTICE PERFORMANCE

5 ASSET MANAGEMENT PRACTICE PERFORMANCE

Electra was independently benchmarked and found to be a leading performer in the NZ EDBs for low unplanned SAIDI relative to the size of its network and keeping costs to achieve this outcome as low as practical, while still committing to best-in-class safety performance.

The ISO 55000 2020 review[10] 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.

The 2020 review also found that Electra needed to improve in three areas: (i) use of asset information systems; (ii) integrated planning from engineering through maintenance to schedule and, (iii) deliver work and balancing continual improvement with business as usual in a lean team. As better use is made of information to specify, plan and schedule work, the teams delivering the work can be further supported and improvement can be tracked across the organisation.

Therefore, Electra is investing in systems to benefit the delivery teams and assist with feedback to the engineering and planning personnel who request the work in the first place. Where problems are encountered in the field or more work is needed, Electra wants to streamline that communication and measure performance so that everyone understands where improvement and support are needed.

Lifting Electra's asset management delivery requires the following:

- Investing in a comprehensive works management system that everyone can share and work together with.
- Use information to better schedule work so that people are confident that they are working on the right jobs with enough time allowed for the work, required parts and materials available and quality procedures to help specify the work to be done.
- Inspections and feedback improve so that precise data about the assets can be fed back to engineering assessment and planning.
- Continual improvement can consider better methods in defect elimination using work history and asset condition information. This will support registered actions to manage out inefficient practices such as communication gaps, limitations in specifying work and improving understanding of the condition of the network.

Improving the approach to asset management is an across-the-organisation effort. Improvement will be achieved through an open and honest approach with good feedback on the problems that people face and what our leaders must address.

Electra's current asset management performance is excellent and with these four areas of focused improvement, the organisation, and the network it serves will be future proofed against unforeseen risks associated with ageing infrastructure as well as a changing external environment such as government expectations, local customers and the risk of major shocks such as come from our changing environment.

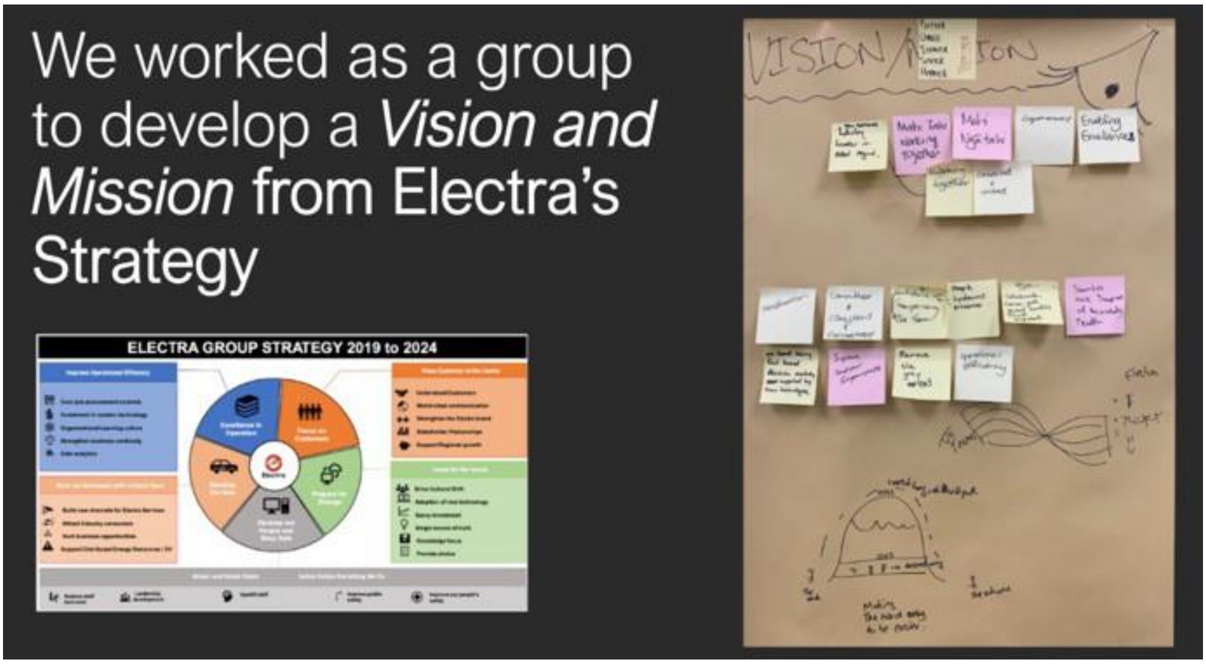
[10] Covaris ISO 55001 Review, July 2020

5.1 Enterprise Asset Management System

As part of Electra's ISO 55000 alignment initiative, Electra has identified an Enterprise Asset Management (EAM) system as a key step in the process improvement journey framed by the Mahi Tahi project which also encompasses the upgrade of our Enterprise Resource Planning (ERP) system to Business Central.

As part of the implementation of Mahi Tahi, which is essentially a one stop shop, Electra has involved industry experts to work with a wider Electra team to identify and streamline existing business processes. A range of process improvements have been identified both system-related and non-system processes. The critical ones are currently progressed in parallel with system implementation of the project.

Electra launched the EAM system in June 2021. After an extensive review, The Asset Guardian or TAG was selected as the most appropriate EAM solution with the best fit for Electra considering our company size, the ease of implementation and adoption from a change management perspective as well as the stage of our asset maturity journey. Our development risks were assessed, and a review will be carried out in three years - and we are excited to be engaged in the drive towards continual improvement in our asset management processes aligned with our ISO 55000 strategy.



Implementation of an EAM system and making the necessary changes to our practices will result in the improvement of our asset management maturity or AMMAT[11] 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.

When fully implemented, Electra will be able to better plan, optimise, implement, and track the health of assets and activities associated with the assets. TAG will provide us with leading asset and works management, reporting capability to ensure the efficient use of resources, reduced downtime, increased visibility of costs and most importantly, provide a single system that can effectively and transparently deliver accurate auditable information – not only for Electra but for our customers, stakeholders, and external regulators.

[11] Schedule 13 Report on Asset Management Maturity, Electra AMP FY2021

Mahi Tahi
one company, working together

5.2 Mahi Tahi Programme

With the adoption of TAG, Electra launched the Mahi Tahi programme, to “co-operate, teamwork, collaborate” – bringing together all business areas with the vision “to connect and empower people to one Electra enabled by industry leading technology” and our mission objectives displayed in Figure 5-1 where we aim to transform our business to improve operational efficiency and achieve excellence in our operations.

Mahi Tahi will deliver a single system to operate the business, rolling out an all-Microsoft solution for finance, job planning, management, and asset management.

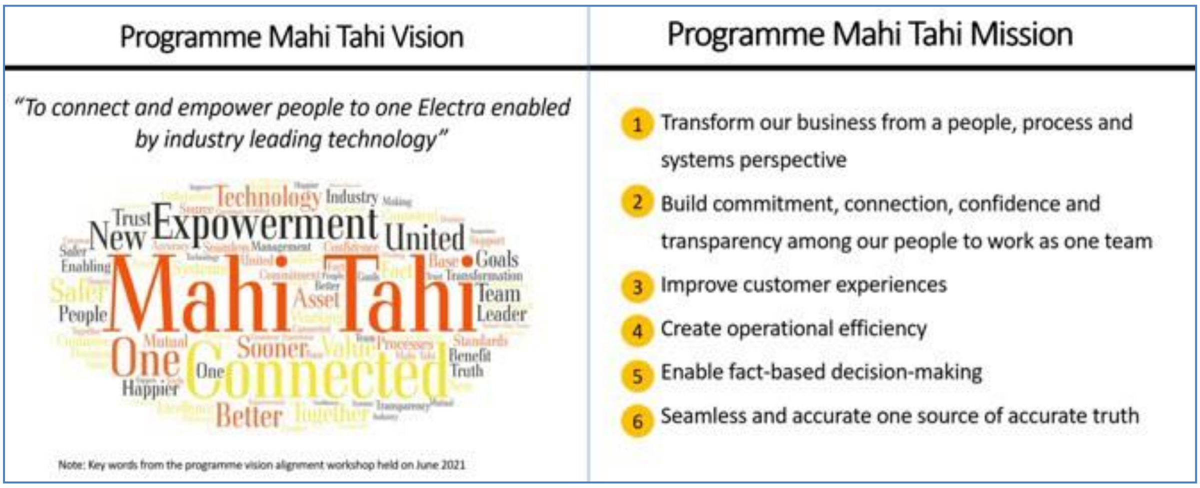


Figure 5-1: Mahi Tahi vision and mission

5.3 Process improvement

To improve our processes, Electra used SIPOC framework to define the voice of the customer or business, then map the current steps we take to identify value-added and non-value-added activities to analyse the efficiencies so that we can define process improvements (Figure 5-2). The acronym SIPOC stands for suppliers, inputs, process, outputs, and customers used in Lean sessions for process improvement.

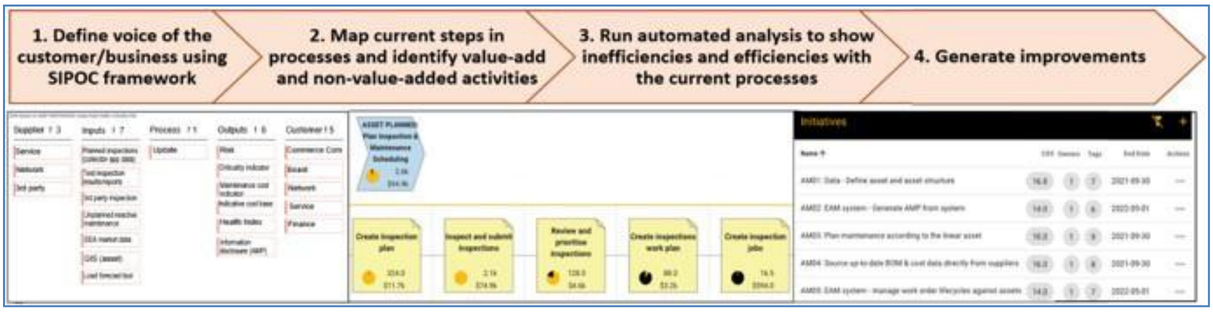


Figure 5-2: Stages for process improvement

The key outcomes benefits and risks and impacts are analysed for our asset management processes covering asset maintenance, project implementation, procurement, inventory as well as financial and sales functions. Figure 5-3 summarises the processes identified for improvement categorised by: (a) Business Centre, (b) TAG, (c) ADMS/GIS/ CRM and (d) non-system improvements including the degree of complexity and the level of risk to the business.

Together with the ADMS, the new system will provide us the tools to analyse asset health, criticality, reliability, and failure modes that will result in a reduction in defective equipment, unknown and weather-related outages as the improved processes and analysis will lead to more targeted inspection, renewal, and maintenance activities.

LEAN workshops involving all levels of staff were conducted where Electra assessed how to streamline systems and remove waste from the current asset management, operational and financial processes. The improved asset management system will be modelled in TAG and systems go live by July 2022.

The process improvement approach called LEAN was used, where it determines which processes are valuable and provided the opportunity to identify improvements that could be made before the new system was configured. The network assets were also modelled into TAG so the setup could be configured for reporting and where gaps in current data sets can be analysed.

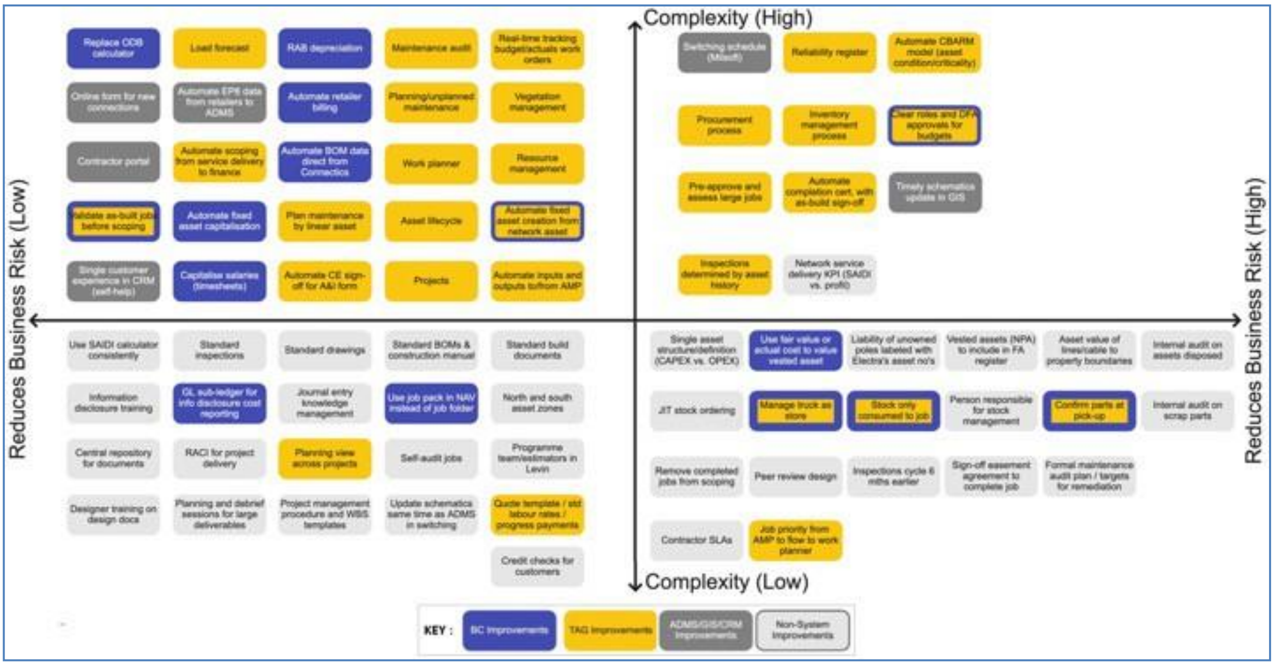


Figure 5-3: Summary of improvement processes

5.4 Asset Information Maturity Framework

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:** InfluxDB is a data solution capable of storing, analysing and displaying large amounts of time seriesdata
- **Power BI:** Power BI is a business analytics service. It enables interactive visualizations and business intelligencecapabilities
- **Splunk:** Splunk is a solution capable of ingesting, storing and analysing large amounts of unstructured event-based data.

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.

An asset data maturity assessment has been carried out as a precursor to the TAG implementation. The current maturity of asset information processes and the state of 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.

NETWORK DEVELOPMENT PLANS

6 NETWORK DEVELOPMENT PLANS

6.1 Network Overview

Comparison of key parameters of Electra's network on 31 March 2020 and 31 March 2021 is shown in the following table:

PARAMETERS	31 MARCH 2020	31 MARCH 2021	% INCREASE
Average number of customer connections in disclosure year	45,192	45,562	0.8%
Maximum demand (MW)	101	104	3.0%
Annual electricity conveyance (GWh)	450	454	0.9%
Total circuit length (km)	2,323	2,330	0.3%
Number of zone substations	10	10	-
Number of distribution transformers	2,563	2,572	0.4%
Network asset valuation	$202M	$209M	3.5%

The maximum demand recorded for FY2021 was 104MW, 1.5% below the forecast of 105.7MW. Annual energy of 454GWh was also 0.7% below the forecast of 457GWh.

6.2 Network System Demand

Based on thirty-minute mean demands at our Mangahao and Valley Road GXPs, the maximum coincident winter demand was 107.4 MW recorded on 29 June 2021, an increase of 3.3% as compared to the previous year's increase of 2.6%. Figure 6-1 shows the demand profile as well as the associated time duration analysis on the percentage of time the load was exceeded.

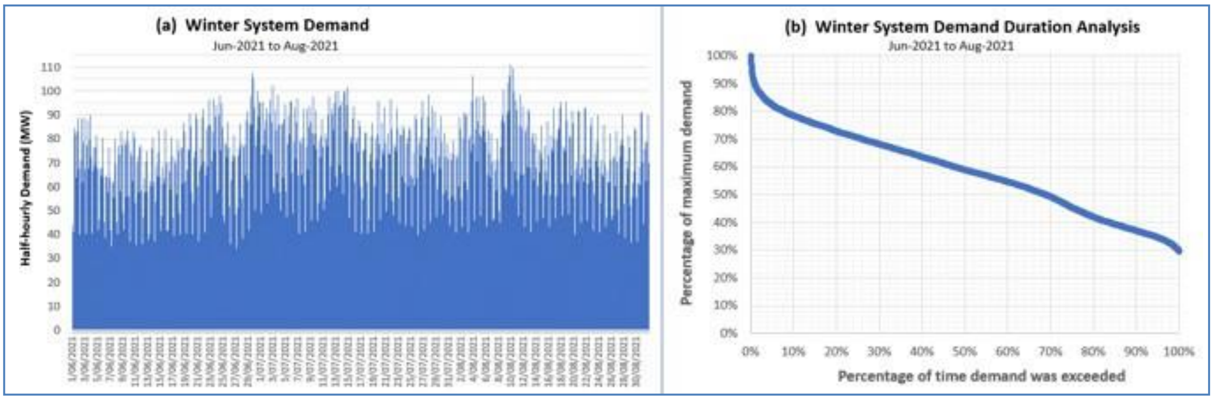
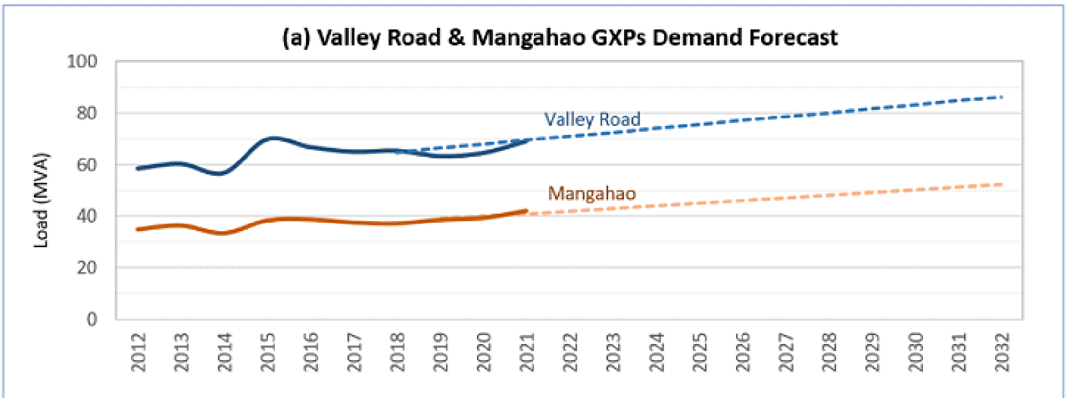


Figure 6-1: (a) Winter system demand profile for June-August 2021; (b) Demand duration analysis

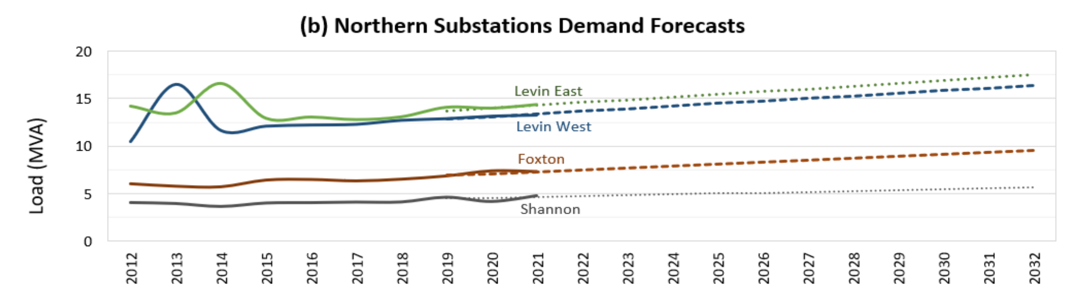
Figure 6-2a shows the Valley Road and Mangahao GXP demand forecasts. Comparing the GXP winter maximum demands (MD) for calendar years 2020 and 2021, Valley Road's MD increased from 64.5MVA to 69.1MVA while Mangahao's MD rose from 39.2MVA to 42MVA. Valley Road's forecasted annual demand based on the current trends was 2.2% whilst Mangahao was slightly lower at 1.4%.

Transpower has reported[12] 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 availability of Mangahao generation and load control options (using hot water loads) are available to Electra to offset the risk of a demand shortfall. 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.



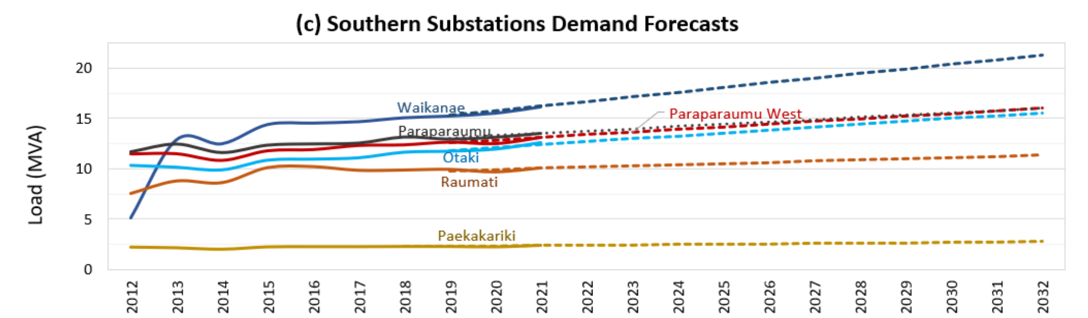
GXP	Actual	Forecast Maximum Demand (MVA)											Annual
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Increase %
Valley Road	69.1	71.0	72.5	74.0	75.6	77.1	78.6	80.1	81.7	83.2	84.7	86.2	2.7%
Mangahau	42.0	42.1	43.1	44.1	45.2	46.2	47.2	48.3	49.3	50.3	51.4	52.4	2.0%

[12] Transpower Planning Report 2021, Section 11 "Central North Island Regional Plan"



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

Zone Substation	Actual 2021	Forecast Maximum Demand (MVA) 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Increase %
Levin East	14.0	14.6	14.9	15.2	15.4	15.7	16.0	16.3	16.6	16.9	17.2	17.5	2.0%
Levin West	13.1	13.7	13.9	14.2	14.5	14.7	15.0	15.3	15.6	15.8	16.1	16.4	2.0%
Foxton	7.4	7.5	7.7	7.9	8.1	8.3	8.5	8.7	8.9	9.1	9.3	9.5	2.7%
Shannon	4.8	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.5	5.6	1.9%



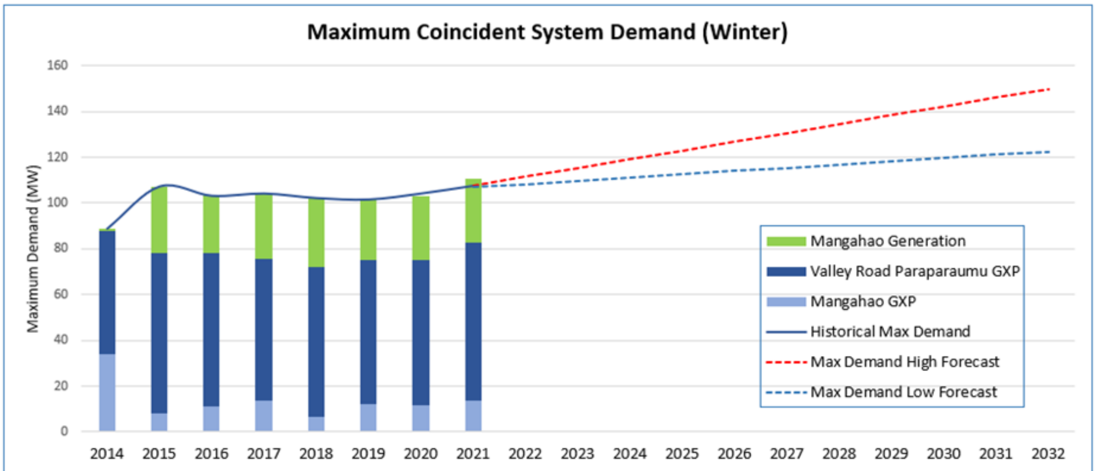
Note: Capacity (n) for Paekakariki is 5 MVA; all other substations = 46 MVA.
The (n-1) scenario for all substations except Paekakariki = 23 MVA.

Zone Substation	Actual 2021	Forecast Maximum Demand (MVA) 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Increase %
Waikanae	15.5	16.7	17.1	17.6	18.1	18.5	19.0	19.4	19.9	20.4	20.8	21.3	2.8%
Paraparaumu	13.1	13.7	14.0	14.2	14.4	14.6	14.9	15.1	15.3	15.6	15.8	16.0	1.7%
Paraparaumu West	12.5	13.4	13.6	13.9	14.2	14.4	14.7	14.9	15.2	15.5	15.7	16.0	2.0%
Otaki	11.9	12.7	13.0	13.3	13.6	13.8	14.1	14.4	14.7	15.0	15.3	15.6	2.3%
Raumati	9.6	10.2	10.3	10.4	10.5	10.6	10.7	10.9	11.0	11.1	11.2	11.3	1.2%
Paekakariki	2.2	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7	2.7	2.8	1.5%

Figure 6-2: Winter system demand forecasts for: (a) Valley Road and Mangahao GXPs; (b) Northern substations; (c) Southern substations.

Details of the northern and southern substations' demand forecasts are shown in Figure 6-2b and Figure 6-2c respectively. Average load growth rates have increased slighty from last year's forecast.

Our Huringa Pūngao Energy Transformation report indicates two scenarios for future uncontrolled and controlled demand (Section 6.3) relating to the uptake of DERs and Figure 6-3 depicts the low and high demand forecasts at 1.4% and 2.6% respectively, relating to these scenarios and based on our current winter demand of 107.4 MW.



GXP	Actual 2021	Forecast Maximum Demand (MVA) 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Increase %
Max Coincident Demand	107.4												
- Low forecast		108	110	111	113	114	115	117	118	120	121	122	1.3%
- High forecast		111	115	119	123	127	131	134	138	142	146	150	3.5%

Figure 6-3: Maximum coincident winter demand

6.3 Flexibility Solutions

Flexibility solutions use DERs or distributed energy resources 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[13].

Electra has commissioned an initiative called Huringa Pūngao or the Energy Transformation Roadmap[14] which aims to reduce our carbon emissions through electrification and increased renewable generation to achieve net-zero 2050, where DERs are a key factor to achieving decarbonisation. 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:

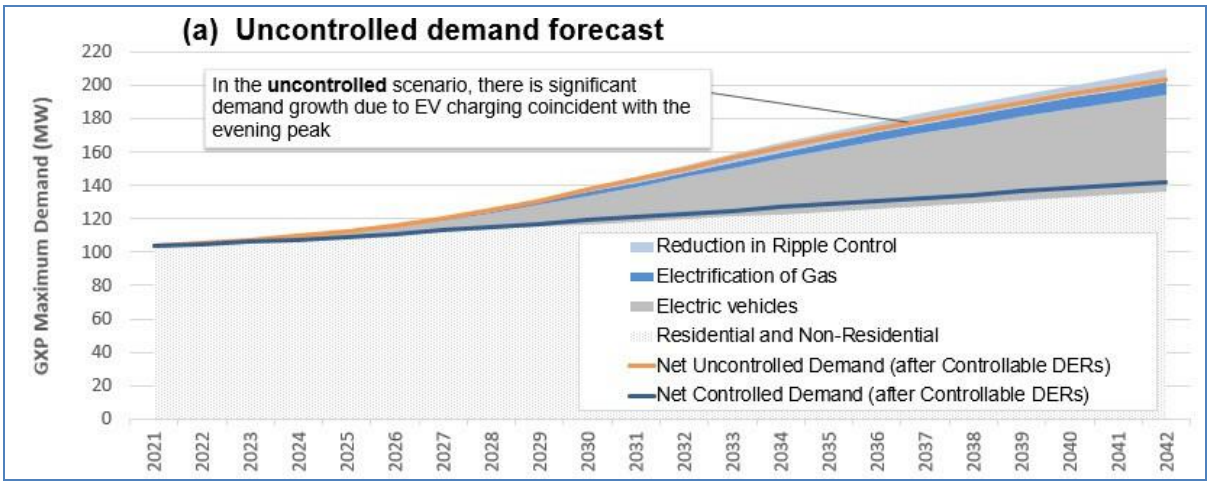
- Population growth
- Future electricity intensity
- Uptake of electric vehicles
- Electrification of gas
- Demand control
- Uptake of distributed energy resource.

6.3.1 Huringa Pūngao Energy Transformation Impact

Two scenarios were developed that demonstrates the impact of energy transformation:

- 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.

The difference in the above two scenarios relates to demand. For the uncontrolled scenario in Figure 6-4(a), demand increases 95% from 104 MW (2021) to 203 MW (in 2042) where the increase is mainly due to uncontrolled EV charging and a degradation in load control. Figure 6-4(b) shows the controlled scenario where demand increases 37% from 104 MW (2021) to 143 MW in 2042.



[13] Electricity Authority's Discussion Paper July 2021, "Updating the Regulatory Settings for Distribution Networks - Improving competition and supporting a low emissions economy".
[14] Energia, Huringa Pūngao Energy Transformation Roadmap Final Report, October 2021

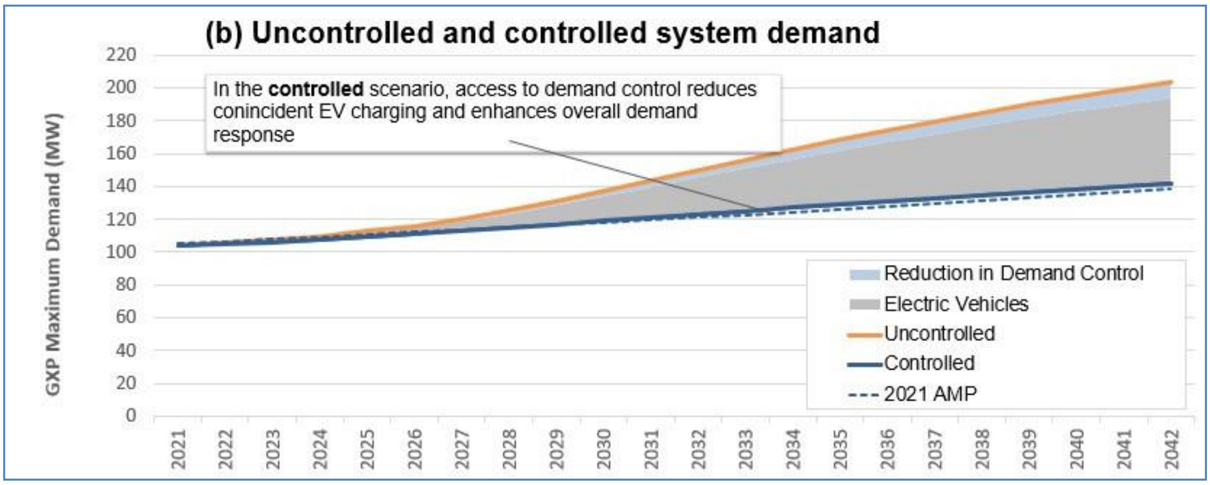


Figure 6-4: Electra demand scenarios for energy transformation until 2042: (a) Uncontrolled demand forecast; (b) The differences between uncontrolled and controlled demand

Electra has identified the potential impact of the above scenarios and our analyses are ongoing - covering capacity, voltage, harmonic and hosting capacity and these impacts are summarised in Figure 6-5.

UNCONTROLLED SCENARIO POTENTIAL IMPACTS	CONTROLLED SCENARIO POTENTIAL IMPACTS
• The capacity at Mangahao GXP is consumed by 2030. There are no constraints at Paraparaumu GXP	• The capacity at Mangahao GXP is consumed by 2039. There are no constraints at Paraparaumu GXP
• Seven of the ten zone substations experience a shortfall in capacity by 2042 where capacity issues will occur at Shannon in 2028, then Waikanae in 2033	• Only Shannon substation experiences a shortfall in capacity, which occurs in 2033
• For the sub transmission network, voltage constraints limit the contingent capacity on the northern sub trans-mission system from 2024 (to Ōtaki), with significant issues occurring across all circuits from 2035. The other sub transmission issue is the contingent capacity on the Paraparaumu to Waikanae cables, which emerges in 2027	• For the sub transmission network, voltage drop limits the contingent capacity on the circuit from Levin to Ōtaki from 2026. The only other sub transmission issue is the contingent capacity on the Paraparaumu to Waikanae cables, which emerges in 2038.
• For the distribution feeders, demand increases above capacity on 20% of feeders by 2025, increasing to 50% of feeders by 2034, and 67% of feeders by 2042	• For the distribution feeders, demand increases above capacity on 20% of feeders by 2026, but only increases to 45% of feeders by 2042.
• The LV system and distribution transformers should have adequate capacity, but the LV will experience voltage compliance issues from around 2028. By 2042, 60- 70% of transformers will have some connected consumers with voltage outside of the 230V +/- 6% requirement.	• The LV system and distribution transformer should have adequate capacity - however, we are estimating that around 5% of transformers will have connected consumers experiencing voltage compliance issues by 2042.

Figure 6-5: Potential impacts on Electra's network for uncontrolled and controlled scenarios

Interim analyses have been conducted for example for distribution transformers and the low voltage (LV) network (see Figure 6-6), indicated that, on average, the LV system and distribution transformers should have adequate capacity, but the LV will experience voltage compliance issues from around 2028. By 2042, 60-70% of transformers will have some connected consumers with voltage outside of the 230V +/- 6% requirement.

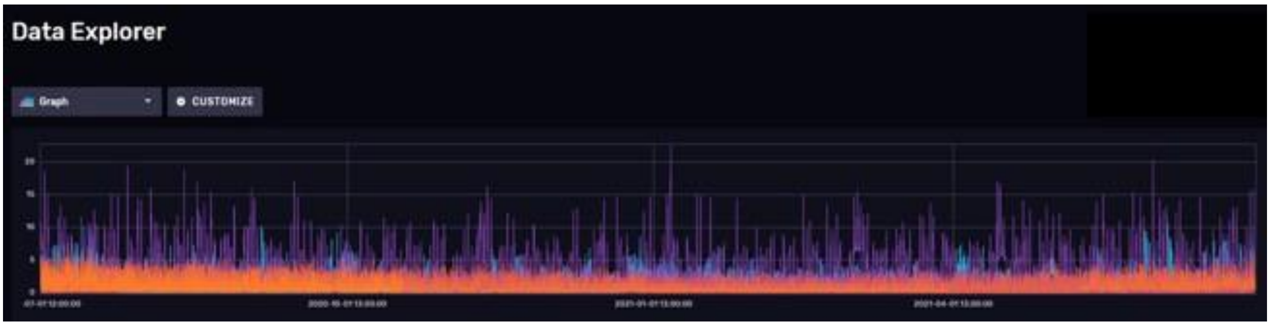


Figure 6-6: Half-hourly consumption over 12 months for 1% area of Electra's network

The issues that will impact consumers located at the end of LV circuits are indicated on the two schematics in Figure 6-7 incorporating heatmaps for a 300kVA transformer (G155) with 86 ICPs supplied from Taitoko feeder from the Levin East substation where the red areas indicate poorer end-of-line voltage drop.

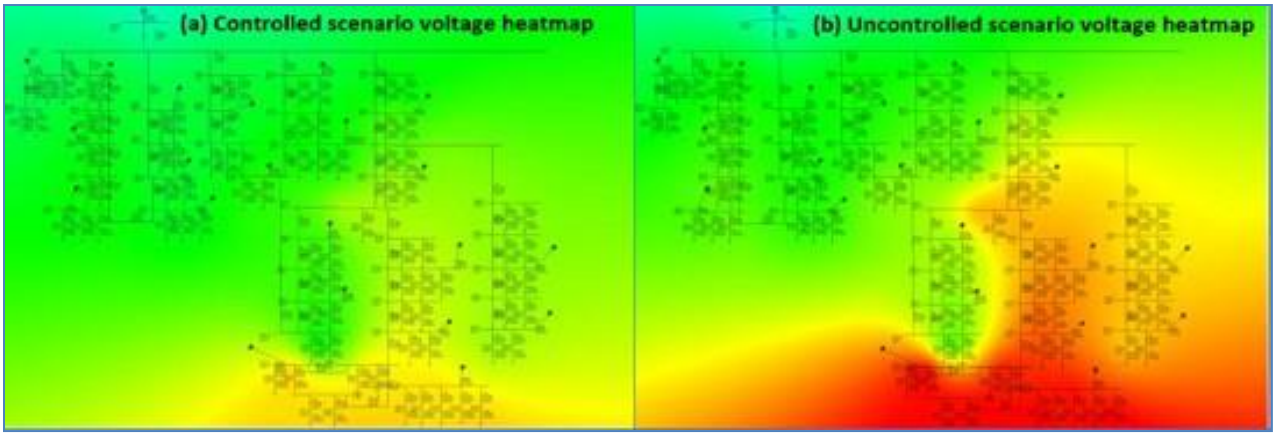


Figure 6-7: FY2042 Voltage heatmaps for (a) Controlled scenario; (b) Uncontrolled scenario

Understanding the scope and cost of the network response is important for Electra as it sets the cost ceiling for pursuing non-network solutions outlined in the roadmap. Studies are being conducted on the network and non-network responses to mitigate the above impacts and the Figure 6-8 is a summary of our ongoing work on the network and non-network responses we have identified.

UNCONTROLLED SCENARIO FOR ENERGY TRANSFORMATION	CONTROLLED SCENARIO FOR ENERGY TRANSFORMATION
• Upgrading of Mangahao transformers in 2030 to resolve GXP capacity and sub transmission voltage issues • Two new zone substations (one in the Waikanae/ Paraparaumu area in 2033 and one in Levin in 2033) • 17 new distribution feeders • 990 new distribution transformers, 70 ring main units, and associated reconfiguration of LV circuits • New systems and processes such as LV monitoring, upgrading of ADMS, connection and consumer data management system • An additional 5.5 FTEs will be required with capabilities in network control, data management; system modelling; asset management and engineering; and new connection management. • Additional investment estimated at $126 million of additional Capex, and an additional $49 million Opex to 2042	• Upgrading of Mangahao transformers but not until 2039 • No new zone substations are required • Most feeder loading issues can be managed via rebalancing and with four additional feeders. • Only minor LV augmentation is required • Systems and processes required are broadly similar to the uncontrolled scenario, but with the addition of functionality for the purchasing and control of flexibility services, and meter data management • Additional investment is estimated at $41 million, with an additional $33 million Opex through to 2042

Figure 6-8: Electra's responses to mitigate the impacts of uncontrolled and controlled scenarios

6.3.2 Huringa Pūngao Energy Transformation Roadmap

Electra's primary objective for the Huringa Pūngao energy transformation roadmap is to ensure that our network capability will allow customers to connect and increase their use of electricity to replace fossil fuels and to integrate DERs into the network. Our objectives also include providing guidance to integrate DERs and to support bidirectional power flow, which includes having appropriate hosting capacity to cater for growth in DERs as well as the development of the systems and processes required to support open access to the distribution network for a wide range of consumers and DERs.

In pursuing the primary objectives, the roadmap will define network and non-network investments that have low investment stranding risk as well as low-to-medium implementation risk where only "current" and viable solutions should be included within the roadmap. The roadmap will also proceed with network and non-network investments that are least economic cost to consumers over the long-term, be consistent with the objectives of regulators and be financially viable enabling us to achieve its long-term SCI objectives.

Pursuing the roadmap should ensure Electra is a capable distributor - who can fully support the decarbonisation of New Zealand - where either the uncontrolled or controlled scenario will achieve this primary objective. The uncontrolled scenario will cost consumers more as shown in Figure 6-9; a portion of the cost of flexibility services will flow back to consumers who provide these services, hence there should be greater consumer benefit in the controlled scenario.

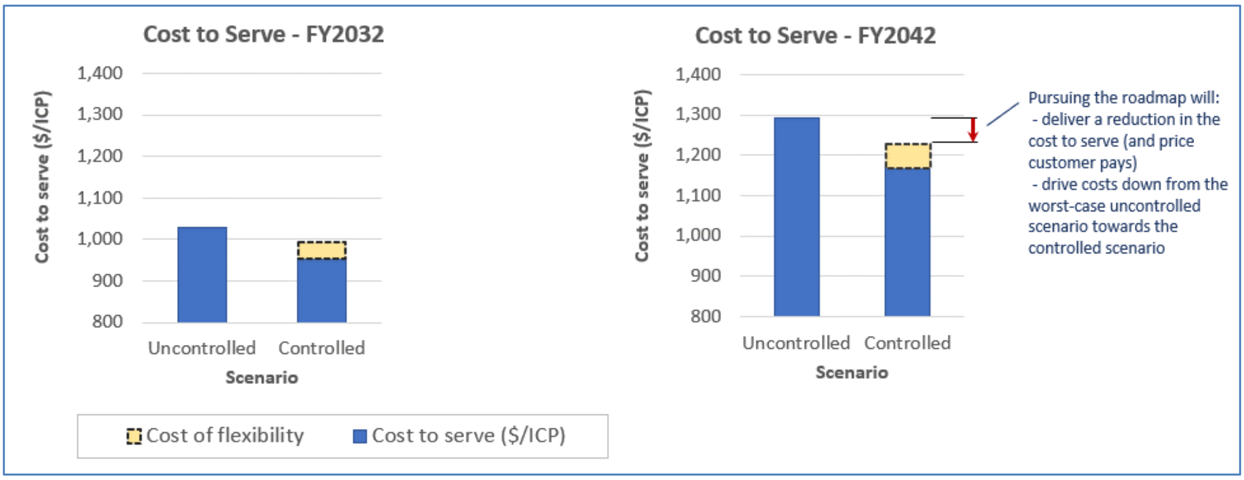


Figure 6-9: What the uncontrolled and controlled scenarios will mean for customers

The roadmap identifies the strategies along two pathways:

1st pathway: Electra has access to flexibility services in the controlled scenario where consumers respond to incentives and where Electra can shift consumption to control demand at an economic cost.

2nd pathway: Electra is unlikely to have access to flexibility services and reliable demand response over the long term and instead proceeds to augment the network to meet its objectives, in an uncontrolled scenario where consumers operate in an uncontrolled manner where we have little influence and control over demand behaviour.

Figure 6-10 provides some details of the two pathways. Electra is focusing on pursuing the access to the flexibility pathway on the roadmap, but we are also undertaking "low regret" actions with low risk of stranding and low incremental Opex to preserve the option of operating the network where limited access to flexibility services becomes the norm and we augment the network to provide the capacity required. The pathways include the possibility that distribution network operators (DNOs) could take on the role of the distribution system operators (DSOs), where they monitor and control demand response and controllable DERs to maximise the value of the flexibility they offer.

Electra recognises the importance of collaboration with the relevant stakeholders and continues to work closely with other network operators, retailers, distributed generators and consumers on the best options for flexibility services.

ACCESSING FLEXIBILITY SERVICES PATHWAY -CONTROLLED OUTCOMES	NETWORK AUGMENTATION RESPONSE PATHWAY -UNCONTROLLED OUTCOMES
CONSTRAINT AND SOLUTION MODELLING: TO UNDERSTAND IMPACT OF ENERGY TRANSFORMATION SCENARIOS AND SOLUTIONS	**CONSTRAINT AND SOLUTION MODELLING**
• Further feeder and LV voltage and capacity modelling • Hosting capacity modelling • Harmonics assessment • Update forecast model; disclose information	• Further feeder and LV voltage and capacity modelling • Hosting capacity modelling • Harmonics assessment • Update forecast model; disclose information
BUILD INTERNAL CAPABILITIES: TO RECRUIT SKILLS TO EFFECTIVELY FULFIL ROLE IN ENERGY SUPPLY CHAIN	**BUILD INTERNAL CAPABILITIES**
• Data analyst/Network planner/System support roles • System controller, Flexibility manager, new connection roles	• Data analyst/Network planner/System support roles
ENHANCE SYSTEMS: TO FULFIL ROLE IN ENERGY SUPPLY CHAIN	**ENHANCE SYSTEMS**
• Meter Data Management System • ADMS upgrade – LV monitoring and optimisation • ADMS upgrade-Flexibility management • Connection and consumer data management	• ADMS upgrade – LV monitoring and optimisation • Connection and consumer data management
MONITOR DISTRIBUTION AND LV: TO SUPPORT LV MONITORING	**MONITOR DISTRIBUTION AND LV**
• Installation of LV monitoring units progressively on distribution transformers • Achieving 5% penetration by 2042	• Installation of LV monitoring units progressively on distribution transformers • Achieving 5% penetration by 2042
ENHANCE CONNECTION STANDARDS TO REDUCE IMPACTS	**ENHANCE CONNECTION STANDARDS TO REDUCE IMPACTS**
• Develop DER installation and connection standards • DER congestion policy • Develop EV charger connection standards	• Develop DER installation and connection standards • DER congestion policy • Develop EV charger connection standards
ENHANCE STANDARDS FOR NEW ASSETS TO IMPROVE RESILIENCE TO TRANSFORMATION	**ENHANCE STANDARDS FOR NEW ASSETS TO IMPROVE RESILIENCE TO TRANSFORMATION**
• Review standards, specifications for equipment and materials, assess costs/benefits of increasing capacity • Assess impact on mechanical loadings, maintenance, training, spares and downstream implications	• Review standards, specifications for equipment and materials, assess costs/benefits of increasing capacity • Assess impact on mechanical loadings, maintenance, training, spares and downstream implications
DEVELOP PRICING TO INFLUENCE DEMAND RESPONSE	**DEVELOP PRICING TO INFLUENCE DEMAND RESPONSE**
• Update pricing strategy, Implement pricing changes • Evolve prices to work with flexibility markets	• Update pricing strategy, Implement pricing changes • Evolve prices to work with flexibility markets
DEVELOP FLEXIBILITY TRADING	
• Monitor evolution of flexibility markets • Determine the value of flexibility services • Determine Electra's market position	
BECOME A COMPETENT DNO AND DSO READY	**BECOME A COMPETENT DNO**
• Monitor evolution of flexibility markets • Develop specification for DSO functionality	
ASSESS NETWORK INVESTMENTS FOR ALTERNATIVES AND UNDERTAKE TENDERS FOR ALTERNATIVES	**ASSESS NETWORK INVESTMENTS FOR ALTERNATIVES AND UNDERTAKE TENDERS FOR ALTERNATIVES**
• Prepare non-network procurement standards • Undertake tenders to assess alternative for major system upgrade projects	• Prepare non-network procurement standards • Undertake tenders to assess alternative for major system upgrade projects
EXECUTE NETWORK RESPONSES OR ALTERNATIVES	**EXECUTE NETWORK RESPONSES OR ALTERNATIVES**
• Prepare project management process for non-network solutions • Prepare monitoring processes for non-network solutions	• Prepare project management process for non-network solutions • Prepare monitoring processes for non-network solutions

Figure 6-10: Summary of the two pathways for controlled and uncontrolled outcomes

Ongoing monitoring of external factors and the impact of the transformation on the network is vital as the intention is to keep both pathways open and viable until it becomes clear which pathway the industry is heading towards. Figure 6-11 lists key signposts that we will monitor as indicators of the pathway that will look more likely - where choices can then be made as to commence, cease or reassess activities.

SIGNPOST	ACCESSING FLEXIBILITY SERVICES PATHWAY	NETWORK AUGMENTATION PATHWAY
Flexibility market rules are developed by the EA	More likely	Less likely
EA develops rules that undermine the existing ripple control system	Less likely	More likely
Integrated EV, DER, and smart appliance load management systems become widely available and cheap to install	More likely	Less likely
Retailer offers tariff products (such as payments/discounts) for flexibility services at their call	Less likely	More likely
Retailer or generator issues an RFP for flexibility services to firm intermittent generation	Less likely	More likely
Distributor issues an RFP for flexibility services to defer a network project	More likely	Less likely
Retailers offer products and services that result in the disabling or removal of hot water ripple receivers	Less likely	More likely
Independent flexibility trader enters the market and actively purchases flexibility from consumers	Less likely	More likely
Existing player in the Transpower instantaneous reserves market offers control device to consumers (by-passing existing ripple control receivers)	Less likely	More likely

Figure 6-11: Signposts to monitor over the next three to five years

Electra has identified the following key activities to be undertaken in the next three years:

- Building internal capabilities to include new roles for Data Analyst, Network Planner and System Support
- Further modelling work to complete the constraint and solution modelling, long-term financial impact assessment, and update the value of flexibility
- LV monitoring is needed to properly test the costs and viability of this aspect of the roadmap
- Preparation and implementation of system enhancements where detailed specifications and business cases will need to be developed for the meter data management system and enhancements to the ADMS
- Enhancing standards in relation to DER/EV connections, network assets, procurement, and project management
- Pricing revision and progressing Electra's pricing strategy to increase the adoption of ToU (Time of Use) prices and to better influence demand response
- Monitoring on the evolving technology, how consumers are taking-up the technology, the direction of government policy and regulatory responses, and how markets are changing
- Communication where the AMP will need to be continually enhanced to ensure that Electra is disclosing its direction and competency as a Distribution Network Operator, and how it is readying itself for the future.

6.4 Emerging technology and low voltage monitoring initiatives

Other smart technology and low voltage monitoring activities that Electra has initiated include the following:

- Power quality monitoring: Over one hundred power quality meters have been installed at our distribution transformer panels. These smart devices will 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 will provide additional information in the event of a fault.
- Installation of four units of S&C TripSavers, a cut-out-mounted recloser which eliminates 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 the energy restored in minutes rather than hours. Distance to fault function in the ADMS is then used to pin-point the nearest location of the fault.

- Equipping ring main units (RMUs) with remote terminal units or RTUs: We installed RTUs at key distribution substations enabling RMUs to be monitored by our SCADA communication network and allow the switch-over to an alternative healthy circuit. In August 2021, feeder 405 Paraparaumu West, one of our most populated 11kV feeders, was interconnected with feeder 402 Paraparaumu West.
- Installation of new equipment 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. We can more rapidly pinpoint a fault in the network, isolate the affected section, and restore power to undamaged sections of the network without the need for fault staff to visit the switch. This cuts down time delays in network switching, in the past we would have had to “hedge hop” between manual switches alongside often busy highways. This in turn allows our work crews to begin repairs on the damaged network equipment much sooner than if we were relying on the original style of switch.
- 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.

Figure 6-12: (a) 11kV Entec recloser switchgear (b) Power quality monitoring at transformer panel

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.

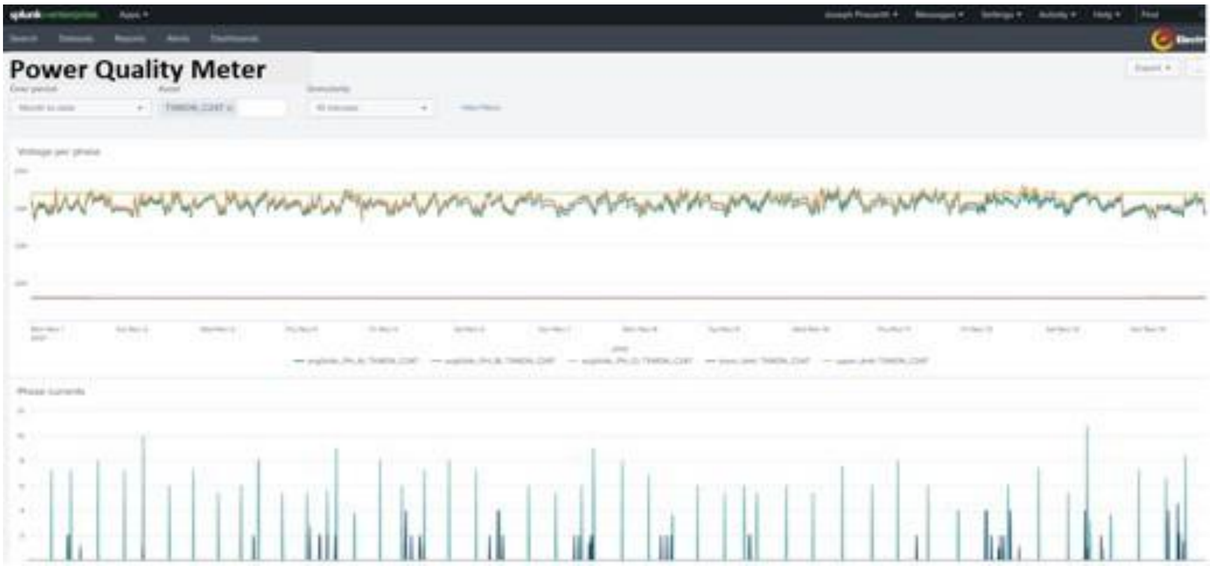


Figure 6-13: Power quality meter output on Splunk dashboard

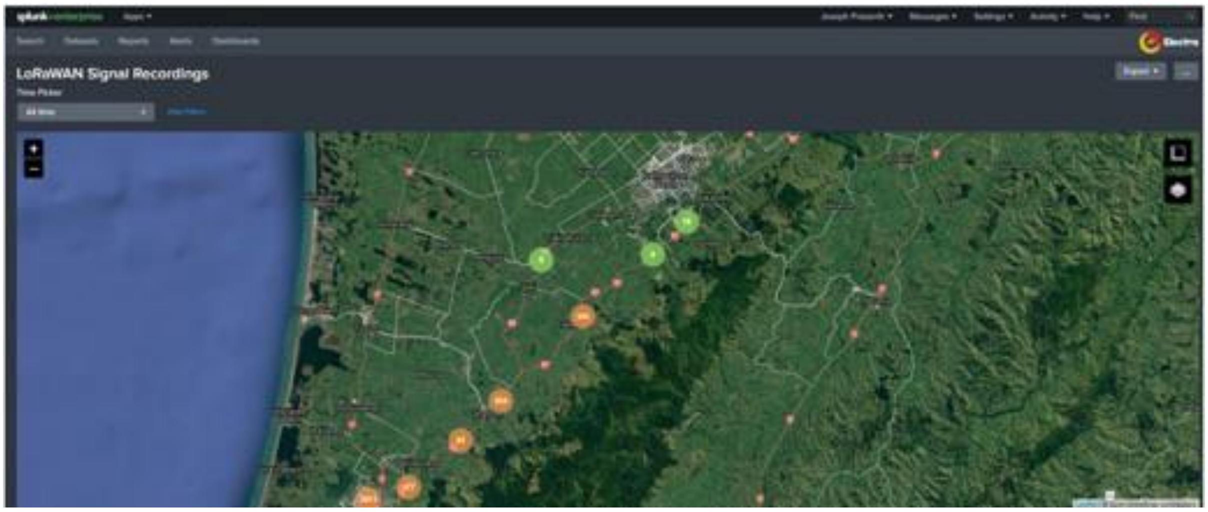


Figure 6-14: LoRaWAN signal monitoring on Splunk dashboard

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.

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

6.4.1 Enhancement of maintenance practices

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

- 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.
- 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 33kV and 11kV overhead structures and assets
- Usage of hot-stick mounted with GoPro cameras.

Figure 6-15: Continued improvement of condition-based risk monitoring of assets using UAV drone inspections and thermal imaging

6.4.2 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:

- A combined busbar and breaker failure scheme has been installed at Shannon in September 2021 where a SEL-487B relay was configured to provide a two-zone busbar protection for the 33kV bus as well as provide breaker failure functionality for the bus section breaker (Figure 6-16). The busbar protection scheme at Shannon will reduce arc flash hazards for bus faults and minimise equipment damage for a bus fault. Shannon breaker failure protection is essential for transformer HV breakers to significantly reduce the risk of transformer fire or explosion.
- Two units each of SEL 751 and SEL 787 relays has been installed at Levin East substation for transformer differential protection to replace the existing relays which are reaching the end-of-life. The upgraded protection will reduce the risk of transformer fires and provide fast fault clearance.
- Feeder protection has been upgraded for five Ōtaki 11kV feeders using SEL-751 relays and will be commissioned by March 2022.

Figure 6-16: Installation of SEL-487B relay for Shannon Substation 33kV busbar protection upgrade

As existing schemes become increasingly unfit for purpose due to interconnections and 33kV network upgrades, Electra will be replacing other 33kV protection beginning with the Mangahao to Shannon differential protection which will be our priority in FY2023. Line differential protection scheme will be installed together with fast-tripping from Mangahao on-bus faults. Following the Shannon upgrade, similar upgrades will be undertaken at Foxton, Levin West and Levin East.

Fibre will be used for the Mangahao to Shannon upgrade 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.

6.4.3 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 and Shannon and single chargers at Levin, Ōtaki, Waikanae, Paekākāriki and Waikanae. EV charging facilities are being rolled out at 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.

6.5 Material Changes for Network Development

The material changes for development projects are classified following the order provided in our FY2021 development plans and are provided in the Figure 6-17.

No	Project Description	Description of New Projects & Project Changes	Material Differences ($000)		
			FY2023	FY2024 - FY2027	FY2028 - FY2032
1	Material price contingency	Material price contingency for the expected metal price increase	+$750	+$0	+$0
2	Reconducting of Low Voltage Overhead Lines	Risk based model for conductors has highlighted the need to focus on the replacement programme to reduce the risks to acceptable levels.	+$675	+$2,600	+$3,500
3	11kV cable upgrade at The Drive, Paraparaumu	Replacement of a section of cable with 5 joints to improve reliability	+$375	+$0	+$600
4	Inspection-driven Crossarm Replacements from 2017	Drone inspections on ex-Transpower 110kV line indicated crossarm replacement cost require an additional $355K for FY2023.	+$355	+$90	+$200
5	Reconductor Carry over provisional budget/ Lidar Survey Allowance	Conditional allowance for planned carry-over ($250K) and Lidar survey output ($100K)	+$350	+$0	+$0
6	Automation of Ground-Mounted Switchgear	Additional $230K forecasted to expedite reliability improvements to fund opportunistic automation of customer-driven works.	+$230	+$90	+$400
7	Seismic Strengthening of Zone Substations	Seismic upgrade as per geotechnical studies and detailed designs.	+$200	+$1,000	+$600
8	Rebuild Foxton Substation	Shifted $400K from FY2025-2026 to FY2023-2024	+$200	-$530	+$0
9	Design of Line/Cable Jobs	Additional budget for standard design drawings	+$175	+$250	+$200
10	Inspection-driven Crossarm Replacements	Additional $125K added after inspections at high density overhead area	+$125	+$0	+$350

No	Project Description	Description of New Projects & Project Changes	Material Differences ($000)		
			FY2023	FY2024 - FY2027	FY2028 - FY2032
11	Install additional new technology to improve reliability such as fault path indicators	Additional $50K for fault path indicators with $50K for line-down sensor.	+$100	+$324	+$171
12	Link between Waitarere and Hokio Beach	Additional budget required; project deferred from FY2023 to FY2024	+$100	+$400	+$0
13	Install LV power quality monitors	$450k added from FY2024-2026 as part of network transformation	+$100	+$450	+$0
14	Replacement of pitch-filled potheads with Raychem terminations	Increase of traffic management & trenching costs with $50K added from FY2023 to FY2026 where replacement completed by FY2028	+$50	+$185	-$85
15	Mangahao to Levin East 33kV double-circuit upgrade to Butterfly	MHO-LE 33kV Cu overhead circuit life assessment shifted from FY2024-FY2027 to FY2025-FY2028 with additional $400k for design and other contingency associated with HDC Taraika development.	+$0	-$1,000	+$1,400
16	Levin East Substation Power Transformer replacement	Budget for detailed design for the replacement during FY2025 and FY2029	+$0	+$250	+$250
17	New zone substation to cater for load growth at Foxton and Shannon and new grid exit point	Detailed design will be done during FY2031 and project shifted to FY2032	+$0	+$0	-$125
18	Substation at Waikawa Beach Road, Manakau	$250K for detailed design in FY2030	+$0	+$0	+$250
19	Paraparaumu Power Transformer replacement	$300K budget for design in FY2025 and replacement during FY2026	+$0	+$300	+$0
20	Paekākāriki Power Transformer replacement	Dependent on CBRM assessment. $300K allocated for design during FY2030 with a project shift from FY2027 to FY2031	+$0	-$950	+$1,250
21	Cable replacement between W97-W98, Olive Terrace	Project shifted from FY2027 to FY2028 with an additional $75K added	+$0	-$250	+$325
22	Foxton to Levin West 33kV Line Up-grade	Upgrade 33kV line from Bee to Butterfly	+$0	+$0	-$50
23	Replacement of second Paekākāriki transformer (cold standby)	Budget moved from FY2024 to FY2026 as this project is dependent on power transformer replacement at Levin substation	+$0	+$45	+$0
24	Rebuild deck transformer C23 at Whirokino Road, Foxton	Project shifted from FY2030 to FY2024 as per recent transformer inspection	+$0	+$100	-$90
25	Replace 33kV breaker (rocket laucher) at Levin East sustation	$650K added to FY2024 associated with new circuit breaker installation for seismic development and expected growth in Levin	+$0	+$650	+$0
26	11kV ground-mounted transformer replacements	Additional budget for transformer conditional improvement with replacement programme as evident by recent inspections	-$100	-$200	+$300
27	Alternative supply to Waterfall Rd, Paekākāriki	Shifted project from FY2023 to FY2025	-$105	+$135	+$0
28	Install cable switchgear for ring circuit at H27 (and underground LV)	Project shifted from FY2023 to FY2024 with a detailed design undertaken during FY2023	-$475	+$500	+$0
29	Substation breaker VT/CT upgrade to enhance protection	Additional $50K for fault path indicators with $50K for line-down sensor	-$610	+$440	+$0

Figure 6-17: Material changes for network projects from FY2023 to FY2032

Figure 6-18 displays the location and estimated budgeted costs of major network projects in the Kāpiti and Horowhenua districts.

The projected capital expenditure from FY2023 to FY2032 is available in Figure A in the Executive Summary and the detailed CAPEX costs are also provided in Schedule 11a Report of Forecast Capital Expenditure in Appendix 1.

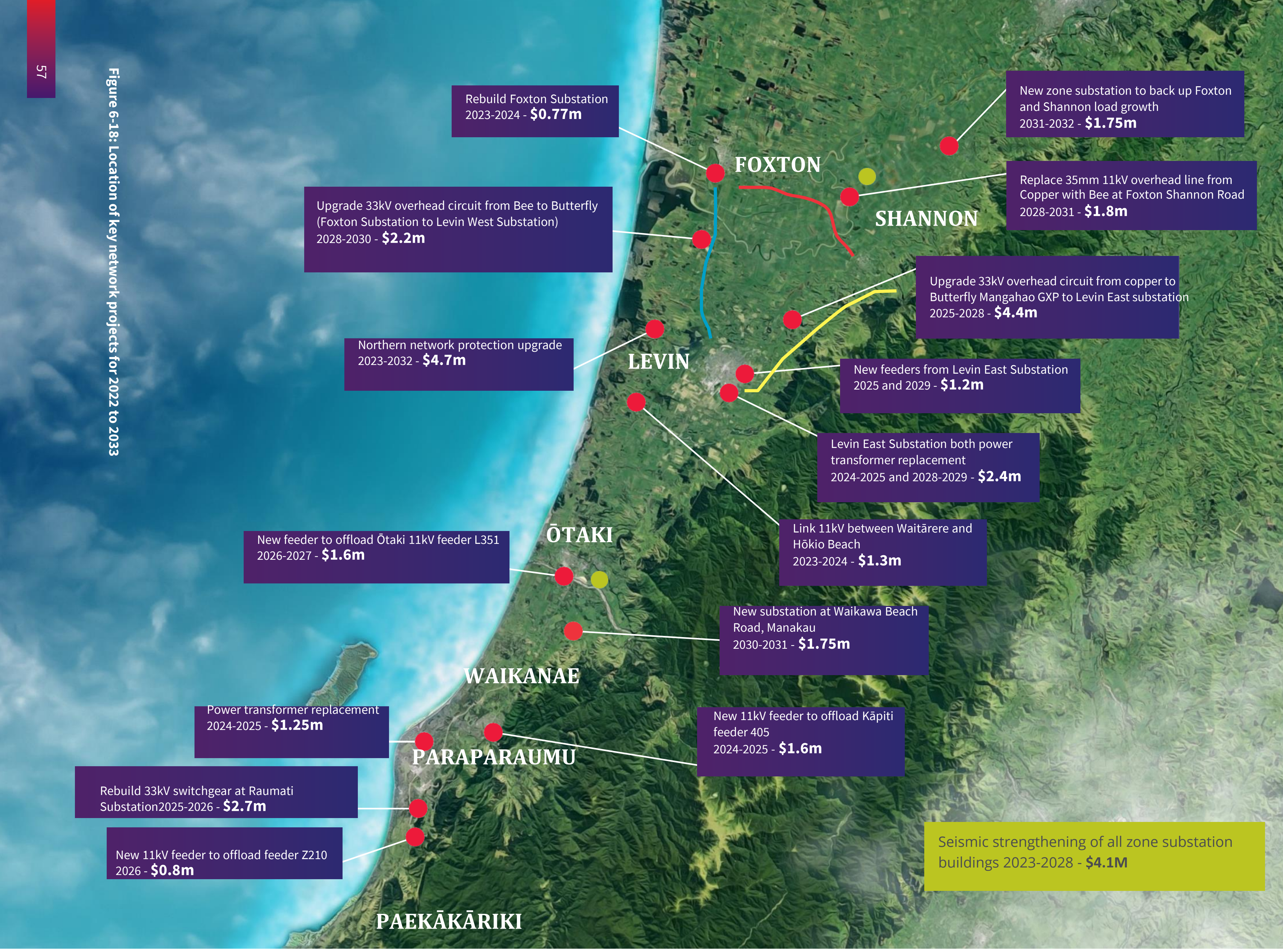


Figure 6-18: Location of key network projects for 2022 to 2033

LIFECYCLE MANAGEMENT PLANS

7 LIFECYCLE MANAGEMENT PLANS

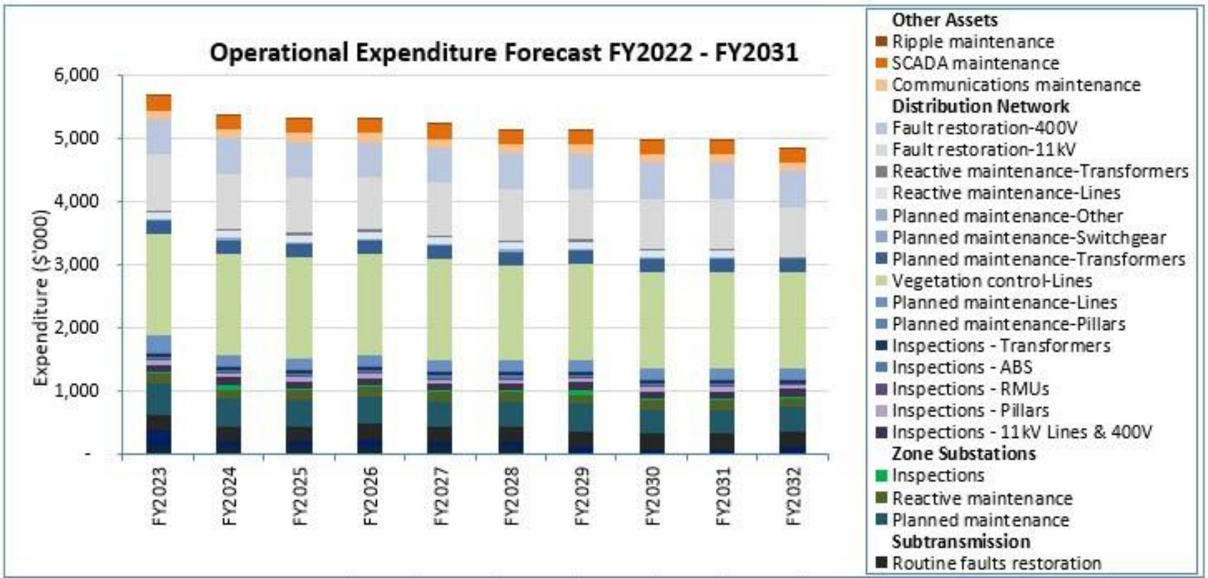
There has been no material change in the management of our assets.

There are also no material changes for our lifecycle management plans as Electra continues to develop our condition-based risk management model for asset renewal and replacement decisions. The use of the model has been extended to include high voltage switchgear, fuses, and distribution transformers besides 33/11kV distribution lines, poles and crossarms, LV overhead lines, LV cables, pillars and zone transformers.

The details of the condition of our assets are in Appendix 3.

Inspections and maintenance for all asset classes are summarised in the following chart and graph of Figure 7-2 and the detailed OPEX costs are also reflected in Schedule 11b Report of Forecast Operational Expenditure in Appendix 2.

Figure 7-1: (a) Training on S&C TripSaver operations; (b) Maintenance on ex-Transpower 33kV H-pole structure



Operations & Maintenance (Current $'000)	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	*Average %*
Subtransmission											
Planned maintenance	124	124	124	124	124	124	-	-	-	-	1%
Annual line inspection	260	70	70	110	70	70	110	70	70	110	2%
Routine faults restoration	247	247	247	247	247	247	247	247	247	247	5%
Zone Substations											
Planned maintenance	494	434	419	434	389	389	434	389	389	389	8%
Reactive maintenance	145	145	145	145	145	145	145	145	145	145	3%
Inspections	26	76	26	26	26	26	81	26	26	26	1%
Distribution Network											
Inspections - 11kV Lines & 400V	120	120	120	120	120	120	120	120	120	120	2%
Inspections - Pillars	62	62	62	62	62	62	62	62	62	62	1%
Inspections - RMUs	26	26	26	26	26	26	26	26	26	26	0.5%
Inspections - ABS	36	36	36	36	36	36	36	36	36	36	1%
Inspections - Transformers	52	52	52	52	52	52	52	52	52	52	1%
Planned maintenance-Pillars	20	20	20	20	20	20	20	20	20	20	0.4%
Planned maintenance-Lines	257	157	157	157	157	157	157	157	157	157	3%
Vegetation control-Lines	1,610	1,610	1,610	1,610	1,610	1,520	1,520	1,520	1,520	1,520	30%
Planned maintenance-Transformers	210	210	210	210	210	210	210	210	210	210	4%
Planned maintenance-Switchgear	27	27	27	27	27	27	27	27	27	27	1%
Planned maintenance-Other	9	9	9	9	9	9	9	9	9	9	0%
Reactive maintenance-Lines	103	103	103	103	103	103	103	103	103	103	2%
Reactive maintenance-Transformers	35	35	35	35	35	35	35	35	35	35	1%
Fault restoration-11kV	869	869	869	817	817	817	787	787	787	787	16%
Fault restoration-400V	569	569	569	569	569	569	569	569	569	569	11%
Other Assets											
Communications maintenance	137	137	137	137	137	137	137	137	137	137	3%
SCADA maintenance	212	212	212	212	212	212	212	212	212	212	4%
Ripple maintenance	21	21	21	21	21	21	21	21	21	21	0.4%
Total Operational Expenditure	**5,671**	**5,371**	**5,306**	**5,309**	**5,224**	**5,134**	**5,120**	**4,980**	**4,980**	**5,020**	***100%***

Figure 7-2: Projected operational expenditure (OPEX) for FY2023 to FY2032

NON NETWORK SYSTEMS

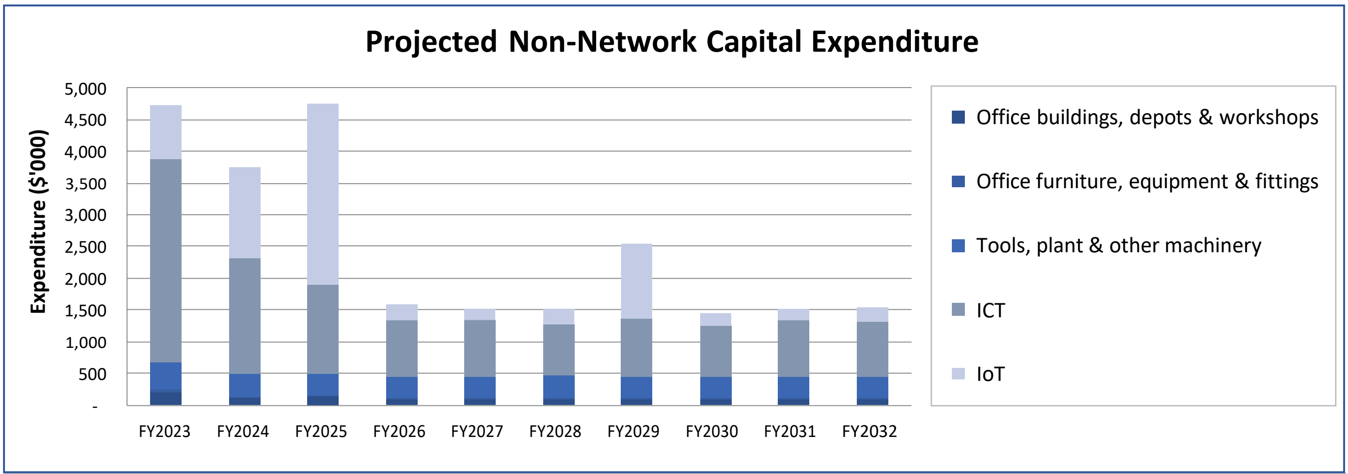
8 NON-NETWORK SYSTEMS

There are a few changes to Electra's practices for the support of the business, to enable the safe and efficient operations of these non-network systems. These functions cover our vehicle strategy (Section 8.3).

There are no material changes however for our ICT, buildings, tools, plant, and machinery capital expenditure.

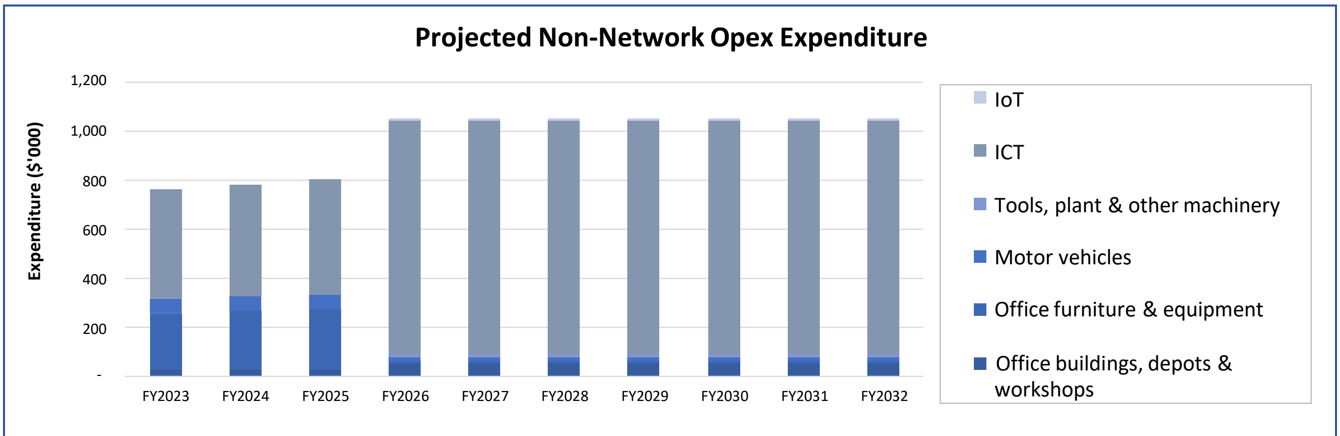
8.1 Non-Network Expenditure Forecast

The overall projected non-network Capex expenditure is shown in Figure 8-1 where the main cost drivers across the ten years are 50% for ICT expenditure, 30% for IoT, 14% for Tools, plant & machinery while the remaining 5% are expenditure for buildings, depots, workshops, furniture, equipment and fittings. The average spend is $2.4 million per year but that for non-network Opex (Figure 8-2) is $1M per year.



Non-Network CAPEX	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	*Average %*
Office buildings, depots & workshops	195	120	125	80	80	85	80	80	80	80	*4%*
Office furniture, equipment & fittings	50	25	25	25	25	25	25	25	25	25	*1%*
Tools, plant & other machinery	420	350	350	350	350	350	350	350	350	350	*14%*
ICT	3,219	1,830	1,405	885	885	805	908	800	885	850	*50%*
IoT	845	1,425	2,835	235	185	255	1,185	185	185	225	*30%*
Total CAPEX	**4,729**	**3,750**	**4,740**	**1,575**	**1,525**	**1,520**	**2,548**	**1,440**	**1,525**	**1,530**	***100%***

Figure 8-1: Projected non-network Capex expenditure



Non-Network OPEX ($'000)	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	FY2032	*Average %*
Office buildings, depots & workshops	25	26	26	50	50	50	50	50	50	50	*4%*
Office furniture & equipment	232	238	244	9	9	9	9	9	9	9	*8%*
Motor vehicles	60	61	63	16	16	16	16	16	16	16	*3%*
Tools, plant & other machinery	-	-	-	16	16	16	16	16	16	16	*1%*
ICT	447	458	470	950	950	950	950	950	950	950	*83%*
IoT	-	-	-	10	10	10	10	10	10	10	*1%*
Total (Opex):	**764**	**783**	**802**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**	**1,051**	***100%***

Figure 8-2: Projected non-network Opex expenditure

8.2 ICT Initiatives

Electra launched the Asset Guardian or TAG system in June 2021 where TAG was the preferred EAM (Enterprise Asset Development) solution. Figure 8-3 displays the key ICT initiatives identified via the TAG digital strategy identification process.

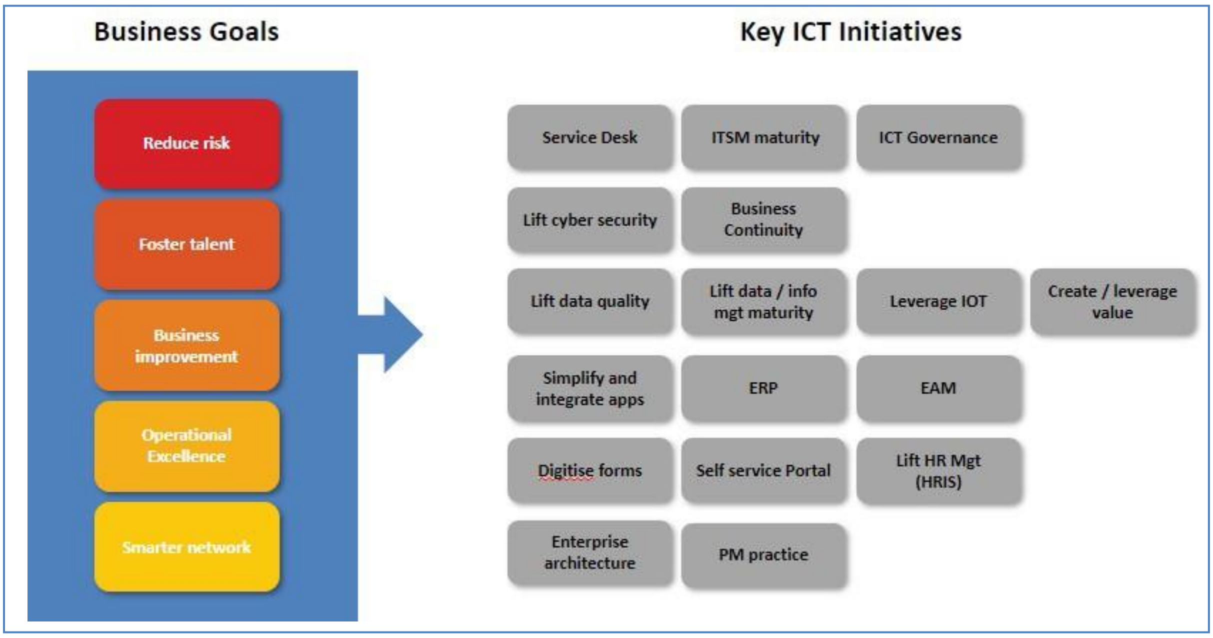


Figure 8-3: Business goals leading to key ICT initiatives

Other ICT achievements made in FY2022 include the following projects:

- Core Infrastructure upgrade: Despite lockdown restrictions, the ICT Team have migrated all virtual servers off the old infrastructure and on to the new system. Our systems at Levin have been replicated to an identical new setup in the Paraparaumu Depot, increasing resilience and the ability to provide the offices with excellent ICT Services. Using Hewlett Packard dHCI (disaggregated hyper-converged infrastructure), we have designed and stabilised our core infrastructure providing the platform for future Cloud/Hybrid-Cloud adoption. The new systems are protected with newly installed server racks, environmental monitoring, swipe card security access and UPS power for any unforeseeable event.
- Two-factor Authentication (2FA): To protect digital identification, 2FA was launched in October 2021 and has been rolled out to all employees. Benefits include strengthening login security, protecting remote access methods and reducing the risk of data theft in line with our risk management policies.

8.3 Vehicles

Electra will be adopting 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.

RISK MANAGEMENT

9 RISK MANAGEMENT

There are no material changes to Electra's risk management processes or key risks identified in our 2021 AMP except for our pandemic risk management procedures.

Some risk activities are covered in the following sections.

9.1 Risk Management during the 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 and the appreciation message from our Electra Board and Trustees is a testament to the number of calls being tirelessly attended by our teams. 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.

Figure 9-1: A message of appreciation for our teams working tirelessly throughout the pandemic

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.

9.2 Sustainability Impact

A Sustainability Group has been established to provide strategic guidance on sustainability issues relevant to Electra, 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.

9.2.1 Sustainably materiality assessment

Electra has commissioned a Materiality Assessment initiative to gauge a clear picture of environmental, social and governance (ESG) issues that matter the most to Electra and its stakeholders and is designed to support the development of Electra's sustainability strategy. A long list of materiality topics was developed, and stress tested against the Global Reporting Initiative, the World Economic Forum Global Risks, Sustainability Accounting Standards Board or SASB and industry peers, Vector and Powerco to create a heat map showing where issues ranked low, medium or of high relevance. External stakeholders comprised of a total of 6 organisations and 12 individuals and internal stakeholders consisted of seventeen employees included in the assessment, with six being in the Electra leadership team. The resulting materiality assessment matrix is shown in Figure 9.2

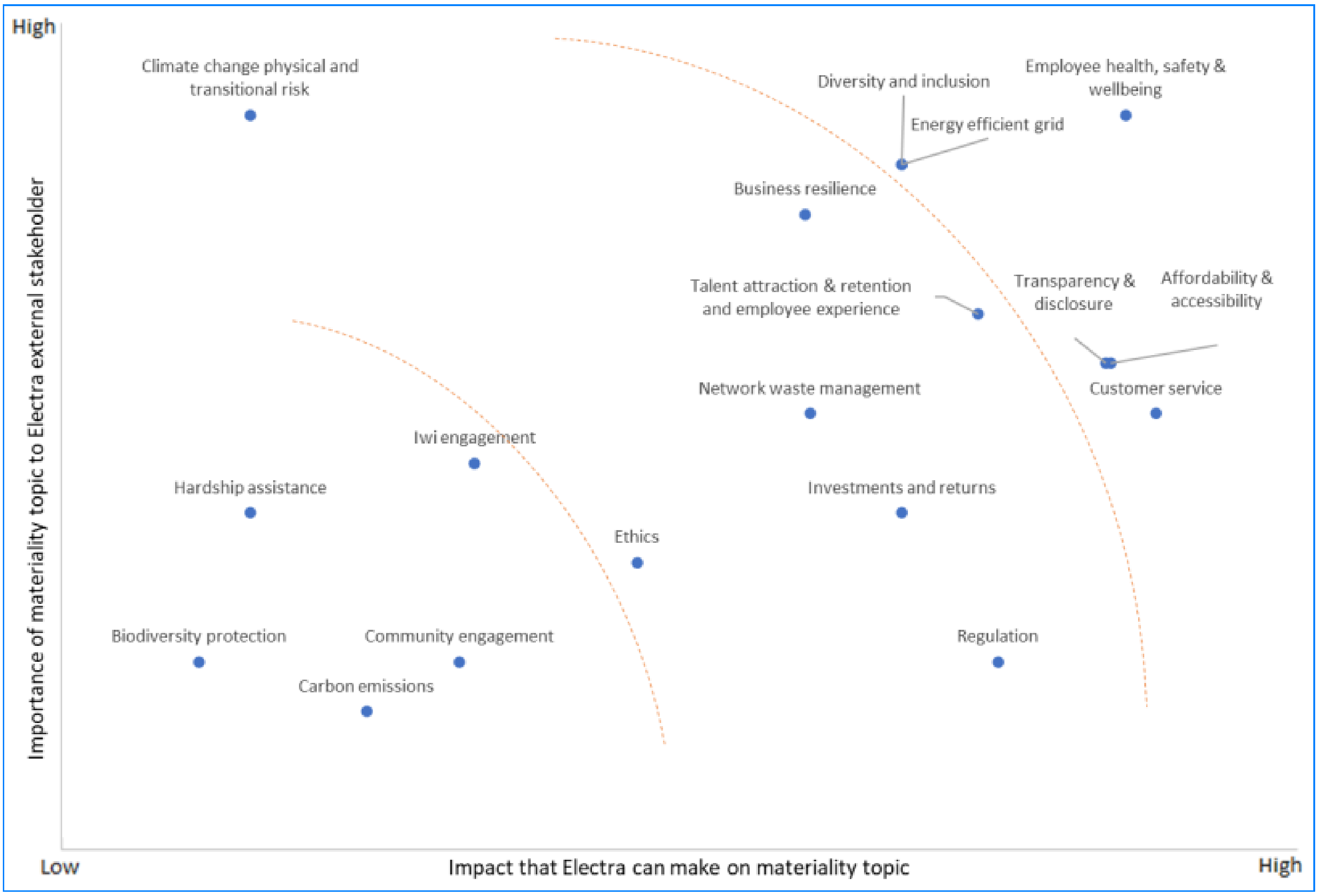


Figure 9-2: 2021 Materiality assessment matrix

The combined internal/external rankings illustrate where Electra can prioritise its efforts to maximise value creation. The highly material topics are the topics that Electra stakeholders care about the most and are the areas Electra employees believe they have the highest impact on, but it is also important to consider the material and relevant topics and how they may support the highly material topics. Figure 9.2 summarises the combined internal/ external stakeholder rankings, spread across the key impact categories. The materiality assessment indicates the key categories where Electra can maximise its sustainability impact within key areas of the Workforce, Environment, Customer & Community supported by Governance & Economic categories. Electra is currently developing the ranking of materiality topics to establish a more focused sustainability strategy, aligned with our business objectives by year 2022.

CATEGORY	HIGHLY MATERIAL	MATERIAL	RELEVANT
Environment	2= Energy efficient	9. Network waste management 12. Climate change - P&T Risk	17. Carbon emissions 18. Biodiversity protection
Customer and community	4. Affordability & accessibility 5= Customer Service		14. Iwi engagement 15. Community engagement 16. Hardship assistance
Workforce	1, Employee health, safety & wellbeing 2= Diversity and inclusion	7. Talent attraction & retention and employee experience	
Economic		8. Business resilience 10. Investments and returns	
Governance	5= Transparency & disclosure	11. Regulation 13. Ethics	

Figure 9.3 Materiality topics ratings by theme

9.2.2 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.

9.3 Climate Change and Decarbonisation Initiatives

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.

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.

Electra has begun a study of the impact of climate change on our business so that we can understand the operational, planning and financial impact on the electricity distribution business. The latest Climate Change Commission information will be modelled against asset classes at different geographical locations that may be exposed to more extreme conditions. This work will be completed in 2022 for inclusion in the 2023 – 2033 AMP.

9.4 Huringa Pūngao

Our Energy Transformation or Huringa Pūngao initiative is covered in Section 6.3.1. 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 6.3.1 covers the recommendations from the study.

9.5 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 unauthorized 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.

10 APPENDICES

Company Name **Electra Ltd**
AMP Planning Period **1 April 2022 – 31 March 2032**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	400	400	410	420	429	437	446	455	464	473	483
11		System growth	-	100	1,281	2,469	1,575	1,640	1,254	1,706	2,204	2,780	1,810
12		Asset replacement and renewal	6,972	8,929	7,966	9,196	10,900	9,038	9,991	9,548	9,008	9,957	8,269
13		Asset relocations	-	-	-	-	-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	3,232	3,075	4,203	3,551	3,274	3,443	2,927	3,076	2,384	2,491	2,540
16		Legislative and regulatory	600	650	461	735	429	383	669	-	-	-	-
17		Other reliability, safety and environment	635	620	707	410	418	661	318	239	244	248	253
18		**Total reliability, safety and environment**	4,467	4,345	5,371	4,696	4,120	4,487	3,913	3,315	2,627	2,739	2,794
19		**Expenditure on network assets**	11,839	13,774	15,029	16,781	17,024	15,601	15,604	15,024	14,303	15,950	13,356
20		Expenditure on non-network assets	3,498	4,729	3,844	4,980	1,688	1,667	1,695	2,898	1,670	1,804	1,846
21		**Expenditure on assets**	15,337	18,503	18,872	21,761	18,712	17,268	17,299	17,921	15,974	17,754	15,203
22													
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
26													
27		**Capital expenditure forecast**	15,547	18,713	19,082	21,971	18,922	17,478	17,509	18,131	16,184	17,964	15,413
28													
29		Assets commissioned											
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
32			**$000 (in constant prices)**										
33		Consumer connection	400	400	400	400	400	400	400	400	400	400	400
34		System growth	-	100	1,250	2,350	1,470	1,500	1,125	1,500	1,900	2,350	1,500
35		Asset replacement and renewal	6,972	8,929	7,772	8,753	10,171	8,268	8,961	8,396	7,766	8,416	6,852
36		Asset relocations	-	-	-	-	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	3,232	3,075	4,100	3,245	3,055	3,150	2,625	2,705	2,055	2,105	2,105
39		Legislative and regulatory	600	650	450	700	400	350	600	-	-	-	-
40		Other reliability, safety and environment	635	620	690	390	390	605	285	210	210	210	210
41		**Total reliability, safety and environment**	4,467	4,345	5,240	4,335	3,845	4,105	3,510	2,915	2,265	2,315	2,315
42		**Expenditure on network assets**	11,839	13,774	14,662	15,838	15,886	14,273	13,996	13,211	12,331	13,481	11,067
43		Expenditure on non-network assets	3,498	4,729	3,750	4,740	1,575	1,525	1,520	2,548	1,440	1,525	1,530
44		**Expenditure on assets**	15,337	18,503	18,412	20,578	17,461	15,798	15,516	15,759	13,771	15,006	12,597
45													
46	**Subcomponents of expenditure on assets (where known)**												
47		Energy efficiency and demand side management, reduction of energy losses											
48		Overhead to underground conversion											
49		Research and development											
50													

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
53	**Difference between nominal and constant price forecasts**		**$000**										
54	Consumer connection		-	-	10	20	29	37	46	55	64	73	83
55	System growth		-	-	31	119	105	140	129	206	304	430	310
56	Asset replacement and renewal		-	-	194	443	729	770	1,030	1,152	1,242	1,542	1,417
57	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:												
59	Quality of supply		-	-	103	306	219	293	302	371	329	386	435
60	Legislative and regulatory		-	-	11	35	29	33	69	-	-	-	-
61	Other reliability, safety and environment		-	-	17	20	28	56	33	29	34	38	43
62	**Total reliability, safety and environment**		-	-	131	361	275	382	403	400	362	424	479
63	**Expenditure on network assets**		-	-	367	944	1,138	1,328	1,609	1,813	1,973	2,469	2,289
64	Expenditure on non-network assets		-	-	94	240	113	142	175	350	230	279	316
65	**Expenditure on assets**		-	-	460	1,184	1,251	1,470	1,783	2,163	2,203	2,749	2,606

11a(ii): Consumer Connection

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
68		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
69	*Consumer types defined by EDB**		**$000 (in constant prices)**					
70	All		400	400	400	400	400	400
71	[EDB consumer type]							
72	[EDB consumer type]							
73	[EDB consumer type]							
74	[EDB consumer type]							
75	**include additional rows if needed*							
76	**Consumer connection expenditure**		400	400	400	400	400	400
77	*less* Capital contributions funding consumer connection							
78	**Consumer connection less capital contributions**		400	400	400	400	400	400

11a(iii): System Growth

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
80	Subtransmission	-	-	-	-	-	-
81	Zone substations	-	-	-	-	-	-
82	Distribution and LV lines	-	-	-	-	-	-
83	Distribution and LV cables	-	100	1,250	2,350	1,470	1,500
84	Distribution substations and transformers	-	-	-	-	-	-
85	Distribution switchgear	-	-	-	-	-	-
86	Other network assets	-	-	-	-	-	-
87	**System growth expenditure**	-	100	1,250	2,350	1,470	1,500
88	*less* Capital contributions funding system growth						
89	**System growth less capital contributions**	-	100	1,250	2,350	1,470	1,500

11a(iv): Asset Replacement and Renewal

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
93			**$000 (in constant prices)**					
94	Subtransmission		915	590	390	590	1,790	1,840
95	Zone substations		135	1,710	2,025	2,955	2,435	135
96	Distribution and LV lines		4,259	4,967	3,490	3,256	4,070	4,327
97	Distribution and LV cables		453	580	710	512	512	602
98	Distribution substations and transformers		915	787	837	1,001	1,001	1,001
99	Distribution switchgear		160	130	160	214	214	214
100	Other network assets		135	165	160	225	150	150
101	**Asset replacement and renewal expenditure**		6,972	8,929	7,772	8,753	10,171	8,268
102	*less* Capital contributions funding asset replacement and renewal							
103	**Asset replacement and renewal less capital contributions**		6,972	8,929	7,772	8,753	10,171	8,268

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
105			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
106		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
107	**11a(v): Asset Relocations**							
108	*Project or programme**		**$000 (in constant prices)**					
109	[Description of material project or programme]							
110	[Description of material project or programme]							
111	[Description of material project or programme]							
112	[Description of material project or programme]							
113	[Description of material project or programme]							
114	**include additional rows if needed*							
115	All other project or programmes - asset relocations							
116	**Asset relocations expenditure**		-	-	-	-	-	-
117	*less* Capital contributions funding asset relocations							
118	**Asset relocations less capital contributions**		-	-	-	-	-	-
119								

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
120			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
121		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
122	**11a(vi): Quality of Supply**							
123	*Project or programme**		**$000 (in constant prices)**					
124	Protection Work		650	650	1,210	500	600	500
125	Improving Network Interconnectivity		1,100	880	960	1,515	775	1,875
126	Network Automation and Sectionalisation		1,177	1,185	1,590	940	1,390	660
127	Fault Locator		230	290	340	290	290	115
128	Condition Monitoring		75	70	-	-	-	-
129	**include additional rows if needed*							
130	All other projects or programmes - quality of supply							
131	**Quality of supply expenditure**		3,232	3,075	4,100	3,245	3,055	3,150
132	*less* Capital contributions funding quality of supply							
133	**Quality of supply less capital contributions**		3,232	3,075	4,100	3,245	3,055	3,150
134								

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
135			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
136		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
137	**11a(vii): Legislative and Regulatory**							
138	*Project or programme**		**$000 (in constant prices)**					
139	Seismic Strengthening		600	650	450	700	400	350
140	[Description of material project or programme]							
141	[Description of material project or programme]							
142	[Description of material project or programme]							
143	[Description of material project or programme]							
144	**include additional rows if needed*							
145	All other projects or programmes - legislative and regulatory							
146	**Legislative and regulatory expenditure**		600	650	450	700	400	350
147	*less* Capital contributions funding legislative and regulatory							
148	**Legislative and regulatory less capital contributions**		600	650	450	700	400	350
149								

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
150	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	Arc Flash Protection	-	-	-	-	-	305
154	New ABS and renewals	325	325	250	200	200	125
155	Replacement of Deck Transformers	-	-	100	-	-	-
156	Replacement of Pitchfilled Potheads	60	90	90	90	90	75
157	Steel Link Pillar Removal	250	205	250	100	100	100
	Replacement of Room transformers	-	-	-	-	-	-
158	*include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	635	620	690	390	390	605
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety, and environment less capital contributions**	635	620	690	390	390	605
163							

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
164							
165	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	Office buildings, depots & workshops	125	195	120	125	80	80
170	Office furniture, fittings and equipment incl. PPE	25	50	25	25	25	25
171	Motor vehicles	15	-	-	-	-	-
172	Tools, plant & other machinery	380	420	350	350	350	350
173	ICT	1,612	2,295	1,485	1,260	835	835
174	IoT	-	845	1,425	2,835	235	185
175	*include additional rows if needed*						
176	All other projects or programmes - routine expenditure						
177	**Routine expenditure**	2,157	3,805	3,405	4,595	1,525	1,475
178	**Atypical expenditure**						
179	*Project or programme**						
180	EAM Development	991	624	-	-	-	-
181	ADMS and SCADA Development	250	100	250	50	50	50
183	HRIS Software	50	150	75	75	-	-
184	CRM Development	50	50	20	20	-	-
185	Replacement of mobiles, tablets, and organic growth	-	-	-	-	-	-
	Network Asset Communications	-	-	-	-	-	-
	IoT - Low Voltage Network Status Monitoring	-	-	-	-	-	-
186	*include additional rows if needed*	-	-	-	-	-	-
187	All other projects or programmes - atypical expenditure	-	-	-	-	-	-
188	**Atypical expenditure**	1,341	924	345	145	50	50
189							
190	**Expenditure on non-network assets**	3,498	4,729	3,750	4,740	1,575	1,525

Company Name	Electra Ltd
AMP Planning Period	1 April 2022 – 31 March 2032

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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,894	1,973	2,022	2,073	2,059	2,100	2,142	2,151	2,194	2,237	2,282
11	Vegetation management	1,645	1,610	1,650	1,692	1,725	1,760	1,695	1,729	1,763	1,798	1,834
12	Routine and corrective maintenance and inspection	1,050	1,533	1,325	1,306	1,375	1,358	1,386	1,381	1,298	1,324	1,399
13	Asset replacement and renewal	418	555	507	504	530	492	502	563	522	532	543
14	**Network Opex**	5,007	5,671	5,505	5,574	5,689	5,710	5,724	5,823	5,777	5,892	6,059
15	System operations and network support	4,688	4,354	5,254	5,514	5,624	5,737	5,852	5,969	6,088	6,210	6,334
16	Business support	4,378	6,229	6,127	6,438	6,566	6,698	6,832	6,968	7,108	7,250	7,395
17	**Non-network opex**	9,066	10,582	11,382	11,952	12,191	12,435	12,683	12,937	13,196	13,460	13,729
18	**Operational expenditure**	14,073	16,253	16,887	17,526	17,880	18,145	18,407	18,760	18,973	19,352	19,787
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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,894	1,973	1,973	1,973	1,921	1,921	1,921	1,891	1,891	1,891	1,891
23	Vegetation management	1,645	1,610	1,610	1,610	1,610	1,610	1,520	1,520	1,520	1,520	1,520
24	Routine and corrective maintenance and inspection	1,050	1,533	1,293	1,243	1,283	1,243	1,243	1,214	1,119	1,119	1,159
25	Asset replacement and renewal	418	555	495	480	495	450	450	495	450	450	450
26	**Network Opex**	5,007	5,671	5,371	5,306	5,309	5,224	5,134	5,120	4,980	4,980	5,020
27	System operations and network support	4,688	4,354	5,126	5,248	5,248	5,248	5,248	5,248	5,248	5,248	5,248
28	Business support	4,378	6,229	5,978	6,127	6,127	6,127	6,127	6,127	6,127	6,127	6,127
29	**Non-network opex**	9,066	10,582	11,104	11,376	11,376	11,376	11,376	11,376	11,376	11,376	11,376
30	**Operational expenditure**	14,073	16,253	16,475	16,681	16,685	16,600	16,510	16,496	16,356	16,356	16,396
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	49	100	138	179	221	260	303	346	391
43	Vegetation management	-	-	40	82	115	150	175	209	243	278	314
44	Routine and corrective maintenance and inspection	-	-	32	63	92	116	143	167	179	205	240
45	Asset replacement and renewal	-	-	12	24	35	42	52	68	72	82	93
46	**Network Opex**	-	-	134	269	380	486	590	703	797	912	1,038
47	System operations and network support	-	-	128	266	376	488	603	720	840	961	1,086
48	Business support	-	-	149	310	439	570	704	841	980	1,122	1,267
49	**Non-network opex**	-	-	278	576	815	1,059	1,307	1,561	1,820	2,084	2,353
50	**Operational expenditure**	-	-	412	845	1,195	1,545	1,897	2,264	2,617	2,996	3,391

Company Name	Electra Ltd
AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	-	-	2.00%	94.34%	3.66%	-	3	2.00%
11	All	Overhead Line	Wood poles	No.	-	-	5.79%	93.25%	0.96%	-	2	6.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	14.00%	81.47%	4.62%	-	3	15.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	69.00%	31.00%	-	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	-	N/A	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	50.00%	30.00%	20.00%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-		50.00%	50.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	41.00%	49.00%	10.00%	-	4	41.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	38.00%	52.50%	9.50%	-	3	38.00%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	-	N/A	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	5.00%	75.00%	20.00%	-	3	5.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	10.52%	78.98%	10.50%	-	4	10.52%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	7.00%	72.00%	21.00%	-	3	7.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	83.38%	16.62%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	2.50%	97.50%	-	-	2	2.50%
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.	-	-	6.00%	12.00%	82.00%	-	4	6.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	-	10.00%	45.00%	45.00%	-	3	7.00%
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.	-	-	-	9.00%	91.00%	-	3	0.50%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	-	3.00%	72.00%	23.00%	-	4	3.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	5.00%	22.00%	73.00%	-	4	5.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	-	-	N/A	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	-	N/A	-
55	LV	LV Line	LV OH Conductor	km	-	-	2.00%	8.00%	41.00%	49.00%	2	2.00%
56	LV	LV Cable	LV UG Cable	km	-	-	-	2.00%	12.00%	86.00%	2	2.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	-	-	-	100.00%	2	1.00%
58	LV	Connections	OH/UG consumer service connections	No.	-	-	5.00%	90.00%	5.00%	-	2	5.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	20.50%	44.50%	35.00%	-	4	20.50%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	10.00%	70.00%	20.00%	-	3	15.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	-	-	50.00%	50.00%	-	4	-
63	All	Load Control	Relays	No.	-	-	-	-	-	100.00%	2	10.00%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Appendix 4: Schedule 12b – Report on Forecast Capacity

Company Name	Electra Ltd
AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Shannon	4.8	5	N-1	6	96%	5	100%	No constraint within +5 years	
10	Foxton	7.3	23	N-1	4	32%	23	35%	No constraint within +5 years	
11	Levin West	13.2	23	N-1	12	58%	23	63%	No constraint within +5 years	
12	Levin East	14.4	23	N-1	12	62%	23	67%	No constraint within +5 years	
13	Otaki	12.6	23	N-1	4	55%	23	59%	No constraint within +5 years	
14	Waikanae	16.1	23	N-1	12	70%	23	79%	No constraint within +5 years	
15	Paraparaumu	13.5	23	N-1	16	59%	23	63%	No constraint within +5 years	
16	Paraparaumu West	13.1	23	N-1	8	57%	23	62%	No constraint within +5 years	
17	Raumati	10.0	23	N-1	12	44%	23	46%	No constraint within +5 years	
18	Paekakariki	2.4	-	N-1 (Switched)	6	-	-	-	No constraint within +5 years	Automatic changeover to Raumati using fault monitors and motorised switches
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Appendix 5: Schedule 12c – Report on Forecast Network Demand

Company Name	Electra Ltd
AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected in year by consumer type*				**Number of connections**		
9				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*
10			for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
11		*Consumer types defined by EDB**						
12		All		420	445	470	495	520
13		[EDB consumer type]						
14		[EDB consumer type]						
15		[EDB consumer type]						
16		[EDB consumer type]						
17		**Connections total**		420	445	470	495	520
18		**include additional rows if needed*						
19		**Distributed generation**						
20		Number of connections		120	130	140	150	160
21		Capacity of distributed generation installed in year (MVA)		0.6	0.6	0.6	0.6	0.6

sch ref									
7		**12c(i): Consumer Connections**							
8		*Number of ICPs connected in year by consumer type*				**Number of connections**			
9				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10			for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
11		*Consumer types defined by EDB**							
12		All		420	445	470	495	520	545
13		[EDB consumer type]							
14		[EDB consumer type]							
15		[EDB consumer type]							
16		[EDB consumer type]							
17		**Connections total**		420	445	470	495	520	545
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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
25		GXP demand		81	82	83	85	86	88
26	*plus*	Distributed generation output at HV and above		26	27	27	27	27	27
27		**Maximum coincident system demand**		107	109	110	112	113	115
28	*less*	Net transfers to (from) other EDBs at HV and above							
29		**Demand on system for supply to consumers' connection points**		107	109	110	112	113	115
30		**Electricity volumes carried (GWh)**							
31		Electricity supplied from GXPs		408	415	424	432	440	448
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**		469	477	486	494	503	511
36	*less*	Total energy delivered to ICPs		435	443	451	458	466	474
37		**Losses**		34	35	35	36	36	37
38									
39		**Load factor**		50%	50%	50%	51%	51%	51%
40		**Loss ratio**		7.3%	7.3%	7.3%	7.3%	7.2%	7.2%

Appendix 6: Schedule 12d – Report Forecast Interruptions and Duration

Company Name	Electra Ltd
AMP Planning Period	1 April 2022 – 31 March 2032
Network / Sub-network Name	Electra Ltd

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
10	**SAIDI**						
11	Class B (planned interruptions on the network)	15.0	20.0	20.0	20.0	20.0	20.0
12	Class C (unplanned interruptions on the network)	68.0	63.0	63.0	63.0	63.0	63.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.06	0.08	0.08	0.08	0.08	0.08
15	Class C (unplanned interruptions on the network)	1.60	1.50	1.50	1.50	1.50	1.50

Appendix 7: Schedule 14a – Mandatory Explanatory Notes on Forecast Information

Company Name	Electra Limited
For Year Ended	31 March 2022

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. This Schedule is mandatory - EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
10- year planning period – Annual CPI allowance for increased cost, based on construction and compliance costs.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
Current disclosure year – nil, no impact.

10 - year planning period – Annual CPI allowance for increased cost, based on construction and compliance costs.

Appendix 8: Certification for Asset Management Plan

CERTIFICATION FOR YEAR-BEGINNING DISCLOSURE -
ASSET MANAGEMENT PLAN
CLAUSE 2.9.1

We, Shelly Anne Mitchell-Jenkins and Michael Charles Underhill, directors of Electra Limited certify that, having made all reasonable enquiries, to the best of our knowledge that:

a) The following attached information of Electra prepared for the purposes of clause 2.6.1 and clauses 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) in all material respect complies with that determination.

b) The forecasts in Schedules 11a, 11b, 12a, 12b 12c and 12d of the attached information are based on objective and reasonable assumptions which both align with Electra's corporate vision and strategy and are documented in retained records.

c) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards

Shelly Anne Mitchell-Jenkins – Director **Date 25/2/2022**

Michael Charles Underhill - Director **Date 25/2/2022**

Appendix 9: Glossary

Term	Description
ABS	Air Break Switch
ADMS	Advanced Distribution Management System
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
ARMM	Asset Risk Management Model
BCMP	Business Continuity Management Plan
CAIDI	Customer Average Interruption Duration Index is the average total duration of interruptions per interrupted customer
Capacity utilisation	A ratio which measures the utilisation of transformers in the system. It is calculated as the maximum demand experienced on an electricity network in a year divided by the transformer capacity on that network.
CAPEX	Capital Expenditure used to buy, improve, or maintain fixed assets i.e., vehicles, buildings, equipment
CB	Circuit Breaker
CBD	Central Business District
CBRM	Condition-based risk management
Conductor	Includes overhead lines which can be covered (insulated) or bare (not insulated), and underground cables which are insulated.
Continuous Rating	The constant load which a device can carry at rated primary voltage and frequency without damaging and/or adversely affecting its characteristics.
CRM	Customer Relationship Management an approach to manage and record interactions with current and potential customers
CT	Current transformer
Current	Capital Expenditure used to buy, improve, or maintain fixed assets i.e., vehicles, buildings, equipment
DDO	Drop-out fuse
DER	Distributed Energy Resources
DG	Distributed Generation
DNO	Distribution Network Operator
DSO	Distribution System Operator. Entities responsible for managing energy and other services (like flexibility services) across the distribution network
Distribution Substation	A kiosk, outdoor ground mounted substation or pole mounted substation taking its supply at 11kV and distributing at 400V.
EAM	Enterprise Asset Management system
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)

Term	Description
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
GLZ	Growth Limit Zone as specified in the Electricity (Hazards from Trees) Regulations 2003
GWh	Gigawatt hours
GXP or Grid Exit Point	The point at which Transpower's Grid is connected to Electra's equipment
Harmonics (wave for distortion)	A distortion to the supply voltage which can be caused by network equipment and equipment owned by consumers including electric motors or even computer equipment.
High Voltage	Voltage exceeding 1,000 volts, generally 11,000 volts (known as 11kV)
HILP	High Impact Low Probability
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 each year.
Lora WAN	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 year
MVA	megavolt amp
MW	megawatt
MWh	megawatt hours (one-million-watt hours)
N-1 Security	A load is said to have N-1 security if for the loss of any one item of equipment supply to that load is not interrupted or can be restored in the time taken to switch to alternate supplies.
NIMs	A Network Information Management System which contains geospatial information for all assets including asset description, location, age, electrical attributes, etc.
OC	Overcurrent
OCPI	Open charge point interphase
OCPP	Open charge point protocol
ODRC	Optimised Depreciated Replacement Cost.

Term	Description
ODV	Optimised Deprival Value.
ONAF	Oil Natural Air Forced
ONAN	Oil Natural Air Natural
OPEX	Operational Expenditure an ongoing expense for running a business e.g., rent, power. wages
PILC	Paper-insulated, lead-covered - a type of cable insulation.
PQ	Power quality
PRV	Pressure relief valve
Photovoltaic	The conversion of light into electricity using solar panels
Ripple Control system	A system used to control the electrical load on the network by, for example switching domestic water heaters, street lighting.
REF	Restricted earth fault
RMU	Ring Main Unit.
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index is the average total duration of interruptions per connected customer
SAIFI	System Average Interruption Frequency Index is the average number of interruptions per connected customers
SCADA	Electra's computerized System Control and Data Acquisition System being the primary tool for monitoring and controlling access and switching operations for Electra's Network.
SCI	Statement of Corporate Intent
SWER	Single Wire Earth Return
TAG	The Asset Guardian, an Enterprise Asset Management system
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.
UAV	Unmanned Aerial Vehicle
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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