Asset Management Plan 2025-35

EA networks

Asset Management Plan for EA Networks' Electricity Network

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EA Networks

Private Bag 802

Ashburton 7740

Website: http://www.eanetworks.co.nz

Telephone: (03) 307 9800

Email: enquiries@eanetworks.co.nz

As of November 2012, EA Networks is the trading name of Electricity Ashburton Limited. References to EA Networks in this document denote Electricity Ashburton Limited.

The owner and custodian of this document is the Network Division of EA Networks, Ashburton. All comments, queries and suggestions should be forwarded to the GM - Network.

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EXECUTIVE SUMMARY

1 Introducing our 2025 Asset Management Plan

This Asset Management Plan (AMP) sets out our assessment of the challenges and opportunities presented to EA Networks by the evolving energy sector and our operating environment. It presents our expenditure plans to ensure we continue to meet the needs of our community in Mid Canterbury.

This AMP provides a summary of the key programmes of work we will undertake to maintain and develop our network along with our expenditure forecasts, for the next 10 years, from 1 April 2025.

2 Our Context

EA Networks, the trading name for Electricity Ashburton Ltd, is a locally owned cooperative providing electricity distribution, fibre network services, and infrastructure contracting in Mid Canterbury, New Zealand.

The network is relatively new overall and in good condition, because of past investment in subtransmission and 22kV conversion to supply the increased irrigation demand over the last 20 years, and urban network renewal replacing overhead network with underground network driven by condition. As a result of the strength of our networks our capital spend is declining over the 10-year AMP period.

EA Networks Network:		
Maximum Demand	182.9 (Dec 2024)	MW
Annual Load Factor	45 (2023-24)	%
Delivered Energy	674 (2023-24)	GWh
Subtransmission Lines/Cables	418	km
MV Distribution Lines/Cables	2 212	km
LV Distribution Lines/Cables	513	km
Distribution Substations	6 767	
(Data as at February 2025)		

3 Delivering a safe, reliable and resilient service, now and into the future

Our network plays a central role powering our community and enabling our customer's energy choices. To continue to serve our community well in this role now and into the future, it is important we invest prudently to manage safety risk, asset health, and available capacity on our network. It is vital we renew and maintain our assets, develop our network to keep pace with customer needs and evolving technology, while managing increasing cost pressures.

Aligned with asset management objectives, our investments over this AMP period have been developed to ensure our network and assets are:

- Safe – we are committed to high safety outcomes. We focus on managing the risks associated with our diverse range of assets and operations and ensuring our interventions are targeted to activities that pose higher risk.
- Reliable – reliable energy services are important to our customers. However, the increasing incidence of climate change driven severe weather events increases the risk of more frequent and extended outages. This is particularly the case as assets age and their condition degrades. We are committed to ensuring we continue to deliver appropriate levels of reliability to customers during this 10-year AMP period.
- Resilient – our customers place a clear priority on us investing in the resilience of our network. Our investments in resilience will increase our network security and its ability to withstand more severe weather events due to climate change. To address both reliability and resilience, we are investing in a combination of physical network assets, automation of network switches and more advanced control systems to reduce the impact of faults on customers.
- Flexible – our customers' energy needs continue to evolve. We expect to see continued, strong growth in customers adopting technologies such as utility scale solar, roof top solar and electric vehicles. We believe it is important that we support our customers in the energy choices they make. We are focused

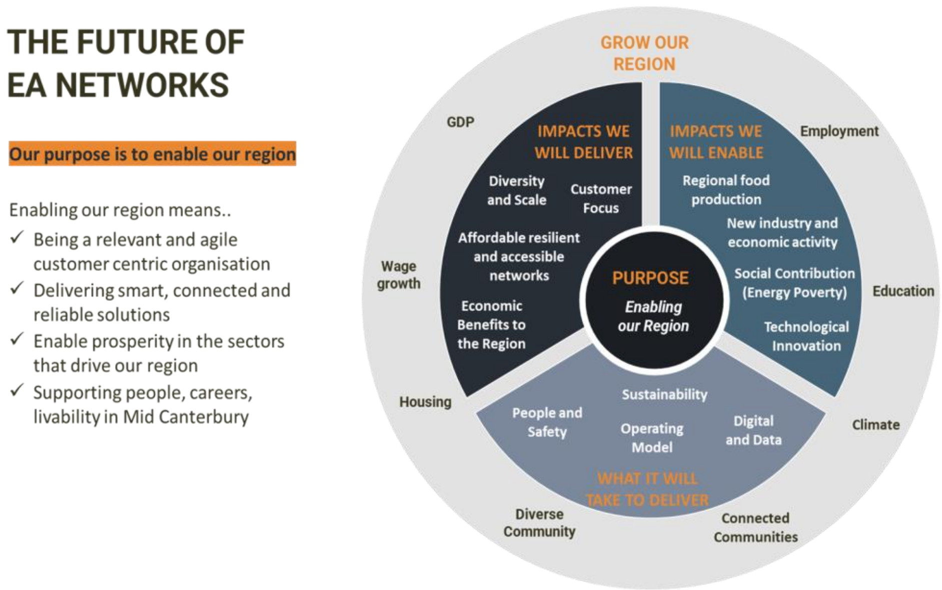
on ensuring EA Networks provides the network capacity and security needed, as well as building sufficient flexibility to accommodate new technologies to benefit our customers.

To achieve this, we are focused on our strategic direction, our commitment to our customers, our people and how our industry is evolving.

3.1 Strategic Objectives

To achieve our commitment to our customers, our people and the wider industry we refreshed our strategy during 2024, which is centred around a purpose of ‘Enabling our Region’ which means:

- Deliver smart, connected and reliable networks.
- Ensure we can safely respond when communities need us.
- Attract, value and retain committed and engaged people through meaningful careers and a vibrant culture with an owner’s mindset.
- Remain locally owned and operated to enable prosperity and liveability in our region.
- Be a relevant and agile customer centric organisation with a strong brand reputation.
- Deliver sustainable financial and environmental performance through diversified infrastructure and optimised delivery.



The strategy has been updated in the context of serving the current and future needs of our customers and responding to the challenges of our evolving industry, as detailed below.

3.2 Commitment to Our Customers

Our customers define our success. As a co-operative, we align our strategies with the best interests of our customer shareholders, eliminating the typical tension between shareholders and consumers. This enables us to focus on delivering strong customer outcomes that drive regional economic growth. We are successful if our customers are successful and have access to energy where and when they need it.

3.3 An Evolving Industry

In line with our strategic aspirations outlined in section 3.1, we plan to meet customer and industry expectations to operate a future-fit, digital network in an increasingly complex environment and deliver the expected needs of efficient network operations and asset management, decarbonized process heat and transportation, as well as enabling connection of fluctuating renewable solar generation and flexible demand.

Our focus for the first three years of this AMP is to replace or strengthen core systems, including replacing the

GIS platform and considering the replacement of our Enterprise Resource Planning (ERP) system. Once these foundations are in place, we will progress to developing further the integration of electricity-specific systems, including our Advanced Distribution Management System (ADMS).

Given the climate of decarbonisation driven by climate change targets, the electricity sector expects a diversity of network investment and capability development drivers out to 2050. Customers will seek new services and expect a continuation of reliable and affordable network connections. These drivers include:

- the decarbonisation of transport,
- process heat conversion to varying degrees between biomass and electricity,
- population growth resulting in both greenfields and infill development,
- new commercial or industrial point loads (e.g. data centres, hydrogen infrastructure),
- residential and commercial gas conversion (only to a minor extent in Mid-Canterbury),
- utility scale and roof top solar generation,
- accommodation of battery storage and flexible demand solutions,
- climate adaption requiring changes to assets,

and the need for investment to:

- improve LV visibility, and
- implement Advanced Distribution Management System functionality to manage the influx of distributed energy resources (DER) and make best use of network capacity.

These are largely new drivers that the sector has not experienced before to the greater extent expected. There is still significant uncertainty related to the timing and scale of these drivers, which affects EA Networks' ability to predict load growth and investment requirements, particularly further out in the future. Development of our load forecasting models is underway to respond to these challenges.

3.4 Commitment to People & Safety

Our ability to deliver the Asset Management Plan and its success relies on our people having the capability and capacity. We must maintain a strong employer value proposition (EVP) that allows us to attract and retain people. Our focus is on developing employer value proposition including:

- Ensuring fair and competitive remuneration that aligns with industry standards.
- Enhance employee satisfaction, productivity, and retention through comprehensive benefits.
- Foster a culture of safety and wellbeing, supporting both physical and mental health.
- Promoting our values and driving consistency in behaviours.
- Strengthen EA Networks reputation as an employer of choice.

We are committed to ensuring the safety of our customers, employees, contractors, and the public. We provide a safe and healthy workplace for our people and contractors that enables us all to function and deliver great outcomes, in the provision of a safe and reliable network for our community. Our strategy is to deliver on our vision and values through:

- Leadership and Culture - We will support leaders in their approach to a positive safety culture, behaviours, attitudes, and work processes.
- Hazard and Critical Risk Management - Our focus is on understanding our critical risks, implementing all required risk controls, and ensuring all of our workers are equipped with enough knowledge, systems, and processes and the right mindset to work safety in the business.
- Suitable Systems and Assurance - We will take a consistent approach to safety across our business, which means our safety systems and documentation need to be simple, fit for purpose, user friendly, and accessible to everyone.

4 Our Network Overview

The network is relatively new overall and in good condition, as a result of investment in subtransmission and 22kV conversion to supply the increased irrigation demand over the last 20 years.

Within the context of the electrification of New Zealand, demand in Mid Canterbury is expected to moderately increase. A continuation of the historic high rates of irrigation load growth are at an end. Mid Canterbury does not have significant process heat requirements compared to other regions, but progressive decarbonisation of food processing industries is expected to introduce manageable demand step changes within the 10-year plan. A forecast of electric vehicle (EV) charging has been produced, showing manageable demand increases provided managed charging is used in line with incentives on the industry to minimise cost.

Fault frequency has generally been better than the average of peer companies and generally better than the average of all companies. Fault restoration time is similar to the average of peer companies.

Increased levels of SCADA distribution automation and control will occur over the next ten years, with the objective of increasing network reliability and ensuring that the network is equipped to respond to increasing penetration of distributed energy resources and two-way power flows.

Capital expenditure is declining from historical highs:

- Urban underground conversion will conclude within the plan horizon but has been spread over several more years as overhead line condition permits.
- 11 to 22 kV conversion will conclude within the plan horizon.
- Rural distribution capacity will be sufficient for the security of existing and forecast load once 11 to 22 kV conversion is complete.
- Urban 11 kV distribution capacity will be sufficient for the security of existing load and forecast load once the 11 kV core network is complete.

Load requirements remain stable:

- Irrigation load growth is static, and irrigation load may reduce in future.
- Residential load growth is modest and typical for provincial New Zealand. Process heat load growth could grow over the 10-year period.
- Some existing customers have indicated they are looking to convert process heat presently supplied from fossil fuels to electricity and this has a notable demand impact on the GXP and some zone substations. It is unlikely that more or larger significant assets will be required to service this additional and possible load requirements.
- Utility scale solar generation has and will continue to occur, providing significant amounts of energy from within the EA Networks network and possibly lower the peak demand
- on the Transpower GXP.
- Electric vehicles, batteries, and solar PV have yet to make a measurable impact on demand. EA Networks is less likely to face widespread issues with EV demand than some other networks assuming managed charging is used.

Reliability, resilience, and load security increases during the plan period because of programmes and projects included in this plan.

The electricity network represents an acceptably low safety risk to staff and the public and is lowered further when the projects included in this plan are delivered.

5 Significant Aspects of AMP 2025

This section provides a brief summary of the significant updates contained in AMP 2025, as follows:

Changes to Network Development Plans including the construction of and likely development of further utility scale solar farms, distribution network investment, updates to projects and programmes like the Decarbonisation & Smart Technology programme, the commencement of the GIS Implementation Project and ongoing development of the Advanced Distribution Management System (ADMS). A ferroresonance safety programme of three phase-switch installations has been added as 5-year programme, switches have been identified and will be prioritized. Specific budget has been allocated for replacement of overloaded HV fuses with a gas switch during overhead renewal projects (in the past these were unbudgeted scope additions within projects as identified).

The total 10-year capital expenditure is overall $3m, 2% higher than AMP 2024. Net of capital contributions, total 10-year capital expenditure is overall $6.7m, 5% higher. Refer to the capital profile presented below.

Prioritisation and review of capex projects targeted the AMP 2024 expenditure profile, while checking that network needs are met (including public and worker safety, reliability, capacity and meeting customer requirements). Significant movements are related to:

- Expenditure on underground projects closely match AMP 2024 for the first 5 years, then due to the limits of deferment and the need to progress network centres and core network cables, there is a $5.3m increase in capex to compensate for cost escalation.
- The urban underground projects are planned to be completed by 2034, and capex in 2035 (the last year of the new ten-year programme) is at $10.4m. This moderates the underground projects cost-escalation.
- Customer driven/capital contribution capex has been adjusted related to an updated solar farm connection cost (Mt Somers Solar Farm) and an industrial processor capacity increase re-phased and budgeted. The Network Centre and Network Core Cables project phasing has been deferred by 1 year due to switchgear uncertainty and needing to access sites.

Two major rural overhead to underground (OHUG) projects are planned for FY26, the Lake Heron Feeder ($2.2m, 25km to be completed between October 2025 and March 2026) and the Methven Highway, Shearers Road to Springfield Road section ($1.1m, 7km to be completed between August 2025 and March 2026). The significant difference in cost per kilometre for these two projects is a combination of higher customer connection density and traffic management requirements on the Methven Highway project.

The 10-year operating expenditure is overall 14% higher ($27m) than AMP 2024. Network related maintenance expenditure is 16% higher, with an uplift related to maintaining aging assets. Non-network operating expenditure (Business Support and Operations & Network Support) is 13% higher, related to investment in systems, people and organisational capability. Aspects of note are:

- The allocation of FY26 maintenance expenditure between activities has been set using analysis of historical expenditure combined with current labour rates. An additional $0.4m of overhead removals is incorporated in FY26 associated with the major OHUG projects mentioned above.
- Over the 10-year period, to reflect aging assets requiring more attention Routine & Corrective Inspection & Testing and Asset Renewal expenditure has been escalated over the 10-year period at 1.5% per annum once works specific asset renewals (e.g. line removals) were excluded. Vegetation management and Interruptions & Emergencies are held at the FY26 in real terms over the 10-year period.
- Operating Cost investments in strategic initiatives and systems development (e.g. GIS implementation, ERP system replacement, ADMS development).
- Increased people costs related to filling vacancies and new roles aligned to strategic initiatives. This organisational capacity will assist in responding to connection demand and resourcing to operate, manage and build the network in line with our strategy of enabling our region.

Two utility scale solar farms (Lauriston and Gartartan) have been connected to the network, and two more potential large solar farm connections have been incorporated within a potential pipeline of circa 54 MW of applications.

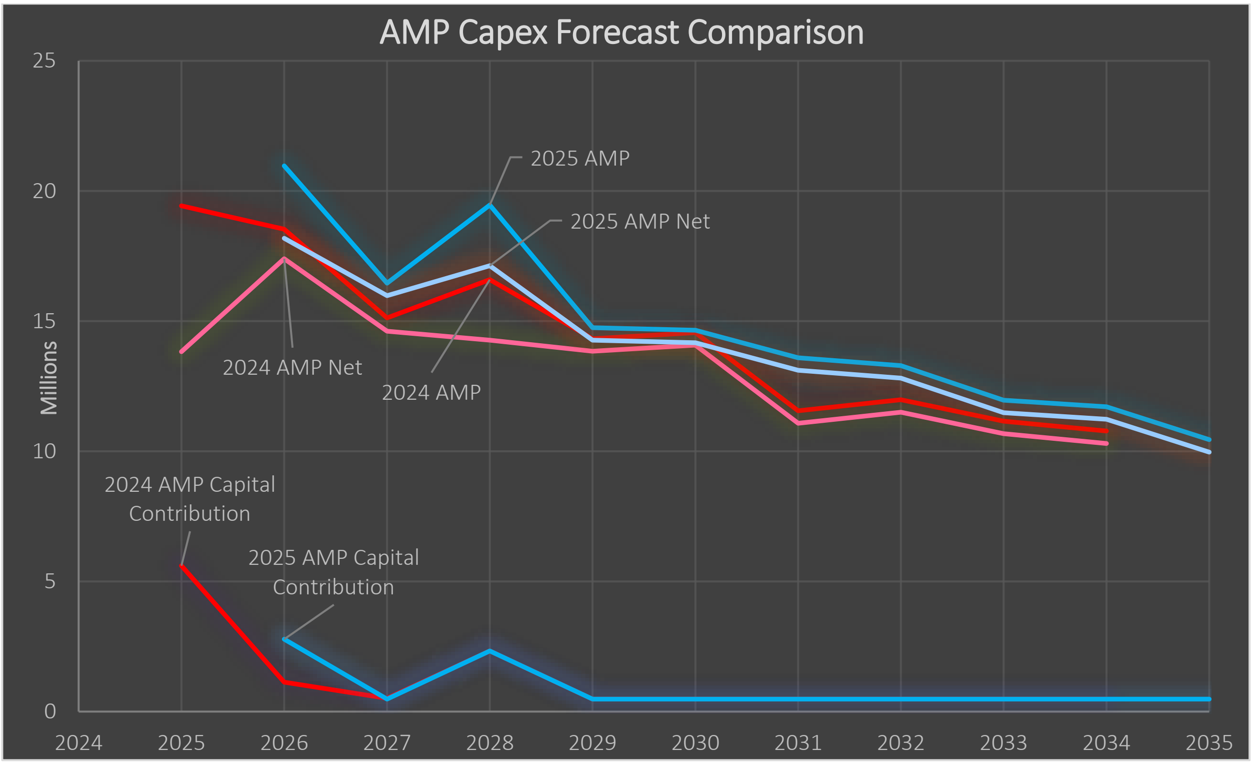
Only one industrial connection expansion in two stages has been incorporated in the plan, related to expected emerging demand. The additional 66kV circuit required for this development could also serve increased solar export if that continues to develop. Several other potential projects have been discussed along with the potential for decarbonisation, but these have not been incorporated, due to the inherent uncertainty and lack of firm commitment.

- Revision of project cost estimates for escalation in materials and labour rates due to inflationary pressure, particularly related to underground projects.

- Inclusion of further information disclosure material required by the Commerce Commission since 31 March 2023 that was not included in the full-format AMP 2023, including additional information disclosure requests from June 2023 and August 2024.
- Inclusion of AMP material from the AMP 2024 update in summarised form so AMP 2025 provides coverage of those practices and outcomes, including deferring the second 220/66kV GXP beyond the 10-year forecast period, the shared lines and transformer poles on private property policy, the Network Risk Register update and Resilience Management Maturity Assessment (RMMAT) and Resilience Action Plan.

5.1 *Total 10-year capital expenditure*

The total 10-year capital expenditure of $138m is $3m, 2% higher than AMP 2024. Net of capital contributions, total 10-year capital expenditure is overall $6.7m, 5% higher. Refer to the capital profile presented below.



The ten-year capital forecast is summarised in the table below ($M):

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
2025 AMP	20.96	16.46	19.46	14.75	14.65	13.59	13.29	11.96	11.71	10.45	147.28
Capital Contribution	2.78	0.48	2.33	0.48	0.48	0.48	0.48	0.48	0.48	0.48	8.95
2025 AMP Net	18.18	15.98	17.13	14.27	14.17	13.11	12.81	11.48	11.23	9.97	138.33

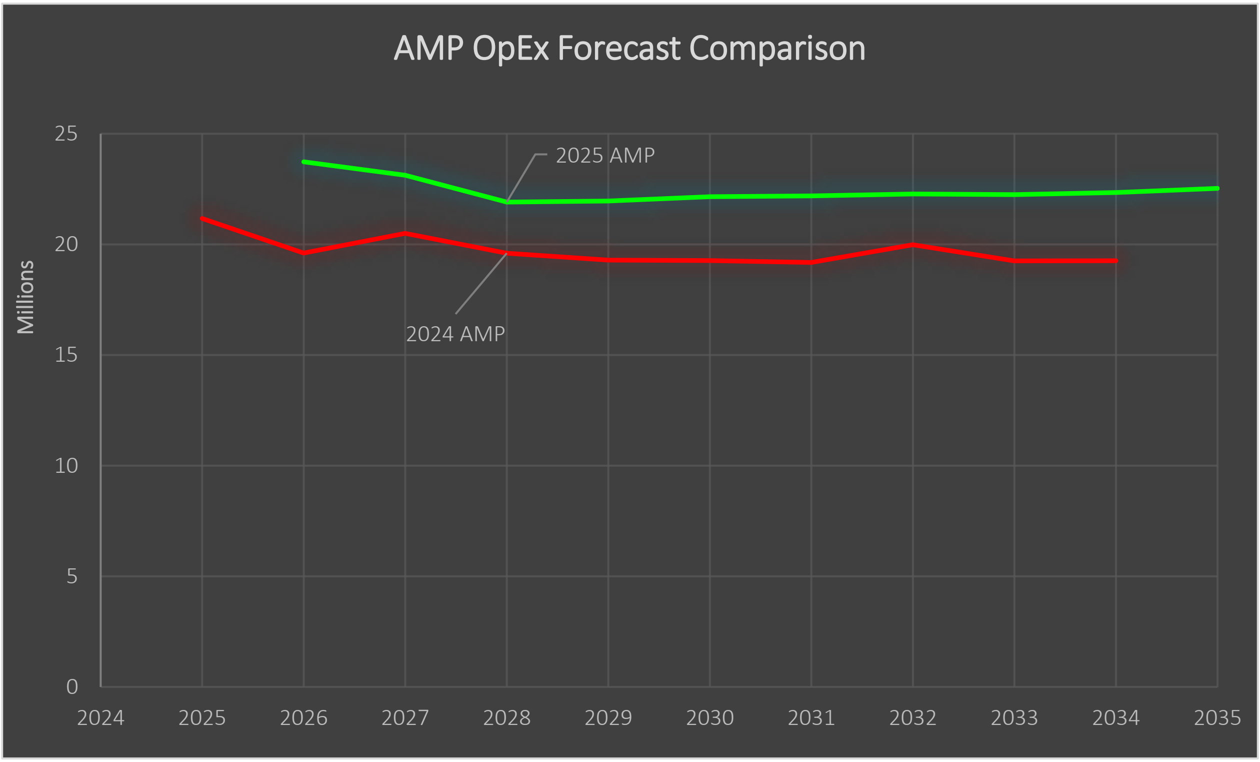
5.2 *Material Capital Projects for FY26*

The AMP drives outlines business capital expenditure budgets and thereby informs the network pricing process. When planning and programming material projects we seek to optimise expenditure and delivery of these projects. Timing is key, balancing the programmes for safety, network development, system growth and renewal, customer requirements, reliability and quality. The significant projects for the planning period include:

Specific Project	Type	Value ($M)
UG Conversion - Lake Heron Line	Asset Replacement / Renewal	2.1
Consumer Connection - Solar Farm	Consumer Connection - Other	1.9
UG Conversion - Methven Hwy (Shearers Rd to Springfield Rd)	Asset Replacement / Renewal	1.1
UG Conversion - Oxford St (Beach Rd - Wellington St)	Asset Replacement / Renewal	0.6
UG Conversion - South Town Belt East (Bridge St - Burrowes Rd)	Asset Replacement / Renewal	0.6
UG Conversion - Carters Tce (SH1 - Grove St)	Asset Replacement / Renewal	0.6

5.3 Total 10-year operating expenditure

The 10-year operating expenditure is overall 14% higher ($27m) than AMP 2024. Network related maintenance expenditure is 16% higher, with an uplift related to maintaining aging assets. Non-network operating expenditure (Business Support and Operations & Network Support) is 13% higher, related to investment in systems, people and organisational capability.



OUR BUSINESS

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1 OUR BUSINESS

1.1 EA Networks' Evolution

In 1908 a private company, Craddock & Co, began supplying electricity to Ashburton township consumers at 220 volts DC. The source of this supply was a 30kW generator driven by a steam traction engine. 3.3kV AC was soon introduced, and this was the distribution voltage of choice until around 1923.

In 1921, the Ashburton Electric Power Board came into existence, and it took over the operation of the generators and began implementing one of the options for connecting to the national grid. The new Public Works Department Ashburton substation (the present Ashburton zone substation is on the same site) began supplying electricity to the Ashburton urban area in 1924. The AEPB initially had both 6.6kV and 11kV supplies from Ashburton substation (having quickly retired the 3.3kV and DC supplies). This system evolved gradually over the next twenty years until second and third 11kV points of supply from the national grid were established near Methven and Springfield Road. During this time (1932) Mr Kemp (the founding engineer at A.E.P.B.) devised an electric tractor. The photo at right shows the mobile substation used to supply the tractor. Six tractors were built, and they each did over 4000 hours of cultivation during an eight-year period.

During the post-war years, the Power Board became the Power and Gas Board – supplying coal gas to a large percentage of Ashburton township. Gas production ceased in 1973 as it had become uneconomic.

As the load continued to increase, it became apparent in the early 1960s that a true subtransmission network would be required. Planning began and once 33kV had been settled upon as the correct subtransmission voltage, the first 33/11kV substations were commissioned in 1967. These substations were supplied from three AEPB owned 5MVA step-up transformers (11/33kV) located at the Ashburton substation.

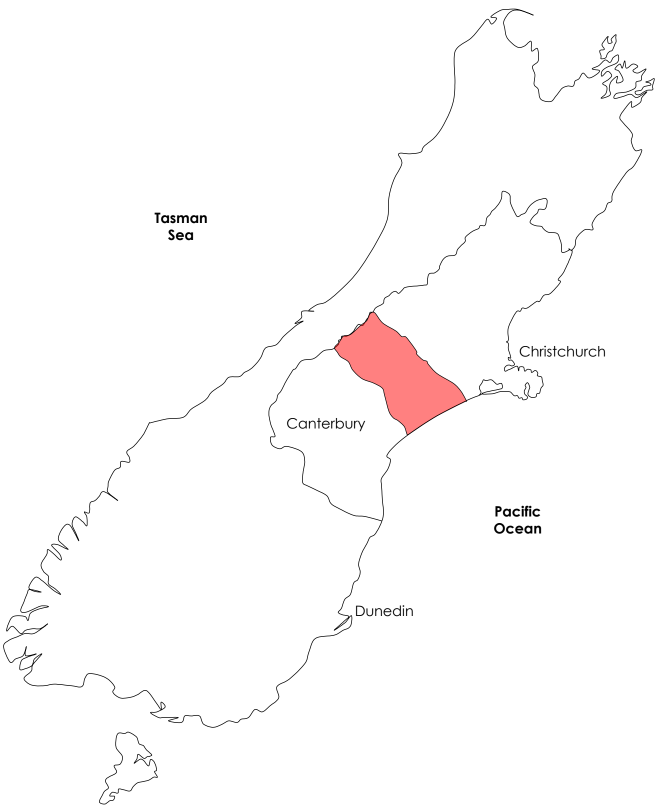
The final portion of 6.6kV distribution was converted to 11kV in 1971. The popularity of pumped irrigation began to increase, and general electricity use continued to rise. As a result of the increased irrigation load and other industrial loads such as snowmaking, animal processing plants and vegetable processing, the number of 33/11kV substations increased. By the early 1980s the three step-up transformers were overloaded, and relief came in the form of a 33kV point of supply at Ashburton and another at Cairnbrae (5km south-east of Methven). This arrangement allowed the creation of a 33kV ring network that initially allowed individual 33kV line faults to be tolerated without extended loss of supply.

A small (1.6MW) hydro power station was constructed by the AEPB during the 1980s at Montalto Hydro. This induction generator continues to operate but is now owned by an electricity retailer.

During the late 1980s and early 1990s, Transpower proposed decommissioning the 110kV circuits between Timaru and Hororata. This required shifting one of the points of supply from the Ashburton township site to a site about 7km south-east of Ashburton. Once the two parties agreed on commercial arrangements, the new 220/33kV substation was built, and EA Networks took 33kV supply from it in 1992.

Around 1995, what was the Ashburton Electric Power Board was transformed into the co-operatively owned company Electricity Ashburton Ltd. Options for this transition, from a quasi-governmental entity with undefined ownership to a limited liability company, were comprehensively researched and what was considered the fairest and most stable ownership option was instituted.

The subtransmission and point of supply rearrangement had assisted in extending the life of portions of the 33kV ring network, but the huge increases in irrigation load were beginning to tax the rural 33kV network beyond its capacity. The same problem was facing the 11kV distribution network in places, so a bold decision was made to begin converting portions of the 33kV network to 66kV and some of the 11kV network to 22kV. The change to 66kV introduced an opportunity to provide a 66kV connection to the Highbank Power Station that had historically been connected to the Transpower network. This option was duly negotiated and a more extensive 66kV conversion undertaken to connect Highbank. The subtransmission development also enabled the Cairnbrae 66/33kV point of supply to be relinquished and there is now only one physical location for EA Networks' connection to the national grid.



Transpower's Ashburton substation (actually 7km from Ashburton) supplies an EA Networks substation called Elgin immediately adjacent to it. Elgin then connects to seven lines in the EA Networks 66kV subtransmission network. In 2019, EA Networks relinquished the 33kV connection to Transpower (leaving only the Elgin 66kV supply). Simultaneous with the subtransmission conversion was the conversion from 11kV to 22kV of some distribution lines. This was also very successful and offers much improved voltage regulation and capacity, thereby increasing power quality to those rural consumers supplied via 22kV. 22kV conversion has continued to progress in many rural 11kV areas where additional capacity is needed. The plan is now to convert the entire rural area to 22kV (excluding the Upper Rakaia Gorge – supplied at 11kV from the Orion network).

The area EA Networks directly services is approximately 3500km². The extents of the area are the Rangitata River in the south, the Rakaia River in the north and the foothills of the Southern Alps in the west. Three distribution lines run up remote river valleys into the foothills, but these form a very small portion of the entire network.

The network comprises of some 27676 poles, 2274km of high voltage overhead lines, 336km of high voltage underground cable, 21 zone substations and switchyards, 6693 distribution substations, one control room, and a communications network.

There are four hydro generating stations embedded in the network. The newest generator is a 0.5MW unit near Barrhill. Cleardale is a 1MW station, Montalto Hydro is a 1.6MW station, and Highbank is a 26MW station. The Barrhill unit is owned by Barrhill Chertsey Irrigation, Cleardale is owned by the farmer the station occupies, while Montalto Hydro and Highbank are owned by Manawa Energy. During 2024, two utility scale solar generation stations were connected; the 47.2MW Lauriston Solar Farm owned by Genesis Energy and FRV Australia, and the Gartartan Solar Farm consisting of two co-located solar farms totalling 6.5MW owned by Lightyears Energy One and RCR Green Developments.

EA Networks' distribution lines have a variety of different capacities, dependent upon local demands and geographical considerations. Operating voltages include 66000 volts (66kV), 33kV, 22kV, 11kV and 400V.

The rural distribution network configuration is predominantly long radial overhead feeders with a number of interconnections to adjacent feeders and substations. This arrangement is largely driven by economics and is the method of supplying rural consumers that offers best value at acceptable levels of reliability. Typically, the capacity of a rural feeder is limited by voltage drop and not the thermal rating of the conductors.

The urban 11kV distribution network is based upon a similar principle to the rural arrangement except the network is largely underground cable, the interconnections are more frequent, and the overall feeder lengths are significantly shorter. The capacity of urban feeders is thermally constrained by the maximum current rating of the underground cable.

Now trading as EA Networks (as of 2012), the company also operate and develop an open access fibre optic network in Mid-Central Canterbury (https://www.eafibre.co.nz).

Summary of Network Assets

(As at February 2025). Circuit voltage is rated voltage (operating voltage quantity in brackets).

Network Inputs and Outputs:

Active Connections	21 164	(21 Feb 2025)
Maximum Load Demand	183	MW (Dec 2025)
Delivered (Injected) Energy	622 (535)	GWh (2023-24)*
Annual (Injected) Load Factor	39	% (2024-25)*
Annual Loss Ratio	5.6	% (2024-25)*

Network Components:

Overhead Lines (circuit km)	371 (351)	66 kV Subtransmission
	37 (37)	33 kV Subtransmission
	1 666 (1 557)	22 kV Distribution
	177 (307)	11 kV Distribution
	39	400 V Distribution
	8	Street Lighting
Poles	26998	All types
Underground Cables (km)	4.4 (4.3)	66 kV Subtransmission
	5.3 (1.6)	33 kV Subtransmission
	230 (167.4)	22 kV Distribution
	138.9 (198.3)	11 kV Distribution
	474.2 (456.0)	400 V Distribution
	343.8 (340.4)	Street Lighting
Zone Substations	18	66kV, 66/11 kV, or 66/22 kV
	2	33/11 kV
Distribution Substations	4 587	Pole Mounted
	2 180	Ground Mounted

* The energy volumes, and hence load factor and losses, differ from information disclosure schedules due to a one-off change in retailer reporting method that affected billed volumes. The above values have been sourced from the reconciliation manager in February 2023.

The future of EA Networks will focus on a 66 kV subtransmission network, a largely 22 kV overhead line rural distribution network, and an 11 kV urban underground cable distribution network in Ashburton and Methven townships. An additional layer of larger 11 kV underground cable distribution is planned to be added in Ashburton, as many of the existing urban feeders have reached security or thermal rating limits. The values of some broad asset categories are detailed in section 4.4.

1.2 Stakeholders

Stakeholders are defined as those parties with interests in EA Networks' asset management from a financial or operational point of view. The principal stakeholders are:

Shareholders

EA Networks' shareholders (who, since EA Networks is a co-operative company, are all consumers) wish to ensure, as owners of the assets, that their financial capital is protected in the long term, by ensuring that the operating capability of the network is maintained, and that the system is maintained efficiently so that they earn a sufficient return on their investment.

The interests of shareholders are actively sought by the Shareholders' Committee. As elected committee members (or Ashburton District Council appointed members as is the case for three of the seven), they are all members of the local community, and they individually and collectively seek feedback from shareholders and shareholder/consumer groups.

The shareholders also have a direct interest in how EA Networks provides customer service and how it meets its obligations to other parties (as described below).

The shareholders elect a Shareholders' Committee, and this group not only appoints the Board of Directors but also provides a consultative role for the Board and management. The Shareholders' Committee review the Statement of Corporate Intent, the Annual Report, and other relevant company disclosures and statements. The Asset Management Plan is also available for reference, to inform, and to comment on. This process provides shareholder feedback and provides the principal means of managing conflicts between most stakeholder interests and asset management practices. The shareholders are also able to address any specific issues at the Annual General Meeting, but more commonly they would use the Shareholder's Committee as the conduit to resolve any issues of principle. Section 3.2 details the representative voice that the Shareholders' Committee provides between all shareholder/consumers and how this influences the asset management philosophy of EA Networks. Other stakeholders are typically consulted on an issue-by-issue basis as and when required.

It is noteworthy that EA Networks shares/shareholders are not a straight-forward vehicle for raising additional capital. Unlike a listed company, raising capital is largely limited to borrowing from banks or similar institutions. The cooperative company structure makes it very challenging to raise capital outside this avenue.

Consumers

These are EA Networks' directly connected end-use consumers (more than 99% are shareholders, and those that are not and have made a conscious choice not to be).

The Shareholders' Committee actually serve as a de facto *Consumers' Committee,* as all shareholders must be current consumers on the EA Networks network. They seek the opinions and balance the interests of the shareholders from a prudent financial management perspective as well as considering the level of network performance that is required to maintain a high level of satisfaction from the consumer/customer base.

EA Networks management also encourage individual consumers and representatives of groups of consumers to engage in constructive dialogue to further refine the focus of EA Networks in satisfying their needs and interests. A biennial consumer survey of consumers takes place, and they are asked a range of questions including preparedness to pay for additional reliability, ownership of on-property lines (in Mid-Canterbury on-property lines are mostly privately owned), and satisfaction with advice and dialogue with EA Networks personnel. The survey is also provided to the Shareholders' Committee for their consideration. A selection of the larger consumers are interviewed as part of the survey to gauge their interests and concerns. These concerns can be addressed with individualised solutions in most circumstances, and it generally comes down to presenting the price/quality trade-off options clearly and in a timely manner so that they can evaluate them objectively.

Generally, the consumers wish to receive a safe, adequate, and suitably reliable network service, and to be assured of being able to receive this over the long term, at minimum cost.

Customers (Retailers and Generators)

The retailers and generators (many of the larger ones are both and are colloquially called *gentailers*) active on EA Networks' network number about twenty (and increasing) and are always prepared to share their opinion of EA Networks' business focus and methodologies. Meetings are held with representatives of some retailers while others (typically those with few customers on the EA Networks network) do not appear to seek regular engagement.

The EA Networks *Default Distributor Agreement* (based upon the Electricity Authority's June 2020 template) provides the major vehicle for translating retailers' interests into the performance required of the EA Networks network. Equally, it provides a standardised path to communicate the requirements EA Networks place on a retailer to use the electricity network. There is no review process available for the *Default Distributor Agreement*, as the intent is to retain standardisation. The *Default Distributor Agreement* superseded the *Use of System Agreement* in April 2021.

Among other things, the retailers want stable business practices, robust network performance, and justifiable charges for use of the EA Networks network. Other issues of interest include timely responses to information requests and, where needed, follow-up actions.

In recent times, it has become apparent that retailers and generators can have diverse viewpoints on issues. Typically, this will be in situations where the retailer with no generation is apprehensive of the market power held by large generators who are almost all *gentailers*. Retailers want the lowest possible market energy price, whereas generators want the highest possible market energy price.

Others

Other parties with a potential interest in EA Networks' asset management include:

- **Transpower** who have an interest in the existing and future utilisation of their assets. Management have regular meetings with Transpower representatives on various issues. Commercial negotiations tend to arrive at a satisfactory resolution of any issues.
- **Other lines companies** in the region with whom common problems and solutions can be shared. This engagement takes place as a matter of course, and there are many examples of a unified approach to identifying, researching, and resolving issues of common interest. These can be in the form of common equipment specifications, design standards, or even principles of application of similar policies.
- **Employees and contractors** who design and build the system, have an interest in the future work that is available, and the safety of the assets. Every time a contractor is engaged, they are fully briefed on EA Networks' safety requirements and, although the level of work contracted out is less than many other lines companies, any request for information is answered promptly and candidly.
- **Suppliers** who provide products and services to EA Networks and financially succeed as a result.
- **The public** on whose land the network may be built. EA Networks are fortunate not to have significant quantities of assets on private property. Whenever private land must be entered, permission is sought well in advance unless it is an emergency when all efforts are made to contact the owner and minimise the impact of any required work.
- **Tree owners** who have a requirement to keep their trees clear of power lines. A full-time employee actively manages the required dialogue with tree owners to minimise the conflict between trees and power lines. This process is typically amiable and very few dialogues become formal exchanges of letters. The tree owner typically has an interest in minimising the impact of tree control work on their tree and subsequently preventing any fiscal or reliability implications of the tree interfering with the line.
- **Regulatory agencies** with which EA Networks comes into contact. The governmental agencies that EA Networks are required to deal with tend to make their interests quite clear by inviting comments on discussion papers or draft regulations that indicate the intent of any future regulation or legislation. Any interaction is typically very formal and open so that all interested third parties can gauge for themselves the validity of the opinions expressed by the regulatory body and EA Networks.

- **Financial institutions** who may be called upon to fund aspects of asset development or maintenance. The financial institutions that EA Networks both borrow money from, and deposit money with, have an interest in ensuring that EA Networks continues to be a viable and profitable business that can service any debt as contracted. These financial institutions always advertise their interests at an early stage and ensure they continue to be well known.
- **Local Electrical Contractors** who are required to comply with EA Networks' connection standards. These standards control a range of performance measures including, but not limited to: safety; the impact the connection has on the reliability of other consumers; the impact the connection's load has on the power quality of other consumers and on the EA Networks network; and the timing/advance notice needed to provide the connection.
- **Interest groups** such as Federated Farmers, Grey Power, irrigation representatives, and electric vehicle owners. These groups are really consumer groups from whom EA Networks actively seek opinions on issues that will impact their members. Obviously, these groups are not the only consumer groups with whom EA Networks seek to engage, and the vested interests of each group are balanced by presenting the Board and Shareholders' Committee with both the interest group's opinions as well as the technical and fiscal implications for EA Networks should they choose to heed any or all of these opinions.
- **Distributed generation (DG) proponents**. These individuals and organisations are encouraged to communicate their interests to EA Networks at the earliest opportunity. As with all lines companies, EA Networks has a published policy and guidelines for the connection of DG to the network. The nature of potential DG connections is that they can be completely unknown to EA Networks and because of commercial sensitivity the proponents do not wish to engage in dialogue until the last stages of any development. This obviously makes it difficult to determine their interests in advance. EA Networks believe the DG policy in place satisfies most DG proponent's interests.
- **Ashburton District Council** as a major shareholder and the body that controls access to the road corridor. Many of the interests of a local body are enshrined in legislation and are therefore very transparent to EA Networks. Unique local interests that are specific to either district development or planning are typically dealt with in management-to-management dialogue and, on occasion, formal consultation for issues such as District Plan reviews and amendments. There are issues in the political domain that are discussed at Board, Shareholders' Committee, and District Councillor level. Asset management personnel are generally aware of the outcomes of these discussions rather than the content. While a significant shareholder, the Ashburton District Council has no greater power as a shareholder than any other individual shareholder.

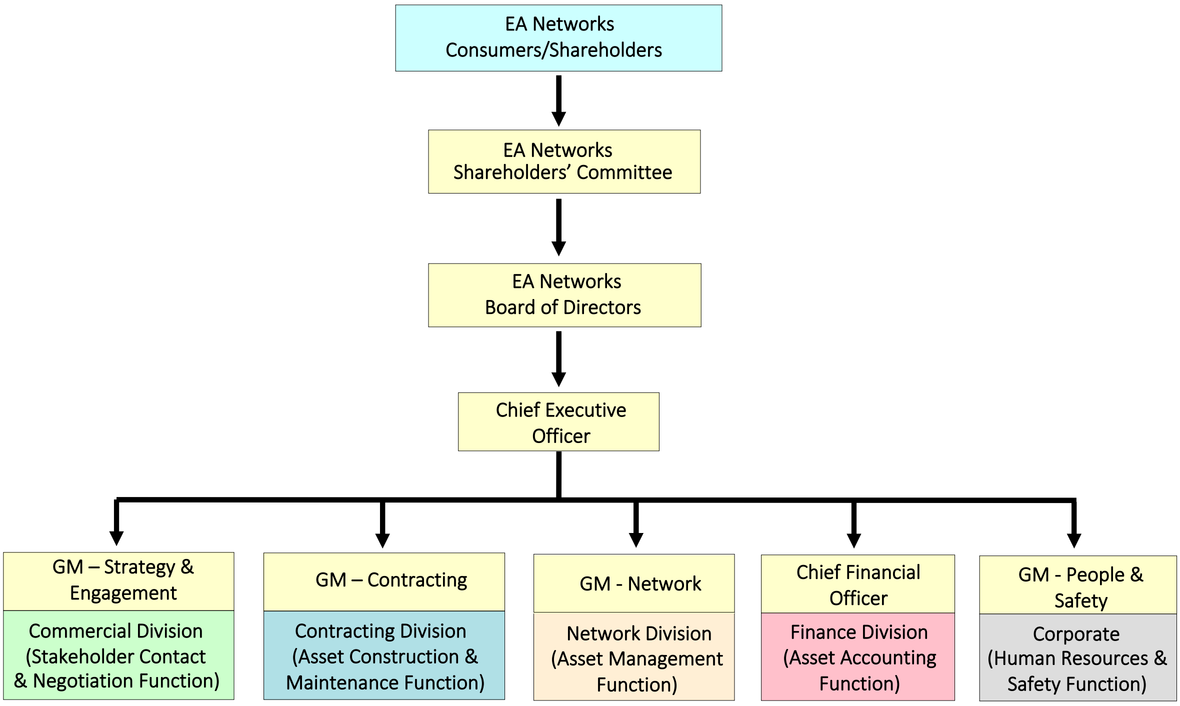
1.3 Overview of EA Networks Organisation

EA Networks operates as a stand-alone co-operatively owned lines business – EA Networks. This business incorporates an asset management function (the Network Division) and an asset construction and maintenance function (the Contracting Division). EA Networks owns, operates, and maintains the infrastructure assets. The Network Division plans and controls the asset management function.

EA Networks offers network line services as its core activity. Ancillary to this function is the Contracting division, which offers services to the Network Division, other line owners, and the general public. Other business activities include a fibre optic data network.

There are 30 587 000 shares issued in EA Networks. The Ashburton District Council holds 28 750 000 of these shares in a non-rebate/non-voting form. The consumer/shareholders hold 1 545 000 rebate shares at 100 shares per consumer (some consumers have more than one connection). There are 292 000 unallocated rebate shares available for new consumers as they connect to the network. Existing consumer/shareholders who add additional connections are not entitled to additional shares.

The Asset Management Team in the Network Division holds the technical knowledge and is responsible for technical decisions concerning the asset. The Asset Management function remains associated with the Contracting function within one corporate body. The company oversees EA Networks assets and personnel – hence the requirements of equipment and personnel safety remain within one corporate body. The upper tiers of the company structure are shown below.



The key functions and responsibilities of the groups are:

Consumers/Shareholders

The end users of electricity supplied over the EA Networks network. All new consumers choose whether to be a shareholder in the cooperative company. Almost every new consumer chooses to retain the shareholding and only a handful of existing consumers opt out as shareholders. Each shareholder (consumer) has one vote to elect a Shareholders' Committee. This is irrespective of the size/scale of their electrical connection(s) or contribution to the company's income or profit. The shareholders have the responsibility to consider their choice of committee member carefully to ensure they faithfully represent their views both in appointing directors and influencing the performance of the company. Ultimately, shareholder dissatisfaction with either the Shareholders' Committee or the Board will firstly result in changes to the Shareholders' Committee by the ballot and then a different emphasis in the Board members appointed by the Committee.

Shareholders' Committee

Representatives of all shareholders. Represent the interests of the shareholders/consumers (to be a shareholder one must be a connected consumer). They appoint Directors, undertake intense scrutiny of the Statement of Corporate Intent (including performance targets), and carry out monitoring and reporting of performance of the company and directors to the shareholders. The Shareholders' Committee can also provide a significant influence to resolve long-term philosophical conflicts between asset management practices and stakeholder interests. Three of the seven members of the Shareholders' Committee are appointed by the Ashburton District Council, the remainder are elected by a one vote per shareholder ballot.

Board of Directors

Review and approval of the Annual Budget and the Asset Management Plan as official company documents that accurately reflect the state and desired direction of EA Networks for the short and medium term.

Chief Executive Officer

Provision of company secretariat and attaining of revenue streams and a key contact point with electricity retailing companies wishing to use the EA Networks network for the distribution of electricity. Provides corporate policies that influence asset management philosophies. Monthly reporting of significant Asset Management Plan project progress and annual summary presentation of progress and plans for asset management to the Shareholders' Committee and Board. The Chief Executive Officer has 131 staff under him.

General Manager - Network (Asset Management Function)

Managing the network including Subtransmission, Distribution, Services, LV Reticulation, Zone Substations, Distribution Substations, SCADA/Communications, Protection systems, and Distribution Transformers to maximise system availability. Develop maintenance strategies, set and manage priorities, set and manage standards, and issue works orders to ensure target reliability is achieved at minimum cost. The GM - Network has 36 staff.

The Network Division completes almost all designs. Only when the scope of a project exceeds the capabilities of the internal staff in resource availability or expert knowledge is an external designer engaged.

General Manager - Contracting (Asset Construction and Maintenance Function)

Carry out the plans and works orders of the GM - Network satisfying the appropriate statutes, regulations, standards, and industry guidelines. Additionally, the Contracting function offers suggestions for innovative work techniques to increase safety, security, and reliability while minimising capital and on-going maintenance costs. The GM - Contracting has approximately 60 staff.

The maintenance of the network is primarily carried out by the EA Networks Contracting Division as the preferred contractor. They are engaged to undertake the servicing and testing, along with fault callout and fault repair work. Most line replacement, enhancement or development projects are also handled by the Contracting Division but when the scope of a project exceeds the capabilities of the Contracting Division, either sub-contractors will be sourced, or the Network Division will offer the complete construction project for competitive proposals from other contracting companies.

General Manager - Strategy & Engagement (Strategy, Stakeholder Contact, Negotiation, and Commercial)

Provides the interface between EA Networks and the external stakeholders – particularly major consumers. Facilitates discussions on changes to capacity and security with major consumers often assisted by technical personnel from the Network Division. The GM - Strategy & Engagement has seven staff.

Chief Financial Officer (Asset Accounting Function)

Financial accounting of network assets and management. Ensures compliance with relevant legislation governing financial activities of EA Networks including financial disclosures and network pricing. The Chief Financial Officer has 15 staff.

General Manager - People and Safety (Human Resources & Safety Function)

Employee lifecycle management. Ensures compliant planning, recruitment, and selection of new employees. Also monitors the performance and wellbeing of existing employees while ensuring fair, equal, and consistent opportunities and treatment of all staff. The GM - People and Safety has seven staff, including the People team and the Safety team led by the Safety and Compliance Manager.

1.4 Objectives of This Plan

This plan aims to document the intended approach EA Networks take in managing EA Networks' electricity assets. As a regulatory requirement, an Asset Management Plan must be published annually (with few exceptions). With this document, every effort has been made to comply with the requirements for disclosure of AMPs outlined in the most recently determined information disclosure requirements for Electricity Lines Companies set by the Commerce Commission under the Commerce Act 1986. To assist readers who have an interest in the regulatory aspect of this plan, Appendix D offers cross-reference to the mandatory disclosure items of the Electricity Distribution Information Disclosure Determination 2012.

This plan clearly defines the service objectives and gives a strong focus on life cycle management by presenting operations, maintenance, and renewal policies and programmes by asset type. Asset management planning processes should effectively integrate best practice features. These establish the service standards and future demands to meet business, legislative, and other needs, while developing optimum lifecycle asset management strategies and cash flow projections based on assessing non asset solutions, failure modes, cost/benefits, and risk.

Asset Management Plans must address growth. The EA Networks network saw dramatic load growth over 2000-2016. This was predominantly caused by various types of rural irrigation. This source of growth has now subsided. There are no additional water use consents issued in areas which would cause unsustainable nutrient leaching into ground water. This directly affects the use of water for agriculture. The consequent decrease in forecast rural load growth is reflected in this plan.

Carbon emission reduction is the next frontier that the electricity network will have to assist in tackling. This will take the form of additional solar photovoltaic generation, more battery storage, more electric vehicle charging, and conversion of some coal-fuelled heating to electrically powered heating. These technologies will change the demands placed upon the network and the way it is operated. There is also an ongoing interest in reducing electrical losses which can provide an improvement in network electrical energy efficiency.

EA Networks has the following Asset Management Plan objective:

> ***To provide a systematic approach to asset management, which is intended to ensure that the condition and performance of the electricity network and associated assets are being effectively and efficiently maintained or improved to satisfy stakeholder requirements while optimising long-term shareholder value.***

1.5 Scope of This Plan

This Asset Management Plan covers the management of EA Networks' electricity network assets for a period of 10 years from the financial year beginning on 1 April 2025 until the year ended 31 March 2035. The main focus of analysis is the first 5 years and, for this period, most of the specific projects have been identified. Beyond this time, analysis tends to be more indicative based on long-term trends. It is likely that new development project requirements will arise in the latter half of the planning period that are not identified here. Hopefully, most new projects would only affect the timing of development funds by displacing a project which has goals that can be mostly solved by the new project.

To provide a framework for asset management within the planning period, it is necessary to determine the longer-term direction in which the system should be developed. For example, it would not be prudent to invest heavily in enhancing a system at a particular voltage if, beyond the planning horizon but well within the life of those assets, it was likely that they would be overlaid by a new higher voltage system. A case in point is the augmentation of supply to the area bordering the foothills of the Southern Alps where currently 11kV is the distribution voltage, but 22kV is the voltage of choice for new lines/equipment. Furthermore, strategic development planning must be responsive to a range of scenarios that might occur.

The regulated timing of Asset Management Plan disclosure coincides with the beginning of a new financial year. A consequence of this is that the data used for comparison with other Electricity Lines Companies is as of the date of the previous disclosure – exactly one year ago. The *disclosed* full year data used in this plan is as of 31 March 2024. Where newer data is available it is used for forecasting/trending (such as power quality, load projections, asset quantities, asset ages, etc) or internal comparisons so that there is as little *planning lag* incorporated as possible.

1.6 Plan Structure and Approach

This plan uses a consistent set of defined activities and asset types to categorise work programmes and their associated expenditure. Budgeting and financial reporting within EA Networks allows actual programme achievement and expenditure outcomes to be compared with the plan. Consistent use of this framework will facilitate comparisons over time.

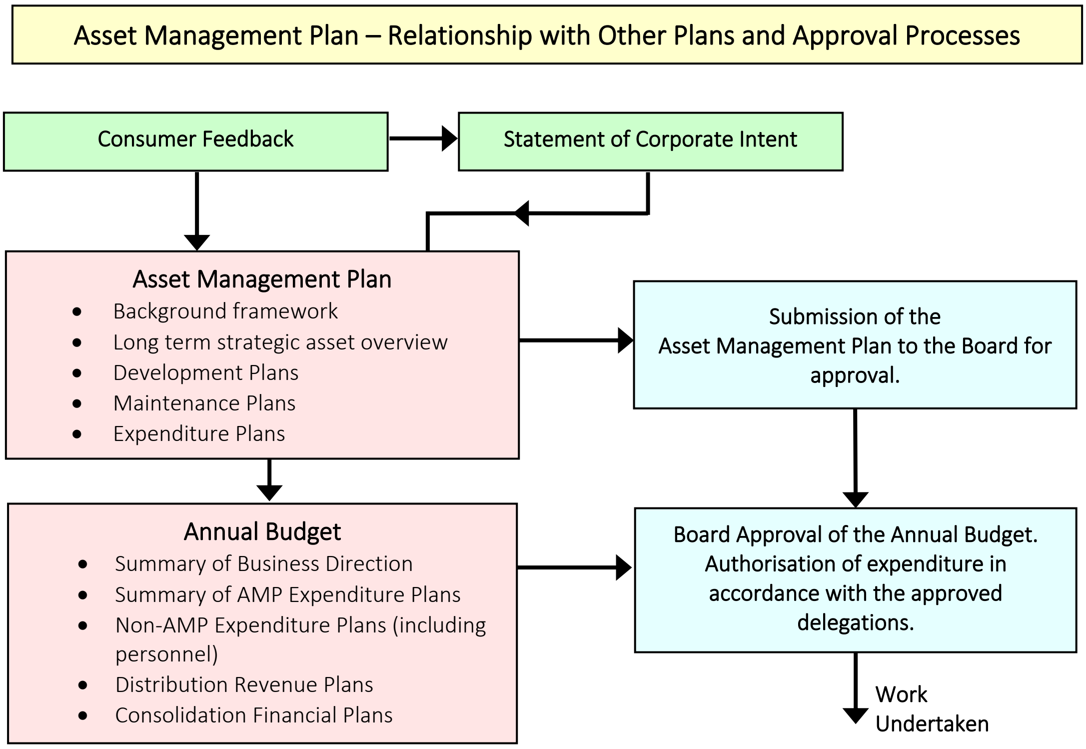
It should be noted that the activity and asset definitions are independent of accounting classifications of expenditure (i.e. between maintenance and capital expenditure). Therefore, trends over time should not be altered by any changes in the application of accounting policies regarding the accounting treatment of expenditure. However, it should be noted that, under the current application of accounting policies, all activities could be classified as either entirely revenue expenditure or entirely capital expenditure.

Similarly, the activity and asset type definitions are also independent of EA Networks' organisational structure and responsibilities, although they are closely aligned with the present structure. In the long run, adherence to the definitions will ensure that the plan remains meaningful despite any changes in organisational structure or responsibilities.

The asset and activity planning categories are defined in Appendix A. Asset Types and Activity categories, known as the Job Costing Tree Structure, are included. It should be noted that not all asset types and activity combinations are used. In addition, maintenance activities generally can be planned at the detailed asset level (e.g. servicing of transformers or circuit-breakers etc). Development projects or programmes, which typically involve a combination of different asset types (e.g. lines, transformers, circuit-breakers, protection, communications, and network management) are kept intact rather than attempting to allocate the expenditure against the component asset types. While no historical breakdown exists, the disclosure requirements will mean that this dissection can occur in the future. Since the same workforce often does different tasks, it is often a relatively arbitrary breakdown between asset classes. For example, in the process of laying cable for an underground conversion, the same staff lay two cables. Backfill and reseal applies to both cables, along with additional works associated with installing pillar boxes and substations. It is not practical or cost efficient to expect field staff to split labour and common materials across asset classes.

One further definition distinction is made throughout this plan: between *projects* and *programmes*. The word ***programme*** is used to define a generic or larger scale activity with a generic or holistic justification, but which may apply at several different sites. Replacement of defective insulators or fitting vibration dampers to lines are therefore classed as such programmes. On the other hand, ***projects*** are site (or asset) specific; for example, adding a second circuit to a particular line, or upgrading a particular transformer bank.

The process used to formulate the Asset Management Plan and other supporting documentation is as shown in the following diagram.



The plan interacts with other EA Networks working plans. Of particular importance are:

- The Statement of Corporate Intent, which is required by law and sets out the business intentions of EA Networks, and
- Annual budgets, which set out the specific resources required for asset management activities. Those parts of the annual estimates relating to the asset management of the electricity network are closely based on the annual Asset Management Plans.

Authorisation of expenditure results from approval of the annual estimates by the Board of Directors and from specific approvals. The Asset Management Plan does not represent an authorisation by EA Networks to commit expenditure, nor does it necessarily represent a commitment on the part of EA Networks to proceed with any specific projects or programmes.

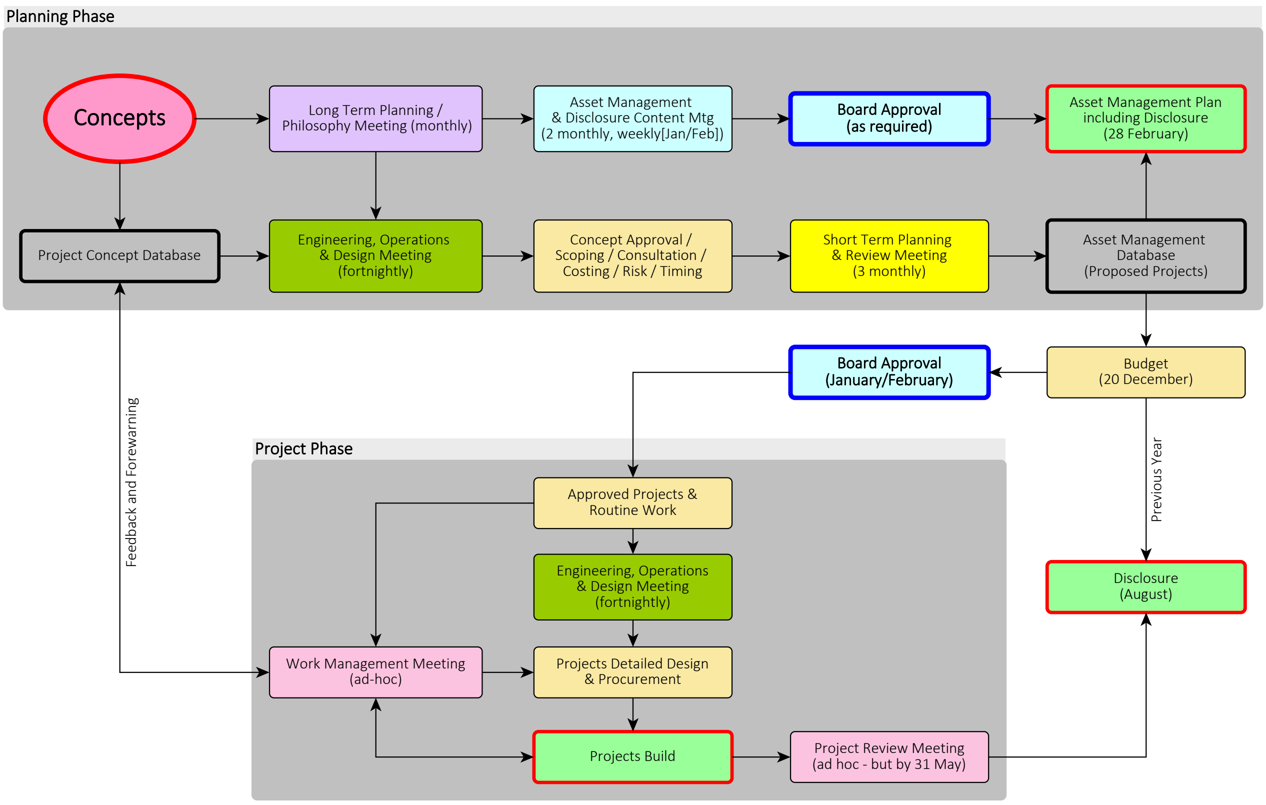
Governance

Any significant addition or alteration to the asset management philosophy of EA Networks is always thoroughly developed at management level using engineering focus groups before being tested for acceptability with the Board. If necessary, the Board will seek further clarification of the implications of any change, and this may include workshops with management to permit less formal open exchanges of information and opinions in both directions. Once an understanding has been reached, the approach will be adopted and documented in Board motions or policy documents and this plan. Alternatively, it can be rejected and either another option is developed, or the status quo remains.

An example of this process is the policy to enforce all new connections to the network to be placed underground. This has significant implications for both EA Networks and the consumer. Once the proposal was instigated, management developed a draft policy that encompassed the philosophical background and rationale along with the necessary technical requirements. The fiscal implications were also assessed and together they were submitted to the Board for consideration. After consideration of the pros and cons of the proposal, the Board adopted it as policy, and it now influences significant areas of the asset management philosophy at the distribution level.

The Board are provided with the schedule included as Appendix B of this plan (which individually identifies all significant projects) at the time of annual budget submission. This ensures that the Board can assess the complete evolution of any multi-stage project that they may be committing to in the budget they are considering. This was certainly the case when the initial conversion from 33kV subtransmission to 66kV subtransmission was proposed, as it committed the Board to more than a decade of expenditure with dozens of future projects worth tens of millions of dollars. This conversion process is nearing its end after more than 20 years. A similar consideration was made with the commitment to embrace 22kV as the preferred rural distribution voltage.

Asset Management Policy, Plan, & Execute Processes



Large projects or programmes that are not part of a previously considered concept draw particular attention from the Board, and the individual justification required is significantly more comprehensive than a project that fits into a pre-approved concept.

The Board take an active interest in asset management. This encompasses not only the direct financial cost of the projects and programmes triggered by a decision, but also the overall outcome achieved projects and programmes. An example of this interest within the last few years was a proposal presented to rebuild as underground cable two rural overhead 22 kV lines (which had reached the end of their useful lives). Both lines occupied State Highway corridor. The positive decision was undoubtedly influenced by the previous decision to enforce new connections to be underground as well as a commitment to reliability, road/public safety, and general aesthetic values of the Ashburton District. The Board made it clear that it would be a pilot project to examine the feasibility of more widespread use of underground cable in the rural area. The projects were studied, and further underground conversion projects have been completed. 2024-25 has seen more of these state highway conversions completed.

Moderate to minor asset management decisions are left in the hands of management. These decisions tend to be influenced more by technical knowledge than overarching fiscal or policy matters. As an example, these items include the preparation of methodologies to set internal performance criteria, the inclusion of new techniques and products (within approved budgets) that enhance the performance of the network, and any decision that has a low fiscal and/or reliability impact on the consumers and customers served by EA Networks.

EA Networks' management has responsibility for the day-to-day management of the company and its assets and for carrying out company policies. They are therefore the *owners* of the Plan – responsible for its creation and for using it as a tool for improving the efficiency and effectiveness of the management of EA Networks' assets.

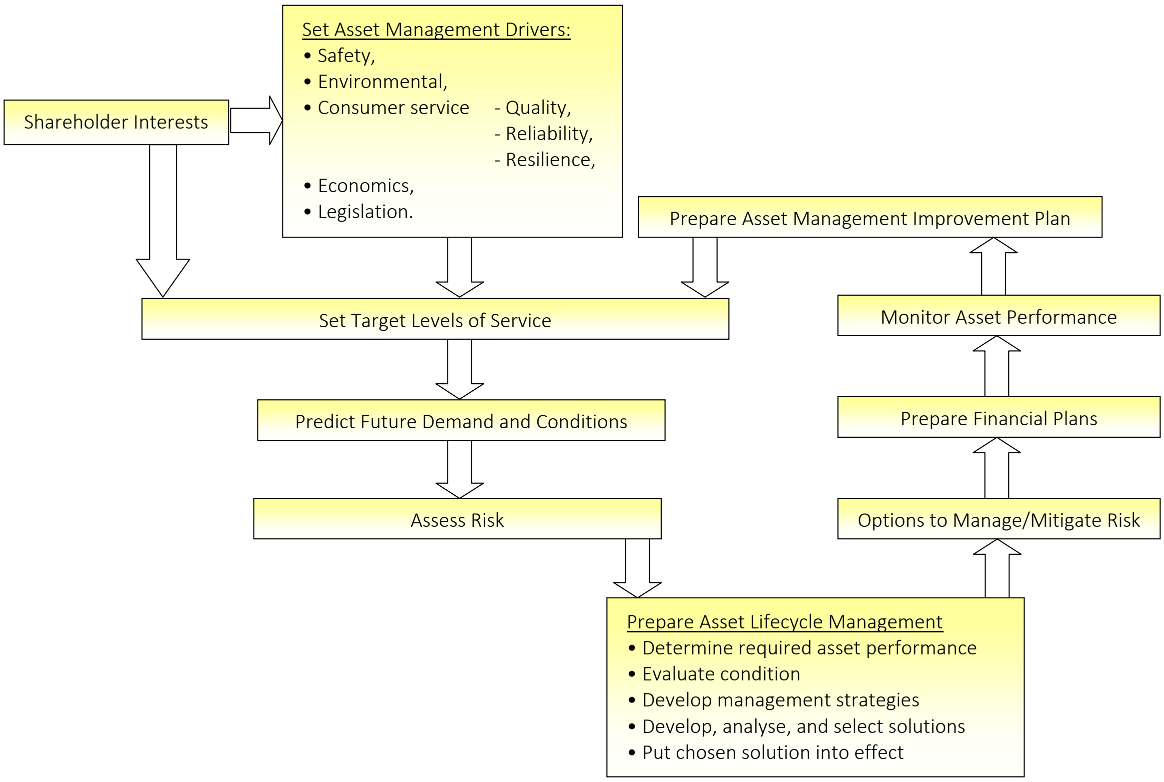
1.7 Asset Management Drivers

The factors that drive asset management activities and their relationship to EA Networks' performance are derived from the external performance required of EA Networks by its consumers, staff (including contractors), shareholders, and the public.

EA Networks' 2024-25 Statement of Corporate Intent identifies the following long-term objective:

> ***Our Purpose: "Delivering critical infrastructure and energy solutions to empower community prosperity"***
>
> ***Our Mission "To be recognised for excellence as the provider of reliable, affordable, high quality network infrastructure and energy solutions that deliver economic growth and wellbeing to our community."***

The Statement of Corporate Intent also encompasses the drivers that have been determined for this plan which are in the following sections.



1.7.1 Safety

Safety is determined by a combination of asset design, asset location, maintaining the assets in a safe condition, preventing unauthorised access, and the use of safe operating and work practices.

The Electricity Act 1992, section 61A sets out requirements for companies such as EA Networks to provide a Public Safety Management System (PSMS).

The PSMS requires reasonably practicable steps to be taken to prevent the electricity supply network from presenting a significant risk of:

- Serious harm to any member of the public
- Significant damage to property owned by someone other than the electricity generator or distributor.

The Electricity Safety Regulations 2010, Regulations 47 to 56 set out the application detail of the PSMS and that it shall comply with either NZS 7901 or Regulations 49 and 50. The regulations required that the PSMS was in place and audited by 1 April 2012. EA Networks has continued to fulfil this requirement annually with compliance to NZS 7901.

The Electricity Safety Regulations 2010, the Health and Safety at Work Act 2015 and the Health and Safety in Employment Regulations 1995 contain additional legal drivers for EA Networks' safety related asset management. These standards require EA Networks to operate as a reasonable and prudent operator.

The Electricity Regulations 2010 have a realigned focus and are less prescriptive than previous versions. The emphasis is now on risk analysis for safe outcomes of design and operation rather than general technical requirements, and considerations for new lines and substations are couched in language that reflects that.

The Regulations also require existing assets to be maintained in good order to assure high immunity from danger.

The Building Act 1991 puts in place a building maintenance regime that is aimed at ensuring the existence of essential safeguards for the users of buildings; specifically, that buildings are safe, sanitary and offer adequate means of escape from fire.

The Health and Safety at Work Act 2015 and the Electricity Act 1992 (Electricity Amendment Act 1993 and Electricity Reform Act 1998) now dictate the legislative framework with a performance-based regime which puts the onus on EA Networks as the Person Conducting Business Undertaking (PCBU) and the employer, to take control for ensuring the safety of workers and others in the workplace.

The Health and Safety at Work Act's main objective is to provide for the prevention of harm to workers, contractor's workers, and the public. EA Networks has the responsibility for putting in place preventive measures.

1.7.2 Consumer Service

EA Networks' consumer service objective is to manage the network reliably, efficiently, and economically to meet the needs of its consumers.

Capacity (Adequacy of Service)

EA Networks' policy is to provide sufficient capacity to meet current and future consumer's requirements, subject to satisfactory arrangements to cover the additional costs associated with any consequential capacity additions. EA Networks plan to provide timely capacity so as not to hinder the development of Mid-Canterbury.

For asset management planning purposes, projected demands, security, and capacity criteria are analysed assuming the additions and modifications to the network which have been projected in the plan take place.

Large step changes in load cannot always be accurately predicted, as these are often associated with large industrial projects whose promoters are notoriously loath to make firm commitments until the latest possible point in time. Nevertheless, EA Networks keeps up regular dialogue with these ventures whenever possible so that it can take potential changes into account when carrying out its regular planning activities. Decarbonisation and electrification are significant future trends with important implications for capacity required on electricity networks but, unfortunately, have a large degree of uncertainty related to the extent and timing of the load increases that may result.

Reliability (Continuity of Service)

Reliability is a function of:

- Asset design, the most important mechanism being built-in equipment redundancy (referred to as the security level) so that, for example, failure of any one component does not lead to a supply outage.[1]
- Asset condition, where this affects the likelihood of failure of a component.
- Efficient operation and maintenance practices (i.e. minimising the effects of planned equipment outages).

Within the network, EA Networks' policy is to focus expenditure on areas that give reliability improvements where the greatest benefits can be achieved for its consumers in the most economical manner. Generally, this involves focusing attention on distribution automation to reduce restoration times. This includes the installation of:

- Modern reclosers for automatic fault isolation; and
- Remote-controlled disconnectors, SF_6 gas switches, and ring main units for fault indication and sectionalising.

Resilience

The resilience of a system characterises its ability to absorb or recover from a potentially damaging event. This event can stress the system or its components beyond the original design limits. The essence of creating a resilient system is to ensure that:

- there is sufficient redundancy built in to allow alternatives in the event of a component failure,
- there is no common-mode failure that will impact many components simultaneously,
- there is an adequate awareness of the risk sources that can cause component failure and the context in which that failure can compromise the system's resilience,
- the mode of failure is not catastrophic – repair is achievable in a modest timeframe without full replacement of the component (it may be possible to continue using the component),
- there is acceptance that non-system alternatives may be an effective means to provide resilience (a mobile generator may be adequate while repairs are undertaken).

The effect of having a resilient system is that consumers experience less disruption to the service provided (an improvement in reliability) during/after an event that is high impact, but low probability. Changes in weather intensity are expected in future as a result of climate change, and EA Networks is commencing a review of line design standards with reference to NIWA 50 year geographically referenced climate forecast data to ensure line design parameters are adequate for the expected environmental conditions over the intended life of the line. A lot of the capital-intensive projects in this plan will assist in increasing the resilience of the electricity network.

Power Quality

With the rapid development of modern irrigation systems incorporating variable speed drives, EA Networks experienced a rapid increase in harmonic levels on its network. This was accentuated in some areas where load growth occurred on relatively weak parts of the network with lower than current design fault levels. EA Networks has put in place a standard for connecting new loads which requires the limitation of harmonic current generation to acceptable international standard levels. EA Networks implemented a subsidy scheme (now ended) to encourage existing variable speed drive users to mitigate the harmonic distortion they created on the distribution network. A generous 50% subsidy of the cost of a suitable filter was available for the first year and this subsidy reduced to 25% over the following years in conjunction with the introduction of a differential (costlier) tariff for non-compliant installations. This scheme gave incentives which fairly and economically encouraged consumers to correct existing loads to acceptable levels. After this *grace* period, where consumers are incentivised to comply, EA Networks may require disconnection if the installation remains non-compliant after 1 October 2018. As of January 2025, 8 connections are non-compliant (no reduction from 2024).

[1] This is referred to as an ***n-1*** security level. Security in which failure of a single component causes a supply outage is referred to as ***n level*** security, while design which allows for any 2 components to fail without causing a supply outage is referred to as ***n-2***.

Transient Effects

Where problems are identified in relation to short-term voltage variations, EA Networks works with individual consumers to identify the best economic and engineering solution.

Voltage Profile

The present terms and conditions of supply specify voltage levels and tolerances at points of supply.

EA Networks generally adopts the policy that the supply bus voltage will not vary from the nominal voltage by more than +3/-4% for supplies at 11 kV or 22 kV. The maximum voltage variation at a consumer's LV connection point is ± 6%. Specific values are agreed with individual consumers where required.

1.7.3 Economic Efficiency

Economic efficiency is an important driver for maintenance and development work. A large proportion of repair work, refurbishment, and asset replacement work is undertaken only after analysis to determine the most cost-effective solution. This frequently involves the choice between a development option and continued maintenance.

With the increase in consumer choice of energy sources (solar PV and battery storage in particular) this driver will become more significant. If peak demand is going to decrease in some parts of the network, then consideration will need to be given to replacement asset design and whether the existing high level of network availability is required during the asset's lifetime as this may affect asset maintenance.

1.7.4 Environmental Responsibility

EA Networks' policy is to act in an environmentally responsible and sustainable manner, and as required under legislation.

The Resource Management Act 1991 is a major legal driver for EA Networks, which is supplemented by the Hazardous Substances and New Organisms Act 1996. The provisions relating to the discharge of contaminants into the environment, the duty to avoid unreasonable noise, and the duty to avoid, remedy, or mitigate any adverse effect on the environment are of particular relevance to EA Networks.

1.7.5 Amenity

Many of EA Networks' network line assets, distribution substations, and some zone substations, are in high public profile areas and the design/condition of these assets reflects on the public perception of EA Networks as a responsible manager of local assets. Similarly, the condition of assets is readily observable by consumers, who have a strong vested interest in their reliability. Owing to its co-operative structure, many customers have a sense of ownership of EA Networks and its assets.

Maintenance programmes recognise the need to preserve visual appearance in conjunction with economic and efficient management. For example, a review of the land around substations has shown that appearances are largely reasonable and only a few can be improved, reducing maintenance costs, by appropriate landscaping and/or revising the land usage.

EA Networks' policy is to develop and maintain assets in a way that reflects well on the organisation, and to adopt a socially responsible attitude towards community impacts. While this is not a major driver of asset management work, it is a consideration in all work.

1.7.6 Legislative Compliance

Although implicit in the philosophy of the company, the accomplishment of legislative compliance can be greatly assisted by documenting its interaction with the management of the assets of an electricity lines business. Achieving compliance with legal obligations under the following legislation (and all other legislation – the list is not exhaustive) is a driver for EA Networks' asset management activities:

- Building Act 2004 and current Building Code
- Civil Defence Emergency Management Act 2002 and associated Regulations

- Commerce Act 1986
- Contract and Commercial Law Act 2017
- Construction Contracts Act 2002
- Cooperative Companies Act 1996
- Consumer Guarantees Act 1993
- Electricity Act 1992
- Electricity Industry Act 2010 and associated Codes
- Electricity (Safety) Regulations 2010
- Electricity (Hazards from trees) Regulations 2003
- Fair Trading Act 1986
- Financial Reporting Act 2013 and associated Regulations
- Fire and Emergency New Zealand Act
- Fire and Emergency New Zealand (Fire Safety, Evacuation Procedures, and Evacuation Schemes) Regulations 2018
- Hazardous Substances and New Organisms Act1996, subsequent amendments, and associated Regulations
- Health & Safety at Work Act 2015 and associated Regulations
- NZ Electrical Codes of Practice
- Privacy Act 2020
- Resource Management Act 1991 and associated Regulations
- Utilities Access Act 2010
- Worksafe Approved Codes of Practice

1.8 Asset Management Processes and Systems

The electricity distribution system is comprised of assets with long lives. The management of these assets (comprising maintenance of existing assets and development of new assets) is EA Networks' primary focus in providing an effective and efficient distribution service to its consumers. Further, because distribution is only one part of an integrated electricity system, consultation and co-ordination of plans is an essential ingredient for the effective functioning of that system.

This plan is an annually produced plan covering the next 10 years and documents likely or intended asset management requirements. The plan provides a focus for on-going analysis within EA Networks aimed at continuously improving the management of the distribution system and it provides a vehicle for communicating Asset Management Plans with consumers.

In many cases, particularly where asset development is involved, the work will be driven directly by consumer requirements and associated financial commitments. This plan is based on EA Networks' present understanding of its consumers' requirements. The plan is part of the process of communication with consumers, and EA Networks will be responsive to consumer input, with regard both to actual expenditure commitment and to long term future planning.

The plan is also intended to demonstrate responsible stewardship of assets by EA Networks to its consumers and shareholders. The plan shows the maintenance and replacement requirements which are intended to maintain the operating capability of the system over the long term. Each year an internal assessment is carried out which reviews EA Networks' achievement with respect to this plan.

This section broadly outlines the current and desired asset management practices and specific improvement initiatives of EA Networks' Network Division. It then goes on to discuss proposed asset management improvements (section 9.6).

To identify and prioritise the asset management practices and needs of the Network Division, asset management improvement tasks are discussed under broad headings of ***Processes***, ***Information Systems***, and ***Data***.

Processes (below) are the business processes, analysis and evaluation techniques needed for life cycle asset management.

Information Systems are the information support systems used to store and manipulate the data.

Data is required for effective decision making (i.e. for manipulation using information systems).

The following tables broadly describe the current EA Networks asset management practices and possible future (desired) business practices it is intended to ultimately develop. The Asset Management Improvement Plan (section 9.6) discusses improvement priorities, timetables, and resources for the next 3 years.

Processes Appraisal

Process	Current Business practice	Desired Business Practice
Level of service	• Most performance standards in place. • Consultation undertaken in association with specific developments and enhancements requested by consumers. • Shareholder/consumer input via Board and Shareholders' Committee.	• Complete range of performance measures. • Additional logic for service level review process implemented. • Regular consumer feedback & consultation. • Greater understanding of consumer preferences.
Knowledge of Assets	• Planned assets are captured by GIS prior to construction so as-built location and quantity can be quickly added after construction. • Some extra data capture for validation of RAB database occurs. • Attribute and condition information collection process from maintenance activities not comprehensive.	• Process for complete collection of maintenance data. • Draft proposals captured digitally for later inclusion in Geographic Information System (GIS) so that double entry is minimised.
Condition Assessment	• Minimal condition feedback requirement from contractors. • Routine maintenance inspection. • Testing of specific sites undertaken where performance is suspected to be outside targeted level of service.	• Enhance programme for condition assessment of critical assets. •Create, document, and implement structured asset inspection and testing regimes for all significant assets.
Risk Management	• Fundamental Risk Analysis is concluded but not refreshed regularly. • Critical assets monitored, failure modes and effects understood and used for contingency planning and asset management prioritisation.	• Establish review process to monitor risk – closing the loop. • Ensure network risk register covers asset specific and stakeholder/environmental risks and controls. • Enhance risk management contingency plans. • Create resilience monitoring process that tracks changes over time.
Accounting/ Economics	• Financial systems record costs against maintenance activities. • Maintenance expenditure allocated against individual assets. • Valuation based on ODV principles.	• Forecast renewals used to measure the drop in service potential. • Robust process for tracking and reviewing projects and asset groupings. • Closed loop model of assets from initial budget proposal to end of life.
Operations	• Substantial documentation of operational processes. • On-going training of operators.	• On-going training/updating programme.
Maintenance	• No formal contractual relationship with in-house service providers.	• Develop cost-effective processes for all maintenance work with internal contractor. • Process for on-going review of maintenance needs and delivery.
Performance Monitoring	• System faults recorded in Advanced Distribution Management System (ADMS). • Power quality monitoring at individual installations at consumer request or	• Greater range of performance standards. • Process for monitoring compliance of contractors with performance standards established. • More power quality monitoring close to consumer

	complaint. • Feeder metering at all zone substations (including power quality). • SCADA evolving beyond zone substations.	interface. • More analytics of gathered data to gain insights. • Energy load loss modelling and some monitoring from grid entry points to consumer.
Optimised Life Cycle Strategy	• Replacement of assets based on assessment by experienced staff. • Formal risk management strategies. • Statistical failure modes not well understood.	• Develop rolling 10-year renewal programme with budgets based on predicting failure for critical assets, just-in-time replacement of non-critical assets. • Life cycle and risk costs considered in optimisation process.
Project Management	• Contract management process in place. • Project management procedures reasonably well documented.	• Document project management procedures to optimise lifecycle costs established.
Asset Utilisation	• Capacity of network assessed by load flow monitoring and computer modelling.	• Introduce real-time load flow analysis (state estimation by ADMS).
Continuous Improvement	• Some inspection of work undertaken, but no formal process for quality assurance of decision-making, management procedure, and data.	• System of quality checks on all key asset management activities in place.

Systems Appraisal

System	Current Business Practice	Desired Business Practice
Asset Registers	• Current database is an integrated financial/physical model with good data linkage from GIS. • Asset database system established and working.	• Close integration of Asset database and GIS database as there are strong relationships between financial, GIS, asset management, and disclosure.
Financial System	• Financial system provider is the same as Asset system and adds financial transactions to assets. • Depreciation based on age of asset.	• Open financial system recording asset transactions and integrated well with other systems. • Maintenance costs always allocated against individual assets in Asset Management System.
Maintenance Management	• Maintenance history of major network equipment assets is being recorded. • Service Maintenance Management system in place.	• Critical and non-critical assets explicitly identified. • Service Maintenance Management system consistently used for cyclic/duty-based maintenance programmes.
Condition Monitoring	• Some basic condition monitoring systems for asset types. • New SCADA system is implemented, and historical reporting is established. • Condition data is loaded into asset management system database.	• Condition monitoring systems extended for key assets. • Predictive modelling capability available for critical assets. • SCADA system data fully integrated with other systems.
Consumer Enquiries	• New system being established to record consumer enquiries and relationships. • Approaching production release.	• Electronic records of all consumer enquiries. • Asset links to consumer enquires. • Integrated with many other corporate systems.
Risk Management	• Risk data in the Asset Management System underdeveloped. • Stand-alone risk assessments.	• Failure modes, probabilities, and risk cost available from Asset Management System.
Optimised Renewal Strategy	• Renewal on systematic basis. • Life cycle costs considered in assessing renewal options.	• Comprehensive renewal strategy in place considering future technology and consumer needs.
Forward Works Programme	• 10-year forward maintenance and renewal programmes based on historical/condition data. • Development needs based on known future demands.	• Optimised future costs based on various scenarios for new technology and consumer needs.

Integration of Systems	• Limited integration of consumer database, Service Maintenance Management System, or Asset Management System.	• Full interoperability between all systems to allow additional knowledge extraction from existing data.
Plans and records	• Overhead records all in GIS. • Geoschematic UG cable records in GIS. • UG cable location records scanned and being vectorised gradually (CAD).	• Fully digital record system in one system allowing on-line access and linkages to other databases and systems.
Operations and Maintenance Manuals	• Some dependence on worker knowledge. • Operations well documented for access to network by others. • Maintenance manuals for limited number of zone substations.	• Basic manuals available for all significant assets.
Document Management	• Primitive system available for capture of documents.	• Comprehensive document management system with integration to asset management system, Financials, Maintenance, and other corporate systems. • Faithful archiving and versioning of all documents that record an asset's lifecycle.
Levels of Service	• Reported continuously by ADMS. • No non-electrical performance measures logged in real-time.	• More fully developed ADMS with data shared with other discrete operational systems. • Consumer relationship management system more developed.
Contingency Management Plans	• Procedures for operational activities documented. • Key contingency plans have been created.	• Comprehensive procedures for high impact contingencies affecting system performance. • Maintain the currency and relevance of contingency plans in a changing electricity network.
Asset Management Plan	• Documented Asset Management Plan process but not sufficiently widely read.	• Mature Asset Management Plan used for all forward planning and stakeholder consultation.
Geographical Information System	• All major electrical assets have been captured into the GIS. Fibre network assets are being progressively captured. • Present GIS is an open system with limited New Zealand based vendor support and reducing New Zealand user base.	• Replacement of outdated and limited functionality GIS with a modern industry standard GIS based on the EPRI Utility Network Common Information Model for enhanced integration with other corporate systems and greater availability of GIS data access within the business, including field mobility and digital data capture.

Data Appraisal

Data	Current Business Practice	Desired Business Practice
Asset Classification	• Network asset hierarchy established. • Asset categories identified for asset cost records and disclosure reporting.	• Coherent multiple-use categorisation established to satisfy Disclosure, Valuation, AMP, Tax, and other uses.
Asset Identification	• Unique ID numbers allocated in Asset database and/or GIS system for all major network assets. • Comprehensive asset register being implemented.	• Asset register data complete and comprehensive. • Asset data correlates to that held in other corporate systems.
Asset Textual/ Spatial Data	• Quality and completeness satisfactory. • Data stored in different forms that does not make for simple integration.	• Appropriate spatial/textual data available on GIS/plans via direct storage or system integration. • Improve attribute data accuracy.
Maintenance Tasks	• Manual check sheets for Zone Substations and other major assets.	• Documented maintenance tasks for network. • Documented maintenance programmes for Zone Substations.
Historical Condition & Maintenance Data	• Limited history available for some assets, but asset management system now storing all available data.	• Full maintenance data history in Asset Management System used for maintenance scheduling.
Future Prediction Data	• Predicted future growth data limited. • Simulated future load flows from computer	• Simulated future load flows from computer model based on growth predictions.

	model based on theoretical growth.	• More authoritative future load growth data.
Life Cycle Costs	• Life cycle costs beginning to be collected per asset.	• Life cycle cost data used for renewal decision-making.

Network Operational Support

EA Networks uses the internal Contracting division as its preferred maintenance contractor for all network associated inspection, servicing and testing, faults response, fault repair, maintenance, replacement, and network enhancement. Some development and maintenance work is put out to external tender where internal capacity or expertise is insufficient or, alternatively, the Contracting division may arrange sub-contractors to assist.

Information Systems Development

An asset management system is fully commissioned, and development of its functionality continues. This system is used to record and manage all significant assets. This system forms the core data repository for current and historical data. The new asset management system shows much more promise as a partner for asset management than the previous legacy system. These advances should help track expenditure by activity, asset type, and other categories.

The capture of asset information has been carefully considered, and EA Networks are content that the level of detail and accuracy presently stored is close to optimal. Additional information could be gathered, but the cost/benefit ratio for doing so is not particularly favourable. Some additional asset types will be captured as time permits.

The asset management system records information about a range of equipment including poles, cables, transformers, substations, switchgear (HV and LV), plus miscellaneous assets such as battery chargers and relays etc. Ancillary to the asset management system is a *Faults* system that records interruptions. A *Competency* register that records an individual's competency for tasks that need to be performed on the network is held in Sharepoint. An Advanced Distribution Management System's (ADMS) core functions have been implemented, and additional features continue to be configured. This system is superseding the Faults, Competency enforcement, SCADA, and several other ad-hoc systems to form an integrated system. The ADMS is from AspenTech and called **m**ulti-platform **o**pen **n**etwork **arch**itecture (monarch™).

The GIS system currently installed at EA Networks is called G/Technology. This system is very *open* (stored in Oracle™ RDBMS), and all its data is accessible by other applications (including the asset management system). EA Networks have converted all data held in the previous GIS into this system and are capturing all new GIS data. The previous GIS was used to capture all primary asset information from paper and digital work-plans and maps. The data is being used for RAB and asset management. In conjunction with the asset management system, G/Technology keeps information on types of equipment installed at a site. The asset management system records engineering and financial details of assets and tracks maintenance history of those assets and other associated equipment. The G/Technology and asset management system databases are continually expanding to accommodate new sources of information. EA Networks can geographically locate any uniquely identifiable asset via G/Technology and the asset management system can provide all available data on that asset.

GIS viewing software provides users information which is drawn from data stored in many different systems. Information from external agencies, the asset management system, GIS, GPS units, and other open data sources can be drawn together for a spatial view of data that can reveal previously hidden relationships. It is hoped to integrate the ADMS data to the GIS so that improved spatial analysis can be performed on fault statistics and other real-time data can be visualised/analysed.

It is planned to change the current GIS to an alternative system that offers a much broader range of features and support options. In 2024-25 a scoping exercise was undertaken to assess the feasibility, functionality, and cost of a replacement system. In 2025-26, a project has been initiated to migrate all of the GIS data and functionality to the new Esri ArcGIS platform using the Utility Network model.

The linking together of GIS, asset management, and the financial system, enables data concerning network assets to be accessed in a multitude of ways and from multiple applications, resulting in better decision-making processes.

EA Networks have a range of in-service systems available for asset management and some are more capable than others. The main systems/applications that are in use are:

Network Information Systems Description

System/Application	Capabilities
Asset Management System	Supplied by Technology One. It offers an integrated solution for storing and analysing asset information. Financial, engineering and maintenance data is all stored in the one database. Due to the multitude of corporate systems being implemented, integration with other key decision software is not complete.
GIS Asset Mapping System	G/Technology is a capable modelling tool for the maintenance of spatial and electrical data but its utility is limited by expensive licencing preventing access across the organisation. Open data storage enables access by many other GIS tools for detailed spatial analysis. Data linking and exchange with other systems is achieved through connections to the Oracle RDBMS. Data is complete, consistent, and spatially fit for purpose. High performance electrical connectivity analysis tools have vastly increased the value and use of the data. Replacement of G/Technology with ESRI ArcGIS is underway and will provide enhanced functionality and productivity, including wider access directly to the GIS across the organisation. Field mobility will allow access to GIS data by the field teams, and as data gathering interfaces are developed, asset condition, maintenance, inspection, and project As-Build feedback will be digitised.
SCADA System	An AspenTech ADMS incorporating the monarch SCADA system has been implemented and is now in production use. The platform this provides is robust, versatile, and comprehensive. Ongoing development and roll out of additional modular functions within the ADMS continues.
Work Management System	System is part of enterprise resource planning system which includes the financial system. The asset management system integrates with the work management system at the work order level (assets are assigned to the work order for either creation or maintenance). Data is captured for all projects and permits reporting in multifaceted ways.
Financial/Accounting System	System is in place and detailed reporting permits useful insights. The use of an industry standard database engine can potentially lead to better availability of data. The potential for close integration of GIS with asset management and financials could provide significant analytical benefits.
Network Modelling and Analysis	DIgSILENT software is easy to use and provides for day-to-day analysis of network fault levels and power load flows. Future prospects for real-time analysis exists by integrating/linking with ADMS and GIS. This would make technical analysis much timelier and more productive. DigSILENT network models are prepared as required. The overhead of maintaining a complete model in an accurate state cannot be justified. In the future, restructuring the GIS data architecture to the EPRI Utility Network Common Information Model will allow direct importation of network data to DigSILENT for network analysis. This will provide a useable model of the entire network without additional data entry. The ADMS has built-in network modelling (using the GIS network model) and analysis (using an internal calculation engine) that is updated in close to real-time – giving alarms for loading and voltage violations in un-metered locations. Some routine engineering needs will be satisfied by the data output of this ADMS analysis. The key limitation of ADMS network modelling is that it cannot model network additions (e.g., future network extensions or distributed generation) that do not exist in the GIS network model. Hence, off-line analysis for future developments is still required in DigSILENT.
Connection System	All connections are recorded and linked via unique identifier to the GIS. Some history of connection changes and occupation are available as is the interruption history, which is

	integrated with the ADMS system. Data is complete and as accurate as required. Access is readily available and widely used. This Customer Relationship Management system (Salesforce) has been implemented to provide a platform for recording and reporting all customer interactions at a connection. It also forms the repository for data about, or related to, connections and communicates with the ICP registry. Associated with this connections system is a consumer management system that records consumer/shareholder details.
Fault Recording System	All interruptions, both planned and unplanned, are recorded in the ADMS and a full history is available that permits anytime calculation of performance indices and any other parameter of interest. Data is reasonably complete. Additional benefit would derive from data capture of fault location to the nearest pole or faulted asset. The ADMS is about to become the only system recording and reporting this data.
Standards Documentation System	There is a minimal intranet-based system for storing documentary standards. A more robust and substantial document management system is needed to provide a framework for storing, versioning, and accessing documentation as it is developed. Once a system is installed that allows storage and access to a wide range of documentation, the desire to commit more information to standards will grow.
Public Safety Management System	As required by legislation, a safety management system has been implemented. The supporting processes and systems for the PSMS help underpin other necessary systems that have historically lacked robust structure.

Specification, Procedures and Manuals

EA Networks has spent considerable effort in preparing a set of drawings which provides information to staff and contractors on EA Networks standard overhead line and underground cabling construction techniques. Further work is still required to extend these publications into documented design standards. Documentation for levels of competency, Network Releases and access to sites is now complete but additional work is still required to provide a completely integrated approach. An underground design/build/operate/maintain manual is in the final stages of preparation. A project is underway with Network Waitaki and Alpine Energy to jointly develop an overhead line design standard with specific location and 50-year climate change derived parameters to ensure long-term resilient line assets are designed. This project is expected to be completed in 2025.

Procedures have also been completed which are deemed to be mandatory for contractors who wish to carry out work for EA Networks or on EA Networks' network.

EA Networks have licensed a set of procedures and standards from PowerCo which assisted in initially developing the significant quantity of documentation required to support asset management and a Public Safety Management System (PSMS). This initiative helped overcome the historic difficulties EA Networks have experienced with high load growth causing rapid network development which prevented adequate resource being available to develop documentation. EA Networks have begun to transition away from the purely PowerCo documents and, as time allows, staff are developing/evolving standards to better suit EA Networks.

1.9 Responsibilities

Within the network division of EA Networks, staff are allocated distinct responsibilities for asset management functions. The General Manager - Network oversees the process and takes direct responsibility for the asset decisions which are made. The smaller size of EA Networks asset management team requires multiple responsibilities by all staff, and this helps to provide perspective on many tasks and assets that would otherwise quickly become foreign.

The modest scale of EA Networks means that planning/analysis/asset management/design/ procurement/standards are all managed by a small core team of personnel. There are no *departments* that separately handle these functions and consequently there is no distinct structural separation.

The entire network group work in close proximity in an open plan environment. This working arrangement encourages the free flow of information and ideas between members of the group and encourages the dissemination of information. A weekly *Network Leads Meeting* is an open forum for discussing all aspects of asset management, work processes, ideas, and the general dissemination of information. The communication paths established, and the relatively small number of people involved in the asset management process, alleviates the need for some of the more formal documentation that would be required in a larger organisation.

The key staff have the following responsibilities specific to asset management, although these are also shared to some extent:

General Manager - Network:

- Electricity network information systems – development and maintenance
- Overall responsibility for asset management and asset performance
- Preparation of documented standards for areas of responsibility

Engineering Manager:

- Graduate engineer management
- ADMS/SCADA – development, maintenance, operation, enhancement, and expansion
- Electrical protection – detailed design, settings, maintenance planning, test plans on various equipment, and procurement of some equipment
- Performance monitoring and analysis of network
- Fibre network IP provisioning and engineering management
- Reporting and analysis of network and planning options using engineering software (load-flow and fault analysis)
- Power quality – investigation and analysis
- Radio communications systems
- Zone substation construction – scheduling and project management
- Zone substation – major equipment specification and procurement
- Zone and distribution substations – maintenance planning and management
- Distribution transformers – specification and procurement

Network Control Manager:

- Network operations – day to day network control and performance including under emergency conditions
- Network performance – capture, analysis, and disclosure of faults statistics and consequently offering engineering recommendations for improvement or investigation of assets

Network Overhead Manager:

- Overhead lines – detailed design and maintenance, investigation of asset failures and recommendations for actions to address issues found
- Overhead line construction and maintenance projects – scheduling and management
- 11 kV to 22 kV conversion – design, scheduling, and management
- Rural new connection interface – network design and specification
- Network stores management
- Overhead distribution equipment – procurement and specification
- Vegetation control management

Planning Engineer:

- Network planning – preparation, analysis, and documentation of medium-long term and medium-large scale network development concepts

- Preparation of Asset Management Plan
- Technical resource for other staff, including investigation of asset failures and recommendations for actions to address issues found
- Electrical protection – architecture, specification, design oversight, some procurement of major equipment, and interpretation of fault events
- Zone substation – conceptual design & aspects of detailed design
- Engineering analysis – incidental load-flow and fault analysis (shared responsibility)
- New technology – investigation and analysis
- Distributed generation approval and technical integration (residential rooftop to multi-MW farms)

Network Underground Manager:

- Underground cables – detailed planning, design, and maintenance, investigation of asset failures and recommendations for actions to address issues found
- Underground cable construction and maintenance projects – scheduling and management
- Underground distribution equipment – specification
- Subdivision development – electrical reticulation negotiations and design
- Urban new connection interface – network design and specification
- Land interests and requirements – negotiation, procurement, and maintenance

Network Information Manager:

- Proposed work – drawing and issuing
- As-built records – capture, documentation, and recording of records as they are returned
- Geographic Information Systems – oversight of architecture and development
- Geographic Information Systems – operation and maintenance
- Fibre network records

Health & Safety, Environmental Management Team:

- Personnel competency – documentation of individual competencies
- Safety and Training – management of the safety and training regimes run by EA Networks
- Public Safety Management System (PSMS) – coordination of implementation
- Environmental Management – Oversight of normal business practices

1.10 Information Sources, Assumptions and Uncertainty

As a forward-looking planning document, this publication relies on a considerable pool of information sources, assumptions, opinions and known facts. Other than facts, these considerations have a degree of uncertainty associated with them which needs to be at least described and wherever possible quantified.

1.10.1 Information Sources

It is impractical to list every source of information used to prepare this document. The items listed below represent the principal foundations upon which this plan is built. They are:

- EA Networks' *2024-25 Statement of Corporate Intent*.
- EA Networks' *2025-26 Business Plan and Budget*.
- *EA Networks' Default Distributor Agreement*.
- *EA Networks' New or Modified Connections and Extensions Policy (17 April 2018)*.
- *EA Networks' 2024 Shareholders' Committee Report*.

- EA Networks' November 2023 *Customer Survey Report*.
- EA Networks' large user consumer interviews.
- EA Networks' asset database.
- EA Networks' *Consumer Connections* database.
- EA Networks' equipment loading records.
- Retailers' generation and energy consumption data.
- Retailers' reports on EA Networks performance.
- Transpower's and EA Networks' GXP energy data.
- Transpower's disclosed development documents.
- *Ashburton District Council's District Plan*.
- Ashburton District Council population projections.
- Environment Canterbury's strategy and policy documents as they relate to home heating and water availability for irrigation. Resource consent data (water) is also supplied from this source.
- Environment Canterbury's flood risk modelling documents.
- EA Networks' internal discussions regarding commercial and technical options for managing security, reliability, increased load, and the value of these considerations.
- External discussions with existing and prospective consumers regarding new electrical load and/or security requirements.
- Deta Consulting's report *Thermal Fuel Transition Impact Assessment* (December 2020)
- Deta Consulting's report *EA Networks Transport Electrification* (November 2024)
- EECA Regional Energy Transition Accelerator report for Mid-South Canterbury (June 2023).
- Correspondence with shareholders (consumers) regarding issues that can be addressed within the scope of asset management techniques.
- Documents by The Treasury such as *Half Year Economic and Fiscal Update 2024*.

1.10.2 Significant Assumptions

It is important for stakeholders that the manner and basis upon which the Asset Management Plan is intended to operate is clearly understood. For the purposes of clarity, and in order to avoid any confusion, the following underlying assumptions need to be taken into account by the stakeholders in dealing with the Asset Management Plan:

- As an Electricity Distribution Business, EA Networks will continue to be a going concern under the regulatory regime in place now or in the future.
- Asset Management, System Control, and Corporate Services functions will be provided internally and be based in Ashburton.
- EA Networks will have access to skilled and experienced staff.
- The Electricity Distribution Business will continue to operate an internal Contracting Division.
- The Electricity Distribution Business must satisfy the twin constraints of providing a risk-adjusted normal profit for its shareholders sufficient to retain investment, while performing within the regulatory limits set by government regulations.
- As a non-exempt entity, the EDB will continue to meet the requirements of the price quality determination.
- The Electricity Distribution Business will continue to meet the requirements of its consumers/shareholders as a co-operative.
- The prevailing regulatory and legislative requirements mandated by central and local government remain

unchanged for the duration of the planning period. This ensures that the environment which influences reliability targets, as well as governing industry codes of practice, health and safety, design and environmental standards is stable.

- The predictions and estimates of load growth are timely, and of reasonable and prudent scale. This ensures that the level of investment to cope with additional load is not unreasonably small or large and occurs in advance of the additional demand occurring.
- The availability of ground water for irrigation will not increase above that presently consented in ECAN *red-zoned* aquifers, but significant water will continue to be available for irrigators.
- Existing irrigation water use is not significantly constrained by national or regional policies. The Government has released an *Essential Freshwater* national direction package that implements changes to *National Environmental Standards*. These revised Standards could result in less irrigation demand on the EA Networks distribution network. ECAN will be responsible for implementing these Standards.
- There are no significant unidentified uncertainties, errors, or omissions in the internal records and databases (they contain suitably accurate information).
- The focus, policies, and key business strategies of EA Networks remain consistent for the duration of the planning period.
- The value of future projects and programmes is not materially affected by the value of the New Zealand Dollar or the cost of constituent raw materials (particularly copper, aluminium, steel, and oil) by more than the official rate of CPI. In reality, these costs will change. The impact of these changes will be reflected within 12 months when a subsequent plan is issued with updated cost projections.
- Wage rate movements are not significantly greater than the prevailing CPI. Significant expenditure has been approved by the Commerce Commission via Customised Price Paths applied for by other EDBs and this may put pressure on resources and therefore wages. Wage rate movements continue to be manageable within EA Networks allowable revenue.
- The availability of sufficient capacity (as described by projected load growth in this plan) from both the existing Ashburton GXP and any new Transpower Grid Exit Point will not be unreasonably constrained by 220 kV operational limits. This applies under steady state and fault conditions.
- The Transpower Pricing Methodology (TPM) remains in its current form which does not emphasise GXP or regional demand. Most of the charges are assigned via an annualised average volume network demand from all sources (including distributed generation). Load management of summer peaking consumers (such as irrigation pumps) is not a necessary commercial consideration under the TPM.
- The consistent pattern of responses exhibited by consumers surveyed annually by EA Networks continues in future surveys. This will ensure satisfaction, expectations, and willingness to fund improved reliability remain within narrow bounds and do not fundamentally change the current asset management strategies.
- EA Networks assets are not exposed to extraordinary natural disasters during the planning period. In particular, events such as a major earthquake caused by a rupture of the Alpine Fault, further Canterbury earthquakes, a massive flood of record proportions, a snowstorm of record proportions, or a windstorm with sustained speeds exceeding 140 km/h (900 Pa). Any of these events is outside the reasonable design parameters for the electricity network to survive without significant damage.
- The impact of electric vehicle charging on peak demand is not significant during the planning period. The moderate initial uptake of electric cars due to high cost is likely to dampen the immediate impact on the network. It is also inevitable that charging will be subject to some form of load control or incentives for off-peak charging. The option to source significant amounts of stored energy from electric cars into the network has not been considered as consequential during the planning period.
- A review of Ashburton and/or Timaru District Plans covering EA Networks' network does not materially affect the ability of EA Networks to manage the network assets using the strategies outlined in this plan.
- Any replacement of the Resource Management Act does not affect the ability of EA Networks to manage the network assets using the strategies outlined in this plan.
- Any as-yet unknown distributed generation that is commissioned during the planning period is of sufficiently small scale as to not materially affect the demand estimates or permit the postponement or

cancellation of any planned projects or programmes.

- The climate during the planning period is within the normal range of precipitation, temperature, wind speed, and humidity. Significant changes in any of these parameters could not only affect the assets but also the characteristics of electricity demand placed on those assets.
- The changing retail cost of electricity does not materially affect the rate or pattern of consumption exhibited by consumers or groups of consumers representing significant demand on the EA Networks network.
- The international price of agricultural commodities remains close to current values. This is particularly relevant to dairy products and irrigated crops. A major drop in price could see less irrigation demand and a major increase in price could see a dramatic increase in irrigation demand.
- No significant agricultural event, such as an outbreak of foot and mouth disease occurs, which could materially affect the value of agricultural production in Mid-Canterbury. An outbreak of Mycoplasma Bovis has occurred and been managed. As of late 2024, there are currently no known cases of Mycoplasma Bovis in New Zealand. The current strategy continues to be monitoring, with the ultimate goal of elimination looking likely to occur.
- A global pandemic does not cause a long-term (multiple year) significant downturn in economic activity. COVID-19 has become widespread globally and the medium-term impact is still somewhat uncertain.
- The performance characteristics of technologies and equipment types new to the EA Networks network are as represented to EA Networks during the equipment approval process. History has shown that on rare occasions vendors have misrepresented the products they sell (generally unknowingly). EA Networks have an expectation that any such technology or equipment performs as specified.
- The consumer uptake of solar photovoltaic generation and battery storage is not sufficient to cause widespread disconnection from the distribution network. If prices for this technology fall sufficiently, then the commercial risk of network earnings being insufficient to earn an acceptable return may exist.
- That the load growth and new connections forecasts will be close to those predicted.

1.10.3 Future Changes to the Distribution Business

Any change in the scale, scope, structure, or focus of EA Networks as an electricity distribution business could considerably affect the validity of many information sources and assumptions used to prepare this plan.

There is no intention to change the ownership or structure of the electricity distribution business that is EA Networks. As such, the prospective information and assumptions used here are consistent with the current scale, scope, and structure of EA Networks.

For completeness, it should be noted that EA Networks are currently involved in one other utility activity:

- A fibre optic communications network (www.eafibre.co.nz). Initially for EA Networks' use as inter-substation communication but also built with the intent of provision of broadband services to other users.

The primary focus of EA Networks for the foreseeable future remains the electricity distribution function.

During 2017, EA Networks divested itself of an interest in a piped and gravity pressurised water distribution network for irrigation from the Rangitata Diversion Race.

1.10.4 Factors Affecting Information Uncertainty

The information sources that have been used in this plan are all subject to a greater or lesser degree of uncertainty. A high level of uncertainty in a parameter is not necessarily problematic unless the plan exhibits a high degree of sensitivity to that parameter. What follows is a description of the information sources that do have a moderate to high degree of sensitivity on the plan's projections and outcomes. Should the uncertainty prove to be significant, it could materially affect any comparison of predictions with future actual outcomes. The factors are as follows:

- The load growth is significantly greater or less than predicted in the plan.
- Water availability for irrigation significantly increases from either ground or storage sources.

- Significant agricultural event, such as an outbreak of foot and mouth disease occurs, would materially affect the value of agricultural production in Mid-Canterbury.
- The regulatory environment changes, requiring EA Networks to achieve different service standards, different design standards, and/or different security standards. This could also affect the availability of funds for asset management.
- Consumer expectations change and/or they are prepared to pay a different amount for a significantly different level of electricity network reliability.
- The Transpower Pricing Methodology is altered to change the behaviour of consumers via electricity distribution business pricing signals.
- A significant natural disaster occurs.
- Significant amounts of distributed generation and/or battery storage are commissioned.
- Large and unforeseen loads require connection to the network.
- The uptake of electric vehicles is much faster and widespread than anticipated and load control, smart charging and off-peak incentives are not effective in shifting EV charging into off-peak periods.
- The District Plans covering the EA Networks network introduce significant new restrictions or requirements on new or existing network.
- The Resource Management Act replacement legislation creates an environment that makes it significantly more difficult and expensive to construct and maintain electricity distribution infrastructure.
- International markets for agricultural commodities boom or collapse causing changes in irrigation or processing industry demand.
- Advances in condition assessment and research in network planning generate additional development and maintenance requirements that are significantly different from current strategies.
- A major item of equipment may fail without warning requiring significant repair or replacement expenditure.
- The ownership of EA Networks may change with new owners requiring different service, design, or security standards to meet business objectives not embodied in this plan.

1.10.5 Assumptions Surrounding Sources of Uncertainty

It is possible to subjectively quantify uncertainty and, in some cases, even objectively quantify uncertainty. Even if the actual degree of uncertainty is open to debate, the effect of the uncertainty can often be evaluated in a much more rigorous manner that establishes the sensitivity of the assumption to uncertainty and ultimately its impact on any information based on the assumption. What follows is a generalised description of the effects of uncertainty on the assumptions of section 1.10.2.

Source of Uncertainty	Potential Effect of Uncertainty	Potential Impact of the Uncertainty
Load Growth	A general acceleration or deceleration in load growth would (as has happened in previous plans) advance or retard the enhancement and development project(s) that had been earmarked to accommodate it.	Low
Irrigation Water	In the unlikely event that significant additional irrigation water sources were made available, the projected demand could increase well above the level expected during the planning period. The rate of increase could also be dramatic as the allocation is likely to be prioritised by the sequence of application. Significant additional network reinforcement (capital expenditure) would be necessary to support the extra load.	Medium – High (estimated 10-25% increase in capital expenditure depending on water quantity and location).

	Alternatively, a significant move from deep well pumped irrigation to gravity fed/surface water could result in significant load reductions. Retention of the deep well water consent and electrical connection could cause very large peaks in drought years (hidden/unused load in average years).	Medium
	A statutory/regulatory restriction on either the volume of water permitted to be extracted or a restriction on the farming practices (e.g. nutrient discharge) would cause changes in the ability of farmers to irrigate. This would pose a significant risk of underutilising assets.	Low – Medium
Regulatory Environment	While most network lines companies remain natural monopolies, it is highly likely that the level of regulation will persist at current levels or increase. Regulatory compliance costs are therefore likely to increase. The Regulator is best placed to quantify the likely impact.	Low
Regional Demand	If the regional demand peak period changes to mostly summer, pressure would come on to control that peak or pay for Transpower network reinforcement. Presently the irrigation consumers have indicated they prefer to pay the peak penalty than accept load control. If peak charges increase, irrigators may accept control capping peak load. This could defer some scheduled capital expenditure.	Medium to High
Consumer Expectations	If the annual consumer survey reveals a change in service quality expectations and/or a preparedness to fund this change, the altered service levels would result in variations in capital expenditure.	Low
Natural Disaster	Widespread equipment damage (potentially irreparable) would require significant funding for repairs and replacements not allowed for in cost projections.	Low – Medium – High severity dependent
Distributed Generation	Widespread small-scale distributed generation could cause localised issues that would need resolution as well as network wide issues. Depending upon generation availability it could defer some development costs. Small quantities of medium-large (0.5 – 5.0 MW) individual distributed generators can generally be accommodated without major service level or network development cost implications. Analysis of large (10 to 50 MW) distributed generation solar farm connections to the 66kV sub-transmission network has been shown to be manageable, depending on the location chosen. The increased capital investment required by distributed generation connections is funded by the generation developer.	Low
Large Loads	Large new loads (typically industrial) will change the load growth estimates by step amounts. Beyond the GXP, additional dedicated investment required to service a new load is typically borne by the new load. This funding can be in the form of a long-term contract requiring EA Networks to initially find the capital. This would change the capital cash-flow projected in the plan.	Low
Electric Vehicles	Rapid and widespread uptake of electric vehicles could require significant network development in dense urban areas. This would be new capital expenditure not allowed for	Low – Medium (estimated 15-20% increase in capital

	in the plan. A forecast of electric vehicles in five-year intervals to 2050 has been completed in 2024 and will inform future network planning.	expenditure)
District Plans	A dramatic change in the District Plan rules or land zoning would typically only impact on new network (existing use rights would protect existing network). A tightened set of controls would increase new network capital cost.	Low
Commodity Prices	A significant rise or fall in agricultural commodity prices would raise or lower existing and new irrigation demand. This would in turn advance or defer planned network capital projects and programmes.	Low – Medium
Planning & Monitoring	The development and maintenance requirements differ from those currently projected, particularly for years 6-10 of the planning period, and generally involving the 22 kV, 11 kV, and LV networks.	Low
Equipment Failure	Widespread or major equipment failure and subsequent repairs or replacement are not factored into current projections. Largest individual item does not exceed 1% of network value.	Low
Ownership	An altered ownership structure or new owners outright could alter the business objectives of the company and therefore the drivers of this plan. This could result in significant changes to service levels and expenditure.	Low – Medium

Weather affects the fault expenditure through the level of storm damage experienced. The budget for fault expenditure can only be an estimate based on historical averages and general knowledge of the asset condition, this average cost will account for an expected amount of storm damage.

The sensitivity of the network to storm damage has greatly reduced over the last 15 years as major subtransmission and distribution feeders have been progressively upgraded with better quality materials. A continuing distribution automation programme is reducing the amount of time and effort required for fault location and repair. The Canterbury and Kaikoura earthquakes have shown the unpredictability of major events and the extent of damage that can occur in a significant earthquake.

EA Networks is regulated using a default price-quality path under Part 4A of the Commerce Act 1986 that applies to 17 electricity distribution business in NZ. *The regulated default price-quality path (DPP) has been reset for a further five-year period from 1 April 2025 to 31 March 2030 and has the following components:*

- *A maximum revenue allowance at the start of the regulatory period.*
- *A maximum revenue path for subsequent years, which incorporates an inflation-based adjustment together with an 11% annual increment.*
- *Revenue incentives and penalties for our performance against allowable operational and capital expenditure.*
- *Minimum service quality standards (SAIDI & SAIFI) that must be met, as well as revenue incentives and penalties to encourage improved quality outcomes*

Complying with the DPP is a legal requirement. Compliance is monitored by the Commerce Commission and any breach can lead to regulatory intervention and prosecution.

If prices are forced downward, profit or costs will have to be reduced accordingly through reduced maintenance expenditure. The most likely area for attention would be that of *Inspection, Servicing, and Testing*, as this has little immediate effect on system performance and can be deferred for short periods to smooth out expenditure.

GDP in the Mid-Canterbury area has a direct effect on EA Networks' revenue stream through increased demand from large consumers. It also has an indirect effect as secondary and tertiary level consumers in the commercial and domestic area expand. As for price control, any reduction in revenue must be reflected in cost savings or deferred maintenance if profitability is to be maintained.

Several major projects have been mooted for Mid-Canterbury over recent years involving agricultural processing or industrial processing. Any large additional loads could require major system reinforcement with associated increased expenditure on development and enhancement projects. This activity would also highlight the potential shortage of skilled labour which could either delay or price-escalate projects. This expenditure will have to be at least partially funded by the end user, either as a capital contribution or through a longer-term contractual arrangement. Maintenance expenditure will not be directly affected, except insofar as competition for resources may slightly reduce the level of non-critical work carried out. These major consumer developments can have significant economic benefits to the community.

1.10.6 Price Inflator Assumptions

The majority of costs quoted in this plan are in *constant price* 2025 calendar year New Zealand dollars (2025-26 financial year). There are some disclosures associated with the plan that require *nominal dollar* values. To convert forecasts made in *constant price* dollars to *nominal dollar* values, a set of assumptions must be made about future economic conditions. The obvious factors that would influence future costs include:

- The consumer price index (CPI)
- NZD/Foreign currency exchanges rates
- New Zealand labour rates
- International commodity prices (aluminium, copper, steel, oil, plastic etc)
- Export/import tariffs and taxes

Although all of these factors are valid, there are very few authoritative forecasts freely available for periods exceeding a few months to a year. The CPI includes most of the other factors to some degree. Consequently, EA Networks have decided that the only price inflator that will be factored into the *nominal dollar* multiplier is the CPI forecast issued by the New Zealand Government Treasury at:

https://www.treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2024

This *Half Year Economic and Fiscal Update 2024* published in December 2024 includes a CPI forecast (June years/quarter) to 2029 and EA Networks will use the 2029 value of CPI for the following 6 years, extending the forecast to 2035. The values are as follows:

Financial Year (ending March)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Treasury CPI Forecast (%)	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	N/A
Cumulative CPI Price Inflator	1.0000	1.0210	1.0414	1.0622	1.0835	1.1052	1.1273	1.1498	1.1728	1.1963

MANAGING RISK AND RESILIENCE

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2 MANAGING RISK & RESILIENCE

2.1 Introduction

This section of the plan will consider the risks that EA Networks' electrical network faces from all sources and the risks it presents to people and the environment.

EA Networks explicitly recognises that the company must take some risks in undertaking its core functions and pursuing opportunities.

EA Networks manages risk by anticipating reasonably foreseeable risk, understanding risk criteria, analysing, and evaluating risk,

- determining risk tolerance,
- implementing risk controls and mitigation, and
- ongoing monitoring and review of effectiveness.

Throughout this process EA Networks communicates and consults with affected stakeholders.

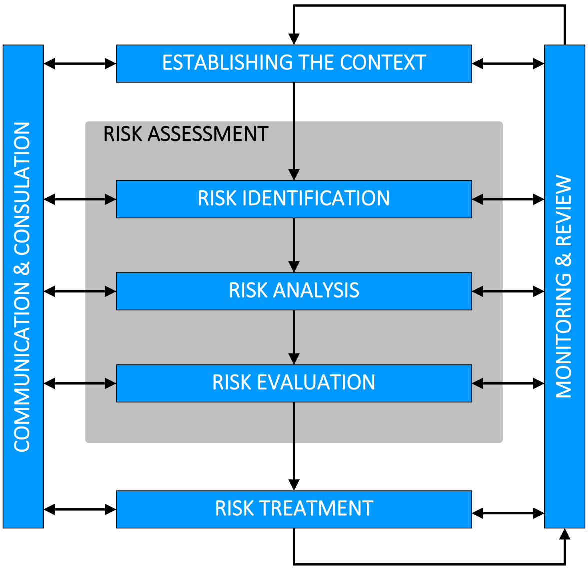
High impact low probability (HILP) events such as catastrophic events, complete failure of critical infrastructure, natural disasters, pandemics, or cyber-attacks necessitate situation specific reporting and responsibility structures. Each HILP event will be different, so EA Networks use a high-level planning framework, and developing event-specific plans through the Resilience Action Planning work where that planning has value.

2.2 Risk Management Framework

The purpose of risk assessment is to provide empirical knowledge and analysis to make informed decisions on the treatment and method of resolution of particular risks.

EA Networks' risk management processes use the methodology outlined in International Standard *AS/ISO 31000:2018 Risk Management – Guidelines for use*.

Establishing the context: This considers company objectives, key drivers, the operating parameters, external environment, and risk criteria.



Risk identification: This is the process of finding, recognising, and identifying risks, which is undertaken by a variety of methods including (but not limited to the following):

- Engineering assessment
- Inspection and Maintenance outcomes
- Defect reports
- Accident/near miss reports
- External advice
- Audits and safety observations

Risk analysis: This is undertaken using both qualitative and quantitative assessment to produce a risk score.

The risk score is calculated by multiplying the Likelihood by Consequence. The established risk score is an indication of the severity of the risk, which, in turn, assists in the evaluation and treatment of the risk.

Recognising that risk analysis is a subjective process, EA Networks encourage staff to seek support in performing initial risk assessments before registering a risk on the register. All registered perceived risks are evaluated by a selection of staff experienced in performing such assessments.

			Consequence Weighting				
			Minor	Important	Serious	Major	Catastrophic
			0.5	1	1.5	4	5
Likelihood level	Almost Certain	5	Moderate	High	High	Extreme	Extreme
	Likely	4	Moderate	Moderate	High	Very High	Extreme
	Possible	3	Low	Moderate	High	Very High	Very High
	Unlikely	2	Low	Moderate	Moderate	High	Very High
	Rare	1	Low	Low	Low	Moderate	High

Risk evaluation: This is used to determine the most effective methods of treating risk, as well as setting priority of execution.

Risk treatment: This is the process to modify risk by either avoidance, reduction by implementing controls, or mitigating the outcome.

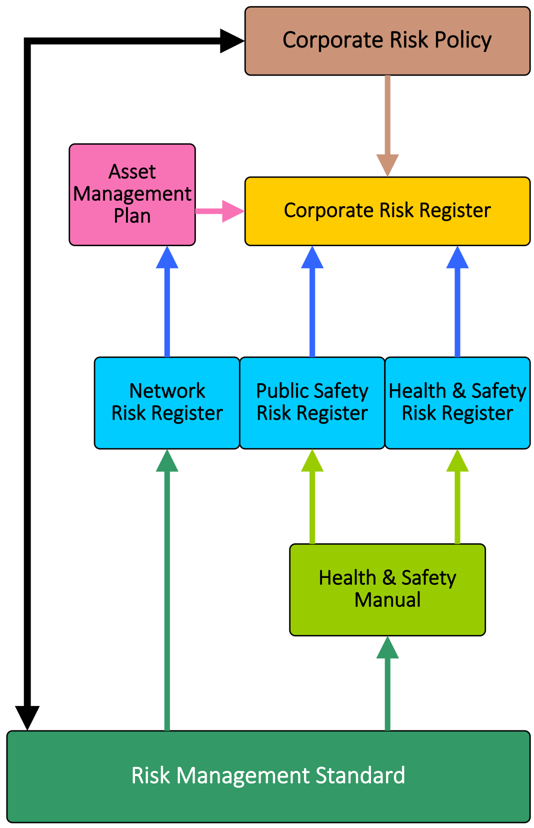
A series of comprehensive risk registers feed into the corporate Risk Management Policy, which provides EA Networks' philosophy to risk management and risk appetite at a Governance and Corporate level.

The purpose of the Policy is to explain EA Networks' underlying approach to risk and risk management and ensures that a systematic and strategic approach to identifying and managing risk and meeting business objectives is taken.

- The identification and management of risk is linked to the achievement of EA Networks' strategic goals.
- Risk management is embedded in normal business processes.
- Everyone is held accountable for considering risk in all decisions
- Delegated authority for accepting risk is defined.
- A risk capability appetite and tolerance statement is maintained and reviewed regularly by the Board Audit and Risk Committee

During 2023, in response to a review of risk management practice by Deloitte, a set of critical corporate risks were identified and analysed using the bow tie technique. Similarly, in response to a Cosman Parkes safety review, critical safety risks have had bow tie analysis completed to record safety risk controls and mitigations.

Risk Management Interconnectivity



The EA Networks network is periodically exposed to events or incidents that subject elements of the electrical network to a high risk of failure. If the location of these events coincides with a critical component of the electrical network, the result is a high risk to the integrity of the electrical network. This risk of failure can in turn lead to high risks for consumers, either as individuals or as larger collective groups.

The range of events that can place the network at risk are extensive and range from a mouse entering a protection panel in a substation to a commercial aircraft crashing into the Transpower substation. These two examples could have similar immediate effects (loss of supply to a wide area) but the likelihood of each one happening is particularly disparate.

Natural disasters are assessed by evaluating the risk cost for each event (probability times the consequences of failure cost) and developing appropriate contingency plans and procedures to ensure business continuation and mitigation of impacts respectively.

Note that the risk of non-supply of electricity is managed by way of service agreements/insurance cover and is outside the scope of this plan.

Network risk assessment identifies:

- the category or specific equipment at risk,
- the supply at risk,
- the risk elements and the likelihood of each element depriving the network of the equipment,
- the initial deprival time and quantity delayed (initial consequences of the risk event),
- the delayed deprival time and quantity (repair time or delayed consequences of the risk event).

This information is then used to form a maximum risk score, which combines the maximum risk element score with the duration and quantities of deprival.

The network risk register details:

- the risk description and current controls,
- inherent and residual risk rating,
- assessment if the risk control is effective and is ALARP,
- If further controls are required, who is responsible for acting on them and
- the date of the most recent review.

Widespread (common-mode) risks to a particular type of equipment that could be affected by an area-wide event are assessed without reference to any particular site. Site specific risks are also included in the Network Risk Register.

The recent rapid rate of network development has resolved some of the most critical historical risks that have been identified in the past. A summary of the Network Risk Register is provided in section 2.5.1

2.3 Environmental

Some level of adverse environmental effects needs to be accepted to recognise the necessity for electricity supply. It is also recognised that EA Networks may have limited choice in locating assets and facilities, given logistical or technical practicalities.

The objective is to provide for the construction, installation, operation, maintenance and decommission of electricity infrastructure where adverse effects on the surrounding environment can be appropriately avoided, remedied, or mitigated.

Network assets are mainly situated on land that has been previously modified. On the Plains, EA Networks do not have any known highly significant ecological, archaeological, or environmental areas within their network footprint. In the foothills, there are a number of sensitive sites and areas that require due consideration and compliance with District and Regional Plan rules.

Fortunately, most of EA Networks' technical infrastructure has been either renewed or upgraded to modern requirements so legacy environmental issues such as PCBs and Asbestos are minimal.

The EA Networks Environmental Management Standard (last reviewed October 2019) specifies how environmental assessments are undertaken, manage possible environmental impacts arising as a result of electricity network activities, and provides detailed information to support the EA Networks' Environmental Policy.

This is supported by Standards relating to:

- Sulphur Hexafluoride management (last reviewed November 2019),
- Legacy Asbestos management (last reviewed March 2024), and
- Specific spillage procedures (last reviewed September 2019).

The three most critical environmental risks are as follows:

2.3.1 Sulphur Hexafluoride (SF_6) gas

SF_6 has unique physical and electrical properties making it a very efficient dielectric and arc-quenching gas.

It has mainly replaced oil-filled circuit breakers (which contained PCBs) and reclosers in some 33 kV and all 66 kV switchgear. The last 33 kV oil-filled circuit breakers are scheduled to be decommissioned before 2027. We have part ownership of oil-filled 11 kV switchgear at the ex-33/11 kV Fairton site and we are discussing the future of this with the new site owner.

EA Networks is committed to adopting best practice with respect to minimising SF_6 emissions when installing new equipment, during maintenance and during retirement of old equipment:

- EA Networks voluntarily follow the International Standard IEC 60694 requirement of less than 1% leakage from equipment per annum
- SF_6 reserves are stored in an approved and secure purpose-built storage bunker. EA Networks are participating in the Emissions Trading Scheme due to holding more than 1 000 kg of SF_6.

At this time, there is no intention to remove SF_6 from the network. Switchgear containing SF_6 is still actively being purchased.

However, techniques to decrease the volume of SF_6 held in reserve are being actively pursued.

2.3.2 Oil

The majority of zone substations have been built or rebuilt in the last two decades, and they are subject to stringent contemporary Resource Consent conditions.

Due to most zone substation transformers holding between 14 000 and 19 000 litres each, the risk to the environment is from the volume of oil that could be released in the case of an accidental spillage, rather than the likelihood of that spill occurring.

All in-service zone substation transformers are in a bunded enclosure. The previous solitary unbunded transformer has now been upgraded to a bunded arrangement. The bunded enclosures are designed to contain the full volume of oil in the transformer plus 24 hours of the heaviest historical rain. All bunds have level monitors to detect modest amounts of fluid in the bund and are monitored by SCADA. When a level alarm goes off, personnel are dispatched to examine the bund and, provided no oil its present (during or after a rainfall event), they will drain the bund onto the surface of the substation ballast. Every zone substation and every EA Networks heavy truck (capable of carrying a distribution transformer) has a spill response kit stored with it and personnel have been trained on spill mitigation. Oil spills are very rare, and when they occur a rapid response using spill kits ensures minimal environmental impact occurs.

EA Networks has recently become aware of an Ashburton District Council requirement for bunding for all transformers containing more than 1000 litres of insulating oil. This translates to some makes of 1 MVA transformers and all 1.5 MVA transformers. Existing older sites have "existing use" rights and do not require retrofitted bunding. New or rebuilt sites will be evaluated on a case-by-case basis, as the Environmental Protection Authority future legislation will move to a more risk-based approach to be incorporated in future district plans. Ashburton District Council have already approved the installation of 1 MVA and 1.5 MVA transformers within an industrial food processing site due to the wider spill containment facilities that exist. It is accepted that transformers containing more than 1000l of oil are very low risk and highly likely to be detected before any problems become an issue and that the risk is no greater than small transformers carrying lesser quantities of oil. Transformers with "eco-friendly" vegetable-based oil will be looked upon more favourably and EA Networks will investigate this. The transformer sites with greater than 1000 litres of oil will be collated and communicated to Ashburton District Council in 2025-26 for evaluation. Refer to section 9.3.4 for a service improvement initiative for this issue.

2.3.3 Fire

One of the most common effects any electricity network has on the rural environment is initiating small brush or grass fires. To date, any fires caused by the network have been very infrequent, small volume, and very localised. The fire is often out by the time FENZ arrive.

It is normally external factors such as airborne debris, vegetation, farm machinery etc. hitting live lines, which causes either drop out fuses to operate or live wires to contact the ground.

Both hot fuse elements and sparks from live contact are a common source of ignition in dry conditions.

Every effort is made to ensure the network is as fault resistant as possible and minimises fire initiation risk.

Active network mitigation methods include:

- Permanently configuring the reclose function on the automatic circuit reclosers to permit only one and at most two reclose attempts before lockout (from the default setting of three attempts).
- During dry weather disabling the reclose function on the automatic circuit reclosers using meteorological data from FENZ and NIWA as trigger points.

Other network projects that benefit fire mitigation include:

- Ongoing overhead to underground conversion projects decreasing the likelihood of live lines or hot fuse elements falling to the ground.
- Removal of significant quantities of in-line drop-out fuses, replacing them with pole-top SF_6 Gas switches or RMUs
- Bird-proofing the pole-top SF_6 Gas switches.
- Installation of Neutral Earthing Resistors in the zone substations, which limits earth fault current to 300 Amps maximum (decreasing the amount of energy available when live wires contact the ground).

To completely eliminate these fire risks would be extremely costly and could not be justified by the reduction in likelihood of environmental harm. There has been a concerted effort to identify situations of increased fire risk and mitigate these where possible. Significant focus and consideration of options will continue in this area.

2.4 Commercial

The key areas of commercial risk affecting EA Networks focus largely on risk to income from electricity demand, in terms of both volume and capacity. Technology and customer choice can materially affect these, though the speed at which this could occur is not (currently) considered fast.

Seasonal demand variation affects gross revenue and prices. Under the recently implemented Transmission Pricing Methodology (TPM), transmission charges are based on four-year average anytime energy volumes delayed by four years. So, annual average energy volume will determine EA Networks' future transmission charges, but the methodology makes those charges much more stable year to year, reducing volatility presented to consumers from the previous TPM approach.

2.4.1 Irrigation

The conversion of some irrigation schemes to gravity-pressurised pipe (surface) networks has allowed farmers to consider whether they can forego the deep well electric pump. In many cases, they have retained wells only for back-up in case of a very dry year or to retain the water-use resource consent. If farmers decide it is not worth retaining the electric pump, then rural load could decrease, risking the income used to earn a return on relatively new rural electrical assets. To date, there have been relatively few disconnections, but some have chosen to reduce the pump size. Much of this electrical load has been converted to Highbank pumping load.

A December 2020 economic study commissioned by the Ashburton District Council considered the impacts of land and water management legislation and government policy statements. This showed considerable negative impacts from water reforms that could damage the GDP of Mid-Canterbury and the local farming community that drive this. The report highlighted the long terms risks that EA Networks is exposed to with respect to dairy and irrigation in the region.

2.4.2 New Technologies

In terms of new technologies, the global electricity industry is entering a new era where the end-user has more choice. The choice between retailers of energy has existed for many years and energy consumers choose between energy sources (gas, electricity, wood, coal, etc) and within that energy source they have choice of provider (Contact, Meridian, Trustpower, etc). Consumers can now generate their own electricity using solar PV, and once generated, can store this in batteries within their premises. The batteries can also be used stand-alone to store off-peak energy. This gives consumers choice over their provider of not only electrical energy but also electrical power (capacity). If they wish, they can decide to completely self-generate and disconnect from the network – though this is a marginal exercise and one that is not considered to be a substantive risk at this point. At this time, it is not economic to completely disconnect from the existing electricity network, and it may never be truly economic, but that opportunity still exists.

Assuming most consumers choose to retain a network connection, the complexity of power flow through the distribution network is going to increase over time and there will be a need to manage that complexity with additional assets and resources. These assets and resources (along with the existing assets) will require a financial return on them, and the mechanism to charge for the facilities provided to consumers must be simple and transparent. The existing energy-based charging is unlikely to be adequate in that regard. Some form of demand/capacity charge is necessary to signal the consumer their fair contribution to charges that will be imposed upon EA Networks by Transpower and reflect their use of the shared distribution network assets.

EA Networks is investigating options for providing data capture and control options for charging, monitoring, and controlling the capacity required by each connection. This would be one piece of the wider puzzle to allow the distribution network to facilitate bi-directional power flow and localised energy trading. It is still not clear how it will be possible to properly coordinate the myriad appliances that generate into, store energy from, and load the network (an *AC* battery does all three). As the way becomes clearer, EA Networks will look to provide the necessary infrastructure to remove barriers to economic and efficient use of the distribution network. EA Networks' development of a suite of Advanced Distribution Management System applications is a proactive measure in preparation for managing the distribution network in this future, complex environment.

2.4.3 Self-generation and Disconnection from the Network

One of the risks to the distribution network owner is that sufficient consumers choose the self-generation/disconnection option and the return on fixed assets must then be recovered from the remaining consumers. The price of capacity will increase to the connected consumers, and this will encourage more to disconnect, leading to an upward spiral of cost to those that remain. This may seem unlikely as asset write-downs would undoubtedly occur, but ultimately the viability of the business is then put at risk.

There are a range of options for mitigating this risk, some of which are within the control of EA Networks, while others lie in the hands of government agencies, and some are unknown. One option already provided for is an accelerated depreciation recovery, allowing up to 15% reduction in asset lives. EA Networks are not able to provide sufficient evidence of asset underutilisation at this time. However, there has been some evidence that even energy efficient appliances have started to reduce individual household energy consumption (but not necessarily peak demand).

2.5 Network Risk

2.5.1 Network Risk Register

This section describes Network Risk Register and processes of managing network asset risks, with a full risk register considering risks related to health and safety, the environment, impacts on stakeholders and impacts of asset failures on network reliability and the cost of replacement/reinstatement. The risk register is formulated in line with the EA Networks Risk Management Standard.

The register contains 106 separate risks, with a High Focus Network Risk report selecting ten risks with a residual rating of Very High for entry onto a heat map. All other risks have a residual rating of High or lower.

Approach to Network Risk Register

EA Networks has a set of 13 organisational critical risks, that appropriately summarises the critical risks at a high level by type. Of those critical risks, the following risks are explored in more detail in the Network Risk Register:

- Public Safety.
- Disaster.
- Significant Unplanned Outage.
- Critical HSE Risks (this takes more of a field operations view on risks, while the Network Risk Register identifies these through a network and asset lens).

The structure of the network risk register categorised into Assets Failure and Operations or Environment and Stakeholder, for each of the four following asset-based categories:

- Overhead Lines (Sub-transmission, distribution, and low voltage)
- Distribution substations, switchgear, and underground assets
- Zone substations
- Other (comprising a variety of risks including GXP and Elgin 66kV bus risks, secondary systems like communications and SCADA, environmental risks like flooding, earthquake, high winds, snow, and stakeholder risks including power quality)

A detailed risk register approach has been selected instead of a more generic critical risk approach for these reasons:

- A detailed approach related to asset types and in cases specific situations (e.g. bridge failures that impact on network cables) allows the impact of those risks to be considered specifically, controls identified, and an assessment made if further controls are needed or possible.
- Treatment of detailed risks contributes to organisational resilience, particularly related to reduction, readiness, and response, not only to emergency events from natural disasters but also asset failures and third-party interference. This can be achieved more comprehensively with a detailed risk register.
- Recording the assessment of risk rating, controls and further actions required with periodic review ensures risk management disciplines are structured and can be revisited when circumstances change or more information is available. This record also is helpful when investigating events and incidents, to understand what the analysis and position of the organisation was in relation to controls that may be in place or under action.

Risk Review Process

The network risk register is reviewed and updated by teams of subject matter experts. Risks are rated in an inherent condition, without controls. In a number of cases where network configuration and asset types are existing, the inherent condition includes historical design and construction decisions when the asset was installed that act as controls. Abstracting from the status quo is largely impractical. The existing controls are listed, and the risk rated at a residual level. The residual risk assessment is evaluated as:

- Effective if within tolerance, ALARP and good industry practice, or no further controls are considered feasible.
- Improving if further action to implement controls are underway.
- Further Controls Needed if additional controls are recommended and no action is yet underway.

Environmental factors specific to Mid-Canterbury are included, such as snow, the extreme AF8 Alpine Fault scenario, the potential Ashburton Bridge failure affecting the network and larger areas of network exposed to flooding. Other network specific factors include harmonics from irrigation pumping, irrigation load patterns, and both network configuration and GXP security.

Analysis of Network Risks with the Register

The following table shows the breakdown of the risk register entries into categories.

Asset Category	Failure & Operations	Environment & Stakeholder	Total
Overhead Lines	12	14	26
Distribution Substations, Switchgear, & Underground	16	13	29
Zone Substations	18	12	30
Other	11	10	21
Total	57	49	106

In overview, the following observations can be made about the network risk register:

- Risk types and outcomes are not out of step with other electricity distribution networks in New Zealand like Network Waitaki, Waipa Networks, and Powerco. In a number of cases, risk exposure to reliability events is lower because of the largely ringed sub-transmission network, the ability to back-feed and back up zone substations, and relatively low ICP counts on feeders. Relatively recent network upgrades and voltage conversions means that the overall network condition is better, reducing asset failure with both reliability and safety risk.
- That said, because of the ubiquity of network assets within places accessible to the public and supplying workplaces etc. and the network role as an essential service, there is an unavoidable degree of safety and reliability risk related to essential distribution infrastructure. Undergrounding of assets in state highway road corridors and urban areas is reducing this risk, and it is lower than many other networks as a result.
- There are more risks related to zone substations than other asset classes because of the increased complexity and diversity of equipment, and the higher impact of key equipment like zone substation transformers and switchgear.
- Distribution Substations, Switchgear, & Underground are not inherently riskier, but the higher risk count relates to the combination of a number of asset classes into this category.
- The risk register is not intended to be completely exhaustive. The intention is to cover material risks, particularly with a high inherent risk ranking, and ensure appropriate controls are applied to reduce risks to an **A**s **L**ow **A**s **R**easonably **P**ossible (ALARP) level. This will include assessment of likelihood, impact, practicality, and economic viability of controls in line with good industry practice.

High Focus Residual Risk Summary

Due to the high number of risks within the risk register, it is necessary to focus attention on a manageable number of the highest residual risks so control improvement is prioritised. Review of the risk register identified the best High Focus Risk category to be risks with residual rankings of Very High, which results in a High Focus risk category containing ten risks. The Network High Focus Residual Risks are shown in a heat map for management and Board reporting. For eight of the risks, the inherent and residual risk assessment is the same. This is because, in spite of controls applied, it was decided that the consequence and likelihood had not changed to within the next classification.

2.5.2 Equipment Risks

Risk assessment has identified a number of pieces of equipment that have a sufficiently critical place in the EA Networks network that the consequences of failure is seen as worthy of further investigation. In most cases, the risk had been informally identified prior to the risk assessment exercise and consideration was already being given to appropriate mitigation.

The following table gives a summary of the highest scoring risks for critical pieces of major equipment which would have implicitly high consequences if they were unavailable.

Summary of highest risk type (words) and severity (colour) for major substations			
Site	Building & Contents	Power Transformers	Switchyard Equipment
Ashburton 66/11	Seismic = Low	Equipment = Low	Lightning = Low
Carew 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Coldstream 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Dorie 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Eiffelton 66/11	Seismic = Low	Equipment = Low	Lightning = Low
Elgin 66/33	Seismic = Low	Seismic = Low	Lightning = Low
Fairton 66/22/11	Seismic = Low	Equipment = Low	Lightning = Low
Hackthorne 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Lagmhor 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Lauriston 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Methven 33/11	Seismic = Low	Equipment = Low	Seismic = Low
Methven 66/22/11	Seismic = Low	Equipment = Low	Lightning = Low
Mt Hutt 33/11	Seismic = Moderate	Equipment = Moderate	Seismic = Moderate
Mt Somers 66/22	Seismic = Moderate	Equipment = Moderate	Seismic = Moderate
Montalto 33/11	N/A	Seismic = High	Seismic = Moderate
Northtown 66/11	Seismic = Low	Equipment = Low	Lightning = Low
Overdale 66/22	Seismic = Moderate	Equipment = Low	Lightning = Low
Pendarves 66/22	Seismic = Low	Equipment = Low	Lightning = Low
Seafield 22/11	Seismic = Low	Equipment = Low	Lightning = Low
Seafield 66/11	Seismic = Low	Equipment = Low	Lightning = Low
Tinwald 66/22/11	Seismic = Low	Equipment = Low	Lightning = Low
Wakanui 66/22	Seismic = Low	Equipment = Low	Lightning = Low

Note: *Equipment* refers to the risks involved in equipment failure.

<u>Risk Rating Rationale</u>

While engineered to a good standard, the Lauriston and Overdale Substation buildings are considered moderate seismic risk due to their proximity to the Mitcham fault system[2].

Mount Hutt and Mount Somers Substations are considered moderate seismic risk due to their close proximity to the Geraldine–Mt Hutt Fault system. Both sites have been engineered to a good standard.

Montalto33 is considered high seismic risk due to being a temporary site (not built to the same engineering standards) and its proximity to numerous fault systems. Remediation work is planned when the network surrounding the substation is converted to 22 kV in the near future, making the Montalto33 Substation redundant.

2.5.3 External Risks

Seismic events, flooding, snowfalls, high wind, and wildlife are the key natural risks faced by the road-side electricity network. A consequence of typically being by the roadside means that vehicles, vandalism, and fire are the significant man-made risks to the electricity network.

Different items of plant will respond in different ways to the same risk. A flood is unlikely to cause major problems for a pole-mounted transformer, but a kiosk-mounted unit will undoubtedly have a higher risk of failure during a flood.

[2] GNS: *General distribution and characteristics of active faults in the Ashburton District, Mid-Canterbury*.

The following table identifies the risks facing different components of the network and the consequences of being exposed to that risk.

Summary of highest risk type and severity (colour) for major asset categories			
Category	Highest Risk	Consequences	Treatment
UG 66kV & 33kV	Seismic	High	Emergency Spares
UG 11kV Cable	Seismic	Medium	Emergency Spares
UG LV Cable	Seismic	Low	Accept & Design
OH 66kV Line	Wind/Snow	Medium	Emergency Spares & Design
OH 33kV Line	Wind/Snow	Medium	Emergency Spares & Contingency Plan
OH 22kV Line	Wind/Snow	Medium	Normal Spares & Design
OH 11kV Line	Wind/Snow	Medium	Normal Spares & Design
OH LV Line	Snow	Low	Normal Spares & Design
Circuit-Breakers	Seismic	Medium	Emergency Spares
Ring Main Units	Seismic/Flood	Low	Normal Spares & Contingency Plan
Disconnectors	Seismic	Low	Normal Spares & Contingency Plan
HV Fuses	Lightning/Seismic	Low	Normal Spares
Pole Mount Transformer	Wind/Snow Lightning/Seismic	Medium	Normal Spares & Revise Design
Kiosk Transformer	Seismic/Flood	Medium	Normal Spares & Revise Design
LV Boxes	Vehicle/Flood	Low	Accept

Design = Ensure Adequate Design

Accept = Accept the risk and repair any damage in a routine fashion

Emergency Spares = Spares set aside for emergency use only

Ashburton District Council's Civil Defence Emergency Management defines a major earthquake as one which closes road access into the Ashburton District for up to 72 hours and severely disrupts Lifeline Utilities within the district. This equates to a 1 in 300-year event[3].

External consultants reviewed the seismic risk to the network after the Christchurch earthquakes. Since then, their recommendations have been adopted – in particular, improved seismic restraint for ground-mounted equipment. Further work is being done to reinforce some older zone substation buildings.

Recent flood protection works to Ashburton's major stop banks (to prevent a 1 in 100-year inundation event) have reduced the risk of major flooding to Ashburton township during the design life of network assets to a very low percentage[4].

2.6 Risk Mitigation Proposals

2.6.1 Procedural Responses

EA Networks can control some aspects of risk. Gathering information about potential risks and proactively planning responses to it can alleviate the likelihood of an event occurring in some cases or, alternatively, lower the consequences to EA Networks if the event does occur.

[3] *Ashburton District Earthquake Initial Response Plan*

[4] Environment Canterbury – *Ashburton River (Hakatere) Flood Hazard Management Strategy*.

The following procedures will be adopted to assist in managing risk:

- Minimise critical equipment failure risks by early identification of issues and subsequent prudent management and maintenance to ensure equipment availability.
- Liaise closely with regulatory agencies and neighbouring electricity companies to compare preparedness and co-operate with technical information
- Ensure design standards are compatible with a risk profile deemed acceptable by the community
- Safety aspects of risk have been addressed in section 2.2 and section 3.8.
- Risk to the environment has been addressed in section 2.3 and section 3.9.
- Development of a range of emergency response plans has been addressed in section 2.8. The majority of these plans have been reviewed in the last 24 months.

2.6.2 Engineering Responses

A certain amount of physical work can be undertaken that helps mitigate the risk faced by EA Networks if that is an element of the chosen treatment for those risks. The following items are engineering responses to distributed risks that are significantly mitigated by this treatment.

- Emergency stocks: Specific items have been reserved in the stores system for use in emergencies. These items are typically items that are long delivery, obsolete items, or potentially difficult to transport in the aftermath of a natural disaster.
- Emergency spare distribution transformer: A universal emergency distribution transformer has been established. It is 1 000 kVA and can be connected to 22 kV or 11 kV, overhead line, or underground cable. This is useful for covering critical individual transformers for failure (hospital, water supply, etc). Reasonable stocks of transformers are kept in common smaller sizes.
- Distribution transformer restraint: Revision of the mounting arrangements for all distribution transformer mechanical restraint has ensured lower risks for people as well as lower risk of interruption during an earthquake.
- All new transformers larger than 100 kVA are now ground mounted on seismically secure precast foundations. A standard holding down arrangement has been established that offers high seismic security.
- Staff awareness: Education of staff has heightened awareness of risk, and solutions are now becoming part of the way of working. Staff are actively promoting risk reduction where they see issues.
- Network renewal: By renewing the network (for other reasons) a lot of the riskiest network components are being removed or replaced.
- Containerised autotransformers: The portable 5 MVA autotransformers that are required at the junction of 11 kV and 22 kV distribution are housed in lined shipping containers to ensure no oil spill risk.

2.6.3 Specific Solutions

Some network risks have been specifically treated by engineering a solution to minimise the likelihood and/or consequences. The following items are the most relevant responses.

- Northtown Substation: The security of Northtown substation has been further enhanced by the addition of the EGN-FTN 66 kV circuit in 2019-20. In conjunction with FTN 66/22/11 kV substation, this provides two full capacity in-feed 66 kV lines.
- Closed Sub-transmission Rings: The risk of spur lines failing in adverse weather and then not being accessible for repair has caused the fundamental design requirement of virtually all zone substations to be on a closed sub-transmission ring. Those sites that are not on a ring must have alternative HV distribution voltage alternatives available that do not share the same pole line as the sub-transmission supply (Mt Hutt Excluded). Sections 5.4.2 and 5.4.3 outline a variety of projects that advance this objective.
- Pendarves and Carew Substations: decrease in risk of transformer fire affecting neighbouring transformer, due to rated firewall built between them.

- Ashburton Substation: substation control room being upgraded to Importance Level 4 (IL4) seismic rating.
- Ripple plant configuration: The possibility of ripple plant failure allowing an uncontrolled system peak has significant risks for EA Networks – both reputationally and electrically. The configuration of the two ripple plants has been engineered to allow the GXP to be partially covered by another plant in the event of a failure. This was relatively inexpensive to achieve and has reused 33 kV ripple plants when the 66 kV GXP was introduced. The commissioning of a new 220/66 kV transformer (T9) has reduced the ability to cover for ripple plant failure. Future and in-progress projects will ensure the security of load control signalling (see section 5.4.11).

2.7 Health and Safety

Electricity is a familiar and necessary part of everyday life; however, failure of the electrical infrastructure or uncontrolled release of electricity can kill or severely injure people and cause significant damage to property.

All participants in the electricity supply industry have an obligation to ensure their workers, contractors and the public are kept safe, and are well informed of risks and how to eliminate or mitigate them.

2.7.1 Health and Safety Management

With many work practices underpinned by legislative requirements, standards and industry guidelines, our health and safety is not only compliance based but embedded safety behaviour leading to good business practice.

An ongoing culture of continuous improvement is practiced by constantly evaluating new technologies, improved work practices, and adopting better methodologies and behaviours.

Over the last four years we have engaged multiple external consultants to review, analyse and make recommendations on improving and strengthening our safety management system in the following areas:

- Safety Leadership and Safety Culture
- Hazard and Critical Risk Management
- Suitable Systems and Assurance
- Worker Training and Competency
- Temporary Traffic Management, in response to Waka Kotahi/ NZTA changes.

This has cumulated in the development and implementation of our Health and Safety Strategy 2024-2027. The EA Networks Health and Safety Strategy drives initiatives ad objectives to develop better health and safety outcomes for everyone that interacts with EA Networks.

2.7.2 Public Safety Management

The Electricity (Safety) Regulations 2010 require electricity network companies to implement and maintain a Safety Management System for public safety. EA Networks is fully committed to this requirement by achieving compliance with annual external audits conducted by TELARC to verify compliance with NZS 7901.

The EA Networks Public Safety Management System (PSMS) covers all aspects of asset management including:

- asset identification, coverage and demarcation,
- lifecycle asset management (network design, construction, operation and maintenance),
- management of risk, hazards, and change,
- safety and operating processes
- emergency preparedness and response
- performance monitoring
- public awareness and communication

EA Networks provide a free condition assessment to owners of HV service lines connected to the network, highlighting any problems to them in writing. If these recommendations were ignored, a copy of the letter was initially forwarded to the Energy Safety Service (ESS) but, after receiving no support from ESS, the letter is simply kept on file. On at least one occasion, EA Networks has isolated the line without the consent of the owner due to their inaction and the severe safety hazard.

Regular investigations and review of all public incidents are undertaken including, but not limited to, the following incident types.

- Vehicles hitting poles or ground-mounted equipment.
- Mobile plant, irrigators or equipment contacting overhead conductors.
- Excavation damage to underground cables.
- Operation of network assets causing damage to private property.

Where network assets have materially contributed to a public incident, consideration is undertaken to either reconfigure, relocate, mitigate access, or remove the asset.

An industry-leading undergrounding initiative across the EA Networks distribution network has led to improvements not only in reliability but also in public safety. This ongoing programme of removal of overhead lines and power poles has led to improvements in public safety by decreasing the likelihood of contact with overhead assets (less mobile plant and equipment contact with overhead conductors, or vehicles hitting poles) as well as decreasing the likelihood of outages from weather, vegetation, or wildlife impacting overhead conductors.

EA Networks regularly collaborate and cooperate with other stakeholders to work together to improve safety.

2.8 Resilience and Emergency Response

It is recognised that the local economy depends on a secure and reliable supply of electricity, and that a catastrophic event such as an earthquake, landslide, tsunami, flood, wind and snowstorms, and terminal failure of key assets can have a significant impact on both the network and the local economy.

Resilience is the ability to withstand, respond to, and recover from significant emergency events.

EA Networks have developed emergency response plans for dealing with widespread abnormal situations created by either asset failure or catastrophic natural events. All emergency response plans are regularly reviewed to ensure that unique risks arising from emergency response have been identified. This has included training relevant staff in the Coordinated Incident Management System (CIMS) and preparing to stage regular simulation exercises to emergency scenarios. As such, EA Networks is improving the capability to deliver on our lifeline utility obligations.

Mutual Assistance Agreements have been signed with peer electricity distribution networks. These agreements were successfully implemented when aiding Orion during the Canterbury earthquakes in September 2010 and February 2011, and to Westpower in the aftermath of 2018’s cyclones Gita and Fehi. Following the 2023 Cyclone Gabrielle event, EA Networks sent control room staff to Powerco to assist in operating their control room during the immediate aftermath. The benefits of exercising control staff with other EDBs have been recognised, and this will be continued during BAU conditions to encourage interoperability.

2.8.1 Business Continuity Planning

The EA Networks building at JB Cullen Drive is constructed to Importance Level 4 seismic standards.

The site is well provisioned with standby generation, water tanks, and EA Networks’ own communications pathways to support critical infrastructure.

Regular electronic backups of mission critical records for retailer billing and consumer identification are carried out. The backup copies are securely stored offsite by EA Networks’ web host.

All ICT servers are virtually hosted across the Ashburton substation data centre and JB Cullen site.

ADMS is similarly distributed across the above sites as well as an independent disaster recovery site at Westpower in Greymouth.

A 20 000 litre bulk diesel fuel tank and pump in the J B Cullen Drive yard decreases reliance on external fuel sites.

The diesel tank is restocked once it drops to half full. 200 litres of petrol are held for portable plant and generators. The diesel storage is sufficient to run the fleet and the site generator for a minimum of one week (assuming tank is half full). The tank would, on average, be 75% full and the diesel vehicle use not as high as originally planned (working hour limits).

Non-perishable food and water are provisioned for essential staff.

For further details refer to:

- Emergency Preparedness Standards (last reviewed -November 2024)
- Pandemic Planning Standard (last reviewed November 2019)
- Critical Infrastructure – Ancillary Services Standard (last reviewed December 2019)

2.8.2 Emergency Contingency Planning

Emergency contingency planning covers any emergency event situation that is the result of any:

- earthquake, eruption, tsunami, landslide, flood, storm, tornado, cyclone,
- explosion, fire, leakage or spillage of any hazardous gas or substance,
- infestation, plague, epidemic, or
- technological failure, complete failure, or major disruption to an emergency service or lifeline utility which cannot be dealt with by emergency services as business as usual, or otherwise, requires a significant and coordinated response.

For further details refer to:

- Health & Safety Manual Section 7: Emergency Management (last reviewed November 2023)
- Emergency Preparedness Standards (last reviewed November 2024)
- Building Evacuation (last reviewed November 2024)

2.8.3 Specific Network Contingency Plans

Specific contingency plans for the restoration of supply to essential services and individual major industrial and commercial consumers exist to complement and supplement the Participant Rolling Outage Plan. The majority of EA Networks' contingency plans have been reviewed in the last 24 months.

These include, but are not limited to the following:

- Network isolation and reconnection of embedded generation stations (Lauriston Solar Farm, Highbank, Gartartan Solar Farm, Montalto Hydro, and Cleardale).
- Alternate network supply pathways after complete failure of a Zone Substation.
- Identification of critical third-party infrastructure and alternate supply pathways.

2.8.4 Participant Rolling Outage Plans

The Electricity Industry Participation Code 2010 Part 9 requires all specified Electrical Distribution Businesses to prepare and publish a Participant Rolling Outage Plan (PROP) for audit and approval by Transpower's System Operator.

The PROP is required to conform with the requirements set out in the System Operator Rolling Outage Plan (latest version -September 2024), and details how electricity distributors will assist the System Operator in managing either a total outage or rolling outages of up to 25% of normal load if there is a national or regional electricity shortage.

EA Networks' most current PROP was updated in - August 2024. A copy of the current Plan can be found on the EA Networks website: EA_Networks_Participant_Rolling_Outage_Plan-2024.pdf

2.8.5 Civil Defence Emergency Management

EA Networks are a member of the Canterbury Lifelines Utilities Group which promotes resilience to risks and develops contingency measures for Civil Defence Emergencies arising from disasters.

As a lifeline utility, EA Networks participates in the development of both regional and local Civil Defence Emergency Management plans. EA Networks also provides technical advice to local authorities and other lifeline utilities as requested.

In the event of a Civil Defence Emergency, nominated staff members are sent to liaise with the local district council's Civil Defence Emergency Operations Centre.

Delegated senior management staff have also attended workshops where the South Island regional preparedness for a magnitude 8 Alpine Fault earthquake was discussed.

Designated staff have been trained in Coordinated Incident Management System (CIMS) protocols to improve EA Networks interaction with Civil Defence Emergency Management.

2.8.6 Post Critical Event Reviews

A post-critical review is carried out after every major emergency event – however, the event may not necessarily impact directly on EA Networks (e.g. the Canterbury earthquakes).

The post-critical review process acts as an effective tool to identify areas of improvement, and lessons learnt from the post-critical review are incorporated into EA Networks' operations.

The most recent review was undertaken after the July 2022, August 2022 and October 2023 wind events.

2.8.7 Resilience Management Maturity Assessment and Resilience Action Plan

This section provides a commentary on EA Networks' EEA Resilience Management Maturity Assessment Tool RMMAT assessment and notes areas for inclusion for improvement in the three-year Resilience Action Plan dated February 2024.

By collation of a resourced and detailed Resilience Action Plan, EA Networks have instigated a structured approach to improving resilience management. The action plan makes a commitment to improvement of resilience that will enhance EA Networks' emergency response capability during events by a better and more balanced approach to the 4Rs of Reduction, Readiness, Response and Recovery.

The Resilience Action Plan focuses on the following areas for improvement:

1. **Reduction:** Areas targeted are in more detailed assessments of major risks, lifelines engagement, network and critical spares management, and contingency planning for major and likely scenarios.
2. **Readiness:** Improvements will be made to capability in business continuity management, contingency planning, communication plans, and contract resourcing.
3. **Response:** A focus on the areas of response systems and processes, as well as EA Networks' generation capability when working with Ashburton District Council on their generation plans at community hubs and critical sites.
4. **Recovery:** This is an area where current capability is quite weak, but development of a recovery strategy, recovery plan, and stakeholder communications and consultation plans modelled on a good industry example from our industry peers will be completed and will quickly lift capability in this area.

The current RMMAT assessment and the three-year improvement plan provides a forecast of what the RMMAT assessment scores are expected to be at the completion of the action plan. The expected FY27 outcome is shown below, a well-rounded and balanced approach to resilience across reduction, readiness, response, and recovery. Capability will be developed and implemented via this resilience action plan and gaps in our current capability will be addressed.

EA Networks RMMAT Assessment

The EEA RMMAT assessment is included in the EEA Resilience Guide, first published in November 2020 and further reviewed in July 2022. The resilience assessment is based around the 4R's (Reduction, Readiness, Response and Recovery) of emergency response as set out in NZ's CDEM framework.

The RMMAT assessment is 72 questions across 19 functions that allow organisations to self-assess their level of resilience management maturity. The RMMAT scoring system is as follows:

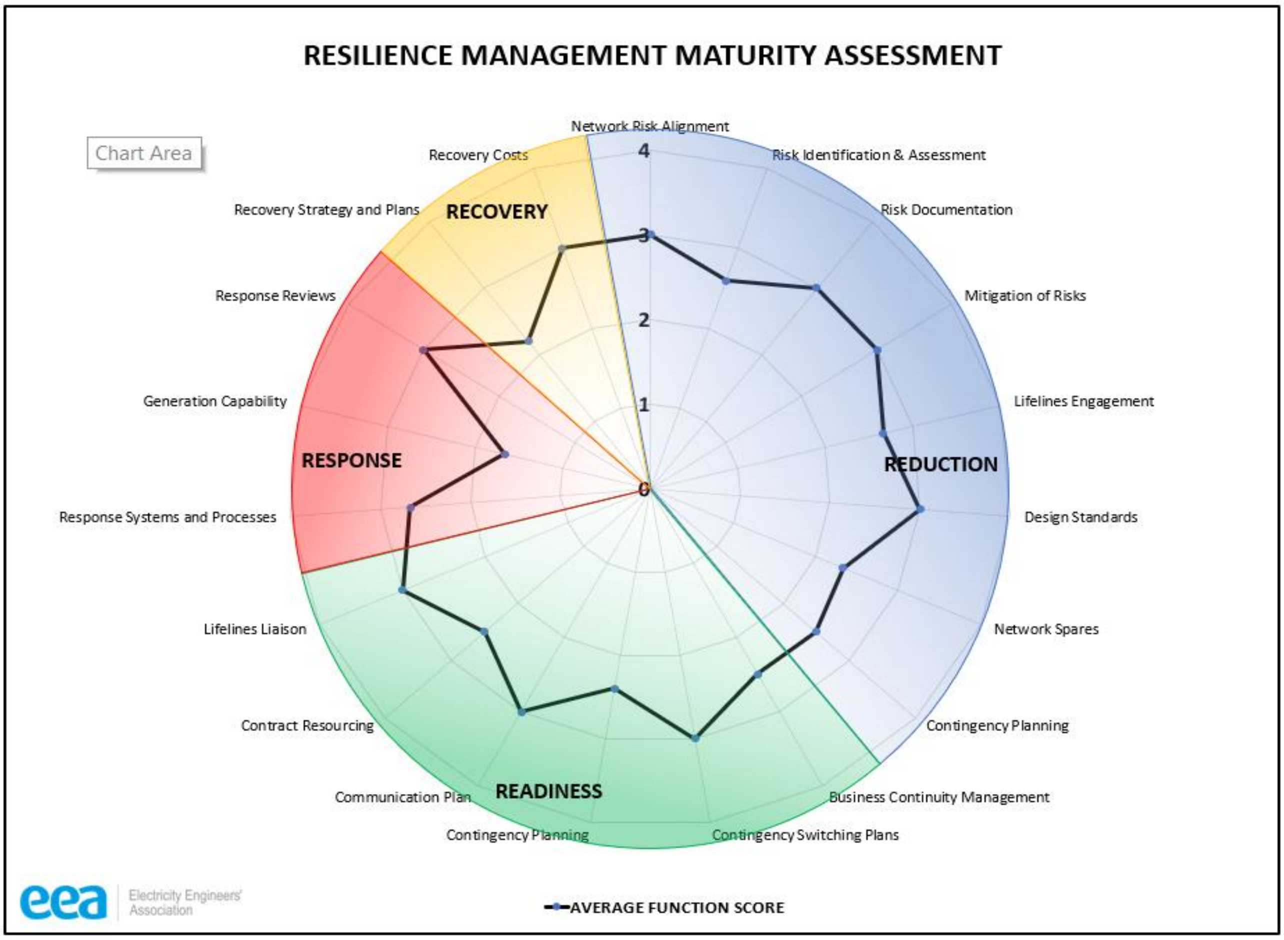
Maturity Level		Maturity Description
0	Not Aware	The organisation has not recognised the need for this requirement, and / or there is no evidence of a commitment to put it in place.
1	Aware	The organisation has identified the need for this requirement and there is evidence of an intent to progress it.
2	Developing	The organisation has identified the means of systematically and consistently achieving the requirement and can demonstrate that progress is being made with credible, and resourced plans in place.
3	Competent	The organisation can demonstrate that it systematically and consistently achieves relevant requirement. Only minor inconsistencies may exist.
4	Excellent	The organisation can demonstrate that it consistently exceeds the requirement. It employs and fosters leading local and international industry practices and has a mature continuous improvement culture to ensure a high standard of maturity and compliance is maintained.

Hence it can be seen that to have a competent maturity level, a score of 3 in all 19 functions (perhaps with some exceptions as discussed below) would be required.

It is easiest to visualize EA Networks' current state of resilience management maturity by the following radar diagram, showing the current score for each of the 19 functions, arranged by the 4R's.

EA Networks' March 2025 RMMAT Assessment

EA Networks has completed further resilience improvement actions along the lines of the above commentary. As a result, the March 2025 updated RMMAT scores are summarized below.



Commentary on EA Networks' RMMAT Assessment

In the majority of the 19 functions, EA Networks scores below a competent level. However, the following observations are helpful:

- Scores can be lifted from 0 or 1 to 2 by means of designing the solution and putting a resourced plan in place. Hence a resourced, detailed improvement plan (the Resilience Action Plan) has lifted scores for the 2024 AMP RMMAT in a number of areas as a result of this planning work.
- Progress in implementing the FY25 Action Plan tasks has lifted scores. Particularly in the Communication Plan under the topic of Readiness.
- In some areas EA Networks policy may be to not match the recommended RMMAT capability. For example, in the Generation Capability function, one measure is if generation capacity is contracted in advance to bring in during events. Our current policy is not to provide generators to customers, and to encourage customers that if electricity is essential to their ongoing operations, they should make their own arrangements. If it was known that EA Networks would provide generators under emergency situations, it's likely that customers would rely on that instead of making rational decisions related to their own circumstances. A second example is related to contingency planning, where the assessed maturity approach is to contract with a structural engineer to respond to a request for seismic assessments following an earthquake event. This service has been costed (an annual retainer) and was considered not good value for money compared to the likelihood of calling on the service. Instead, it is expected that a request to CDEM to allocate a structural engineer to assess our critical infrastructure buildings will be sufficiently prioritized as an alternative approach.

EA Networks Resilience Action Plan

Actions for inclusion in the Resilience Action Plan where we will lift capability in a meaningful way and cover gaps in our capability are as follows:

Category	Action Planned	Phasing within the Plan
1. Reduction	Identification and Mitigation of Network Vulnerability Risks	
Risk Identification and Assessment:	Prioritise and document risk control plans for high focus risks related to emergency preparedness, asset and systems related vulnerabilities, and natural hazards.	FY25, FY26, FY27
Asset Criticality Framework:	An asset criticality framework will be developed with reference to the EEA Criticality Guide, to classify asset classes and particular equipment into criticality grades. This will assist in quantifying vulnerability and consequence metrics from a network resilience perspective.	FY27
Network Spares:	EA Networks has reviewed critical spares against asset types and commenced reviewing critical spares holdings and storage. A wider review of critical, emergency, and operational spares requirements is underway but needs to be completed, including documenting what spares are held and where they are stored, what critical spares and volumes required to be held, what procurement is needed based on gaps identified, and budget provision made for that in the AMP. Seismic security and strapping needs to be assessed. Sub-transmission lines stock is maintained for the ongoing build work and emergency response. Further work is needed to complete a risk analysis of how much stock would be needed in the credible worst-case scenario. Documentation of our network spares and critical spares approach is required.	FY25, FY26 (In progress)

2. Readiness	Pre-Event Contingency Planning and Training	
Ongoing CIMS improvement:	Roles, exercises, and coordination with CDEM and other lifelines organisations. Focus on organizational resilience related to business continuity (logistics, systems, IT, and communications).	FY25, FY26, FY27 (In progress)
CDEM Liaison:	Coordination with ADC regarding resilience and emergency preparedness.	FY25 (Completed)
Business Continuity Management:	Analysis of the performance of critical business systems, applications, functions, processes and services, and identification of agreed recovery timeframes with the relevant business owners. Cover ERP/EAM, SCADA/ADMS, GIS, Stores/procurement, and Network Information.	FY26
Business Continuity Management:	Review supplier and out-sourced service provider dependencies, including contractual responsibilities are in place to support critical services. Vegetation contractors have informal engagement to respond for emergencies - Vegetation Management RFP should improve the formality of this. Implementing emergency response traffic management service contract. Related to stores and procurement of network materials, there are standard procurement arrangements in place, but no specific contractual arrangements related to business continuity.	FY25, FY26 (In progress)
Contingency planning:	Document high risk/critical scenarios e.g. major Ashburton flood, ASB 220kV/Elgin faults, major snow or windstorm, bridge or key roading access failures, and earthquake including AF8. Seek experience in past events from other EDBs etc.	FY25, FY26, FY27 (In progress)
Contingency planning:	Seismic assessment contract in place for post-earthquake assessment; identify providers as part of contingency plan. Revisit phasing for seismic assessment and remediation programme for zone substation buildings and consider more rapid roll out. Seismic assessment retainer not considered value for money, check approach with CDEM of seeking allocation of a structural engineer for critical infrastructure and buildings.	FY25 (Completed, further action in FY26)
Contingency planning:	Contingency Plans for critical staff such as NOC Controllers. EA Networks is involved with Westpower, Mainpower, and Powerco as Aspentech SCADA/ADMS users and have begun planning for cross-functional training and harmonisation of operating procedures to allow network controllers to move between control rooms in a major event. Considering training more duty controllers to cover this skilled position. A fuller review of contingency planning and alternative locations is required, including an alternative control room (potentially equipping a desk at Westpower, Methven, or at Ashburton Zone Substation).	FY25, FY26, FY27
Generators:	EA Networks existing generation covers JB Cullen Drive, Ashburton Substation, Gawler Downs, Round Top, and Ashburton radio repeaters all with permanently connected generators. Purchase a generator for the Methven Substation to support that important node. Assess need for contingency control room in a container connected to power, generator plug, and communications. Potentially stored at	FY26 (In progress)

	Methven Substation and can be relocated where needed depending on the contingent event. Transpower Ashburton 220kV GXP is another potential back up control location. Consider the scenarios where this would be required and assess justification.	
Generators:	Evaluate critical sites for generation to be connected to and work with Ashburton DC CDEM function and stakeholders to prioritise and develop plans for generator plugs and generator supply by users, including: • ADC Critical infrastructure, CDEM welfare centres, Hospital, Medical centres, Supermarket(s), Service station(s), at least one ATM, Mobile cellular sites, Other data solutions – Starlink Hinds base station resilience, Schools, Other essential contractors who need depot electricity.	FY25 (Completed, further action in FY26)
Generators:	• Investigate feasibility of tractor PTO generators. Liaise with ADC CDEM if this is a useful lower cost solution, e.g. for mobile cellular sites or smaller critical sites like medical centres. • If EAN supplied generators, need to secure them from theft and re-fuel them which also consumes resources (look for support contractors to do re-fuelling).	FY25 (Completed)
Reduction and Readiness:	Bridge dependencies: Need to consider the resilience and redundancy of the above critical sites north and south of the Ashburton River.	FY25 (On track to complete)
Emergency Incident Communication Plan:	Currently there are communication tasks/methods for use during emergencies, but no overall communication plan. Communications are briefly mentioned as part of the Public Information Manager role in the CIMS structure. Obtaining a good example of a Communication Plan from one of our peer EDBs and customising it would be an easy way to implementing this capability. When combined with implementing customer outage communication via the ADMS Outage Management System and Salesforce customer contact records, this will lift capability in this area. The plan will have a regular review cycle.	FY25 (Completed)
Contract Resourcing:	Improve interoperability, make plans for bringing in external resources and ensuring they can be housed and fed. Working hours / fatigue management policy to be developed and implemented.	FY25, FY26 (In progress)
3. Response	Immediate Actions Following an Event	
Response Systems and Processes: (Outage Communications)	Improving our Response Systems and Processes will improve our effectiveness in an emergency event. Work is underway to develop the ADMS Outage Management System and customer communications capability (Phase 1 due March 2024 for planned outages, unplanned outages to follow in FY25). The ability for administration staff to take outage calls and enter them into the ADMS is being developed to scale up our ability to respond to larger events. Review and solution for volume of fault calls, e.g. call avalanche system to off-load controller/call takers or other solution. Budget and phasing to be determined in FY25 for potential implementation in FY26.	FY25, FY26 (In progress)

Emergency Incident Communication Plan:	Include thresholds for enacting the customer/stakeholder communication response plan.	FY25 (Completed)
Generation Capability:	In conjunction with the generator planning work with Ashburton District Council, document a generator deployment process for emergency diesel generators and suitable leads for critical sites and long-repair time damaged networks.	FY25, FY26 (Planned for FY26)
Response Reviews:	Document how EA Networks uses the appreciative inquiry method (What worked well? What didn't work so well? What can we improve?) for major and extreme events. These trigger lessons learnt summaries and improvement actions. Define the thresholds that constitute a major and extreme event that would then require a response review. Will be completed when the draft Standard - Emergency Preparedness Part 2 Extreme Events is finalized.	FY24 (Complete)
4. Recovery	**Long Term Reinstatement of the Network**	
Recovery Strategy and Plans:	The recovery phase is where the immediate response to an emergency is completed, and the longer-term tasks of restoring the network to a satisfactory state are now required. This may involve “building back better” given the lessons of the emergency event, consulting with affected communities where the emergency has fundamentally changed their needs or occupation of the land, determining longer term refurbishment or replacement of assets where temporary repairs have taken place. Obtaining a good example of a recovery strategy and plans (ask Westpower, Orion…) and adapting for our use is a pragmatic way to progress this. Documentation of communication plan and stakeholder consultation and engagement plan. Consider management of potential regulatory compliance issues. Draft in FY25, further development over FY26 and FY27.	FY25, FY26, FY27 (Planned for FY26,27)

In terms of resourcing for the above action plan, in general the improvement actions will be resourced by internal people mostly from the Network and Contracting teams, and in the Strategy and Engagement team related to specialist aspects like customer communications and stakeholder engagement, IT, and business systems etc., drawing on in-house expertise. Involvement of Ashburton District Council’s CDEM team and Infrastructure team will be required. Consultation with external experts e.g. for seismic or wildfire risk assessment etc. will be completed as needed. A small amount of budget will be allocated for the work from within the wider consultant expenditure and, where necessary, network and non-network budget will be approved within the Asset Management Plan approval process. It should be noted that in the case of network capital expenditure, a number of projects already planned within the 10-year capital forecast will have a resilience benefit, hardening the network through asset renewal, improving reliability from undergrounding overhead network or improving security by redundancy, switching and configuration improvement, and network automation.

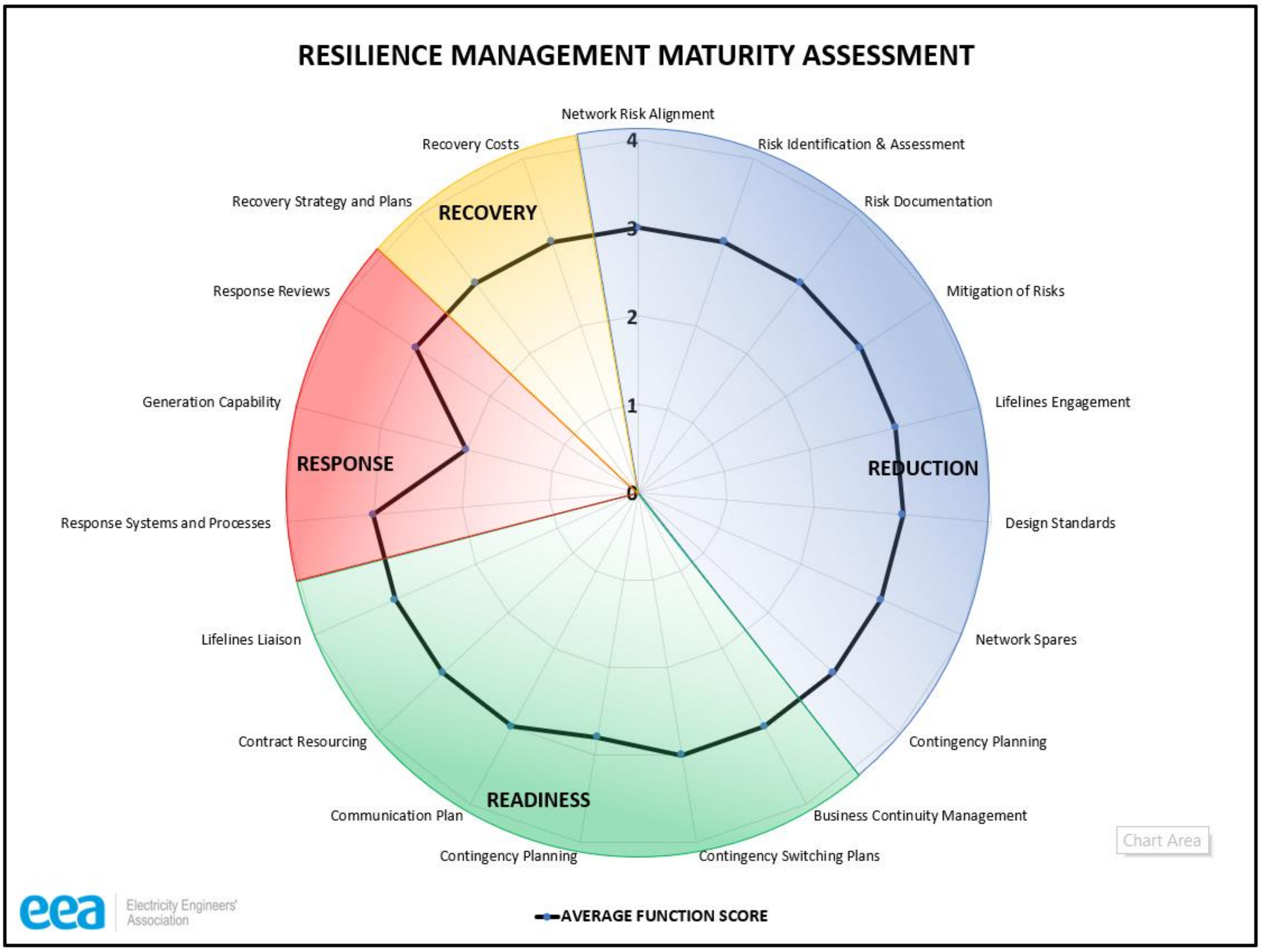


Figure 4: EA Networks FY27 Forecast RMMAT Scores

EA Networks' Forecast FY27 RMMAT Assessment

By completing the above Resilience Plan, we expect that RMMAT scores will be improved as shown in the above radar diagram (Figure 4). This shows a well-rounded and balanced approach to resilience across reduction, readiness, response, and recovery. Capability will be developed and implemented via the above action plan and gaps in our current capability will be addressed.

OUR CUSTOMERS

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3 OUR CUSTOMERS

3.1 Introduction

EA Networks is required by statute to take all reasonable precautions to secure continuity of service. A certain level of outages is inevitable, and they occur in all utilities. As a predominantly rural electricity supplier with several townships, it is not always reasonable to compare EA Networks directly with a predominantly urban supplier. It is EA Networks' goal to ensure that it continues to perform above the industry average for comparable line companies and it is targeting an on-going quality improvement with a consistent price path.

Service is about satisfying all stakeholders, and this includes safety aspects and environmental responsibilities as well.

This section outlines: stakeholder expectations; past, current, and desired network performance; and goes on to detail service improvement solutions that are either proposed or have already been implemented.

3.2 Consumer Research and Expectations

To set reasonable security standard targets that are compatible with end user expectations, appropriate research must be carried out.

The needs of electricity users have changed greatly over the last decade or so with the rapid introduction of technology into the domestic market. Appliances using the internet, personal computers, and security/fire alarm systems are ubiquitous in homes and have greatly increased the sensitivity of householders to power outages and minor interruptions.

The degree to which modern society has come to be reliant on a secure supply of electricity was clearly demonstrated during outages in the Auckland area in recent years. While EA Networks' area cannot boast a similar level or density of critical business users, this perception is merely a matter of degree. The small gift shop owner in Ashburton, running on small margins and high overheads, is just as reliant on electricity to power cash registers and EFTPOS terminals as the largest multinational company is for power to its multi-storey tower office block.

EA Networks' 2024-25 Statement of Corporate Intent Objective (see section 1.7) details the governance philosophy of the business. This approach has been crafted by embracing the feedback received from the community of consumers that the company serves.

Words used in the Statement of Corporate Intent such as *efficient* and *reliable* are relative terms that are subject to personal perceptions. These perceptions must be viewed from the consumer's perspective, which must be actively sought.

The most recent (2023) survey provided a worthwhile response to the different questions posed, with overall satisfaction being very high.

Local Ownership Importance

	Number of respondents	Important	Unimportant	Important – change from 2021
Importance of EA Networks remaining locally owned	1,580	94%	2%	+2%

Power Outages

	Number of respondents	Agree	Disagree	Agree – change from 2021
Overall, EA Networks does a good job of minimising power outages	1,578	87%	1%	0%
Power was restored within a reasonable timeframe	395	86%	6%	-4%
Information received about the outage was accurate	337	69%	12%	0%
It was easy to get information about the outage	350	59%	18%	-2%

Customer Perceptions

	Number of respondents	Agree	Disagree	Agree – change from 2021
Overall, EA Networks: Is a reliable and trustworthy organisation	1,551	87%	1%	+3%
Overall, EA Networks: Does a good job of minimising power outages	1,578	87%	1%	0%
Overall, EA Networks: Communicates well with consumers	1,555	71%	6%	+5%
Overall, EA Networks: Uses efficient operating procedures	1,552	68%	1%	+4%
Overall, EA Networks: Uses modern technology	1,556	68%	1%	0%
Overall, EA Networks: Cares about the environment	1,539	60%	1%	+2%

Balancing Prices and Service Levels

	Number of respondents	Keep things the same	Willing to increase bill amount	Reduce bill amount	Keep the same – change since 2021
Willingness to pay higher lines charges to reduce potential for outages	1,578	70%	3%	11%	-4%
Willingness to pay a higher lines charge in order to reduce time without power	1,468	71%	4%	11%	-4%

EA Networks' Services

	Number of respondents	Satisfied	Dissatisfied	Satisfied –change from 2021
Overall satisfaction: electricity and fibre networks, reliability of supply, communication, and reputation	**1582**	**90%**	**1%**	**+2%**

Overall Satisfaction

	Number of respondents	Positive	Negative	Positive – change from 2021
Fibre installation - satisfaction	**25**	**96%**	**0%**	**+22%**
Fibre installation - ease to interact with EA Networks	**25**	**92%**	**8%**	**+11%**
Other service - ease to interact with EA Networks	**160**	**88%**	**5%**	**+3%**
New power connection - ease to interact with EA Networks	**100**	**83%**	**6%**	**-4%**
New power connection - satisfaction	**100**	**85%**	**8%**	**-3%**
Other service - satisfaction	**159**	**87%**	**5%**	**+5%**
Tree vegetation/trimming - ease to interact with EA Networks	**48**	**67%**	**12%**	**-19%**
Complaint - ease to interact with EA Networks	**22**	**82%**	**10%**	**+32%**
Complaint - satisfaction	**22**	**73%**	**9%**	**+5%**
Tree vegetation/trimming - satisfaction	**48**	**67%**	**21%**	**-13%**

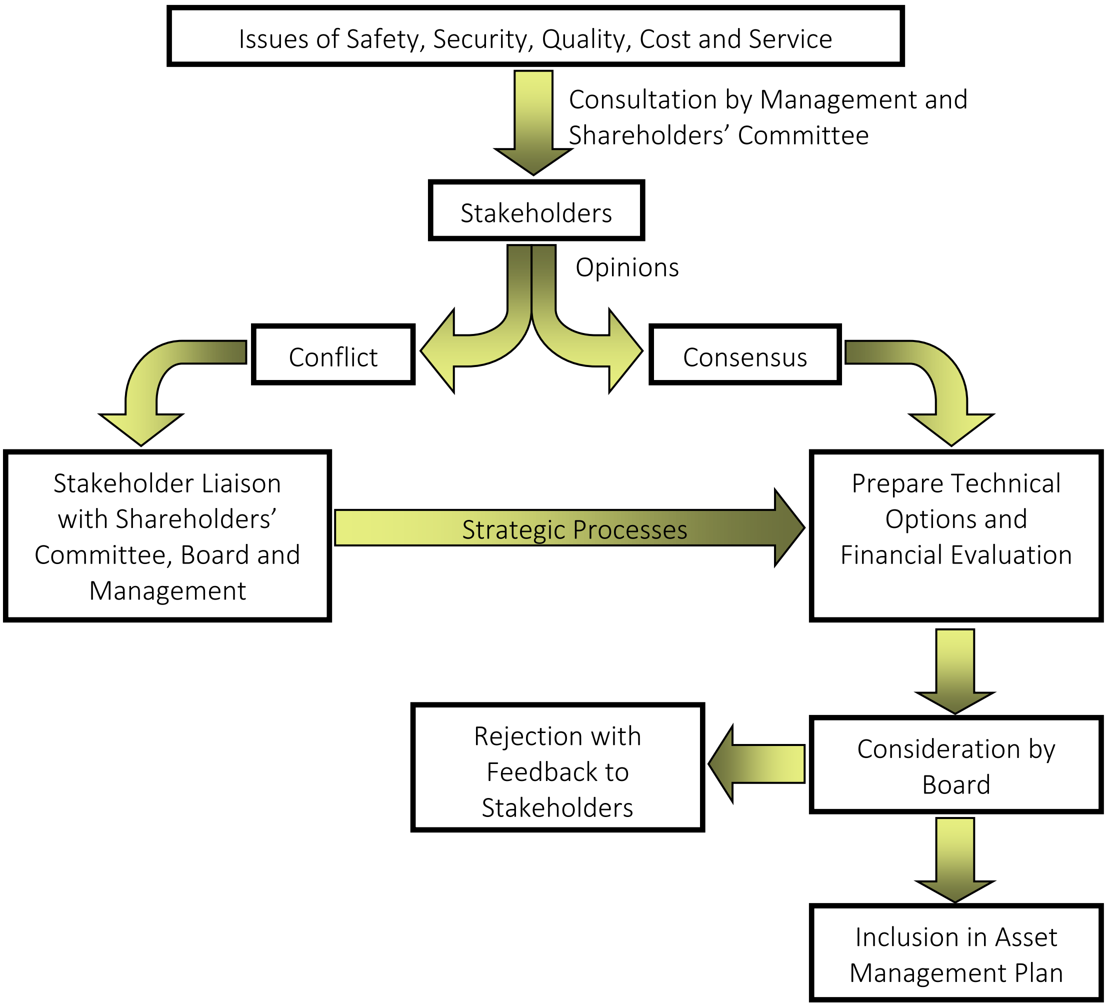
How People Would Prefer to Receive Power Outage Updates

	Number of respondents	Would use this information source	Would use – change from 2021
Text message	**1,573**	**76%**	**+3%**
Pre-registered email	**1,573**	**48%**	**+4%**
Phone app	**1,573**	**44%**	**+4%**

The key action points and messages from this survey are:

- The communication from EA Networks about planned and unplanned outages needs to be better and preferably by SMS text message or email.
- EA Networks' complaint management has improved significantly on previous years.
- Overall satisfaction with EA Networks as a whole remains high.
- EA Networks needs to increase communication to the community around the steps they take to manage environmental impacts, as well as celebrating the contribution made to the community by way of their sponsorship activities.
- Retaining local ownership remains very important for the vast majority of survey respondents.
- Respondents had a high level of awareness of what EA Networks does in the community, as well as the deferred discount credit received.

Managing Conflicting Stakeholder Interests



As a co-operative company, the vast majority of consumers are in fact shareholders (more than 99%), and they directly elect four of seven members of a Shareholders' Committee (the remaining three members are appointed by the Ashburton District Council) who, in turn, appoint the directors. When shareholder viewpoints are required, the Shareholders' Committee provides the effective voice for consumers/shareholders. Regular consultation occurs between the Board and the Shareholders' Committee where any issues that concern either party are discussed. Examples of the type of discussion that occur are:

- the cost implications of various network performance improvements (price/quality trade-off)

- the conflict of the differing scale of urban versus rural reliability/cost/capacity/aesthetic impact
- the balancing of asset management practices with potentially conflicting shareholder interests
- the path of proposed network development and the consumer price implications
- major projects that are proposed and the impact they will have on EA Networks and consumers
- the Statement of Corporate Intent which documents targeted financial and reliability performance indices into the future (the Shareholders' Committee receive/scrutinise the Statement of Corporate Intent).

The Shareholders' Committee provide a commentary on the performance of EA Networks for inclusion in the EA Networks Annual Report each year. In short, it continues to endorse the general direction of the company's performance. The company have taken this endorsement as concluding an appropriate method of reconciling stakeholder/shareholder interests and asset management practices.

Perhaps the most potential for tension tends to exist between company owners and customers. The co-operative by its nature self-manages this to an extent, given that EA Networks' owners are also EA Networks' customers (generally). As such, if one group is favoured over the other, ultimately the same person benefits. The balance is between consumer service levels and shareholder financial return – both benefitting the same person. Between the Shareholders' Committee and the Board of Directors, the interests of these two groups are considered and managed appropriately.

When an obvious conflict between significant stakeholders' interests arises, the technical and strategic elements are separated. The technical options are conceptualised, and approximate costs prepared along with the pros and cons for each option. These are presented to the Board for consideration alongside the strategic ramifications of the technical options that exist to address the conflict. Once in the realm of socio-strategic evaluation, the process of reconciling the technical and social aspects is left to the Board and Shareholders' Committee to reach a consensus. The decision is then passed back to management for implementation.

In conjunction with the abovementioned forms of consultation, EA Networks is always available to liaise with the Energy Retailers to determine the expectations of their customers and quantify these in terms of desirable reliability indices as well as other relevant system or process improvements.

The EA Networks control centre accepts calls from consumers (but does not actively encourage them) and this forms another useful avenue for informal consumer research and feedback. Although the consumer is generally contacting EA Networks to report a power outage, the consumer's attitude is almost always courteous and understanding. There are relatively few instances of angry callers, and where appropriate the caller's concerns are documented and passed on to the relevant staff member. Field staff also pass on any constructive comments from consumers to the relevant staff members.

When requested, large users of electricity are contacted to ascertain their satisfaction with current service levels. The Commercial Division of EA Networks undertake this consultation. When service issues are raised, a range of alternative solutions are prepared to encourage the consumer to consider the service/cost trade-off. Typically, this has resulted in relatively minor changes to the status quo.

3.3 Customer Service Practices

EA Networks looks at customer service from two key perspectives:

1. Our core role of providing electricity.
2. Customer initiated work - in particular New Power Supply, New ICP Connections, Fibre Connections and Complaints Management.

Our core role of providing electricity

Within our bi-annual survey, EA Networks seeks feedback from customers across Mid Canterbury in the following areas:

- Minimising outages.
- Being a reliable and trustworthy organisation.

- Using modern technology.
- Using efficient operating procedures.
- Communicating with customers.
- Caring about the environment.

Customers are asked to rate how much they agree with each of the above statements.

In addition to this, customers are asked an overarching customer satisfaction question "Overall, how satisfied are you with EA Networks in relation to the provision of electricity and fibre networks, reliability of power supply, quality of communication, and reputation).

The 2023 customer satisfaction result was 90% satisfaction across this generalised question.

Customer initiated work

For customer-initiated work, EA Networks measures:

- Customer Easy Score – Based on recent experiences for a particular service, how easy or difficult was it to interact with EA Networks?
- Customer Satisfaction – Was your (specific service) completed to your satisfaction?

The results from the bi-annual survey are included in section 3.2.

Customer service levels

In the absence of a Customer Charter, EA Networks is guided by Service Level Measures as outlined in the Default Distributor Agreement. These include:

Frequency of interruptions:

- Urban – No more than 4 unplanned service interruptions per annum.
- Rural – No more than 10 unplanned service interruptions per annum.
- Remote Rural – No more than 20 unplanned service interruptions per annum.

As EA Networks is a community owned organisation, the intention is to put in place and publish a Customer Charter for inclusion in the AMP Disclosure, 2026.

Complaints Management

EA Networks is a member of the Utilities Disputes Complaints Management Scheme. Our complaints process is documented on the EA Networks website https://www.eanetworks.co.nz/contact/your-feedback/.

Customer complaints are directed to the Customer Engagement Manager, who captures the complaint in EA Networks customer management system (CMS). From here, the following steps are undertaken:

1. Formal acknowledgement of the complaint (if not already done so over the phone), within two working days of the complaint being received.
2. The customer is advised of EA Networks complaint management process, including that there is a 20-working day timeframe for EA Networks to resolve their complaint and if not done to their satisfaction, they are able to contact Utilities Disputes.
3. If the complaint is resolved, then we update our CMS (Salesforce) and close the complaint.
4. If resolution cannot be reached, EA Networks advises of the next course of action, being to contact Utilities Disputes.

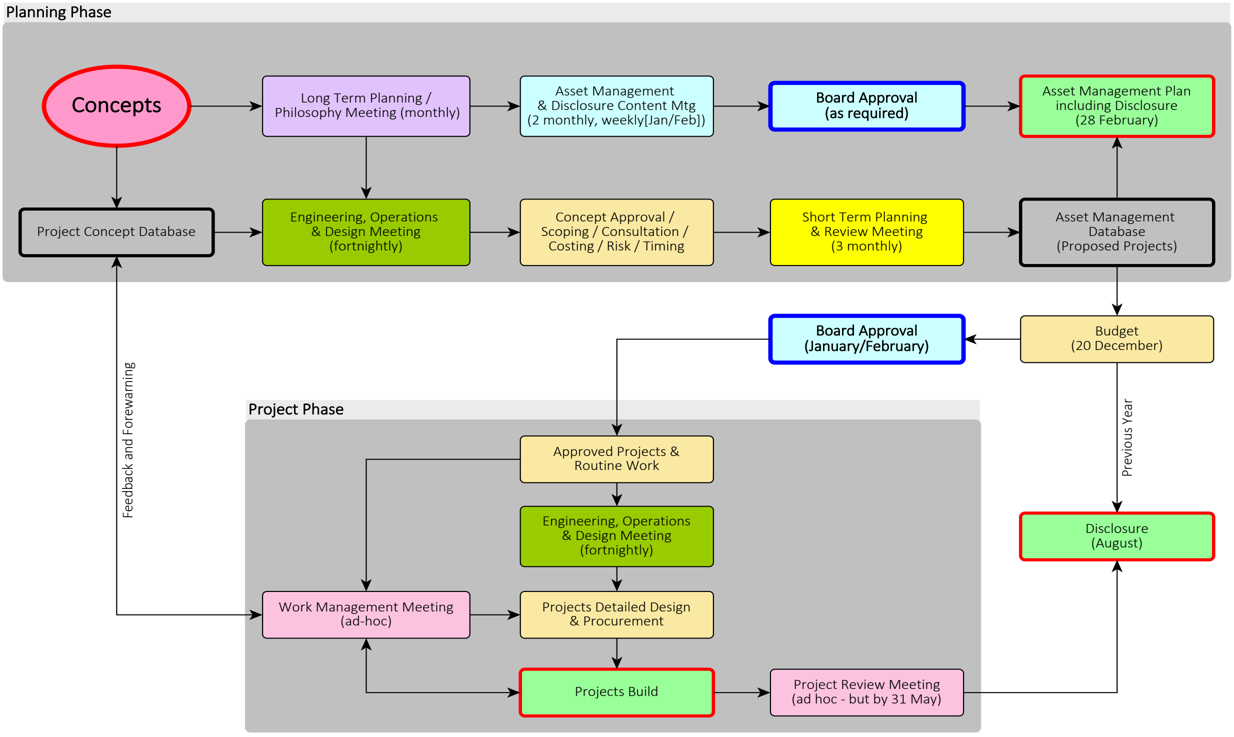
EA Networks also includes Utilities Disputes information on all email correspondence within the standard signatures and on quotes for New Power Supply applications.

3.4 *Strategic and Corporate Goals*

Strategic Objectives

We have refreshed our strategy during 2024, which is centered around a purpose of 'Enabling our Region' which means:

- Deliver smart, connected and reliable networks.
- Ensure we can safely respond when communities need us.
- Attract, value and retain committed and engaged people through meaningful careers and a vibrant culture with an owner's mindset.
- Remain locally owned and operated to enable prosperity and liveability in our region.
- Be a relevant and agile customer centric organisation with a strong brand reputation.
- Deliver sustainable financial and environmental performance through diversified infrastructure and optimised delivery.



The strategy has been updated in the context of serving the current and future needs of our customers and responding to the challenges of our evolving industry, as discussed below.

Commitment to Our Customers

Our customers define our success. As a co-operative, we align our strategies with the best interests of our customer shareholders, eliminating the typical tension between shareholders and consumers. This enables us to focus on delivering strong customer outcomes that drive regional economic growth. We are successful if our customers are successful and have access to energy where and when they need it.

An Evolving Industry

In line with the strategic aspirations above, we plan to meet customer and industry expectations to operate a future-fit, digital network in an increasingly complex environment and deliver the expected needs of efficient network operations and asset management, decarbonized process heat and transportation, as well as enabling connection of fluctuating renewable solar generation and flexible demand.

Our focus for the first three years of this AMP is to replace or strengthen core systems, including replacing the

GIS platform and considering the replacement of our Enterprise Resource Planning (ERP) system. Once these foundations are in place, we will progress to developing include further the integration of electricity-specific systems, including the Advanced Distribution Management System (ADMS).

Given the climate of decarbonisation driven by climate change targets, the electricity sector expects a diversity of network investment and capability development drivers out to 2050. Customers will seek new services and expect a continuation of reliable and affordable network connections. These drivers include:

- the decarbonisation of transport,
- process heat conversion to varying degrees between biomass and electricity,
- population growth resulting in both green-fields and in-fill development,
- new commercial or industrial point loads (e.g. data centres, hydrogen infrastructure),
- residential and commercial gas conversion (only to a minor extent in Mid-Canterbury),
- utility scale and roof top solar generation,
- accommodation of battery storage and flexible demand solutions,
- climate adaption requiring changes to assets,

and the need for investment to:

- improve LV visibility, and
- implement Advanced Distribution Management System functionality to manage the influx of distributed energy resources (DER) and make best use of network capacity.

These are largely new drivers that the sector has not experienced before to the greater extent expected. There is still significant uncertainty related to the timing and scale of these drivers, which affects EA Networks' ability to predict load growth and investment requirements, particularly further out in the future. Development of our load forecasting models is underway to respond to these challenges.

People and Safety

Our ability to deliver the Asset Management Plan and its success relies on our people having the capability and capacity. We must maintain a strong employer value proposition (EVP) that allows us to attract and retain people. Our focus is on developing employer value proposition including:

- Ensuring fair and competitive remuneration that aligns with industry standards.
- Enhance employee satisfaction, productivity, and retention through comprehensive benefits.
- Foster a culture of wellbeing, supporting both physical and mental health.
- Promoting our values and driving consistency in behaviours.
- Strengthen EA Networks reputation as an employer of choice.

We are committed to ensuring the safety of its customers, employees, contractors, and the public. We provide a safe and healthy workplace for our people and contractors that enables us all to function and deliver great outcomes, in the provision of a safe and reliable network for our community. Our strategy is to deliver on our vision and values through:

- Leadership and Culture - We will support leaders in their approach to a positive safety culture, behaviours, attitudes, and work processes.
- Hazard and Critical Risk Management - Our focus is on understanding our critical risks, implementing all required risk controls, and ensuring all of our workers are equipped with enough knowledge, systems and processes and the right mindset to work safety in the business.
- Suitable Systems and Assurance - We will take a consistent approach to safety across our business, which means our safety systems and documentation need to be simple, fit for purpose, user friendly and accessible to everyone.

3.5 *Network Service Levels*

The overall level of system reliability can be measured in many ways that are combinations of the number of interruptions, the length of interruptions, the frequency of interruptions, the number of consumers affected by the interruptions, the total number of consumers, and the total length of lines. These parameters are used to disclose a range of performance measures which are used for comparison with other, similar, companies.

The following published parameters are used to measure EA Networks' performance in comparison to other Power Companies (see Appendix A for explicit definitions):

Consumer Service Levels:

System Average Interruption Duration Index

SAIDI	=	Sum of (number of interrupted consumers x interruption duration) / Total number of connected consumers

System Average Interruption Frequency Index

SAIFI	=	Sum of (number of interrupted consumers) / Total number of connected consumers

Customer Average Interruption Duration Index

CAIDI	=	Sum of (number of interrupted consumers x interruption duration) / Sum of (number of interrupted consumers)
Total Interruptions	=	Sum of (number of interruptions)

The above indices reflect a measure of continuity of supply and supply restoration time to individual consumers. While SAIDI largely depends on restoration time, SAIFI is a measure of outages – which depend on the planning, design, and condition of assets. While it is possible to control these indices to an extent, it is not always feasible or practical to do so. As examples, extreme weather conditions and vehicle vs. pole collisions can significantly influence these parameters.

Asset/Financial Performance Levels:

Faults per 100km	=	100 x Sum of faults at a particular voltage and line type / Sum of (length of particular voltage and line type) in km
Fault Restoration	=	Maximum time taken to restore power to the EA Networks network after an unplanned interruption.

Electricity (Information Disclosure) Regulations are designed to ensure that Network Line Companies provide an appropriate level of reliability and security of supply to their consumers.

3.5.1 Target Level of Service

While ultimately it is consumers' requirements and financial commitments that drive work, possibly altering system reliability, the Asset Management Plan is based upon meeting or exceeding a set of predetermined targets.

It should be noted that the statistics used to measure performance against these targets could vary significantly from year to year due to the random occurrence of a single major outage, seriously weighting the overall statistic. Further analysis by EA Networks will seek to identify trends in underlying system reliability so that appropriate management responses can be taken.

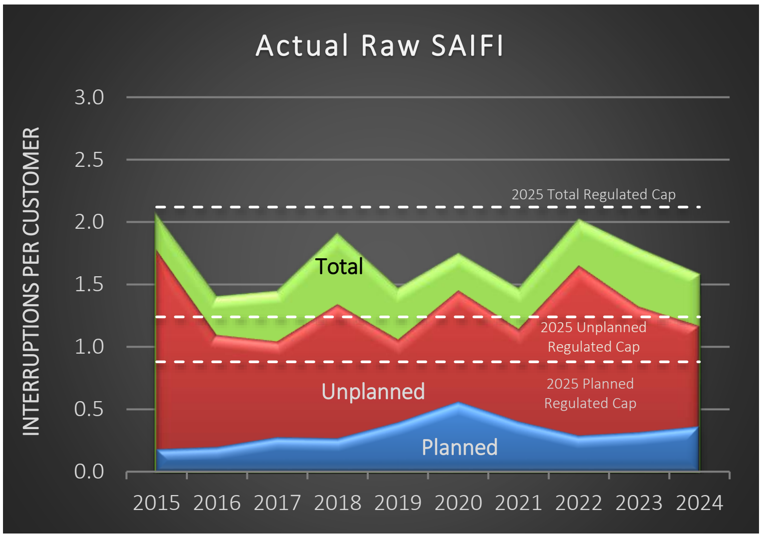
2025-26 Reliability Forecast : Target			
Index	Unplanned	Planned	Total
SAIDI (min)	87.4	247.7	335.1
SAIFI (p.a.)	1.24	0.88	2.12
CAIDI (min)	70.2	281	351
Faults/100km			10

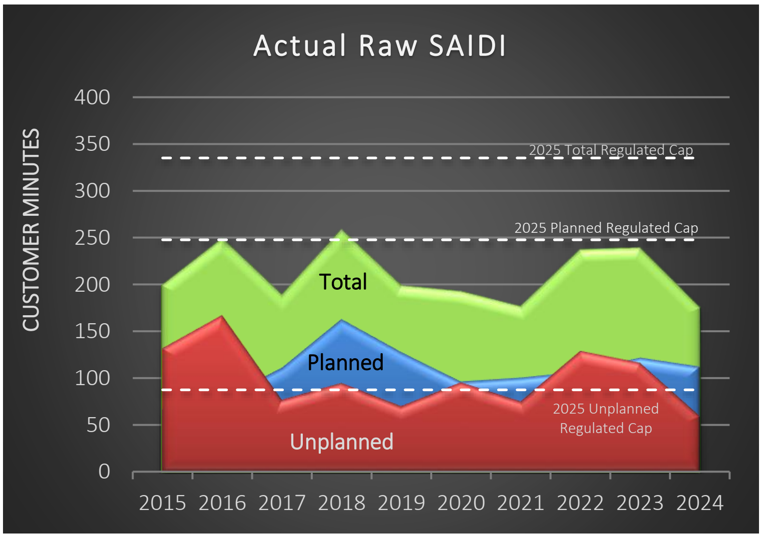
Note: SAIDI and SAIFI are the normalised regulated limits (caps) for DPP4, CAIDI is mathematically derived from those limits but is not directly regulated. Planned targets are the total five-year DPP4 allowance divided by five. Faults per 100km is non-regulated.

The regulated targets are set by:

- examining the historical performance of EA Networks,
- normalising the annual performance statistics to expose only the underlying levels of reliability.

Normalisation is a somewhat complex process to remove/cap the impact of significant outage events that would otherwise distort background reliability. The cap for normalised unplanned performance is set at two standard deviations above the ten-year (2015-2024) average performance (the regulatory target).



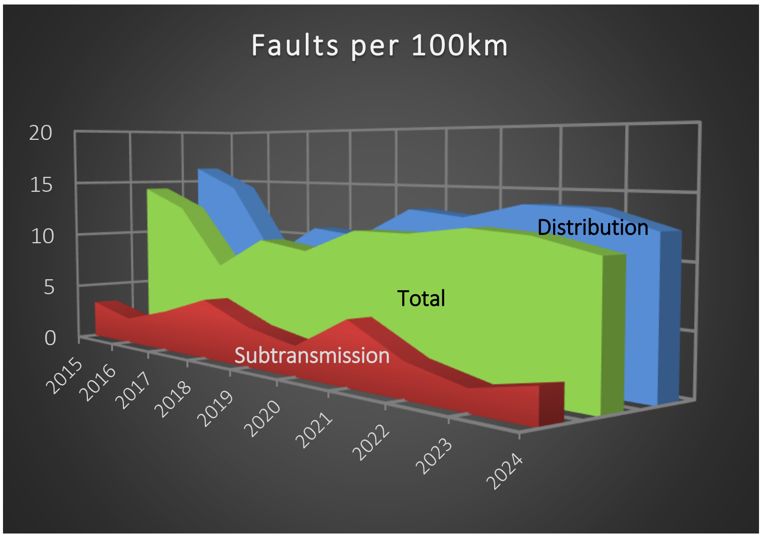


When significant amounts of capital are being spent on development, it does not necessarily follow that dramatically higher levels of reliability will occur. In fact, at times through the 11 kV to 22 kV conversion process, security is temporarily lowered as previous tie points must remain as an open point because of the voltage difference. In the long term, security will increase for most consumers and EA Networks are confident this will have a positive effect on reliability (all new assets are designed to meet security standards while a range of existing ones do not meet them). There has however been no effort made to mathematically quantify the likely increase in reliability in this plan due to the complexity and effort required. Future plans may attempt to provide analysis of this data thereby influencing targets and future investment in reliability and security, with consideration of the price/quality trade-off and levels of service expected by customers.

The SAIDI and SAIFI charts above illustrate EA Networks' actual historical performance and overlaid are the regulated caps (normalised for unplanned). The faults per 100km chart shows the distinctly different historical performance of the sub-transmission and distribution networks. A fault on the sub-transmission network impacts more consumers than the distribution network and is therefore designed and maintained to be more resilient.

The targets are reviewed annually by management, the Board, and the Shareholders' Committee to ensure that they are relevant and reflect consumer feedback accurately. These targets assume *severe weather events* (admittedly undefined) are excluded from the averages.

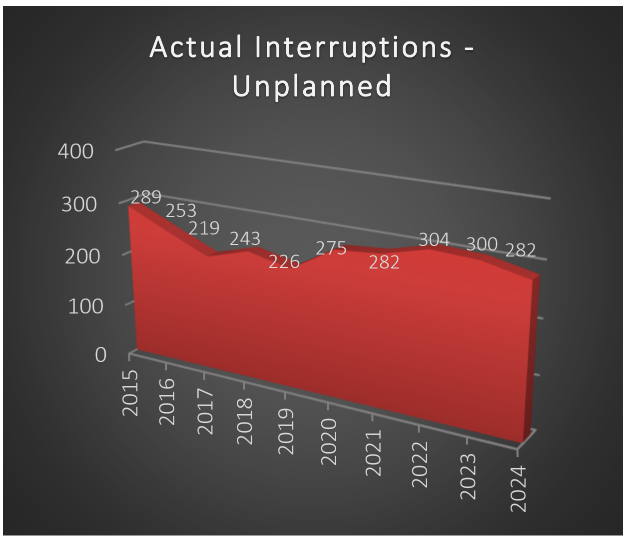
The Hexagon Geographic Information System (G/Technology) that EA Networks uses, can *trace* the network to determine which connections are without power for any open/close combination of switches and fuses. The Aspentech Advanced Distribution Management System can also do this. The results of these analyses are fed into the Faults system (to be supplanted by the Aspentech Outage Management System) that records each outage against individual connections. This system can then be interrogated to establish performance over any time scale at each connection.

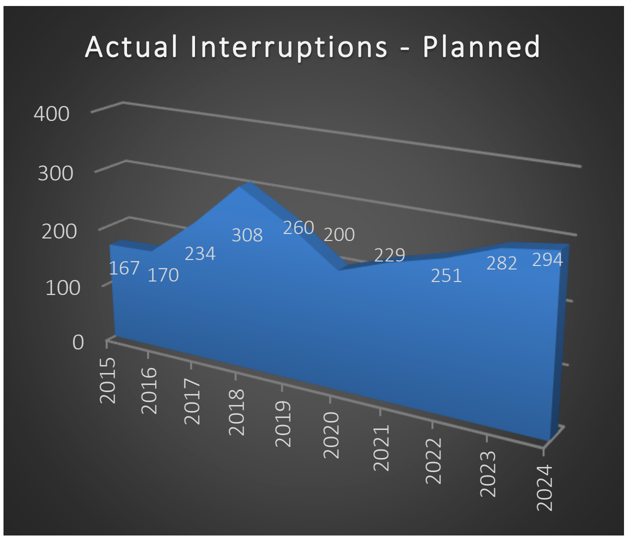


EA Networks have additional detailed targets. The following tables provide some of these.

Faults per 100km: Target			
Year	66kV & 33kV Lines	11kV & 22kV Lines	All Lines
2025-28	3	11.5	10
2029 – 2035	< 3	< 11	< 10

Number of Interruptions: Target			
Year	Unplanned	Planned	Total
2025-28	230	270	500
2029 – 2035	< 230	< 270	< 500





The number of interruptions is an absolute value that varies with both unplanned activity (fault) as well as planned activity (construction or maintenance). The marked increase in planned outage numbers in 2017 and 2018 was caused by a suspension in live line working which also impacted the 2018-19 year. EA Networks has now returned to live-line working for specific high-impact work which would otherwise have significant impacts on customers. EA Networks' revised live-line risk assessment justification has safety and customer impact at its core. The criteria for live line use are now more stringent and this will mean higher ongoing level of planned outages than seen historically. The 2020 year saw lower levels of planned outages as the risk of a breach became apparent. During the last quarter of the 2020 year, most planned work was suspended. The regulated allowance for planned SAIDI and SAIFI has been increased to allow network construction, renewal and maintenance to proceed, and EA Networks has made use of the planned outage allowances for completion of work programmes and projects, evidenced by the increased number of planned interruptions from 2021 onwards.

The number of interruptions is probably the simplest measure of reliability available, as zero interruptions means SAIDI and SAIFI would also be zero.

Network Performance Target Comparisons

The performance achieved by the EA Networks network is acceptable within its peer network line companies. Although EA Networks can improve its performance, the medium-term target for the critical indices is to be better than the median performance of all New Zealand power companies and in the top third amongst its predominantly rural peers (measured by percentage of urban network and percentage of underground cable).

The following table compares EA Networks' 2023 performance targets with the industry performance as a whole and then peer companies. The *Industry Average* is the average value for all disclosing distribution lines companies. The *rural average* is the average value for those companies that have:

a) *Underground peers* (10 EDBs) have between 19% and 28% of *Total Circuit Length for Supply* as underground. EA Networks have 25.6% underground supply network.

b) *Urban peers* (14 EDBs) have between 1.2% and 9.8% of their overhead network in urban areas. EA Networks have 3.0% of their overhead network in urban areas.

Comparison of Target Performance Indices: 2025

		EA Networks 2025 Target	2018-24 Industry Average	**% of Industry Average**	2018-24 All Peers Average	**% of Rural Peer Average**
SAIDI	**Total (mins)**	335 248 Planned 87 Unplanned	291	**115%**	344	**97%**
SAIFI	**Total (interruptions)**	2.12 0.88 Planned 1.24 Unplanned	2.27	**93%**	2.61	**81%**
Faults/100 km	**Total**	10.0	16.67*	**60%**	12.64	**79%**

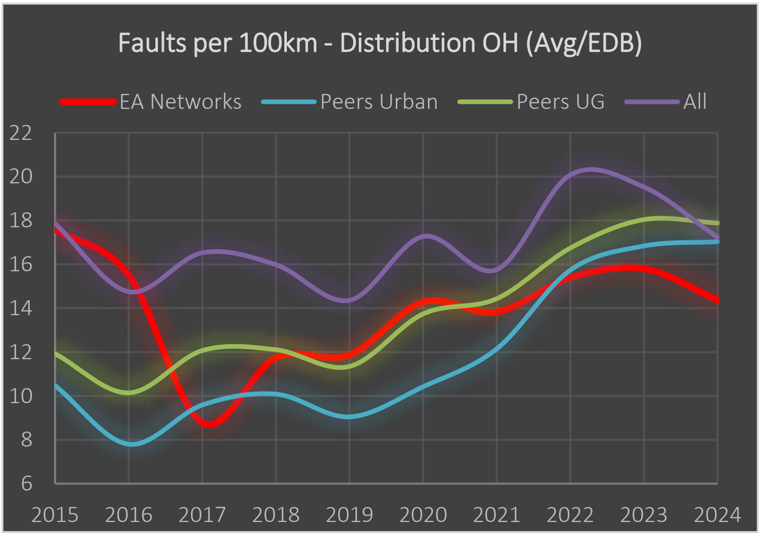
* This value is calculated by summating all faults from 2018-2024 (121 437) multiplying by 100 and dividing by 7 years then dividing by the sum of all *Total Circuit Length (non-LV)* from 2024 (104 030 km).

The predominantly rural group of 17 peer companies supply 38% of the total consumers in New Zealand using 64% of the total lines in New Zealand that have 46% of the total distribution network value. The *% of average* is an indication of EA Networks target level (lower is better, and better than average is less than 100%).

Comparing EA Networks 2025 targets with the actual industry performance (disclosed as of March 2024), it is apparent EA Networks' reliability targets are appreciably better than the average performance of peers and all other companies except for total SAIDI. If the targets can be achieved regularly it will reflect in a newly revised target in the following regulatory period. This will probably reflect in a lowering of the average score percentage when compared to the industry average. This will provide useful feedback to the stakeholders allowing them to consider how much reliability is sufficient or even what the added cost of reliability well above the industry norm may be and whether they wish to pay that cost in the future.

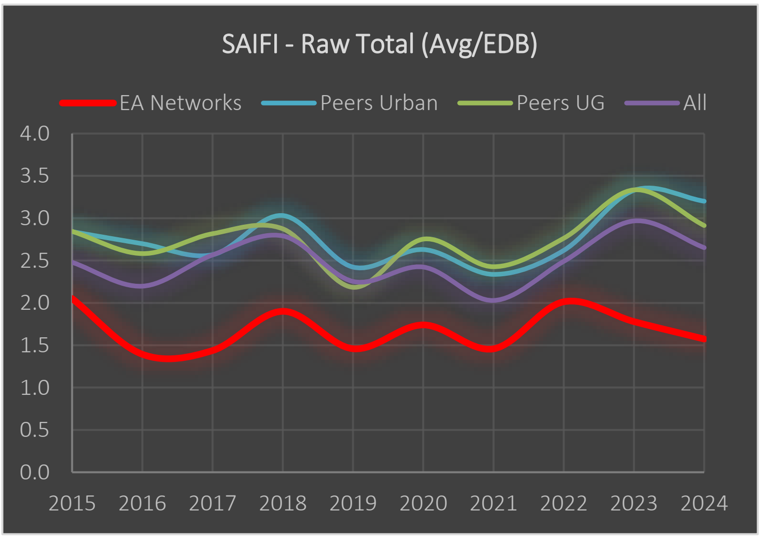
There continues to be reasonable amounts of planned development and maintenance work. Planned SAIDI and SAIFI is one of the few outage reasons that EA Networks has direct control over. If stakeholders indicate that the duration or frequency of planned outages are above tolerable levels, then EA Networks could use less efficient but lower outage duration approaches to doing planned work. These approaches could include:

- employing additional contractors or staff to get much more done during any given outage or shortening the outage,
- using live line working techniques to do some work that is currently done de-energised,
- more widespread use of generators to supply load that would otherwise be interrupted,
- building new lines on routes not occupied by the existing lines (for example the other side of the road),
- converting more of its rural network to underground.



Although all these approaches are possible, there must be demonstrable advantages to employing them. Several of the approaches have been used – not always for lower outage duration during construction, but that has become a side benefit.

It must be remembered that the industry-wide *All* average values above include all of the urban network data which are not considered to be typical of EA Networks' peer companies. Another aspect of the EA Networks network is that one Transpower substation serves the entire EA Networks area. This is uncommon for the size of network load EA Networks carry. One of the consequences is that EA Networks takes the *risk of fault* on the additional length of subtransmission lines that are borne by Transpower in most other line company networks.



Historically, EA Networks has undertaken a lot of planned development work, and this is reflected in traditionally high planned SAIDI values. This will change now that 66kV line development work is expected to be minimal within the period, although 11kV to 22kV conversion work still has an impact.

EA Networks averaged EA Networks averaged 11.06 planned interruptions per 100km of lines in 2023-24 compared to an average of 14.12 for the industry (78% of the industry average). This is an increase for both EA Networks and the industry generally. Planned work has an increasing focus on preventative work and safety. This can mean an increase in the number of planned outages over time. It is anticipated that this planned outage rate will vary in proportion to the level of overhead line development work and line maintenance. Line development is largely dictated by on-going load growth.

Internal reporting and targeting of performance indices are more detailed than those discussed here. EA

Networks management report performance against these to the Board each month and they take an active interest in not only the nature of the targets but also how they are influenced by a variety of factors.

There are other financial and technical indices published as part of the disclosure process, but these can be very misleading without a great deal of technical analysis using background information about each company's load types, locations, profiles, and seasonality. In future plans, more detailed cross-company comparisons may be attempted if significant asset management benefit is seen by using these indices.

As part of its on-going commitment to improve system performance, the Company is in the process of implementing an advanced distribution management system (ADMS). This system has the potential to reduce response times significantly. Future plans will detail when and how these new features facilitate these improvements.

As part of this effort to improve its service performance, EA Networks has started to implement an analytical approach to identify various network trends. Several initiatives will be possible as the ADMS system becomes fully implemented. Granular analysis will be possible at ICP level upwards. In future, feeder performance comparisons will be included as part of a regular reliability analysis.

Distributor Agreement

As of 1 April 2021, and updated in December 2024, EA Networks use the Electricity Authority's *Default Distributor Agreement* with energy retailers. This outlines a number of connection service standards that EA Networks undertake to meet.

Service guarantees to consumers include:

- To provide written notice 4 business days in advance of planned maintenance interruptions.
- To electrically connect a new connection to the network within 5 working days, provided all necessary equipment is in place and a *certificate of compliance* and *record of inspection* is completed.
- To advise requirements for new connections within 5 working days and connect on agreed day provided all requirements are met.
- To disconnect or reconnect for safety at an agreed time, or within 8 business hours for urban addresses and 12 business hours for rural addresses from request – subject to safety approvals.
- To respond with findings to a complaint of power quality within 25 working days of notification.
- For each network connection point, to limit the annual quantity of unplanned outages and the delay to restoring power supply after an unplanned outage to:

Location	Unplanned Outage Service Standard	
	Outage Duration	Annual Outage Count
Urban	<3 hours	≤ 4
Rural	<6 hours	≤ 10
Remote	<12 hours	≤ 20

3.5.2 Notices Advising of Interruption

This section details EA Networks' consumer outage communications capabilities, both current and proposed.

Existing Consumer Communications

EA Networks have recently configured the ADMS system in combination with the Customer Relationship Management (CRM) system (Salesforce), for consumer communications regarding both Planned and Unplanned Interruptions via the Power Outages page on our website. Interruption areas are identified with a polygon on a map with road descriptions but are appropriately anonymised to avoid identifying a small group of customers. Interruptions affecting a small group of customers will not be displayed.

Planned Interruptions

After tracing the planned network outage in the Advanced Distribution Management System (ADMS) to identify the affected customers, EA Networks informs the Registry using the EIEP5a protocols along with displaying the planned interruption on EA Network's website - https://www.eanetworks.co.nz/power/outages/. The Registry communicates this notification information to Retailers so they can advise their affected customers of the upcoming outage. Future, cancelled, and recently completed planned interruptions are displayed on the Power Outages page.

Unplanned Interruptions

Unplanned interruptions both current and recently completed are communicated via the Power Outages website in near real time (as soon as they are activated in the ADMS system by the Network Controller). Updates to estimated restoration times are added as information becomes available. EA Networks will attempt to inform the Registry, but this is not always possible because of the timeframes involved. For smaller events affecting a small group of customers there may not be an indication on EA Networks' website to manage the potential for this public information to be misused.

EA Networks Planned Changes to Consumer Communications.

Planned changes are to begin communicating interruption information via SMS text messaging to customers who opt-in to this function. A pilot of this capability is being prepared.

3.5.3 Forecast Level of Service

The targets set in the previous section indicate the normalised level of service that EA Networks would expect to deliver in most years. Meeting these targets with actual (non-normalised) performance would be considered a good, although not extraordinary, year.

A normal year will have external influences impact on the actual level of service EA Networks delivers and it is probable that the normalised target will be exceeded by actual (non-normalised) performance in some years.

The future performance forecast uses the normalised regulatory targets to provide a realistic expectation of future performance. The regulatory targets have been calculated based upon historical fault performance and reasonable expectations for planned work (see table below).

It is anticipated that these targets should be met by normalised performance most years, and, on occasion, actual (non-normalised) unplanned performance may be below these regulatory caps. Planned performance should be below these targets every year.

Future Performance Target/Forecast (normalised): 2026-35

Indicator	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Default Quality Path Limit
SAIDI Planned (mins)	248	248	248	248	248	<248	<248	<248	<248	<248	**247.7** [1 2]
SAIFI Planned (#/yr)	0.88	0.88	0.88	0.88	0.88	<0.88	<0.88	<0.88	<0.88	<0.88	**0.88** [1 2]
SAIDI Unplanned (mins)	87	87	87	87	87	<87	<87	<87	<87	<87	**87.4** [1]
SAIFI Unplanned (#/yr)	1.24	1.24	1.24	1.24	1.24	<1.24	<1.24	<1.24	<1.24	<1.24	**1.24** [1]
SAIDI Total (mins)	335	335	335	335	335	<335	<335	<335	<335	<335	-
SAIFI Total (#/yr)	2.12	2.12	2.12	2.12	2.12	<2.12	<2.12	<2.12	<2.12	<2.12	-
Faults/100 km	10	10	10	<10	<10	<10	<10	<10	<10	<10	-

[1] These are the Commerce Commission Default Quality Path (DQP) limits. These limits are *normalised* and remove a proportion of aberrant fault events. The performance targets are *non-normalised* and include all events.
[2] These are 5-year cumulative limits averaged over each of 5 years.

Over recent years, EA Networks has had a program of installing additional remote controllable switching points within the Network. Considerable effort has been expended to enable the remote-control of these devices. While some devices are installed specifically to improve network segmentation, most are installed as part of other works – most commonly an overhead line requiring rebuilding (either overhead or by underground cable). As a result of this approach, devices tend to be scattered around the network rather than concentrated in specific areas. While each device helps to improve reliability, large improvements are not seen until the population reaches a critical mass or a specific area is completed. EA Networks are hopeful of a general improvement in reliability due to the increase in switching points. The population is on the cusp of being extensive enough to see wholesale improvements, particularly with remote-control and indication available.

It has already been noted that a lot of the *Quality of Supply* expenditure in this plan will increase security of supply for relatively rare but very consequential events. If none of these events have occurred in recent years or occur in the disclosure year, then the future impact on the level of service of this expenditure may not be particularly measurable/visible. Having said that, it is expected that the increases in security will have considerable advantages to the consumer in service level improvements, but those improvements are difficult to directly quantify.

For many years, EA Networks experienced load growth well above the national average load growth. This has resulted in rapid expansion of the network's load-serving capability. In meeting this huge load growth, it has often not been possible to fully complete the finer details of the job. For example, fuses are uprated to gas switches or reclosers and this new equipment has remote-control capabilities. Unfortunately, time and the pressure of other load growth requirements meant that effort could not be devoted to completing the remote-control aspect. As load growth tails off, time and resources are becoming available to complete these projects with high returns in reliability and safety.

Similarly, load growth has bought about the requirement to convert parts of the network from 11 kV to 22 kV operation. Again, time and resource constraints mean that only the practical minimum is converted to meet the increased load at that time. This has resulted in what was once a highly meshed network having open points introduced because of the different voltages. With the reduced new rural connection growth currently being experienced, EA Networks are now in a position where resources can be allocated to go back and rectify the reduced security introduced by the former load growth requirements. As this work is not directly caused by load growth, it is classified as a reliability improvement. In reality, it is only returning security to previous levels.

In a similar vein, EA Networks has a policy of converting urban overhead lines to underground when they fall due for condition-based replacement (the *Urban Underground Conversion Programme*). This work is classified as *Asset Replacement*, however, at times it is appropriate to go further than the absolute minimum, e.g. convert a further section of line so the underground area become contiguous or extend it further to remove the risk from a significant tree plantation. These extensions are classified as *Reliability Improvement* when often they are *Asset Replacement*s done in advance of the actual need.

There are many types of faults that are almost impossible to prevent without disproportionate cost – particularly in rural areas. Trees falling through overhead lines is one; as the tree regulations do not permit obligatory tree control beyond a set radius of the line. A tall tree can fall from across the road (well outside the trim radius) and cause considerable damage to any overhead line. The only way to avoid this risk is to build outside the road corridor (easements and associated cost and access difficulties) or underground conversion of the line (cost). EA Networks are currently talking to tree owners where an overhead line is within the fall distance of their tree. EA Networks are encouraging these tree owners to consider the ramifications if their tree damages EA Networks' line and encouraging them to take appropriate action.

3.5.4 Significant Recent Events

It is considered worthwhile to document any recent events that have had a significant impact on network performance and asset management strategies. The following events are ones that have caused sufficient impact as to cause (or potential to cause) network performance to exceed targeted values.

December 2019 Lightning Event

In December 2019, a significant lightning event took place that caused many small-scale outages. This had a significant SAIDI impact for the month (22 minutes compared to about 6-10 minutes for an average month). The event was the longest and most intense lighting in living memory and lasted about 12 hours continuously. Large lightning events are rare in Mid-Canterbury and there is a low benefit/cost ratio in attempting to make the network more lightning resistant.

December 2019 Rangitata River Flood

Around the same time as the lightning storm, torrential rain in the headwaters of the Rangitata River caused an extremely flood event. The two 11kV crossings of the river were washed away (having stood for around 40 years) and Transpower also had at least one tower washed away and significant damage to eight others.

Click picture for link to article.

Generators were introduced to supply the network beyond the failed 11kV crossings. The total SAIDI *cost* is in the order of 10 minutes. Repair of one of the crossings was achieved within weeks while the second much longer crossing was considerably more challenging. The second crossing was eventually reinstated in May 2020 after several engineering challenges and the COVID-19 lockdown difficulties.

Now that the network is fully restored, options for increasing the resilience of the affected network are being examined.

January 2021 Wind Event

In January 2021, a moderately strong wind blew through the Ashburton District, and this caused a poplar tree to fall over a roadway and contact the 66kV line on the other side of the road. The line is one of two supplying Northtown substation, and, under normal circumstances, this would have caused the line to trip and the other line feeding Northtown to supply the load. Unfortunately, a setting error in a line relay at Northtown triggered the Northtown 66kV bus to trip and this caused about 5 000 consumers to lose supply. The SAIDI impact was low as it only took about 10 minutes to restore supply, but the SAIFI impact was 0.254 (non-normalised) and this represents about 20% of the annual maximum limit. Remedial processes were implemented as a consequence of this event and include: peer review of setting changes before application, more systematic application of standardised setting files to relays, and a review of existing in-service setting files to ensure anomalous settings are detected.

July 2022 Wind Event

A significant wind event from 17 to 19 July occurred, with strong winds impacting the plains resulting in outages totalling 12.92 SAIDI minutes and 0.083 SAIFI. Normalised to the 24-hour cap this resulted in SAIDI of 1.88 minutes and 0.017 SAIFI.

August 2022 Wind Event

A major wind event occurred on 6 August, with high winds funnelling out of the Rakaia and Rangitata gorges. The event started on the night of 5 August and continued on 6 and 7 August, causing numerous outages, many tree related. This caused outages totalling 32.93 raw SAIDI, our biggest single event for several years but normalised to 1.17 SAIDI minutes. Raw SAIFI of 0.080 was normalised to 0.012.

October 2023 Wind Event

The “red warning” high wind event for Canterbury on 14 and 15 October had a manageable impact on our network and customers but was intensive because of high northeast winds. A total of 15 faults occurred, affecting 1063 customers and caused raw SAIDI of approximately 10.2 minutes normalised to 1.17 SAIDI minutes. Raw SAIFI of 0.05 was not normalised.

3.6 Network Security Standards

3.6.1 Introduction

Electrical supply security can be generally defined as the ability of a portion of the electrical network to resist loss of supply to consumers. EA Networks have adopted a security standard that is comparable to the *Security of Supply in NZ Electricity Networks – 2013* prepared by Electrical Engineers Association of New Zealand Inc. It is EA Networks’ assessment that the comprehensive standards that have been adopted meet, and in some circumstances exceed, the above-mentioned standards.

As previously discussed, security is normally defined in terms of *n-a* where *n* is the number of possible supplies for a particular consumer or group of consumers, and *a* is the number of these supplies whose loss can be tolerated while still keeping full capacity available. If *n* is one, then the loss of one supply (*a*=1) means no supply. If *n* is two, the loss of one supply (*a*=1) will mean at least 50% of the total capacity is still available, and if the load is less than 50% of the total supply capacity it can be said to have *n-1* security. If the load is more than 50% of the total supply capacity, then only a portion of the load has *n-1* security (some load will be turned off). For example, Ashburton zone substation has a nominal total supply capacity of 40 MVA (two x 10/20 MVA transformers), allowing for loss of one transformer means this substation has a *firm capacity* of 20 MVA. For all practical purposes, this substation is considered a 20 MVA substation, so following the loss of any one item (transformer, incoming line etc) to be at *n-1*, then a *full* 20 MVA of load can be supplied. Where additional switched capacity is available, the firm capacity can be considered as the overload capacity of the smallest transformer or line (if there is more than one) for the duration of switching excess load to other substations. This overload capacity can easily be 20% for typical switching times (24 MVA for a 20 MVA transformer).

Very secure loads can be configured to have *n-2* security, which means two supplies can fail and the supply capacity can still be greater than the load. EA Networks have no consumers with any assurance of *n-2* security. The more secure a system is, the more reliable it tends to be.

Another term that requires definition is the *firm* capacity available to a consumer. The *firm* capacity is the total supply capacity with the largest of any possible supplies out of service. *Firm* capacity can be either *no-break* or *break/switched*. *No-break* would infer that two supplies are operating in parallel, and no loss of supply is experienced when one supply fails. *Break/switched firm* capacity is when the supply fails and the alternative unit/supply must be switched into service to restore the supply. For the purposes of this plan, *no-break firm* capacity is generally only used when referring to parallel zone substation transformers and *firm* capacity without a qualifier will be the alternative supply capacity available after switching.

Environmental security has two aspects: (1) the effect of the environment on the electricity network and (2) the effect of the electricity network on the environment. Both are considered under the environmental security standards.

The resilience of the network is typically increased with additional security. Some projects are driven solely by the need to improve resilience and do not result in any additional security of supply but do ensure the system components can more adequately resist failure or recover from it.

3.6.2 General

When the EA Networks network is maintained or upgraded, the electrical configuration of the network can change. This rearrangement could lead to individual connections or groups of connections having a different level of security of supply. An example of this is with the continuing conversion of the distribution network from 11 kV to 22 kV. This work was initially triggered by increasing loads. As parts of the network have been converted, the lack of 11 to 22 kV conversion on the boundaries of the converted area led to a temporary reduction in security until further parts of the network are converted.

The security level of any one connection will not permanently decrease over time. The only exception to this is at dedicated, high voltage, single user connection points, where security can be varied by agreement. For the purposes of this guideline, the term *permanent* means any period greater than 24 months.

The term *critical load* describes load that would be severely disadvantaged by an outage of more than about 90 minutes. Examples of critical load would include diabetics, hospitals, milking machines on dairy farms, retirement homes, lighting at night, refrigerated food storage, processing plants, etc. Non-critical load would include all air-conditioning, pumped irrigation, some types of industrial load (where they have discretion), commercial heating, and all water heating etc. For the purposes of this standard, critical load will be taken as 50% of the peak through/busbar load unless more authoritative information is available.

A significant proportion of the EA Networks network meets the adopted security standards. Proposals to improve the remaining portions are included in Section 5 – Planning Our Network. The dynamic nature of the subtransmission and distribution network in recent years (caused by significant development) has made thorough analysis of the areas that do not meet the security standards difficult. Engineering staff have been diverted to load-driven development rather than assessment tasks. All development will ultimately improve security levels. Additional effort will be required to identify non-compliant portions of the network, and these results will appear in future plans as they are completed.

3.6.3 Transpower Grid Exit Points

The main on-going requirement for Grid Exit Points (GXPs) will be that the firm transformer, or alternative feed capacity, will match or exceed the any-time GXP maximum demand. This criterion will mean that the failure of any single item of Transpower plant will not lead to on-going loss of supply under any conditions. Depending upon the Transpower failure, restoration of all load by switching within the EA Networks will occur within 90 minutes.

3.6.4 Main Subtransmission Ring Systems

Sufficient redundancy shall be designed into the subtransmission system to ensure no on-going loss of supply should certain credible contingency events arise. The following criteria define these contingencies:

- All load must be restored within 90 minutes of any single circuit becoming unavailable.
- For a single point failure affecting 2 circuits, critical load must be restored within 90 minutes and all load within the designated Connection Service Standard target time limit.
- No single point failure will affect more than two circuits.

Subtransmission system design shall allow for maintenance (including major component replacement e.g. transformers, circuit-breakers, poles, and conductors) to be carried out at appropriate times, without the above criteria being violated to any significant degree or for any significant length of time.

The precise level of redundancy built into specific parts of the subtransmission system depends on the likelihood of contingency events occurring, the costs of reinforcement, and the desired level of resilience. Each situation shall be treated on its merits and subject to financial/engineering analysis.

3.6.5 Radial Subtransmission

The radial subtransmission system comprises those parts of the network that act as spur supply systems for specific sites or connections. Currently these spurs include:

- Montalto Hydro Power Station, and Montalto33 Zone Substation,
- Highbank Power Station and Pumps (by agreement),
- Seafield Substation (by agreement with sole consumer),
- Dorie Zone Substation,
- Mt Hutt Zone Substation.

These sites have a single circuit supply (some in common with adjacent substations) and any failure will result in the need for a back-up supply via the 11 kV and/or 22 kV distribution system. The restoration of all load, after any one failure, must occur within the designated Connection Service Standard target time limit (unless agreed otherwise with the connected consumer e.g. Highbank, Mt Hutt, Seafield).

3.6.6 Zone Substations

The zone substation's function is to provide transformation from the subtransmission voltage to the distribution voltage. In performing this function, it is a critical element in the path from the GXP to connection. If it fails, the consequences are seen over a wide area and there are relatively few parallel paths to provide back-up supply. To minimise the risk at these substations, the following criteria have been developed:

- The capacity of any subtransmission or distribution busbar within a zone substation will not limit the operation of the network for credible network configurations.
- Except for bus-coupling devices, all zone substation switchgear can be worked on with only one other circuit element (i.e. electrically adjacent transformer, line etc) out of service.
- All zone substations normally supplying less than 2 000 connections shall permit restoration of critical load within 90 minutes and the balance within 72 hours under all credible *n-1* contingencies.
- All zone substations normally supplying greater than 2 000 connections shall have a no-break supply for all load under all credible *n-1* contingencies.

- Zone substations dedicated to an individual connection will have a security level negotiated with the electricity user supplied using that connection.
- All zone substations must be able to deliver nominal secondary voltage for *n-1* scenarios whilst delivering supply (except for Highbank, Mt Hutt, Seafield).
- The distribution voltage substation bus must be able to be used as a *through/linking* bus when the transformation is out of service.

In lieu of a second transformer at many of the high seasonal load, low consumer count, rural substations, a second spare 66/22 kV transformer was purchased (Carew) that can be relocated at any time to replace a failed unit. This unit also provides cover for a second failure while a faulty unit is either replaced or repaired. These types of repairs can take up to 12 months and a new transformer will typically require 9-12 months for delivery from order placement.

The resilience of zone substations is of critical importance and significant effort has been undertaken to ensure as many known risks as possible have been considered and factored in during design.

3.6.7 22 kV and 11 kV Distribution System

The overhead line distribution system is typically less reliable than the subtransmission system. There is significantly more length of distribution line, it is lower to the ground, and there are significant numbers of privately owned distribution lines connected to the same system (which are outside EA Networks' direct control for maintenance and tree control purposes). Rural underground cables offer a higher level of reliability, but they are still subject to reliability issues arising from being supplied via overhead lines or overhead lines being supplied from the cables. The urban underground reticulation has a much higher reliability than the rural overhead lines. The urban network is also heavily interconnected which typically allows faster restoration times.

EA Networks' policy of requiring all new connections (under 33kV) to the network to be by way of underground cable is helping to improve the reliability of the rural distribution system. Many consumers who now see the reliability and safety gains of having their on-property lines underground are voluntarily converting existing overhead lines to underground cable.

The only performance requirement for the distribution system is that the restoration of all load, after any one failure, must occur within the designated Connection Service Standard target time limit.

3.6.8 Low Voltage System

The low voltage system has levels of switched back-up in urban areas, with link boxes allowing low voltage feeders to be back fed for planned or unplanned outages. In rural areas, typically only a single LV feeder is available and interconnection to alternative transformers is not provided.

The only performance requirement for the low voltage system is that the restoration of all load, after any one failure, must occur within the designated Connection Service Standard target time limit.

3.6.9 Protection

The systems that detect and isolate either faulty equipment or external interference with electrical equipment have a large influence on the outcome of any incident. The systems that detect and isolate electrical plant when undesirable electrical situations arise is generically known as *Protection*. Protection systems generally measure AC currents and voltages to determine when an undesirable situation has arisen.

As a policy, new or rebuilt nodes on the subtransmission network will have protection systems that are in line with modern standard practice.

Protection systems for the EA Networks network will be designed to:

- detect faults between phases or between phase(s) and earth,
- allow plant to carry rated maximum load without disconnection,
- disconnect faulty plant from the system with minimum damage,
- disconnect faults quickly enough to avoid system instability,
- minimise the likelihood of personal injury or property damage,

- minimise supply interruptions,
- detect abnormal operating conditions which could result in plant damage,
- disconnect only the plant item affected,
- prevent damage due to through faults,
- operate with a level of reliability that can be economically justified,
- operate with a level of sensitivity that will not result in tripping of circuit-breakers at normal load levels.

Abnormal Conditions

For zone substation transformers the protection will be set to detect conditions that may lead to significant overheating and possible failure of equipment. Overload protection will be provided for subtransmission circuits only where potential system configuration could lead to sustained overload conditions.

Selectivity

The protection will be set so that when all protective relays and circuit-breakers are functioning as designed, the protection system will clear only the faulted equipment from the system.

If a circuit-breaker fails to operate correctly, it is desirable that the remaining equipment operates selectively.

Fault Clearance Time

Clearance times will be:

- limited so that damage at the point of fault is reduced to that economically justified by the increasing protection expenditure,
- such that the short time rating of equipment is not exceeded,
- short enough to ensure that system stability is maintained for all foreseeable fault conditions, where the fault is cleared by the main protection. It is desirable that this time is also short enough even when the fault is cleared by backup protection.

Risk to People

The protection system will always comply with the Electrical Supply Regulations. Particular attention will be paid to providing fast and reliable protection in urban areas.

Protection Reliability

Protection systems will be designed to have a high degree of reliability because of the extreme consequences of failure to operate.

Protection Security

Protection systems will be designed with a form of backup protection should the primary protection fail for some reason. This backup protection will be in line with industry standards.

3.6.10 Reliability by Design

To ensure some emphasis is placed on minimising the extent of any one outage, the target maximum number of connections on any one continuous section of network (no isolation within the section) has been defined. This provides guidelines limiting the number of consumers who have an extended outage while a fault is repaired (reducing SAIDI). In addition, the maximum number of consumers on a distribution feeder limits the impact of a feeder circuit breaker tripping on a fault (reducing SAIFI).

These design parameters ensure that the network can be restored as quickly as possible after a fault with as few consumers left without supply as possible. It also provides a degree of determinism about how many consumers should be affected by any on-going outage for the duration of a repair. This determinism does assume that the network can provide adequate back-feed capacity at every location on every feeder at all times of the year. This is not currently possible. Provided the repair does not exceed the Connection Service Standard target time limit, the performance standards have still been met.

The table below identifies the current guidelines for design.

These parameters also drive useful increases in resilience as the number of connections on a failed section of network will directly influence the impact of a significant event if it causes that section of network to fail. The resilience of neighbouring sections is therefore increased with the ability to isolate the failure and restore supply.

Indicative Target Number of Consumers per Electrical Asset				
	Design		Maximum	
	Urban	Rural	Urban	Rural
Radial Subtransmission	1500	1500	2000	2000
Zone Substation	1000	1000	2000*	2000*
Distribution Feeder	200	200	250	250
Distribution Segment	45	45	50	50
Distribution Substation	45	5	60	5
LV Feeder	20	4	25	4
LV Segment	10	3	15	3

Design – Maximum number of consumers connected to asset when asset is designed.

Maximum – Maximum number of consumers connected to asset during steady state operation. Once exceeded, redesign/reconfiguration required to reduce to design level.

***** For single transformer zone substations. Once zone substation consumer count exceeds the maximum limit, a second transformer is required.

The derivation of these targets has occurred over time and largely revolves around the historical impact of faults and how best to mitigate the outcome of those faults in future. With approximately 20000 ICPs connected to the network, a fault impacting 1000 ICPs is 5% of the total. If this single interruption lasts for 60 minutes, it adds 3 minutes to SAIDI (about 3.5% of the regulatory cap) and 0.05 to SAIFI (5.7% of the regulatory cap). It was decided to, by design, limit the impact of a 60-minute distribution feeder fault to less than one minute of SAIDI. SAIFI performance will also be improved by having fewer ICPs on each feeder. 20000 divided by 60 is 333 ICPs. To allow for feeder ICP increase, load growth, and feeder operational variability, at the date of design the upper limit is set at 60% of that value or 200 ICPs (~1% of total ICP count). The maximum ICP count has been set at 75% or 250 ICPs as a point at which consideration of feeder configuration should be examined. Above 250 ICPs on a feeder, there may be the need to address ICP count with alternative solutions to reduce single fault SAIDI and SAIFI impacts. The other ICP count targets are more pragmatic and reflect the current range of ICPs on the various parts of the network. The correlation of a rural distribution segment target (50) with an urban distribution substation target (60) reflects an attempt to have a comparable target for each of the ICP groups based upon maximum ICP numbers that would be off for the duration of a repair. Each of these groups could expect to be impacted by an initial feeder fault, but power should be restored by switching during the repair.

An evaluation of these consumer count targets is planned for 2025-26 to explore any current gap that exists between the target and actual number of consumers per electrical asset at a sub-transmission and distribution voltage level (i.e., LV excluded at this time). The analysis will approximate the view on any gap following implementation of the 10-year plan of projects and programmes, and an estimate of the investment required to close that gap. Significant contributors to closing the gap within the current plan are the Ashburton urban network centres and network cables projects, and rural switch installations. The outcomes of the analysis will inform the value of further investment, or the tailoring of the targets to a more appropriate level.

3.7 Network Power Quality Standards

The principal aspects of quality are voltage variation and control, and the voltage waveform. Ideally, it is EA Networks' intention to supply a pure sinusoidal voltage to all consumers and for consumers to take a pure sinusoidal current from the network.

EA Networks is judged by the quality of electricity delivered to consumers. There are some aspects of power quality that are outside the control of EA Networks. It is not the responsibility of EA Networks to *condition* the supply voltage waveform it receives from generators either directly or via Transpower. Transpower are contracted to supply an appropriate level of power quality performance at the GXP.

The network is designed to remain within the normal tolerance voltage ranges for the forecast loading conditions considered. For the various credible contingency situations identified and studied for security purposes, the voltage should not go beyond the voltage range prescribed by the regulations.

3.7.1 Steady State Voltage

Programmes and projects are typically justified on the basis of the following benefits from improved voltage level or controls:

- the ability to meet any legal or contractual requirements with respect to voltage standards,
- specific consumer requirements which the consumer is willing to pay for,
- improvements in circuit capacity and the consequential deferment of capital expenditure.

Most consumers are connected to the system at LV (230 or 400 volts) and EA Networks undertakes to control this as per legal requirements – currently a range of ± 6%.

For 11 kV and higher voltage consumers, the design voltage range is from 96% to 103% of rated voltage.

In recent years, the number of voltage complaints have consistently reduced. This can be attributed to much better harmonic distortion controls and the extent of 11-22 kV conversion improving voltage regulation. When a complaint does occur, it is investigated rapidly and typically resolved either by confirming:

- there is no problem,
- the problem is within the consumers wiring,
- the problem is with EA Networks and the necessary adjustment or other work is completed.

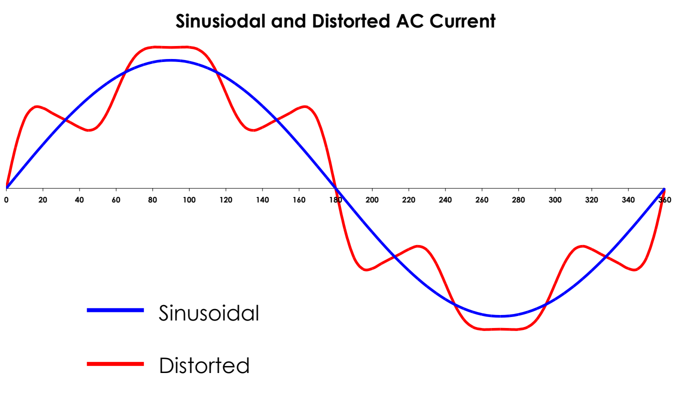
There are currently no unresolved voltage issues on the network under normal operating conditions.

3.7.2 Transient Voltage Disturbances

EA Networks design to limit transient voltage disturbances in accordance with the AS/NZS 61000.3.5 (LV) and 61000.3.7 (MV) standards. Motor starting is controlled according to The Electric Supply Engineers' Institute of New Zealand Inc. *Committee Report on Motor Starting Currents for AC Motors – February 1982*.

3.7.3 Harmonic Voltage and Current Distortion

Harmonics are non-sinusoidal currents or voltages produced by nonlinear loads. Nonlinear loads such as Variable Speed Drives (VSD), switch mode power supplies (SMPS), electronic ballasts for fluorescent lamps, and welders inject harmonic currents into the power distribution network. These harmonic currents couple with the system impedances creating voltage distortion at various points on the network. As a result, equipment such as computers, digital clocks, transformers, motors, cables, capacitors, and electronic controls connected to the same point, can suddenly malfunction, or even fail completely – beyond economic repair.

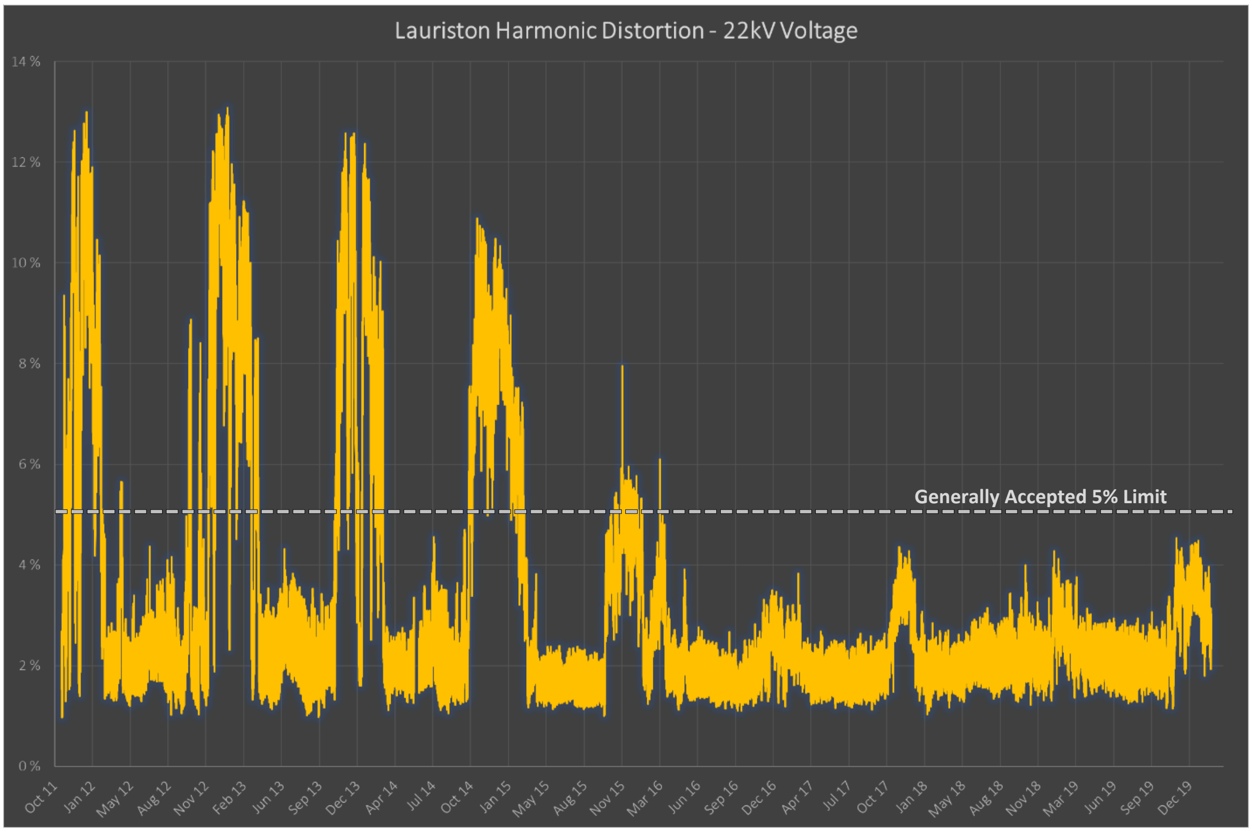


As harmonics are produced by the end users, it is important that these harmonics are controlled at the end user connection. This is considered good practice, as by controlling the emission levels of individual sources of harmonics, the flow of harmonics into the network is restricted at the point of common coupling (PCC) with other consumers. This will, in turn, limit widespread effects of harmonics in the entire network.

EA Networks endeavours to ensure that the quality of voltage in the network is always maintained at an acceptable level. In recent times, EA Networks has observed network voltage problems that are associated with harmonics. EA Networks acted and took all the necessary measures to minimize the widespread effects of harmonic pollution. The end result has enabled EA Networks to provide better voltage quality to all consumers.

EA Networks have implemented measures to control harmonic currents (and therefore voltages) in the network. The network standard that has been implemented requires all new rural loads to meet current distortion limits (typically 8% maximum). It is expected that the network design practices, equipment procurement for the network, and customer connection standards will continue to meet the requirements of EA Networks' harmonic standard by limiting harmonic voltages at consumer connection points.

There are about 1 600 irrigation connections to the network, and they constitute most of the summer peak load. About one quarter of these loads are active harmonic producing loads. This assessment is based upon a full survey completed during 2013-14. EA Networks realised that it is not easy to track the exact number of variable speed drives because the consumer's equipment can change over time and any new equipment's characteristics are not necessarily provided or available to EA Networks. The number of variable speed drives increased steadily between 2000 and 2015 and some more may be connected in future. The per substation irrigation load shown in Section 4.2.3 provides an illustration of the potential scale of distorting irrigation loads on each substation.

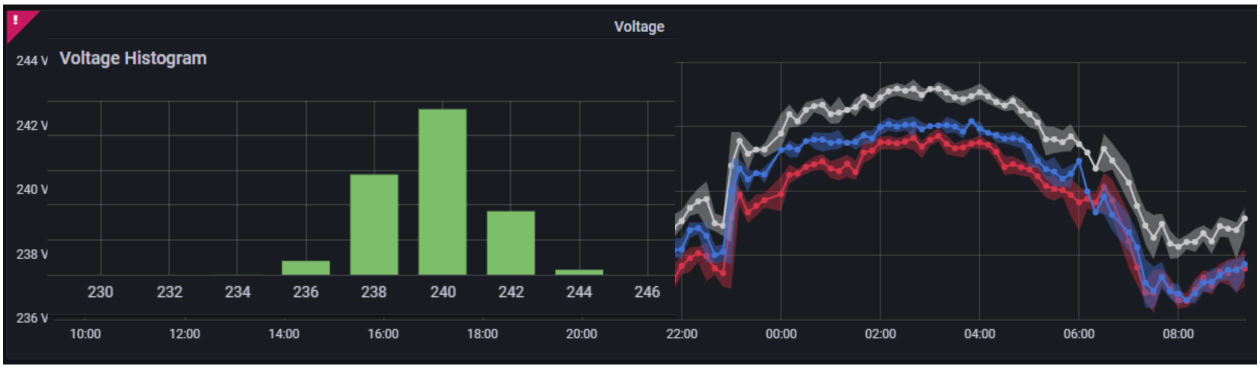


A scheme to subsidise the mitigation of harmonic distorting equipment was introduced (April 2014). Under this scheme the cost of a filter or other form of mitigation was heavily subsidised for the first year of the scheme's operation and this rolled back to no subsidy over the subsequent two years. Owing to the economic downturn in the rural area a differential tariff that was to operate from April 2016 was delayed. Some discretion may be exercised with the loads that have not been corrected by October 2018. Without compelling reasons, these distorting loads will be disconnected for non-compliance. The zone substation power quality monitoring devices have shown a worthwhile reduction in peak harmonic distortion since 2014-15 summer (see chart above) during which, an all-time peak demand was experienced. This programme will continue until all rural pump loads comply (only a handful remain unfiltered). Overall, the harmonic reduction scheme has been very successful. Monitoring of the 1 000+ connections with VSDs to ensure filter effectiveness is an ongoing process requiring site visits. Anecdotally, there is evidence of filter failures that individually may not increase voltage distortion appreciably beyond the ICP but collectively will eventually cause an issue. Consideration will be given to installing monitoring equipment at each filtered site to allow real time remote indication of all major electrical parameters (voltage, current, power factor, current distortion, and voltage distortion) alleviating the need for site visits. Filter failure would be immediately obvious with such a system. It would also allow the ADMS to run more accurate load flow modelling with knowledge of actual site loading.

A further potential source of higher harmonic currents in the network is the connection of utility scale solar farms. Within the Distributed Generation (DG) connection application process, a harmonic assessment is required from the solar farm developer to demonstrate the level of harmonic currents related to the solar farm inverters remain within specified limits.

3.7.4 Monitoring Power Quality

Power quality covers a number of key aspects of the voltage waveform as discussed in section 3.7.3. Of most note is the magnitude of voltage, which is governed by the Electricity Supply Regulations to be within ± 6% of 230 volts. EA Networks do not own any of the revenue meters at ICPs, and this means visibility of the voltage supplied to consumers is currently low. Steps have been taken to improve the monitoring of portions of the LV network and further work will be done to enhance this. The installation of a PowerPilot device on new ground-mounted distribution substations provides pseudo real-time 10-minute resolution data of minimum, maximum, and average voltages on all three phases (see below) as well as a myriad of other extremely useful power system data. The PowerPilot has displaced a much simpler logging device that was manually read twice a year and only gave a single maximum demand (kVA) value over that period. PowerPilot data is logged in a central database for reporting and analysis.

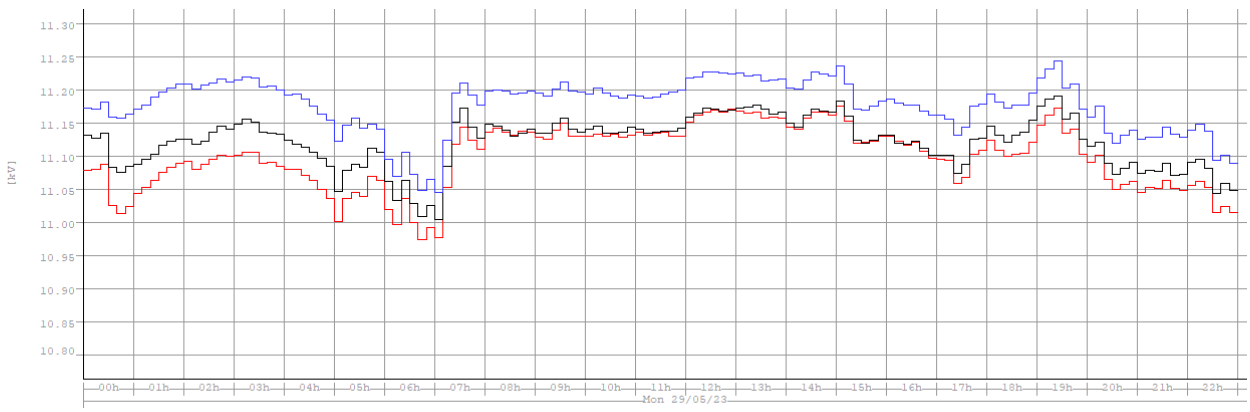


Statistics from Voltage Histogram

Minimum	Maximum	Avgerage	Median	P5	P95	Std. Dev.
232 V	244 V	239.68 V	240 V	238 V	242 V	1.63 V

The PowerPilot reporting interface (dashboard) provides measures of compliance with legal voltage tolerances both in histogram form (at left) and in statistical form (below). These parameters will, in future, be logged and non-compliant events/sites automatically sent to asset managers to evaluate for mitigation. Voltage imbalance, which is important for three phase loads, can also be reported from captured data and per phase loading can then be examined to help resolve the voltage imbalance.

Historical issues with rural harmonic distortion caused EA Networks to install dedicated power quality metering at each zone substation 11 kV or 22 kV busbar. These devices log a large range of power quality parameters every 10-15 minutes, and each night the log is downloaded to a central database which contains over ten years of data for some sites. An example of the type of data captured is shown elsewhere in the AMP (section 3.7.3), and a day of 11 kV voltage at Ashburton substation is shown below. These meters also record short-term and



transient events that consumers will sometimes observe, and the central database can be used to determine the nature and magnitude of any disturbance at a later date.

In general, EA Networks install distribution transformers on a tap setting of 415 volts output for nominal 11 kV or 22 kV input. This represents +3.75% voltage boost at no load above a nominal 400/230 volts. The zone substation transformer(s) regulates the 11 kV or 22 kV voltage at 101% ±0.94%. This means the maximum no-load voltage to appear on a distribution transformer's LV terminals is 105.7%, just below the maximum permissible. The minimum voltage to appear on a distribution transformer's LV terminals depends upon the minimum zone substation output voltage ~100%, the 11 kV or 22 kV feeder voltage drop (~2.5%), and the voltage regulation of the distribution transformer (~1.5%). The summation of these quantities means a typical minimum voltage at the distribution transformer LV terminals will be ~100% or 400/230 volts, the nominal LV voltage. There are exceptions to this, particularly at the end of more remote 11 kV feeders and during contingent events when back-feeding occurs.

A consequence of the above nominal voltage profile, underground conversion, and 11 kV to 22 kV conversion, is that there are very few complaints of low voltage. The advent of rooftop solar has caused some instances of voltage exceeding 244 volts (106%) causing the inverter to turn off and this results in enquiries from solar providers wanting to have the voltage reduced. This is where the historically valid LV network design comes into conflict with solar generators' export. On sunny lightly loaded days, when solar output is at its maximum (for a few hours around midday), even 5 kW of solar export at the end of a LV feeder can elevate the voltage by several volts, and this is sufficient to cause the network voltage to exceed 244 volts. EA Networks obtain no income from solar export, but its presence does reduce the effective capacity of the network (total voltage bandwidth) unless the solar is constrained at its most productive time to keep peak voltage within regulatory limits. The proposed introduction into the electricity supply regulations of a +10% voltage tolerance (253 volts) on standard nominal LV (230 volts) would resolve most of these issues.

The current level of voltage monitoring is inadequate to detect end of LV feeder non-compliant voltages. It is possible to contract with smart meter owners to obtain a picture of the voltage experienced by consumers. This is currently not as simple as requesting the information from them, since voltage is not a default data point they record. In the coming year, EA Networks will continue to investigate the feasibility and affordability of obtaining representative data from smart meters so that delivered power quality can be assessed more broadly. With the best possible outcome, smart meter voltage data is unlikely to be available for at least two more years. In the interim, EA Networks are considering the installation of temporary or permanent PowerPilot devices at the end of some urban LV feeders to either sample or continuously monitor not only steady state voltages but also harmonics and short term events such as dips and spikes. The end of a LV feeder is typically where voltage swings are at their greatest, and known impedances of network conductors and cables can guide the placement of the monitors to give representative worst case daily voltage profiles. There are a number of PowerPilot devices already being trialled on individual ICPs and these provide an insight into the voltage quality experienced by consumers. The type of voltage data available is identical to that shown above for distribution substations.

When repeated non-momentary voltage excursions are detected, typically during low or high load periods, a range of solutions exist to address the issue. If the voltage is too high, the simplest approach is to change the tap position on the distribution transformer supplying the consumer, normally by 2.5%. If this is problematic and will cause low voltage during times of peak load or high voltage during times of low load, then that solution is not viable. The next possible solution is to reconfigure the LV network to reduce or increase upstream impedance and thereby alter the variation of voltage with load or generation. Another option is to look at the phase the consumer is supplied from and, if beneficial, change them to one of the other two, thereby raising or lowering the voltage they experience. If none of these network tuning options are feasible, then discussion with consumers on the LV feeder may take place to determine if subtle behavioual or load changes could prevent the need for more asset intensive solutions. Examples would be (a) power factor correction of very poor power factor loads that not only use excessive thermal capacity but also drag down voltage at peak times or (b) the impact of retail tariffs that have a "free hour of power" that encourage maximum power use in very small windows of time – driving out diversity in loads (the power network has been designed and built with diversity in mind). The progressive underground conversion of most of the urban areas in the Ashburton District has provided a significant boost in power quality to urban consumers by replacing smaller overhead conductors with two (each side of the street) larger underground cables. In the most marginal cases, it is possible additional assets may be required to bolster the voltage control on a weak or heavily loaded LV feeder. This will normally be a case of a much larger cable being installed to a point at least half way along the existing feeder and the second half of the feeder being fed from the new cable. This retains all of the existing cable but halves the load and distance to significantly reduce voltage fall/rise from load/generation. The last resort, and typically most expensive option, is the addition of another distribution substation between existing ones. This not only halves most LV feeder lengths, but also halves the load on the LV feeders, reducing the load on several existing distribution substations. This is possibly a more sensible option if uncontrolled EV chargers are causing new peak loads that thermally stress the existing LV cables and distribution transfomer.

In rural settings, the most effective means of resolving feeder-wide voltage issues has been conversion to 22 kV from 11 kV. There are several 22 kV conversions planned or underway that will address known areas of high voltage regulation. The reduction in voltage variation is always considerable once 22 kV conversion has been completed. If the voltage issue is confined to one rural consumer, then the (normally dedicated) distribution transformer tap adjustment is generally the most applicable solution, particularly for pumping connections.

Upon identification of a voltage issue or receipt of an enquiry/complaint about voltage quality, it is directed to the operations area of EA Networks. The operations staff will investigate and normally install logging equipment to confirm the issue and its magnitude. Once a voltage issue has been confirmed, the location of the issue's cause will be identified and if that is in the consumer's installation, a recommendation will be made to the consumer to contact a reputable electrician. If the cause is on EA Networks' system, the consumer will be advised and one of the remedies identified above initiated. When the remedy has been fully implemented, a further check will be undertaken to ensure the issue has been resolved and that the consumer is content.

The historically very low number of voltage enquiries has resulted in no formal register of enquiries and their resolution. A recent development at EA Networks is the use of Salesforce CRM for logging interactions with customers. Although a specific workflow for voltage enquiries is yet to be implemented, the interaction can still be logged and the enquiry's progress monitored. Salesforce is likely to become the formal record of voltage enquiries and any dashboards and reporting will be sourced from that dataset. Salesforce can also be used to communicate with a group of consumers when remedial work is to be undertaken. This ensures a record of the consumer dialogue is kept should any difference of opinion occur at a later date.

Potential future development of both field measurement devices (mostly PowerPilot) and the back-end systems they provide data to (Chronus - ADMS historian database) will allow better visibility and analysis while providing more proactive responses to looming or actual voltage issues without the need for a consumer enquiry to prompt action. Continuing Customer Management System (CMS) development will permit a more seamless and traceable process for receiving, progressing, communicating, and resolving any voltage enquiries.

3.8 Safety

Electricity is potentially dangerous. All participants in the electricity industry have an obligation to ensure staff, contractors and the public are well informed of potential hazards and how to avoid them. Industry participants also have an obligation to minimise the exposure of all people to hazards by designing to an appropriate safety level for the environment in which the electrical equipment is installed.

In general terms, the safety standards are determined by relevant legislation and industry best practice on any particular issue.

The commitment to education and training of all staff is a core obligation of EA Networks' approach to safety. EA Networks are committed to having appropriately competent persons working on and operating the network. All work is carried out in accordance with nationally accepted regulations, guides, codes, and rules. Records of worker competency levels are held on file with regular refresher training undertaken to maintain current competence. EA Networks work closely with the industry training organisation (Connexis) to promote worker competency standards.

The general public are kept informed of safety issues by regular radio and newspaper advertising of the hazards of all electrical equipment – particularly overhead lines. Safety presentations are regularly made to emergency services personnel to ensure safe behaviour of all people in emergency situations. EA Networks are always available to educate on safety matters. Extensive warning labelling of EA Networks equipment is undertaken where public access to kiosks, poles or other safety perimeters is possible. All accidental line contacts are recorded, and informative letters sent out to those involved in the event.

EA Networks are aware of increasing safety issues with privately owned lines. Aging overhead lines are creating potential hazards by contacting trees, sagging lower than legal heights, and component failure. A free condition assessment is offered to owners of HV service lines and this highlights any problems to them in writing.

EA Networks have a Public Safety Management System (PSMS) in place that covers all aspects of asset management including:

- management of risk, hazards, and change,
- equipment specification,
- procurement,
- network design,
- network construction,
- network operation,
- public awareness.

3.9 Environmental

Impact of Electricity Operations on the Environment

EA Networks is committed to being environmentally responsible and strives to minimise the effects of its activities and actions on the environment.

Statutory Obligations

The electricity network has an influence on the environment. To control this influence, certain statutes apply to EA Networks in its operation and maintenance of the distribution network.

These include the Resource Management Act. Section 9 of RMA relates to Restrictions on use of land -

"*(1) No person may use any land in a manner that contravenes a rule in a district plan or proposed district plan unless the activity is*

a) *Expressly allowed by a resource consent granted by the territorial authority responsible for the plan; or*
b) *An existing use allowed by section 10 (certain existing uses protected)*."

EA Networks' Network currently crosses land governed by two different Territorial Authorities, each with their own District Plan and each slightly different in the rules governing the construction of new distribution lines.

EA Networks' protection of existing works is covered by Section 22 of the Electricity Act 1992 and the rights of entry in respect of these works are covered in Section 23 of the Act. Prior to commencement of any construction or maintenance of works, EA Networks must give notice to other utility owners and the appropriate Territorial Authority of its intention to commence construction or maintenance on its works.

EA Networks' distribution network generally runs along the roadside throughout the Mid-Canterbury plains area. Mid-Canterbury is predominantly a farming area and historically the most cost-effective means of supplying these farms with electricity is via overhead power lines. The installed cost of underground cable is now comparable in some circumstances. In the future, for specific applications, EA Networks may be required to use alternative methods of construction to minimise the effects on the environment. An example of this was the supply to Mt Hutt ski-field. The impact on the environment would have been too great had an overhead line been constructed. An underground cable was installed in that case. District Plan rules require consultation with the Council when installing lines in areas of high scenic value and EA Networks consults and works with the District Councils when working in these areas. This consultation may be required for tree trimming, agreement regarding line routes or just general distribution line upgrades.

Other sections of the Resource Management Act also help shape EA Networks' approach to network design and construction. As an example, the urban underground conversion programme is a way EA Networks chooses to improve the urban environment with no assistance from external funding sources.

There are two significant materials used in the electricity network that can have a negative environmental impact: insulating oil and SF_6.

Oil Containment

It is policy to provide oil containment facilities at substations with oil filled equipment or storage facilities containing 1 500 litres or more of insulating oil. The standard design incorporates a bund wall around transformers with manually controlled storm-water drainage to a field drain or to the surface (where there is no risk of the discharge entering waterways).

Oil spill kits are maintained at certain strategically placed zone substations and any discharge from the bund is controlled by strict guidelines stipulating no contamination.

EA Networks has recently become aware of an Ashburton District Council requirement for bunding for all transformers containing more than 1000 litres of insulating oil. This translates to some makes of 1MVA transformers and all 1.5MVA transformers. Existing older sites have "existing use" rights and do not require retrofitted bunding. New or rebuilt sites will be evaluated on a case-by-case basis, as the Environmental Protection Authority future legislation will move to a more risk-based approach to be incorporated in future district plans. Ashburton District Council have already approved the installation of 1MVA and 1.5MVA transformers within an industrial food processing site due to the wider spill containment facilities that exist. It is accepted that transformers containing more than 1000 litres of oil are very low risk and highly likely to be detected before any problems become an issue and that the risk is no greater than small transformers carrying lesser quantities of oil. Transformers with "eco-friendly" vegetable-based oil will be looked upon more favourably and EA Networks will investigate this. The transformer sites with greater than 1000 litres of oil will be collated and communicated to Ashburton District Council in 2025-26 for evaluation. Refer to section 9.3.4 for a service improvement initiative for this issue.

If oil is spilled, all the contaminated earth is collected and disposed of at authorised disposal facilities.

SF_6 Gas

SF_6 is a major greenhouse gas, and each kg of gas has a global warming potential over its lifetime equivalent to 22 800 kg of CO_2. A typical car will release about 4 000 kg of CO_2 in a year from its exhaust.

As a major user of SF_6 gas, EA Networks is a participant in a monitoring regime to ensure annual loss of gas is kept below 2%. To date there has been no loss detected that is outside the measuring tolerances. EA Networks have also registered with the New Zealand Emission Trading Scheme as a major user of SF_6 (greater than 1 000kg of SF_6 in use and storage).

Carbon Footprint

Our sustainability strategy includes a target of reducing our scope 1 and 2 emissions carbon emissions by 5%, excluding lines losses.

The wider sustainability strategy includes specific measures, over three time horizons to:

- Reduce Carbon Footprint
- Enhance Energy Efficiency
- Promote Sustainable Procurement
- Sustainable Design

Some deliberate actions already assist in this area such as reducing the electrical losses by using larger conductors and particularly increasing the operating voltage from 11 kV to 22 kV and 33 kV to 66 kV.

We also strive to be the easiest network in the country to deal with for renewable distributed energy developers.

Impact of the Environment on Electricity Operations

A range of environmental phenomena have an influence on the security of the electricity network. The following environmental factors are considered significant in electricity network performance and impact:

Seismic

EA Networks has taken expert advice on seismic design and a design standard has been prepared for structural design of foundations, supports, structures, and buildings. The level of seismic resistance incorporated into the standard is at least 50% higher than the general building requirement.

The standard has been reviewed because of the Canterbury earthquakes. A revised standard based upon NZS1170 Part 5 methodologies and updated risk factors has resulted. Typical seismic horizontal load coefficients in use are 1.0 – 1.1g.

Pollution

Where harsh environmental conditions exist, such as saline pollution in coastal locations, appropriate provision is made in specifications for anti-corrosion protection of surfaces, and for insulation performance.

Acoustic

EA Networks currently requires certain equipment to meet international and district plan standards on noise levels, and in locations adjacent to urban areas will require plant to be installed to meet defined criteria at the site boundaries.

Climate

The summer peak of EA Networks' network demand requires careful consideration of the specifications of major transformers and the sag and clearance design of network overhead lines. Climate change may influence future specifications. This will be investigated further in the coming year, with reference to NIWA's 50-year forecast climate data gridded to specific locations in our network area. This will be used in a review of EA Networks' overhead line design standard and will inform design standards for other climate sensitive assets such as underground cables, switchgear, and transformers.

OUR NETWORK

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4 OUR NETWORK

4.1 Service Area Characteristics

The Mid-Canterbury area (see below) has a number of activities that in some way contribute to the demand on the EA Networks electrical network or influence the design and operation of the network.

The activity that Mid-Canterbury is most known for is farming. The *patchwork quilt* effect when flying over the district illustrates the various crop types that are growing, each crop having a distinctive shade of colour. The variety of colours are reducing as more farms are converted to grow grass which feeds dairy cows. The productivity of Mid-Canterbury dairy herds is amongst the highest in New Zealand. To grow enough grass, thereby ensuring an economic level of milk production, it is essential to irrigate the grass. This irrigation demand influences the design, capacity, and maximum demand of the EA Networks electricity network. Irrigation occurs throughout the Plains area of Mid-Canterbury. Currently, EA Networks have about 1 600 irrigation connections. The dairy sheds associated with these farms also place a significant demand on the network. Farmers are very keen to have high electrical reliability to these dairy sheds as a couple of missed milking cycles can cause the cows to *dry off* (cease producing milk) and this can have a catastrophic impact on the farmer's income.

Another feature of the district is the meat and vegetable processing facilities. There is one meat-works supplied by EA Networks as well as a vegetable processing factory (with the possibility of another in the next year or so). These facilities either have dedicated electricity substations or a dedicated supply from a substation. The key issues these consumers have are capacity and reliability.

Mt Hutt ski-field is also located in the district, and it has electric lifts and snow-making facilities. The location of the ski-field means that the electricity supply is both electrically and environmentally challenging. The supply to the ski-field requires dedicated 33 kV power lines from Methven to a 33/11 kV substation above the Rakaia Gorge. From the substation, a pair of 11 kV underground cables wend their way up a steep slope across the main ridgeline and descend into the Mt Hutt basin. This cable route was the only one that was acceptable to the Department of Conservation and overhead lines were not acceptable from an environmental perspective or from a viewpoint of serviceability. In winter, the route can be covered by several metres of snow and winds on the ridges regularly exceed 160 km/h. This is no place for an overhead line.

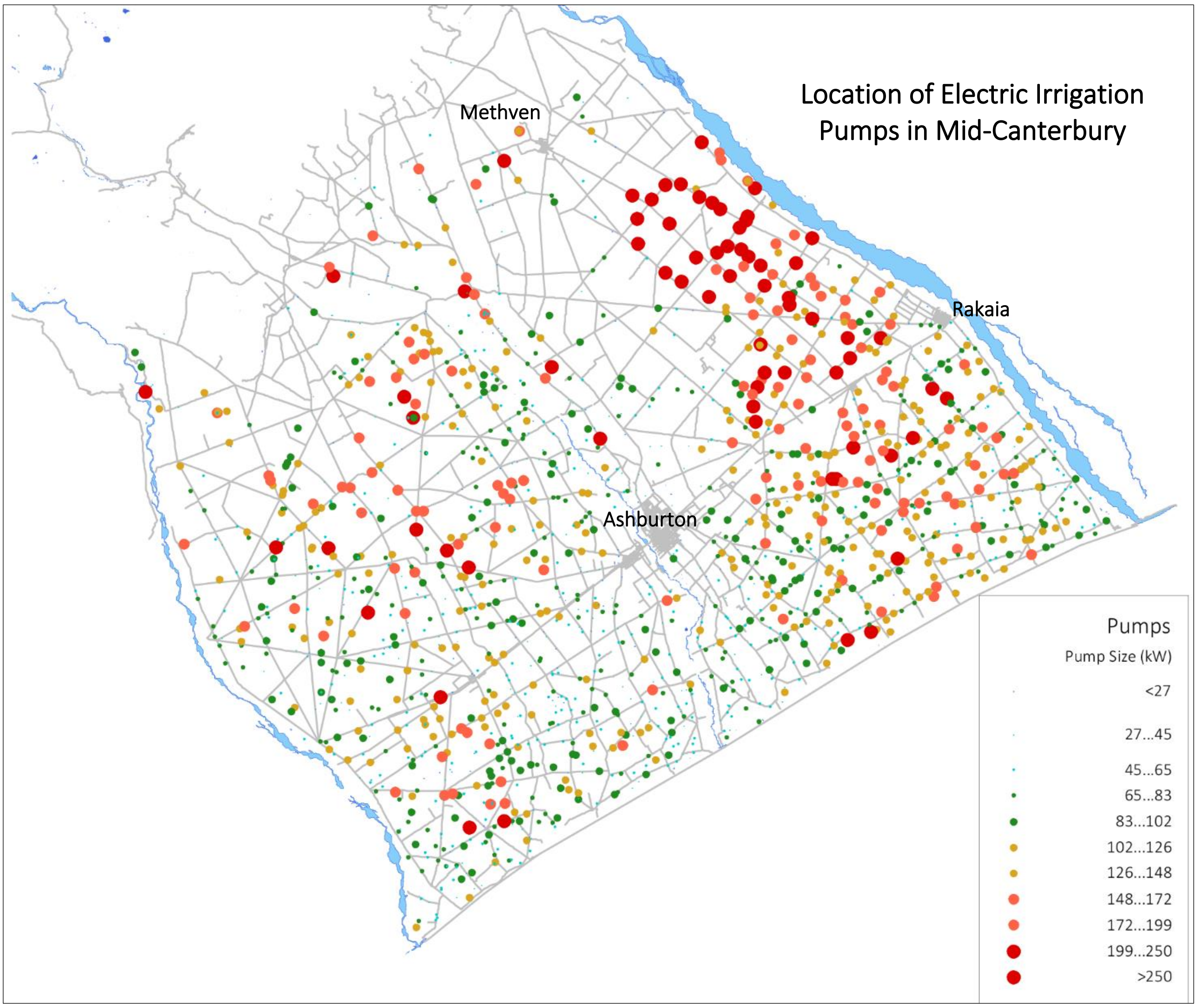
The main settlement in the district is Ashburton township and it holds about 20 000 people. Smaller towns of Methven (1 900 people) and Rakaia (1 500 people) are also significant in terms of electricity consumer count.

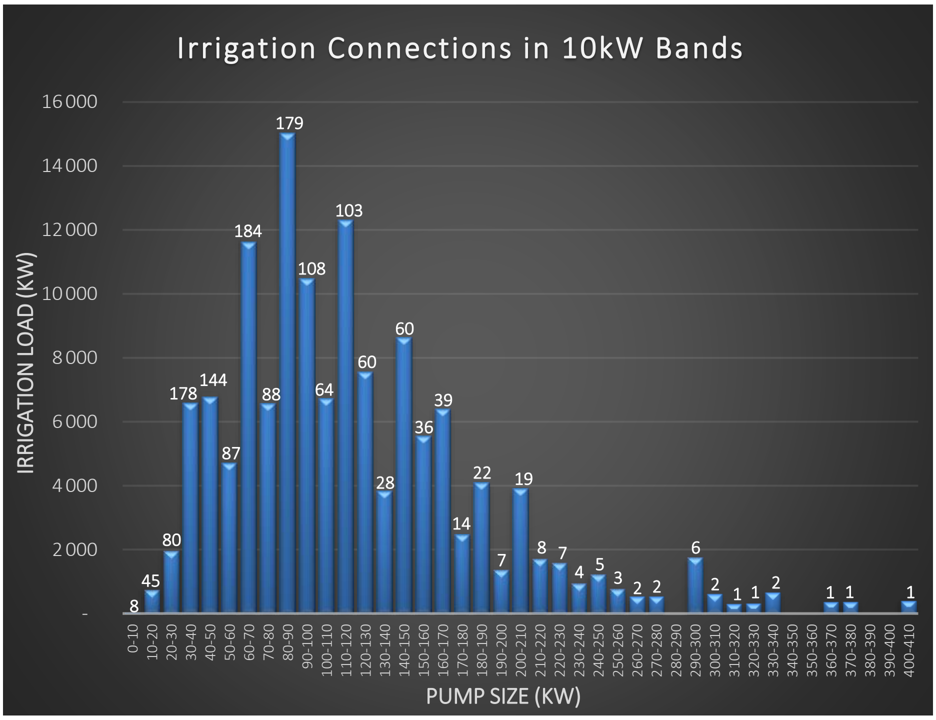
The district has a total population of about 35 000 people.

In the early 20th century, the Government decided to build an irrigation canal that takes water from the Rangitata River and transports it across the Canterbury Plains as far as the Rakaia River. This canal is called the Rangitata Diversion Race (RDR). During summer, the RDR is used as an irrigation water canal and several downstream irrigation schemes are supplied from it. These schemes distribute water onto farms using various sizes of irrigation races. In recent times, some of these races have been converted to piped schemes which eliminates evaporative and ground losses as well as providing gravity pressurised water to the farm gate. To reduce the risk during dry periods, many farmers on open race schemes have constructed large storage ponds on their farms. The farmer may then take their full allocation of water at any time it is available, and any water not required at that moment is stored for later use. The farmer can pump the water from the pond at any rate they choose.

One of the uses for the RDR is power generation. There are two hydro generators on the RDR, one at Montalto Hydro and another at Highbank. The Montalto Hydro generator provides variable output all year round while Highbank can only generate if most irrigation schemes are not taking water (during autumn, winter, and early spring).

There are several other small hydro generators in the district at Cleardale (Rakaia Gorge), Barrhill, and on an irrigation canal at Ealing.





The electrical demand needed to irrigate a hectare of land at a rate of 0.6 litres/second/hectare (the generally accepted rate) varies depending on the source of water and irrigator type. A modern centre pivot irrigator supplied with water from a surface pond will require about 0.55 kW/hectare. So, a 900 m radius centre pivot will require a pump of approximately 140 kW to drive it. If the water comes from a deep well, the pump must also overcome the additional gravity head of the well. If the same 900 m centre pivot is supplied with water from a 120 m deep well, another 0.71 kW/hectare must be added. This would mean the installation would need a 320 kW electric pump to drive it. This type of load places considerable demand on a rural electricity network. The average size of EA Networks' irrigation connections is 86 kW.

The Highbank Hydro Power Station has been equipped with an array of six 1.5 MW pumps that allow it to take water from the Rakaia River and pump it up the power station penstock (a height of about 100 m) into the RDR. The water is then available for irrigators to use. This scheme is generally referred to as the *BCI scheme* (www.bciwater.co.nz). This load is typically coincident with the summer peak demand (dry years cause low diversity of irrigation demand). There is an understanding in place that should a 66 kV subtransmission circuit be unavailable because of a fault, the supply to these pumps will not be available (i.e. the Highbank pump load is interruptible). This is a condition negotiated before the load was initially supplied.

The following table depicts the major loads supplied by EA Networks.

Significant Load	Typical Energy (MWh)	Peak Load (kW)	Demand Season
Meatworks #1	30 000	6 900	All Year
Ex -Meatworks (Refrigeration only)	3 000	500	All Year
Vegetable Processor	26 000	5 000	All Year
Plastic Goods Manufacturer	4 900	1 600	All Year
Ski-field	2 200	2 500	Winter
BCI Irrigation Scheme	5 800	8 000	Summer
Irrigation (District-wide)	220 000+ (Typical Year)	143 000	Summer
Other Load	250 000+ (Typical Year)	65 000	All Year
TOTAL	600 000+ (Typical Year)	182 900	

More than 50% of the energy transported by EA Networks is delivered to 8% of the connected consumers. The magnitude and timing of the peak demand (which occurs in summer) is almost entirely determined by the amount of rainfall, which in turn influences the amount of irrigation that takes place. The winter peak demand is approximately 40% of the summer peak and is largely determined by the harshness of the winter and low temperatures driving residential heating. The winter load is concentrated in the townships, particularly Ashburton, and the urban underground network is designed with this in mind. Mt Hutt ski-field is also peaking its electricity usage in winter and the early part of winter can see the snow-making systems working at full capacity, particularly overnight when it is colder. The diverse types of loads do cause low asset utilisation when viewed by various system-wide metrics. The transformers and lines that supply irrigators are largely idle during winter and the urban transformer and lines are much less loaded during summer. This means measures such as (GXP peak demand) / (total distribution transformer capacity) does not compare favourably to networks with year-round load types.

The diagrams in section 4.2.3 show the seasonal variation in load between rural/urban zone substations as well as the seasonal load/generation balance.

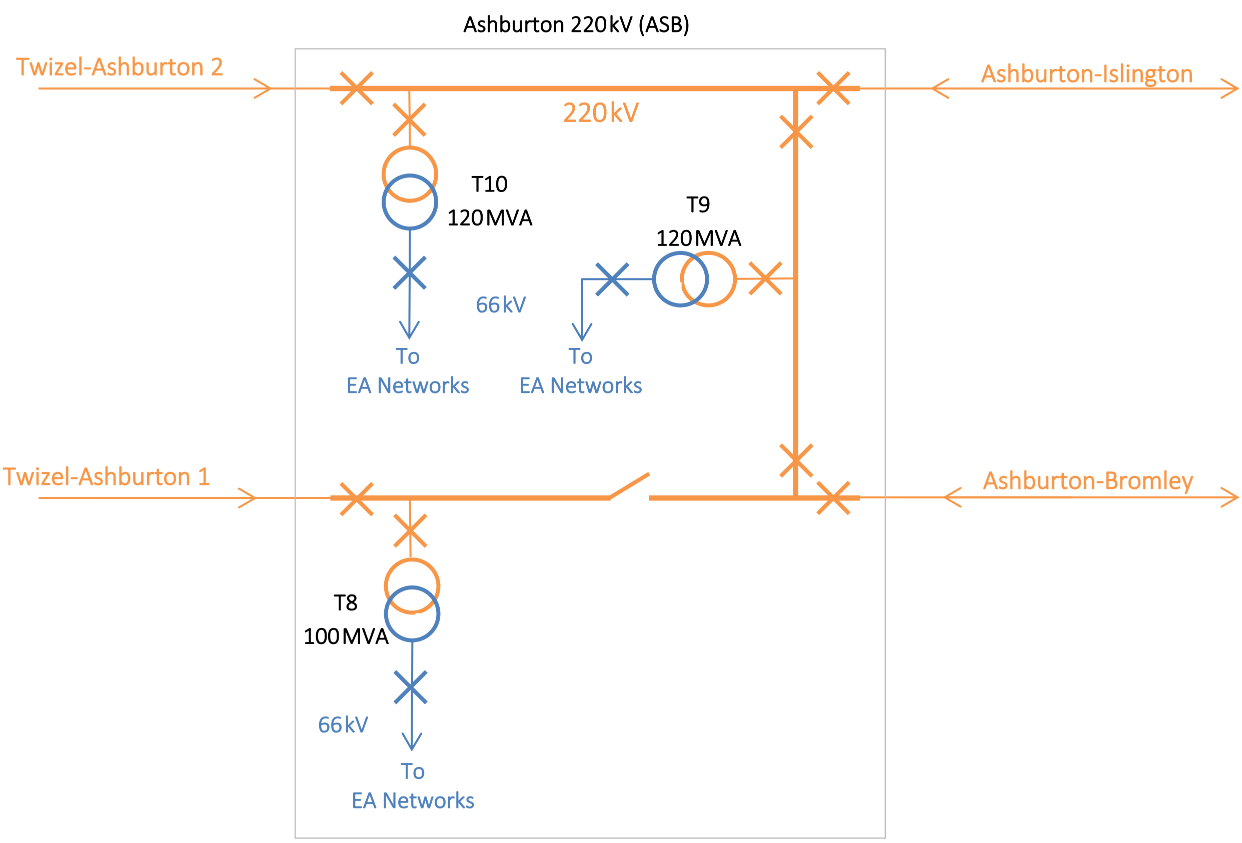
4.2 Network Configuration

This section describes the general arrangement of each major section of the EA Networks electricity network.

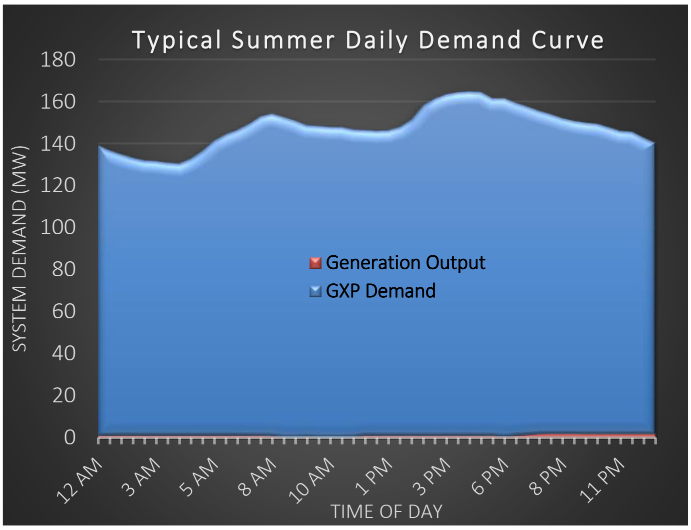
4.2.1 GXP and Generation

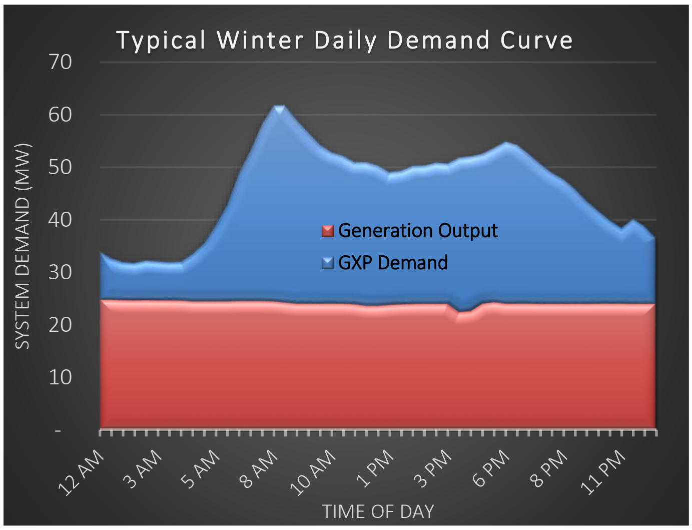
EA Networks take supply from the national grid company (Transpower) at a site approximately 7 km south-east of Ashburton township. The Transpower Ashburton Substation (known as Ashburton220 or ASB – since EA Networks also have an Ashburton substation) supplies EA Networks with 66 kV subtransmission voltage. This supply point is also known as a Grid Exit Point (GXP). The following diagram illustrates the configuration of the Transpower ASB substation.

EA Networks Grid Exit Point Configuration

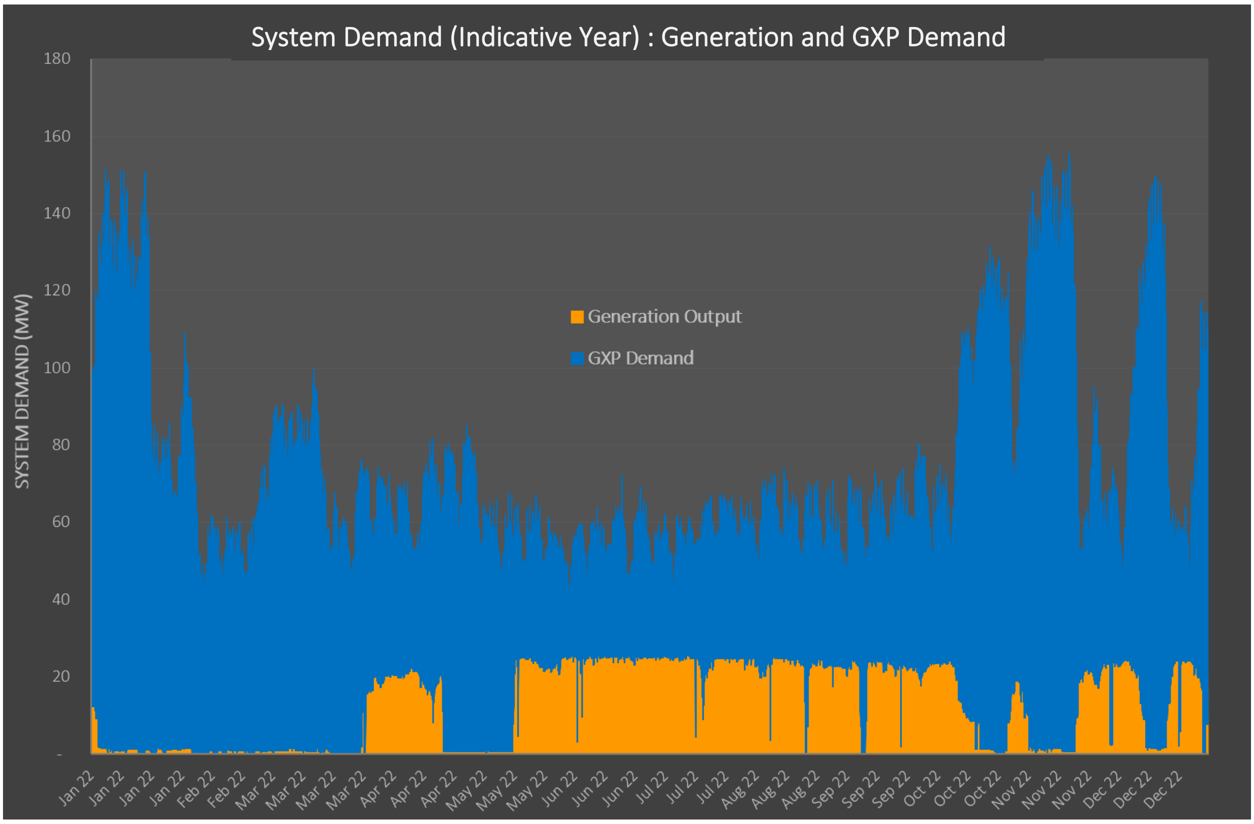


The orange lines represent 220 kV (the national grid transmission voltage). The blue lines are 66 kV. The capacity of each transformer is shown above. The 66 kV GXP has a peak load below the combined rating of T8 (the smallest of the three 220/66 kV transformers) and one other of T9 or T10. T9 was commissioned during 2013. This configuration ensures 66 kV loads have *n-1* security up to 220 MVA steady state or 250 MVA cyclic.

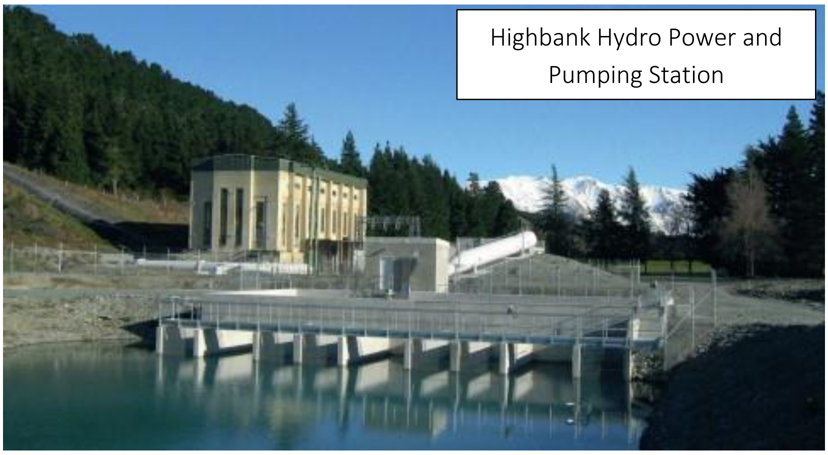




The 66 kV GXP supplies all of EA Networks' consumers. The load charts above illustrate the irrigation vs residential/commercial nature of the load on the GXP. It is important to note the different vertical scales on the two charts. In summer, the large irrigation base swamps the daily residential variation, while in winter the residential/business variation is clear to see (and significant generation is present). The daily load variation is very marked during morning and evening mealtimes with both heating and cooking loads being heavily used. The chart below illustrates the seasonal and weekly load variation for a typical year which can be clearly seen with significant dips at the weekends during winter. It is at these times that water heating load control is used to ensure both the Transpower grid and EA Networks assets' required capacity can be minimised to meet a controlled peak load, where water heating load can be shifted a few hours without consumer impact.

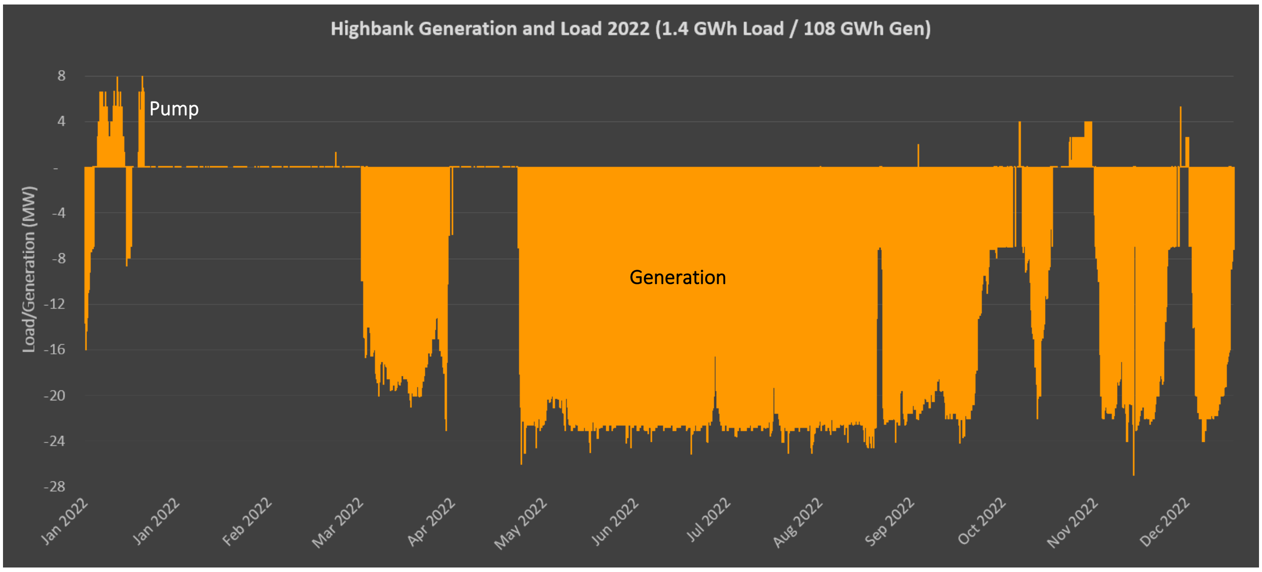


Irrigators do not tend to have a daily or weekly load variation. Once the water is required, the irrigator is left to run for possibly weeks on end. The irrigation is predominantly used in the summer although a farmer's growing season can extend into April in some years. Equally, a dry winter can cause early irrigation demand to occur in August or September, as happened in 2014. A wet spell during December 2022 reduced that demand for several weeks and even allowed some hydro generation. The load on the 66kV GXP varies from a maximum of 180MW in summer to a minimum of 25MW in winter.



Highbank Hydro Power and Pumping Station

The [Highbank Hydro Power Station] is rated at about 28MW output. It has a single turbine with a head of 104m. The RDR race has a flow of 31m³/s at peak times when no water is being used for other purposes. There is no ability to store water in the RDR and Highbank is considered a *run of the river* station. The output diagram for 2022 can be seen below and when irrigation demand begins in September and October, the water supply becomes less consistent and daily peak generation output can vary significantly. Being a single turbine station with no water storage facilities, EA Networks cannot rely on Highbank operating at any particular point in time (see Apr-May below). As such, EA Networks do not factor in Highbank output during supply security studies.



Highbank also has pumps located at it to allow Rakaia River water to be pumped up into the RDR. These pumps were not used significantly during 2022 and appear on the Highbank graph as load of about 8MW. So, the Highbank 66kV connection demand varies from -27MW during winter (generation) to +8MW during summer (pump load). From October 2024 to June 2026 Highbank is undergoing a complete refurbishment. Over this period generation will be limited to circa 6MW from the pumps operated in generation mode.

There are five other distributed generators of note connected to the EA Networks network.

Lauriston Solar is a new solar farm that is located approximately 1km from Lauriston zone substation (LSN). Connected at 22kV, the inverter-based generator injects up to 47.2MW into the LSN 22kV busbar. Output is obviously restricted to daylight hours, but single axis tracking ensures rapid increase in output in the morning and significant generation until close to sunset.

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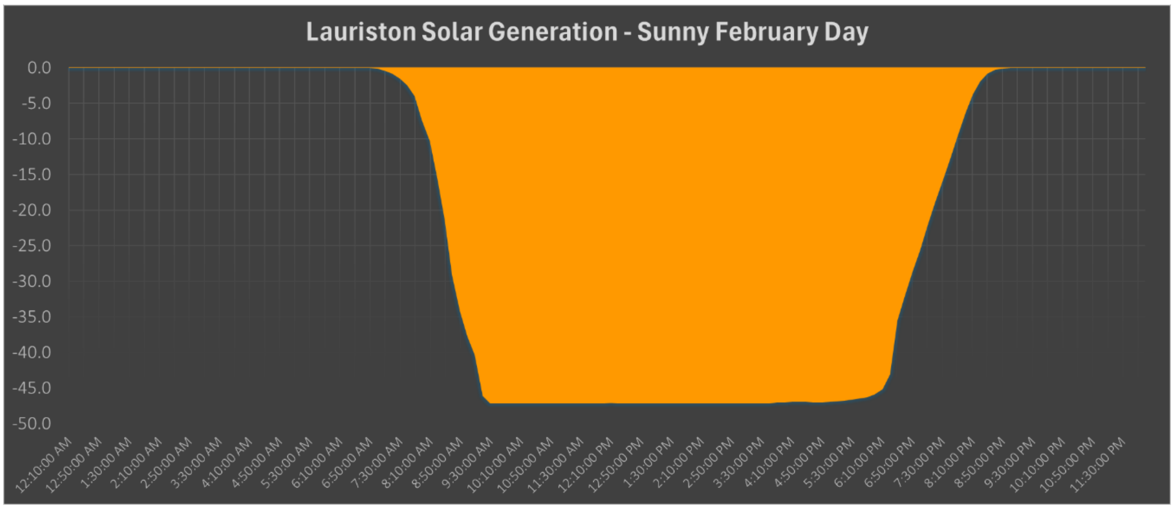
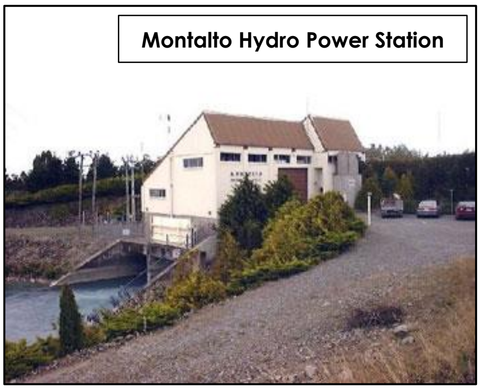
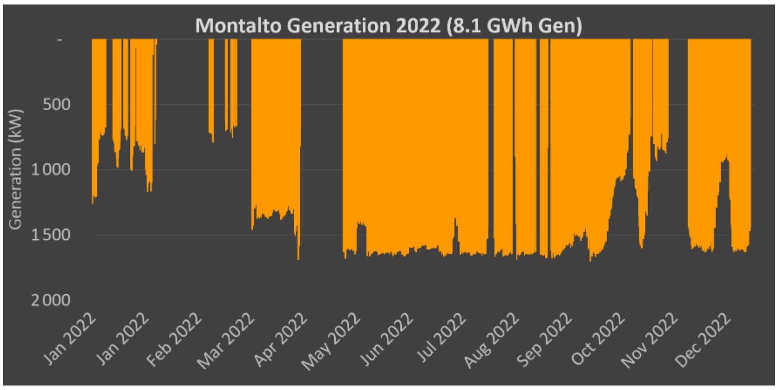


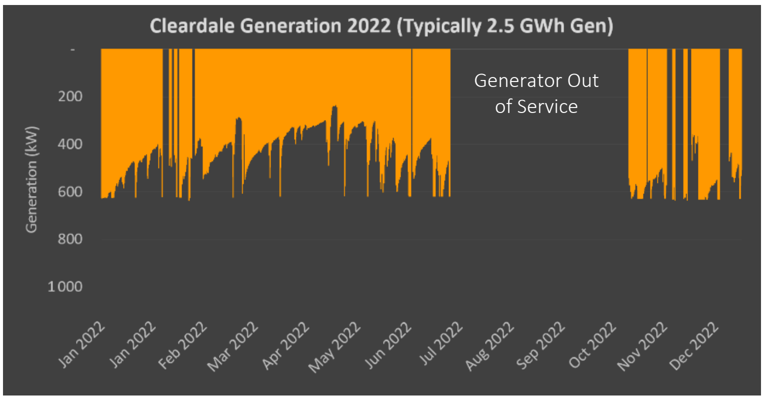
Gartartan Solar is a co-located pair of solar farms (GSF1 and GSF2) that, combined, have an output of up to 6.5MW. These farms also have single axis tracking panels. GSF1 and GSF2 are connected to a 22kV feeder from Elgin zone substation, which is coincident with ASB GXP.

Montalto Hydro is also located on the RDR, but its location offers year-round output. Connected at 33kV, the generator is an induction machine which means it cannot provide any system support or provide emergency output during network faults. Winter output is around 1.6MW while summer output is about 1.1MW.

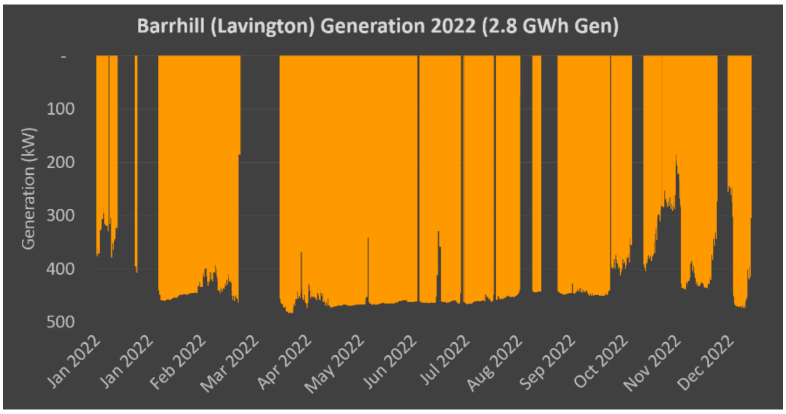




Cleardale is a 1MW generator in a valley adjacent to the Rakaia River gorge. A high head low flow machine, it generally has year-round output. The 11kV connection is relatively remote, and its output is largely absorbed in the Methven area after being transformed up to 33kV. The machine cannot provide emergency output (no islanding ability). The additional expense to provide islanding ability was examined at the time of installation but could not be justified for the small variable output and local fault frequency/consequences. Cleardale generation was out of service for part of 2022.



In 2016, an additional hydro generator was connected to the EA Networks 22kV system near Barrhill. The unit is owned by BCI Irrigation and rated at 520kW output. This output is absorbed into a 22kV feeder from Lauriston zone substation. The output of the generator is determined by BCI's irrigation customer demand for water. The intake for the generator is some 6.7km upstream of the generator site and a large diameter plastic pipe delivers the water to the generator with a 32m static head. Just above the generator site is a bifurcation of the delivery pipe and gravity pressurised irrigation water is diverted as required for delivery onto the Canterbury Plains. Flow into the irrigation system is controlled by the main valve on the generator. The generator offers close to rated output for a significant portion of the year, but during peak irrigation demand in summer (when it would be of most use on the 22kV network), its output drops to zero.



The very small hydro turbine at Ealing Pastures is located on an irrigation race and is normally used as a mechanical drive to a pump. When there is excess mechanical power a 200kW induction generator provides electrical power for on-farm needs and any excess is then exported onto the EA Networks system at 22kV. The generator has virtually no impact on the network other than to periodically reduce the farm's demand during the irrigation season (although not reduce the capacity required to supply the peak demand).

The geographic location of the main generators as well as Transpower's ASB substation are shown in the diagrams in section 4.2.2 and section 4.2.3.

Distributed Generator	Typical Annual Energy (MWh)	Capacity (kW)
Highbank Hydro (HBK)	115000	28000
Lauriston Solar (LAU)	97000	47200
Gartartan Solar (GSF)	13000	6500
Montalto Hydro (MON)	10000	1650
Cleardale Hydro	3400	1000
Barrhill (Lavington) Hydro	2800	520
Ealing Pastures Hydro	35	200
TOTAL	276200	85070

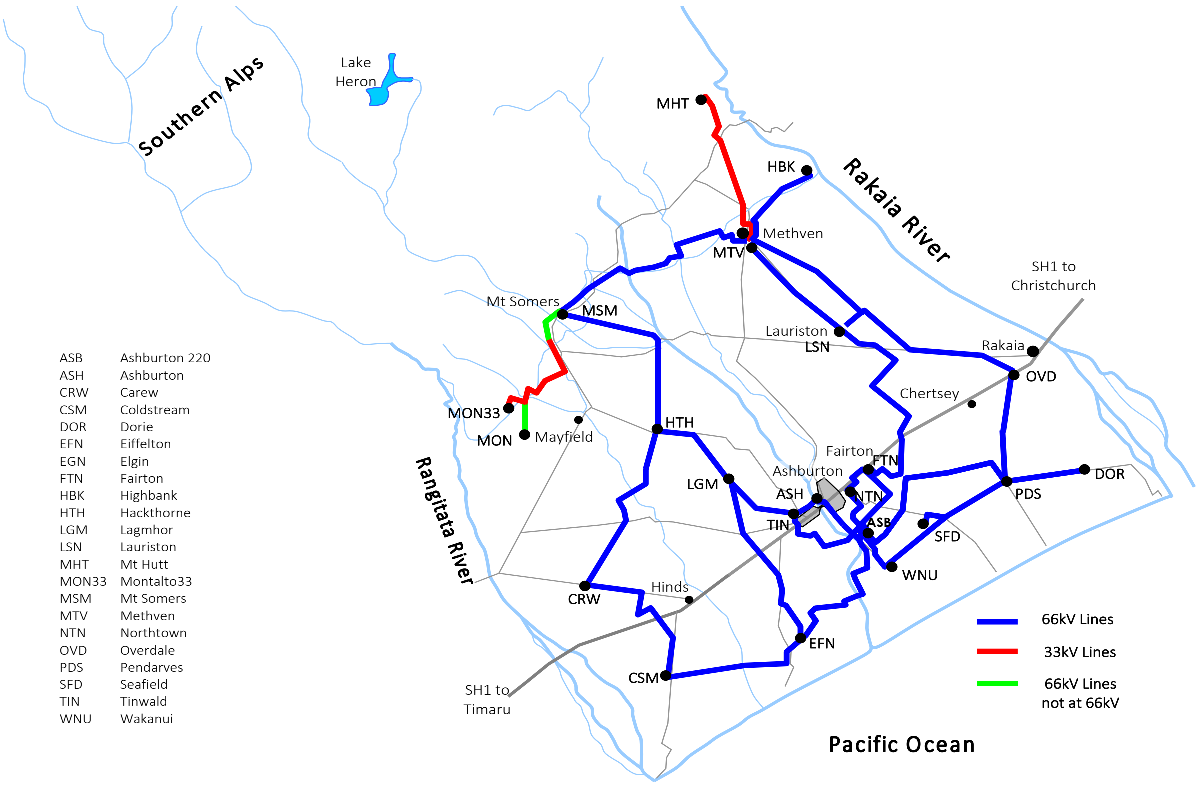
4.2.2 Subtransmission

EA Networks use two voltages for subtransmission: 33kV and 66kV. The 33kV network is limited to two distinct zones with one radial line within each.

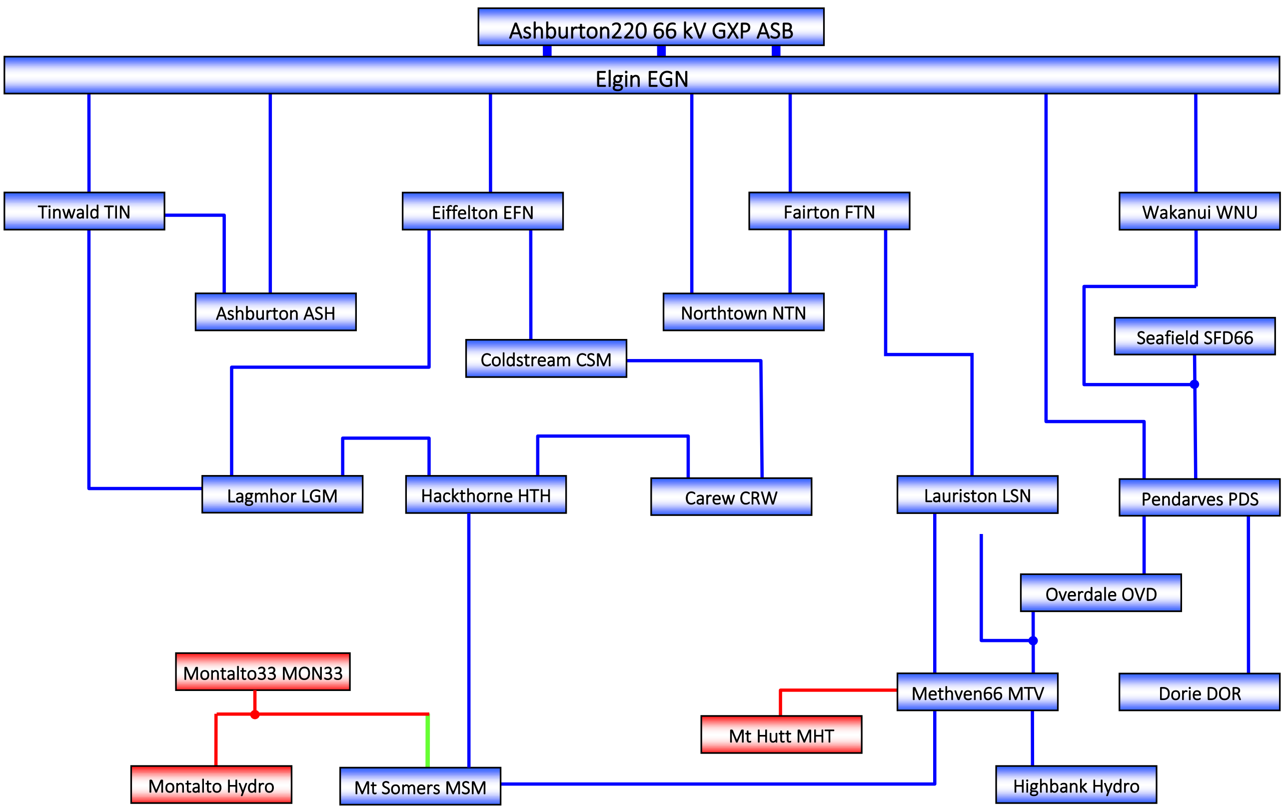
Progressively, the 33kV network has been largely replaced by 66kV network. The most heavily loaded 33kV network was directly connected to the 33kV GXP and supplied Ashburton, Fairton, and optionally, the ANZCO meat works (SFD). This network was retired from service during 2019 after conversion of a zone substation to 66kV (ASH) and construction of a new zone substation at 66kV (FTN).

The remaining section of 33kV network consists of a radial 33kV line supplied from the Methven 66/22/33kV substation. This line is dedicated to the Mt Hutt 33/11kV substation, which supplies the Mt Hutt ski field and the Cleardale generator. Another 33kV line, from Mt Somers substation, supplies Montalto33 substation, and Montalto Hydro Power station. These two 33kV lines are radial, so a fault anywhere along their length means loss of supply will occur.

The 66kV subtransmission network is the core of the rural supply system for EA Networks. The configuration of the 66kV network consists of two internally interconnected closed rings linked between Methven 66 and Mt Somers. The existing 66kV line between Methven and Mt Somers (formerly operating at 33kV) was converted to 66kV during 2024. This has increased security to Mt Somers and Methven by connecting the southern 66kV circuits to the northern 66 kV circuits.



2024 EA Networks Subtransmission Network

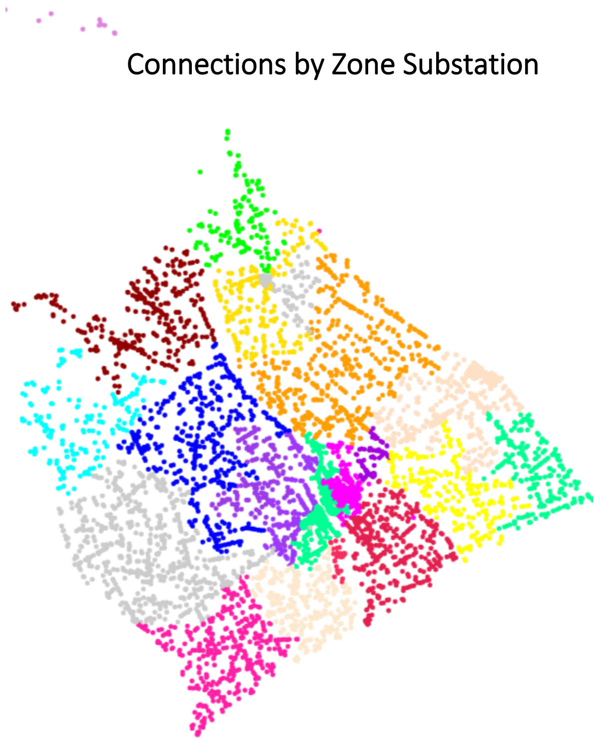


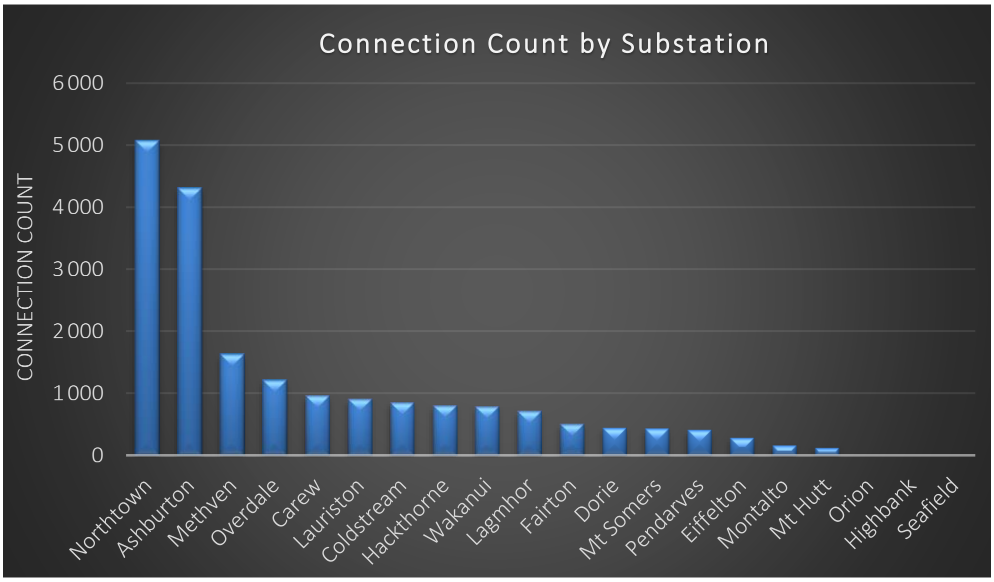
The northern network supplies a number of 66/22kV substations as well as Methven 66/22/33kV & 66/11kV substation. There is a three terminal 66kV line in this section of the network that supplies the Seafield66 (SFD) zone substation. In the middle of summer, the northern network supplies more than 100MVA of load.

The southern 66kV ring is also operated closed and has an internal 66kV line joining two substations. This line offers additional security for faults in the first section of the ring leading away from the 66kV GXP. A fault in any 66kV line in the southern ring should not result in any outage for consumers. A 66kV line between Elgin (EGN) and Ashburton 66/11kV substation (ASH) has recently been completed and includes about 2km of 66kV underground cable. This new circuit has increased the security of Ashburton township considerably.

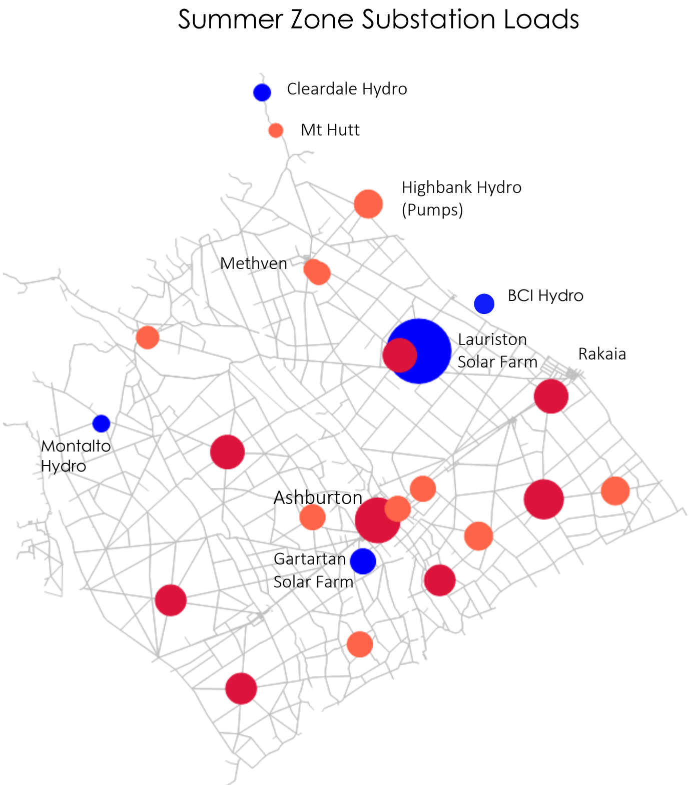
4.2.3 Zone Substations

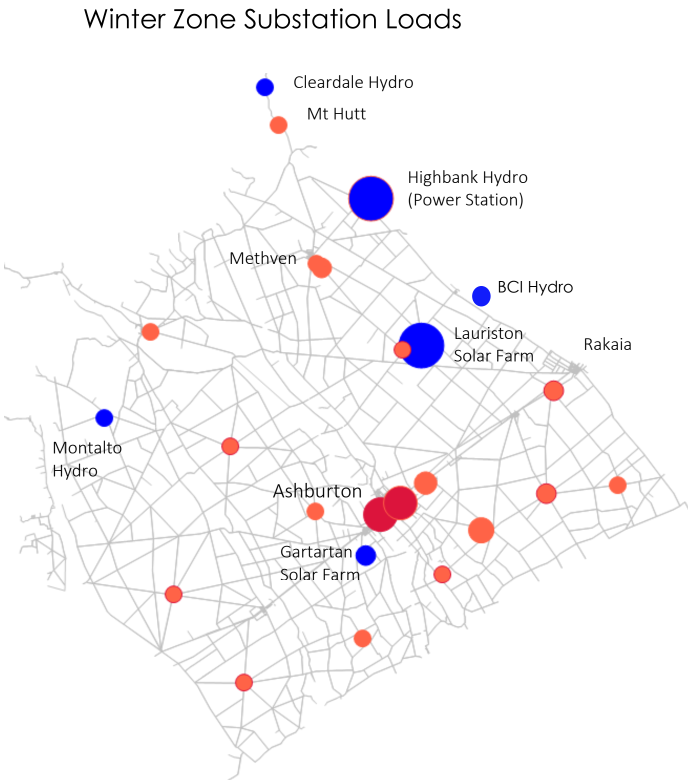
Zone substation loads and security are detailed numerically in section 6.7 as well as Appendix C. The load/generation centres shift between the summer/winter seasons. This shift requires the network to support high urban loads and high rural generation during winter. During summer, the rural load increases dramatically, most hydro generation disappears, and solar is intermittent. These two distinct load/generation configurations are not particularly conducive to efficient network utilisation since energy is not being generated close to the available load. Another factor with electric irrigation is the need to keep fault levels relatively high so that large motor starting (an intrinsically poor power factor situation through predominantly reactive overhead lines) is less disturbing to other consumers. Modern *soft* starters and variable speed drives have helped this aspect, but drives can introduce other potentially disturbing characteristics. Increased lengths of 22kV capacitive underground cable have also improved overall power factor. Consequently, in winter, many rural feeders experience leading power factor.

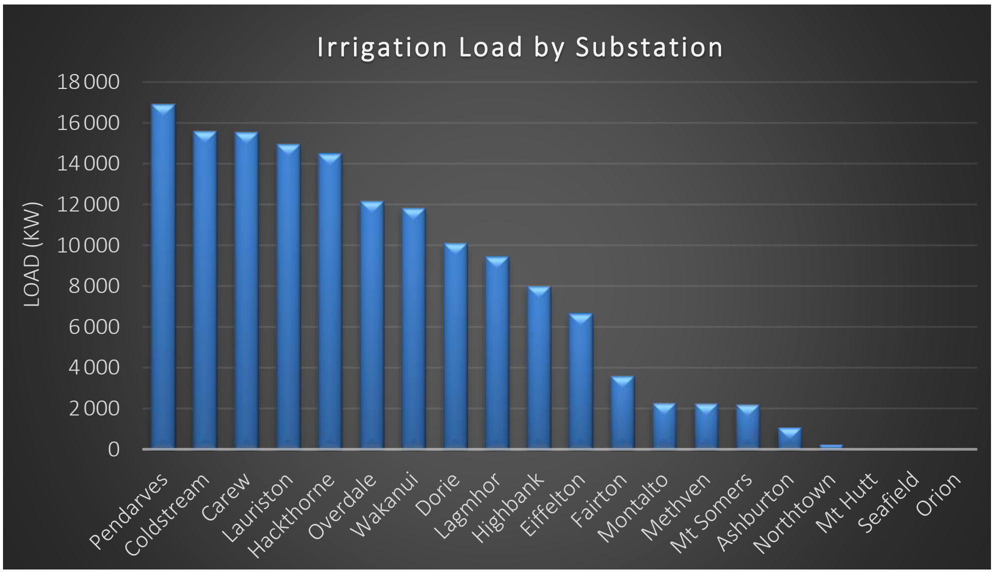




A typical 66/22kV zone substation will have two 66kV lines supplying it. Line differential and distance protection is installed on each 66kV line terminal circuit-breaker. The tubular aluminium 66kV bus is supported by steel stands and has high impedance bus zone protection installed. An ONAN/ODAF 10/20MVA 66/22kV transformer with a +5/-15% tap-changer is installed with an accompanying 22kV 40Ω NER (neutral earthing resistor). A numeric transformer differential relay protects the transformer. An indoor 22kV 5-way switchboard (one incomer and four feeders) is installed with numeric protection relays. The 22kV feeders leave the substation in 250 amp rated underground cables







that are terminated outside the substation on suitable poles connecting to overhead lines. Large urban substations will have multiple 66 kV bus-sections, bus-section circuit-breakers, multiple 66/11 kV transformers, an 11 kV NER, and multiple 11 kV switchboards with at least one bus section circuit-breaker in each board.

The preceding load maps represent existing zone substation maximum demands themed by colour and circle diameter. The larger and redder the circle, the larger the load is. The blue circles represent distributed generators. Highbank at 28 MW is by far the largest of the four hydro sites and currently only runs consistently during winter due to irrigation demands on its water supply (Rangitata Diversion Race) during summer. The two solar sites commissioned in late 2024 are year round with variable output (and nil at night).

The three charts above and below show the irrigation load by zone substation as well as the connection count per substation. Examination clearly shows the large disparity between the two measures. Roughly 50% of the connections that EA Networks supply are on two substations (Ashburton and Northtown). The irrigation load that these two substations serve is minimal.

A more detailed description of the assets at each zone substation is included in section 6.7.

4.2.4 Distribution System

The distribution system is the most obvious and visible part of the electricity network. It is on the side of many roads and, when it is overhead, the poles and wires are immediately evident. It is also the most numerous, asset intensive, and fault prone portion of the electricity network.

Medium Voltage

EA Networks operates two medium voltage distribution voltages.

The 11kV network is the system which has been used since around 1960 in Mid-Canterbury. It has served EA Networks well and it will remain as the dominant voltage for distribution in Ashburton and Methven townships. The extensive 11kV underground cable network in both townships means that it is not economically viable (or currently technically necessary) to convert it to 22kV.

The 22kV network voltage has been in use since about 1997. Each year since then, some portion of the heavily loaded 11kV rural network has been converted to 22kV. 22kV has become EA Networks' rural distribution voltage of choice. The dramatic increases in irrigation load during the early part of this century could not have been accommodated on the pre-existing 11kV network or even a heavily upgraded 11kV network.

It is fortunate that the small rural townships had not been heavily converted from overhead lines to underground cables. This has allowed townships such as Hinds, Rakaia, and Chertsey to be supplied directly from the surrounding 22kV distribution network. Other townships such as Mayfield and Mt Somers have also been converted to underground distribution and all these cables are operating at 22kV.

A typical rural 22kV feeder will have about 175 connections on it. The feeder will leave a zone substation indoor circuit-breaker in a short length of underground cable and connect to the overhead line on a nearby pole. The main feeder line will then radiate away from the substation for an average of about 10-15km. At the end it generally encounters an adjacent feeder (typically fed from another zone substation) with an open switch between them. At various points along the feeder there may be spur lines protected by reclosers, ring main units, fuses, or sectionalisers. These devices prevent the main feeder circuit-breaker from tripping for faults on these spur lines, thereby keeping supply on to most consumers during such faults. There will typically be several points along the feeder where it can be interconnected with adjacent feeders. These normally open switches are either disconnectors, SF_6 gas switches, or ring main units. Remote control of these switches can speed restoration significantly. Fault indicators will be located at some junctions where multiple lines branch off the main feeder line. These indicators will show if a fault current has passed it recently. If an indicator is triggered, the fault is beyond that point, aiding in locating faults more swiftly. Ring main units are being used at points in the rural network where there are many lines that require switching (at least three, normally four). 22kV feeders can have peak loads up to 7MVA although typically they are around 4MVA. The length of a rural feeder is constrained by voltage drop along its length. It is very rare that a thermal limit is reached as conductors must be sized for voltage drop, and this typically results in larger conductors than would otherwise be thermally required to supply the load.

A typical urban 11kV feeder is completely underground and currently has about 450 connections on it. At every distribution substation on the feeder a ring main unit will be installed that allows isolation of the cables connected to it, as well as the transformer supplied from it. This allows ready isolation of a faulted item, speeding restoration as well as permitting planned outages of assets without supply interruption. Fault indicators are used at regular intervals along a feeder to permit prompt identification of a faulty cable or transformer (which will normally cause a feeder circuit-breaker tripping). The opportunity for interconnection with other feeders is far greater in an urban area simply because of proximity/density. It would not be uncommon to have four or five points that permit at least partial back-feeding of an urban 11kV feeder. The *reach* of an urban 11kV feeder is normally constrained by cable thermal considerations. The rating of a buried cable is thermally limited, and prudent sizing is required to ensure adequate capacity for future demand without over-specification. An underground feeder may radiate up to 4km long (cable route) and typically has a peak load of around 3MVA. This limit ensures a 4.5MVA capacity feeder can provide back-feed support to adjacent feeders in case of a fault.

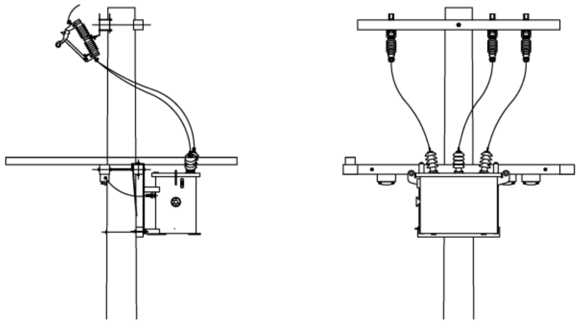
The degree of underground cable usage is very dependent on the voltage. The urban 11kV areas adopt intensive use of underground cable. Methven township is completely underground at both 11kV and LV levels. The only poles in Methven are street lighting poles (supplied from underground cables). Ashburton township is by circuit length approximately 93.4% underground cable at 11kV and at LV is 96.2% underground cable. Overall, the 11kV network is 44.0% underground, and the LV network is 92.1% underground.

At 22 kV, the penetration of underground cable is much less. 12.1% of the 22 kV network is underground.

The distribution network (22 kV, 11 kV, and LV) is 30.9% underground by circuit length.

Distribution Substation

A distribution substation is a facility in the network that accommodates equipment that switches and transforms medium voltage (MV – 22 kV and 11 kV) to low voltage (LV – 230-400 volts). There are a range of styles of distribution substations.



A pole-mounted substation is a relatively simple assembly of assets. The key component is the transformer which is hung from a short crossarm using galvanised steel brackets that are supplied with the transformer. These brackets are secured to the crossarm for both seismic security and restraint should a vehicle contact the pole. The transformer has a set of MV drop-out fuses mounted above it (generally on a separate crossarm) that provide the transformer with fault protection as well as the ability to isolate the transformer should it be required for maintenance or replacement. A set of LV fuses are installed on the transformer hanger arm which ensure any fault in the connected LV network does not cause the MV fuses to operate and also provides some overload protection to the transformer.

Several types of ground-mounted distribution substations are in use. The simplest ones consist of an off-the-shelf *microsub* or *minisub*. These are a ground-mounted transformer with two cabinets directly attached to the body of the transformer. One cabinet has the MV bushing wells in it and can have one or two cables per phase connected (two cables allows a connection to another transformer). The second cabinet houses the LV bushings and can accommodate several LV cables and a number of LV fuse-disconnectors. This style of substation is used when small (<150 kVA) supplies are needed and there is no need for multiple high-capacity LV circuits. They are commonly used on rural properties for houses, sheds, small dairy sheds, etc particularly when they are fed from a nearby overhead line. Some of the larger microsubs have two MV bushing wells per phase (bridged internally) that allow two cables to be connected. This permits simple disconnection of one set of screened elbow terminations to occur when the need arises. The microsub and minisub both use precast concrete foundations.

The next level of sophistication comes with a pad-mounted transformer and either one or two separate small steel kiosks. This arrangement provides the ability to house a MV ring main unit in one kiosk and a multi-way LV switchboard in the other kiosk. These substations can be large (up to 1 000 kVA) and are used in commercial/industrial applications where an exposed transformer is less conspicuous. The concrete foundations for these units are also precast to one of two standard designs (depending on transformer rating). These substations can be integrated into an interconnected urban/industrial/commercial LV network.

The final variant of the distribution substation is a large single kiosk design (below; 11 kV left and 22 kV right). The kiosk is either fibreglass (11 kV) or steel (22 kV) and houses a transformer (up to 500 kVA), a MV ring main

unit (up to 5 x 11 kV or 3 x 22 kV circuits), a LV switchboard (up to 7 x 630 amp rated circuits plus 3 x 60 amp streetlighting/auxiliary circuits), and any ancillary equipment such as streetlighting ripple relays and maximum demand indicators or a PowerPilot power quality and demand meter at more modern sites. These substations are the standard style used for residential areas and integrate fully into the MV and LV networks.

An urban distribution substation can supply up to 100 residential connections on multiple LV feeders.

Low Voltage

The low voltage distribution network is largely located in the urban areas. Rural LV is typically short overhead lines or underground cables from a pole mounted distribution substation to the property boundary (EA Networks ownership typically ends at the boundary).

The urban LV network is either a small amount of older overhead lines located in the townships or predominantly underground located in the townships. Overhead LV is smaller in capacity and has virtually no interconnection (via switches) with adjacent overhead LV network fed from other distribution substations. The reason for the low level of interconnection is twofold: (a) the small LV conductor capacity means it is typically incapable of providing adequate back-feeds and (b) the pole-mounted distribution substations are typically much smaller, further apart, and cannot provide the extra capacity for back-feeding. The urban underground LV network is much higher capacity and has a great deal of interconnectivity. This allows the shifting of segments of the LV network from feeder to feeder and substation to substation during either planned or fault work. The switching of these segments (between substations) takes place at distribution boxes housing compact LV switchgear (see image above right). The style of switchgear in use allows live (dis)connection of cables, installation of new ways, and even interconnection of two adjacent cables without using the bus. This very flexible system provides opportunities to accommodate unusual operating conditions. The distribution boxes are standardised designs that use a common backplane/bus that permits addition/removal of plug-in switching devices as required.

4.2.5 Secondary Assets

There are a range of EA Networks assets that are ancillary to the structural or high current/voltage functionality of electricity distribution. These include the following:

<u>Protection Relays</u>

The protection relay assets at EA Networks vary from very few older solid-state devices through to almost entirely modern microprocessor-based units. The standard approach is to use a limited range of standardised devices so that existing designs can be readily reused, and staff do not have to retain familiarity with too many different devices. Although this may not be the lowest initial cost, it provides the most economical lifetime cost. At subtransmission voltages, every protection scheme incorporates a local device that will provide back-up in the event of failure or non-detection of a fault. This ensures that the minimum amount of equipment is removed from service during a relay fault. At distribution voltages, the zone substation transformer protection provides back-up to the feeder protection. Beyond the feeder circuit-breakers exist a range of reclosers, ring main units, and sectionalisers that do not have local back-up, but rely on the feeder protection relay to detect the fault if they do not. This leads to larger loss of supply, but the fault is still cleared safely.

Section 6.12 provides some additional information about the protection relays at EA Networks.

<u>Ripple Injection Systems</u>

EA Networks operate a 283 Hz decabit ripple injection system. The injection plants are all solid state. There are two operational injection plants. The 11 kV plant at Ashburton 66 kV substation (ASH) provides signal injection in conjunction with the 22 kV plant at Transpower's Ashburton220 substation (ASB). The 22 kV plant utilises a 66/22 kV transformer in the adjacent Elgin substation to couple into the 66 kV network. These two plants work in synchronism, providing signal for the entire 66 kV network. In the event of a problem with the ASB plant, the ASH plant can provide some signal, but it is unlikely to provide complete system coverage during peak loading conditions. There are projects in the plan to enhance load control signal strength and resilience. It is planned to replace some components of both ripple plants with higher capacity items. Section 5.4.11 and Section 6.15 provide more details on these projects.

SCADA Systems

The SCADA system is available at all of EA Networks' zone substation sites. Sites with numeric protection relays have all been integrated onto the SCADA system. One of the smaller sites does not have full monitoring but does have remote control. Section 6.14 provides additional information about the SCADA system.

Telecommunication Systems

EA Networks own a fibre-optic data network (as a separate commercial function) and extensive use is made of it for electricity network telecommunications. A digital mobile radio (DMR) network has been implemented as the primary voice communication system for EA Networks. DMR offers digital audio clarity and the ability to transparently transport small data packets such as GPS location, device control signals, or SMS messages. Another advantage of DMR is the ability to integrate multiple base stations to provide better coverage. The seven base stations are interconnected using TCP/IP over the fibre network or microwave radio links.

Other uses of the large reliable bandwidth that fibre offers include the SCADA system, protection systems, and video monitoring of zone substation buildings and yards. This allows not only intruder detection but also an additional layer of safety as the control centre can monitor staff while they are on site and response to any incidents can be immediate.

A more comprehensive description of the telecommunications network is available in section 6.14.

4.3 Asset Justification

In order to justify the existence of the present EA Networks owned electricity network assets, one could look at it from first principles and prove by calculation that the class and size of each asset category is the minimum needed to support the loads that exist on the network. Alternatively, one could assume that only variations from the Australasian norm would need to be justified – the evolution of the Australasian electricity networks have occurred progressively over the last 60 years and most networks have ended up with a similar style and scale of investment. The following table documents what EA Networks anticipate the electricity industry considers to be the *average* network:

Network Feature	Characteristics
Connection(s) to National Grid:	One or more supply points operating at one or more voltages at or between 11 kV, 33 kV, 66 kV and 110 kV. Typical respective capacities: 10-60 MW (11 kV urban supply), 20-100 MW (33 kV general supply), 50-250 MW (66 kV general supply), and 150-500 MW (110 kV general supply). Capacity is comparable with the peak load of the supplied network with an appropriate security margin.
Subtransmission Network:	33 kV, 66 kV or 110 kV network with typical respective capacities of 25 MW, 55 MW and 95 MW per overhead circuit. Maximum voltage drop not exceeding 10% during *n-1* security events. Typically, overhead lines in rural and light urban settings. Normally, underground cables in high density urban settings.
HV Distribution Network:	6.6 kV, 11 kV, 22 kV, and rarely 33 kV network. Capacity determined by thermal rating for short feeders and voltage drop in long feeders. Rural network and older urban network are usually overhead lines. Newer urban network is usually underground cables. Typically rated at between 200 and 400 amps. Voltage drop should not exceed about 5% under normal peak loading.
LV Distribution Network:	230/400 volt network. Rural network and older urban network

	typically overhead lines. Newer urban network typically underground cables.
Distributed Generation:	If it exists, it is typically up to several MW at discrete locations around a network, with cases of 10 to 100MW of solar, hydro, geothermal, or cogeneration stations. Can be connected to either HV distribution or subtransmission networks. In recent times, solar photovoltaic systems have begun to appear on domestic and some commercial rooftops. These generally do not exceed 10kW output and 100% self-consumption is the most economic strategy. Of late, the economics of utility scale PV solar farms have become favourable, with an upturn in applications nationwide.

EA Networks' network can be briefly described as follows:

EA Networks Network Feature	Characteristics
Connection to National Grid:	One supply point operating at 66kV. 66kV capacity 2x120MVA + 1x100MVA. 66kV peak load approx. 180MW. EA Networks have fewer supply points (1) than most similar companies.
Subtransmission Network:	Extensive 66kV network with capacity 55MW per overhead circuit (500 amps). Some radial 33kV network (approx. 17MW per circuit) with no alternative 33kV supply. All significant subtransmission is overhead, except for one run of 66kV cable in the Ashburton urban area. Prior to conversion to 66kV, parts of the 33kV network were operating at 30kV (-10%) during historic peak loads (30% of today's) with all circuits in service.
HV Distribution Network:	11kV and 22kV network. Urban network is predominantly underground 11kV with some at 22kV. Per circuit capacity of 200 to 400 amps. Rural network is predominantly 22kV with some 11 kV and mostly overhead lines with some underground cables. Portions of 11kV rural network can approach 5% voltage drop during peak loading. Prior to conversion to 22kV much of the 11kV network exceeded 5% voltage drop at peak loading.
LV Distribution Network:	230/400 volt network. Rural network and older urban network overhead lines of modest capacity. Newer urban network is underground cables of significant capacity.
Distributed Generation:	Six significant distributed generators: 0.5MW, 1.0MW, 1.6MW, 6.5MW, 26 MW, and 47.2MW. The 0.5MW, 1.0MW, 6.5MW and 47.2MW units are connected to the distribution network. The 1.6MW, and 26MW units are connected to the subtransmission network. The 26MW unit required dual 66kV circuits from Methven to Elgin to provide additional security and limit voltage rise.

The reader is directed to section 1.1 for the evolution of the present network and it is hoped that along with this section it provides adequate justification for the network in use today.

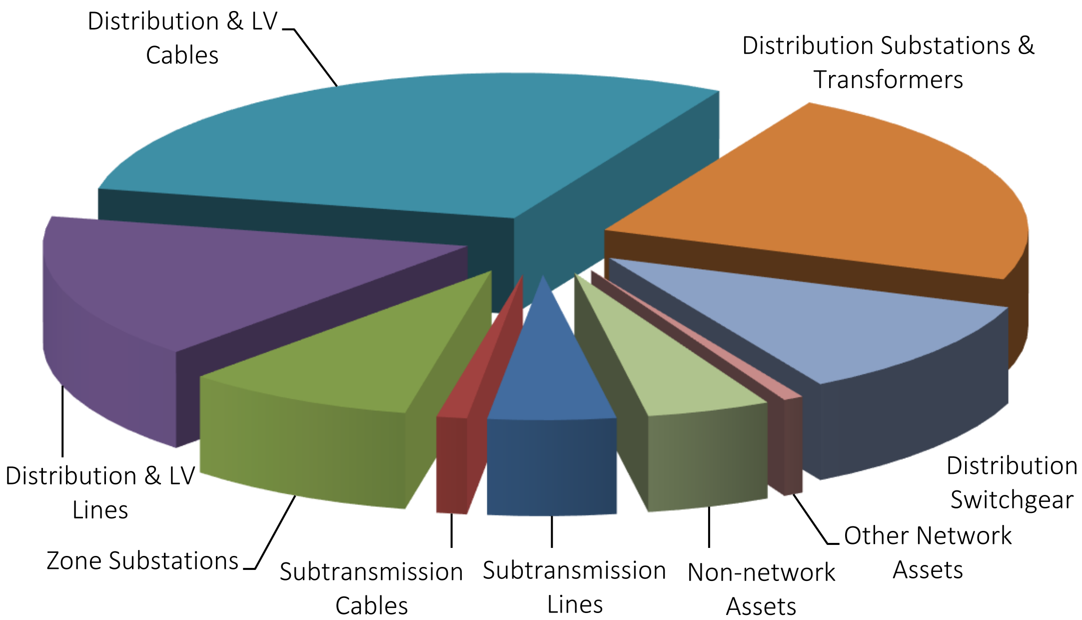
4.4 Asset Value

EA Networks are required by regulation to periodically disclose the value of its assets. This value derived from this process is called the Regulatory Asset Base (RAB).

In order to provide indicative values for the assets covered by this asset management plan, the most recent RAB components are detailed below. The table and chart (below) describe the proportion and value of assets in each category.

The values stated in the table and displayed in the chart are extracted from the 2024 RAB disclosure of asset value as at 31 March 2024. The RAB categories are not completely aligned to the categories used in this plan but do provide an indicative distribution of the value in each category.

Summary of EA Networks Regulatory Asset Base (2024)		
Asset Category	RAB Value ($M)	Percent of Total
Subtransmission Lines	17.2	4.9%
Subtransmission Cables	4.1	1.2%
Zone Substations	31.0	8.8%
Distribution & LV Lines	57.4	16.3%
Distribution & LV Cables	105.1	29.8%
Distribution Substations & Transformers	79.4	22.5%
Distribution Switchgear	39.6	11.2%
Other Network Assets	2.9	0.8%
Non-network Assets	16.6	4.7%
TOTAL	**$353M**	**100%**



The 2024 closing Regulatory Asset Base (RAB) was $353.22 Million.

Additional information concerning the make-up of EA Networks RAB can be downloaded from:

http://www.eanetworks.co.nz/Disclosures/.

Schedule 5e(i) provides the values used above and can be found under:

Information Disclosure Year Ended 31 March 2024 / Schedules 1-10.

PLANNING OUR NETWORK

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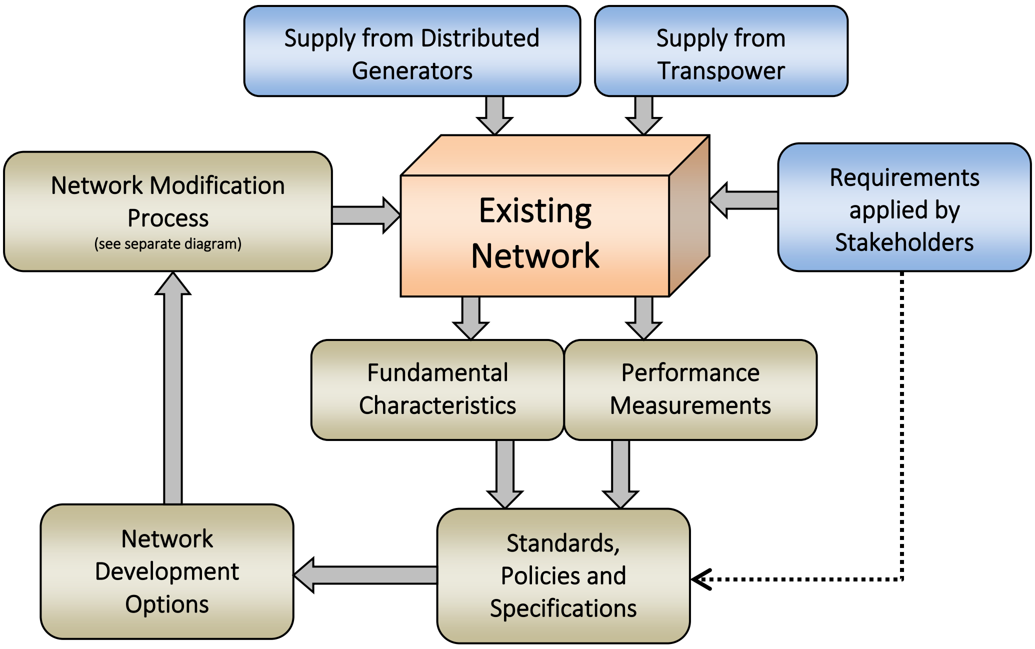
5 PLANNING OUR NETWORK

5.1 Network Development Processes

This section of the Plan attempts to outline the processes and criteria used for network development. It cannot be completely authoritative because the network development environment is not purely technical in nature and normal business negotiations can provide solutions that would otherwise not have been considered.



The EA Networks electricity network that exists today exhibits characteristics and levels of performance that may or may not be adequate to satisfy stakeholders requirements now or in the future. These stakeholder requirements are encapsulated by standards, policies, statutes, regulations, specifications, and contracts/agreements between EA Networks and other parties. If the performance of the network is considered to be inadequate because it does not meet one or more of the stakeholder requirements or a new requirement occurs, some form of network development must be initiated. Once initiated, there are a vast range of methods available to modify the characteristics or performance of the network.

5.1.1 Network Characteristics

An electrical distribution network is fundamentally simple to characterise in electrical terms. Its prime purpose is to transport electricity from one location to another with maximum reliability and minimum loss. The inputs are from Transpower, a directly connected generator (even solar PV), or in future, a Battery Energy Storage System (BESS). The outputs are to consumers who are connected to the EA Networks network.

At each point in the EA Networks network the fundamental characteristics are voltage and fault level. The voltage is what consumers observe. The fault level defines how the network responds to demands placed upon it either by loads or faults.

EA Networks use standard voltages that are industry norms and have international standards that support their use. The range over which these standard voltages can vary is partly controlled by standards and regulations. This is particularly so for standard low voltage supplies (230/400 volts). Higher voltages have standard prescribed upper limits that equipment is built to tolerate both in steady state and in temporary overvoltage situations. EA Networks have determined operational limits for all voltages in use. The standards and operational limits are detailed in the following table.

Voltage	Normal Operational Range (Design)	Contingency Operational Range	Maximum Rated Voltage[1]	Short-Time Withstand	Impulse Withstand
66 kV	105% to 92.5%	106.5% to 89%	72.5 kV	140 kV	325 kV
33 kV	105% to 92.5%	106.5% to 89%	36 kV	70 kV	250 kV
22 kV	103% to 96%	103% to 94%	24 kV	50 kV	125 kV
11 kV	103% to 96%	103% to 94%	12 kV	28 kV	75 kV
230/400 V	106% to 96%	106% to 94%	n/a [2]	n/a [2]	n/a [2]

[1] Maximum rated voltage is approximately 9% above nominal voltage, but other limitations preclude operating at this level.

[2] Because consumers are directly connected at this voltage, the voltage limits are determined by appliance tolerance to overvoltages and appliance standards vary. No overvoltage tolerance is assumed.

Fault levels vary depending upon the electrical path taken from the respective supply points to the point of interest. The maximum fault levels observed on the network determine minimum equipment specifications and minimum consumer connection standards. It is possible to control some additions to fault level by specifying new equipment so that it restricts the contribution it can make to the total fault level. High fault levels cause equipment heating, mechanical stresses on equipment, and require the capability for equipment to interrupt high currents.

EA Networks have established limits to the maximum prospective fault current at each voltage level. These are based upon a combination of historical fault levels that Transpower provide, likely future GXP expansion, typical transformer impedances, and future distributed generation. The maximum fault levels are detailed in the following table.

Voltage	Maximum Prospective 3Ø Fault Current [1]	Power Equivalent	Typical 3Ø Fault Current [2]	Minimum 3Ø Fault Current [3]	Typical 1Ø Phase-Earth Fault Current [4]
66 kV	16 kA	1800 MVA	7.5 kA	1.3 kA	1 kA
33 kV	4 kA	250 MVA	3 kA	0.7 kA	1 kA
22 kV	16 kA	600 MVA	7 kA	0.5 kA	0.3 kA
11 kV	20 kA	380 MVA	9 kA	0.5 kA	0.3 kA
230/400 V	20 kA	14 MVA	9 kA	0.5 kA	9 kA

[1] This value represents the assessed highest future fault current anywhere on the EA Networks network rounded up to the next standard IEC value.

[2] This value is the typical fault current close to the source of that supply voltage.

[3] This value is at the extremes of the EA Networks network with at least one network element out of service.

[4] All voltages other than 230/400 V and 33 kV have Neutral Earthing Resistors restricting the total maximum earth fault current to that shown. Actual currents flowing to earth in a fault would normally be less than this value.

5.1.2 Network Performance

Given a network with the characteristics detailed above, applying the electrical loads, reliability expectations, and the stakeholders' power quality requirements tests the capability of that network to deliver satisfactory performance. The reliability of the network is continuously measured and reported in documents such as this Plan. The two things that determine reliability are fault frequency and the ability of the network to tolerate that fault with minimum or no interruption to consumer's supply. Fault frequency can only be influenced when probable causes can be prevented. Network resistance to faults can be influenced by asset availability, design, and operation. Power quality is influenced by many factors, only some of which can be directly controlled by the network owner.

Reliability Requirements

The stakeholders determine the acceptable level of reliability by providing feedback to EA Networks using the methods detailed in section 3.2. This information is used to set desirable network performance criteria which are then measured against the required stakeholder-influenced targets. If these targets are not able to be met using the existing asset configuration or operational methods, then a network development process is initiated. Once triggered, this process is likely to influence the security requirements in some way.

Security Requirements

In simple terms, the security level is determined by the level of redundancy built into the electricity network either by quantity and/or configuration. Section 3.6 details the criteria EA Networks apply when evaluating the suitability of the network to deliver the required level of reliability.

Resilience

A resilient network can resist or tolerate a degree of damage or other adversity and recover from that situation quickly. To have a resilient network, a combination of factors come into play. To name a few:

- redundant circuits
- adequate network segregation
- asset strength
- surplus capacity
- simple asset repairability
- adequate spares
- adequate staff
- adequate plant

Other considerations will also be involved.

Resilience is particularly relevant when considering **H**igh **I**mpact **L**ow **P**robability (HILP) events such as major earthquakes, storms, or floods. The degree of resilience required is difficult to ascertain due to the rarity of events that provide a true test. The breadth of factors that influence resilience means that EA Networks are continuing to consider both the way resilience can be objectively measured and the minimum level of resilience that is required in various parts of the network.

Power Quality Requirements

The simplest power quality measure is the presence or absence of voltage. Very short blackouts (less than 2 seconds) are typically considered as a power quality issue rather than a reliability issue. The effects can be very similar to a much longer outage, but the cause is generally very different. Another fundamental power quality issue is low or high voltage. Consumer-observed low voltage is typically an indication that the LV feeder load has increased to a point that the network cannot keep within the voltage design range. This unexpected issue would initiate the network development process.

A range of other power quality measures are considered as network development initiators including harmonic distortion and flicker. If reliable measurements show that the network is delivering unacceptable levels of any power quality measure, a response will be initiated.

Section 3.7 details the power quality criteria that EA Networks apply when assessing the performance of the network.

Safety Requirements

If it is apparent that the network is providing elevated levels of risk to people or property, the risk will be quantitatively assessed and, if it is unacceptably high, a network development response will be initiated. Sections 1.7.1 and 3.8 outline the primary criteria integrating safety into asset management.

5.1.3 Equipment Characteristics

Any item of electrical equipment should perform satisfactorily when it is used within the parameters considered when it was designed. It is important to respect the limits of any item's capabilities while still considering any limited scope to use temporary overload capacity to increase security. An important set of network development criteria relate to the specification of equipment used within the network, as the *network* is simply an assemblage of many individual items of equipment. Once the equipment is in the network, how it is operated is as important as how it was specified.

Specifications

EA Networks specify all equipment to exceed the relevant electrical parameters detailed in the Network Characteristics section above. This ensures the item will operate reliably regardless of its location within the network. Each type of equipment (transformer, circuit-breaker, cable, etc) has additional characteristics that are specified on a case-by-case basis, but every effort is made to specify standard models of equipment with standard ratings tested to internationally accepted specifications such as IEC.

The capacity and performance requirements of each asset type is detailed in Section 5.4.

Operating Range

Every item of electrical equipment has a rated current and a rated voltage. Utilising these ratings to their maximum (or above) during contingencies can provide a more secure network. To do this reliably, good knowledge is required of the overload capabilities of the equipment and the effects any overload will have on continued equipment operation.

To allow adequate margin for contingent operation, the normal level of operation must be below the rated maximum capacity. Different categories of asset may permit unique (over)loading characteristics.

EA Networks have a largely radial distribution network with multiple interconnections to adjacent feeders and zone substations. The same principle applies for urban 230/400 volt distribution between distribution substations. This network architecture assumes that if an item of equipment fails, the distribution network will be able to back-feed from adjacent feeders. In most cases this will mean a faulted feeder will have at least two adjacent feeders that can provide back-up, and a faulted transformer would have two adjacent substations to provide back-up. These principles allow the following general design/operation thermal limits to be stated in the following table.

Asset Type	Assumed Conditions	Normal Operation	Contingent Operation	30 minute Operation
Power Transformer	Still Air @ 25°C	100%	120%	135%
Overhead Conductor	1ms^{-1} Air @ 25°C	75%	100%	110%
Underground Cable	Ducted in 15°C Soil	75%	100%	110%
Feeder Circuit-Breaker	Air @ 25°C	75%	100%	100%
Disconnector /Switch	Air @ 25°C	50%	100%	100%

For specific network development designs, these general guidelines for normal operation are indicative only. Certain situations may require lower or permit higher loadings than those shown. The contingent operation limits are fixed and determine the required nominal rating of each item of equipment based on any contingent scenarios considered at the design stage.

The operational voltage limits of equipment have been incorporated into the network characteristics contingency limits detailed above (see Section 5.1.1).

5.1.4 Design Standardisation

An approach to design that encourages standardisation has many advantages that can provide tangible cost efficiency gains. Provided the standard designs are not over-specified for the average application (a design that considers the anywhere anytime worst possible case is generally over-specified) then EA Networks will normally consider adopting the design for use elsewhere.

The standardisation approach is particularly prudent when external design expertise has been used to certify or validate a design such as seismic or structural elements. Repeated use of external consulting to *optimise* a design is frequently a loss-making exercise (the cost saving in optimised equipment is less than the consulting cost of the expert). In these circumstances, the designer is advised of the need to consider the design to be a *standard* design and document the environmental and operation limits of the design so that it can be reused with confidence within those limits.

The tangible benefits of standard design include:

- Lower equipment population lifetime engineering costs, although the initial standard design process may be much more time consuming than a one-off design.
- Standard designs can be applied by personnel with less design expertise provided they appreciate and keep within the limits of the design.
- Staff and contractors are familiar with the techniques used to construct and operate the design, which should promote a safer operating environment and more cost-effective construction.
- Design staff have confidence that the design will perform as expected (based upon experience already gained with the design).
- Minimising the stock of spare equipment that must be kept for repairs and new on-demand projects.
- Incremental design improvements can normally be incorporated without affecting backwards compatibility.
- The components for the standard design can be purchased in bulk which encourages cost-effective procurement.
- Standard designs based upon standard components can be more cost-effective assuming the components are in turn based upon some common standard that allows multiple competitive sources for the component.
- Any issues that may arise with a standard design can be attended to with a universal solution rather than individually engineered solutions.

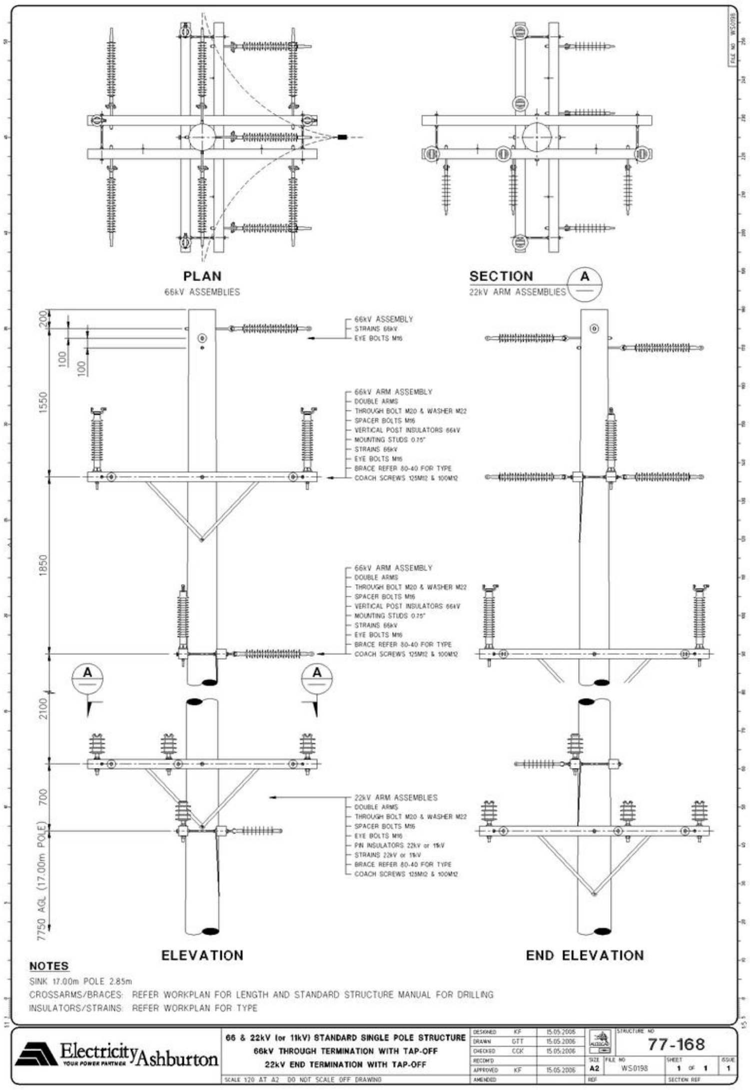
EA Networks' standard designs are identified by the frequency of use and the incremental cost of both the equipment and the design resource required to adequately engineer a solution. If a design is expensive to do and the equipment relatively inexpensive then is makes sense to standardise the design. Alternatively, if the incremental cost of equipment is expensive and the design is relatively inexpensive it could make sense to individually examine each application of the equipment to ensure it is necessary and not excessive in that specific circumstance.

An example of expensive design and relatively inexpensive equipment is protection schemes. The design effort required to specify and document the details of a 66 kV bus zone scheme are typically more than the cost of the protection relay hardware, so it makes sense to standardise the design. Conversely, long runs of 66 kV cable are incrementally expensive to increase in size and it pays to spend sufficient design time to ensure the optimal choice is made (within a preferred selection of sizes).

The following table identifies the range of standard designs (either in full or in part) that contribute to the cost efficiency of EA Networks' asset management:

GXP	
Transformer Size	Compatible with transformer *n-1* situations (all transformers share the same/very similar rating).
Zone Substation	
Transformer Design & Size	Standard size, foundation interface, HV outdoor interface, MV cable interface, control cable interface, impedance, tap range, etc allow any 66 kV transformer to be relocated to any other site without redesign. All units can be parallel connected if needed.

Standard Design Drawing for 66-22 kV Overhead Line Structure



66 kV Bus and Line/Transformer Bays	Seismically certified stand designs and buswork designs are reused at each new/expanded site.
Foundation Design	Seismically certified foundation designs are reused at new/expanded sites.
Building Design	A standard seismically certified building design is reused where appropriate.
Protection Design	Standard protection designs are reused at new/expanded sites for 66 kV lines, 66 kV bus, 66 kV transformer, and 22 kV feeders.
22 kV Switchgear Type	A restricted range of 22 kV switchgear types maintains compatibility with standard buildings/foundations, mounting frames, arc flash controls, and seismic restraints.
66 kV Switchgear Type	Standard styles of 66 kV circuit-breakers (dead tank) and disconnectors (centre rotating) ensure foundation, stand, and mechanical interfaces are all compatible with the standard designs.

66kV Overhead Line	
Structure Designs	All 66kV structures are standardised other than for very rare specific applications.
Conductor Type & Size	A limited range of conductors is used at 66kV (currently only 2). This assists in minimising structural design and inventory of spares and production stock.

66kV Underground Cable	
Cable Size & Type	Wherever possible, one of a limited selection of standard cable sizes are used. Only two types of cable construction have been used.
Trench Profile	A standard trench profile/backfill has known thermal and mechanical performance characteristics which do not require further design for reuse.

22kV Overhead Line	
Structure Designs	All 22kV structures are standardised other than for very rare specific applications.
Conductor Type & Size	A limited range of conductors are used at 22kV (currently 4) when building new lines. This ensures spares and production inventory is kept to a minimum.

22kV or 11kV Underground Cable	
Cable Size & Type	A limited selection of cable sizes and types are used to keep the stock of spares and accessories to a minimum.
Trench Profile	A standard trench profile/backfill has known thermal and mechanical performance characteristics which do not require further design for reuse.

Distribution Substation	
Foundation Designs	Several standard seismically designed foundations are in use. A number are precast designs which are recoverable for reuse should the site be decommissioned.
Kiosk Cover Designs	A range of standard kiosk covers with matching foundations allows a versatile mix of standard modular substation components to be combined. An example would be a high-capacity substation consisting of: MV kiosk for MV switchgear, a precast pad for the transformer, and a LV kiosk for the LV switchgear.
Switchgear Support Frame Design	Support frames for MV and LV switchgear are standardised and allows different standard switchboard design combinations to be accommodated.

Distribution Transformer	
Size	Standard sizes based upon industry standards.
Bushing Interface Design	Interchangeable outdoor (porcelain) and indoor (bushing wells for screened elbows) bushings, which mean the transformer manufacturer's standard configuration can be accommodated under kiosk covers (no special bushing layout for EA Networks).
Foundation Interface Design	All ground-mounted transformers have standard hold down positions which ensures standard foundation use, full interchangeability, and certified seismic strength.

HV Switchgear	
Mounting Design	Gas switches, RMUs, 22 kV or 66 kV zone substation CBs all fit on standard mounting frames or foundations.

LV Switchgear	
Model Range Limitation	Three styles of LV switchgear are used, and each has standard housings and mountings. The link/distribution box switchgear has a standard touch safe busbar that accommodates modular switch types. Only the necessary modules are initially installed, but any combination is possible after installation.
DIN Standard Design	The use of DIN standard design LV Fuse Disconnectors allows standard busbar mounting and interchangeability with multiple manufacturers' equipment.

LV Underground Cable	
Cable Size & Type	A limited range of cable sizes and types is used to keep the stock of spares and accessories to a minimum.
Joint Types	Standard joint types for standard cable sizes allows stocks of spares to be kept to a minimum.
Box Designs	Standard box designs and layouts allow spare box stock to be kept to a minimum and known capacity of LV switchgear can be accommodated. Also allows production of preassembled boxes for stock.

SCADA & Communications	
SCADA Protocol	Use of the industry standard DNP3.0 protocol ensures that engineering work is limited to settings per device. Combined with standard protection designs, this encourages engineering efficiency.
Ethernet Switches	The layer 2 & 3 Ethernet switches in use within the SCADA data communications infrastructure are all industry standard devices which are interchangeable with various makes and models.

5.1.5 Statutes, Regulations, Standards and Policies

Almost all network development will be in response to one or more non-compliant network performance measures which are in turn based upon statutes, regulations, standards, policies, codes, specifications, contracts, or agreements. The range of documents this covers is significant and only those that have broad application will be detailed here.

- Safety. Overarching all the other criteria is the requirement to design, build and operate the network in a safe manner.
- Statutes and Regulations. Statutory/regulatory obligations are a given and the network is operated and developed to comply with all statutory requirements.
- Service Levels. Service levels are set by agreement with stakeholders and these can change from time to time. Service level standards flow through into many technical standards which are intended to result in a network that meets the service level standards.
- Technical Standards. These cover the bulk of asset intensive network activities. Areas covered by technical standards include: Equipment Specifications, Procurement Standards, Design Standards, Construction Standards, and Maintenance Standards.
- Financial Requirements. EA Networks need to make an adequate return on new network development. Any network addition should meet minimum criteria for financial viability and/or provide other non-financial benefits deemed to make it viable. A determination of financial viability is a trade-off with other (possibly future) benefits that are less tangible in the short term.
- Default Distributor Agreement. All consumers who connect to the EA Networks network are bound by the obligations of the *Default Distributor Agreement* via their Retailer. This document encapsulates references to other policies and standards that ensure consumers do not cause unexpected effects on the network or other users of the network. Equally, it obliges EA Networks to provide the levels of performance prescribed by the multitude of standards and policies currently in force. The *Connection Standard* referenced by the *Default Distributor Agreement* includes obligations on consumers regarding underground connection, power factor, harmonics limitation, motor starting limitation, and consumer owned equipment safety. The *Default Distributor Agreement* applies to all retailers operating on the network.

The policies and standards of EA Networks are based on certain underlying principles. The following list provides a broad summary of these:

- The network will not present an elevated safety risk to staff, contractors, the public or their property.
- The network will be designed and operated to meet or exceed all statutory requirements.
- Procurement and installation of network equipment will be compliant with network standards and manufacturer’s instructions to ensure optimal life and performance.
- Network developments will provide an acceptable commercial return for EA Networks.
- Different consumer connection groups will have different reliability and security standards applied to them which represents the price/quality trade-off.
- The reasonable electricity capacity requirements of a consumer will be met.
- A prudent level of additional capacity is designed into the network to allow for predicted load growth.
- All network assets will be operated within the design thermal and voltage ratings to ensure they are not damaged by overloading or overstressing.

5.1.6 Network Development Initiation

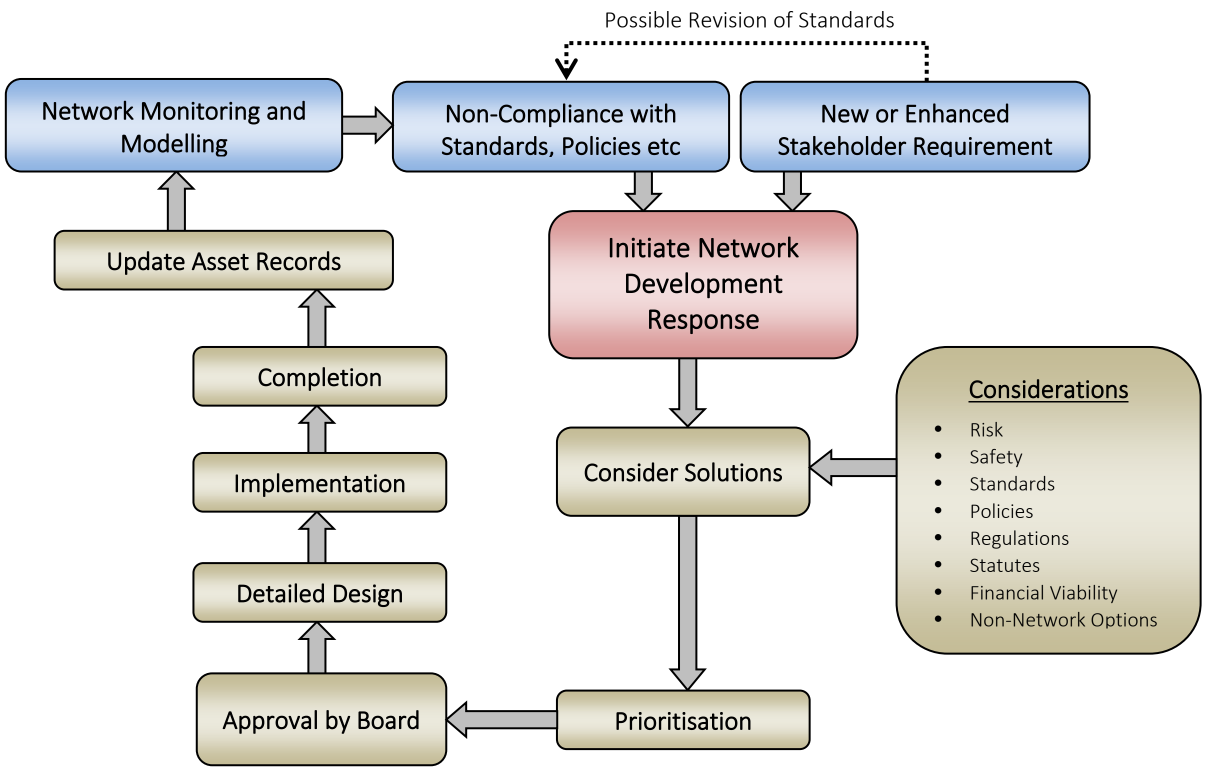
The network development planning process is tightly integrated with this plan. The diagram of section 1.7 gives some idea of the continuously looped sequence of events that deliver the network development strategies presented in this plan. Given that there is an existing network that exhibits certain characteristic levels of performance, the best place to enter the loop is by measuring the performance of the network *Network Monitoring and Modelling*.

There are essentially three key reasons the network development process will be initiated.

1) If an existing or new stakeholder approaches EA Networks with either new or increased electrical demand, a new or increased generation connection, or a desire for enhanced requirements/characteristics at the interface(s) with EA Networks.
2) One or more of the statutes, regulations, standards, policies, codes, specifications, contracts, or agreements is not being complied with.
3) Monitoring determines that a portion of the network is likely to exceed standard loading criteria.

Once the process is initiated it goes through the same series of tests and justifications as any business proposal.

Network Development Initiation, Modification Process and Responses



5.1.7 Connecting New Consumers or Altering Existing Connections

EA Networks implemented an improved, digital process to manage customer-initiated connections to the network at the end of May 2023.

- New Power Supply Request – getting power from the Network to a connection point at the property boundary, or on the property at a required connection point.
- New ICP Connect Requests – getting electricity switched on at the required connection point, working with retailers and metering providers as required.

The main goals of the new process are to improve customer communication across the end-to-end process:

a. Customers now apply for new connections via a webform, and that connects into the EA Networks customer management system.

b. Automated communications keep the customer up to date as required throughout the process (from initial application, through to quote and installation of a New Power Supply).

c. Customers are reminded to apply for a New ICP Connection and work with their retailer if they haven't done so, which helps to minimise any delays in getting electricity livened.

In addition to communication benefits and improved process efficiency across the organisation, the new processes will enable clear reporting of timeframes taken to complete New Power Supply requests and New ICP Connections.

The process for injection customers is still based upon a pdf form with fillable fields that details the necessary information to process and approve the injection application. The form also provides a formal acknowledgement by the generation owner or the generation owner's agent (the form must be signed) that they agree to comply with the relevant EA Networks connection standards and the Electricity Industry Participation Code 2010 (The Code). The timescales and information required to be exchanged is governed by Part 6 of The Code. For injection below 100 kW the connection normally has had load for some time or load is planned to consume the majority of the generation output. These applications are exclusively low voltage and require little to no network alteration. Injection between 100 kW and 300 kW can be either associated with an existing or new load or, on occasions, a dedicated connection for generation. Above 300 kW of injection, the generator is generally using an experienced installer and have good knowledge of what is involved. It would not be uncommon for a dedicated transformer to be required for this scale of injection, and this can be a long lead-time item. Some form of 11 kV or 22 kV isolation from the generator is generally required to allow EA Networks personnel to safely work on the network. The cost of this isolation is passed on to the generator as it is only required because of the new energy source. Large generation connections (>1 MW) are usually rural by their nature (a lot of area required for solar, or a lot of large wind turbines, or a large flow/fall of water). These connections take a relatively long time to negotiate and construct under Part 6 of The Code. There are applications, responses, approval, commercial negotiations, contractual negotiations, equipment procurement time frames, and finally the construction activities (which may require resource consents). For a smaller company such as EA Networks, the effort needed to see a large generation connection through the process is significant. The first two utility scale solar generation connection processes completed during 2024 have provided many lessons and established approaches for future generation connections.

Altering a connection for load follows a similar process to that shown for a new connection. The consumer simply applies for a different scale or style of connection and the relevant personnel are informed for assessment, design, and pricing if necessary. From there the process is one of offer and acceptance, proceeding to the alteration being completed.

An injection alteration is a slightly different process because the purely injection consumer does not provide any ongoing revenue for EA Networks. The consumer will apply for an alteration to the injection connection and the principle of Part 6 of The Code will be followed to offer a cost of network alteration to accommodate the new injection capacity.

The cost of either a new or altered offtake connection has certain thresholds depending upon the scale and location of the connection (the principles that establish these costs are in EA Networks' New Connections & Extensions Policy). The current approach is that a standard fee will apply to connect to the existing network for loads below 300kVA in the rural area and below 100 amps in the urban area. Above these thresholds, the consumer will be required to find the actual non-recoverable cost of the new or altered connection. Network extensions to reach the consumer's connection point are at the cost of the consumer. In rural areas this can have a 10-year duration refund (10% reduction per annum) to the funding consumer by any additional users that connect to the network extension (prorated by distance shared). Where the offtake consumer is required to fund any new network (for a new or altered connection), the general principle currently applied is that they will fully fund any non-recoverable asset. This means that any buried cable, consumables such as terminations, all labour, all plant, and all civil costs will be funded by the consumer. EA Networks will provide the distribution transformer(s), 11 kV or 22 kV switchgear, kiosk cover(s), and any other substantial recoverable asset without charge. The idea is that the customer will provide income through lines charges for EA Networks while they are connected, and should they cease to be connected, EA Networks will recover the unused assets for reuse elsewhere. If the consumer becomes insolvent, it is likely another owner will purchase the entity and continue to provide income for EA Networks, thus funding the recoverable assets. This approach minimises the up-front cost of a new connection to the consumer, while reducing the risk of EA Networks having non-recoverable stranded assets. Consumers are free to engage contractors other than EA Networks Contracting Division for on-property electrical works and this ensures a competitive situation exists for construction of asset not owned by EA Networks.

An injection consumer is required to fully fund any new or altered assets and any other costs in line with Part 6 of The Code. Standard connection requirements are still being established for some sizes of injection, but they are based upon safety and technical need, and this determines the style/rating, and therefore cost, of the necessary assets.

The timeframes for establishing connections varies considerably depending upon the assets and work required.

A simple urban or rural low voltage supply from an existing low voltage network is much quicker to achieve than a connection requiring a new transformer and extension of the network. EA Networks hold a limited stock of transformers available for new connections, but many of the transformers in stock are for use in fault conditions and cannot be allocated to new or altered connections. The myriad of approvals and notifications required for physical site works will always involve some delays and the addition of traffic management requirements adds not only additional resources (that are in scarce supply), but also not inconsiderable cost.

On occasion there exists a tension between planned capital and maintenance works on existing or new EA Networks assets versus the need to satisfy consumers desire for new or altered connections. Generally, it is possible to balance these two calls on resources and if not, there is often the ability to defer network works so not to delay customer connections. However, on occasion when network work is urgent due to safety or reliability, it can cause delays for consumers.

5.1.8 Network Development Implementation

Once an option or strategy has been adopted and approved, it is incorporated into the internal policy documents as well as the Asset Management Plan. This will cause any new project or programme to comply with these approved strategies. An example of this would be the continuing use of 22 kV conversion as a solution to increasing distribution system capacity and quality issues as the norm. 11 kV reconductoring projects would require a different style of approval mechanism as they do not fit an approved strategy.

Once a project is approved by the Board it enters the normal process for scheduling, detailed design, and construction. This is typically completed using internal resources. Once complete, the new/altered asset is incorporated into the asset records and the fiscal/accounting aspects completed.

5.1.9 Network Development Options/Considerations/Methods

There are multiple possible reasons the network development process has been initiated. Not all of these will involve changes in load or security, although the majority do. At times, stakeholders will request changes in perceived safety or even aesthetics and the Shareholders' Committee, Board, and management will consider these requests with the same rigour as any other.

The options available to respond to changes in load or security are very similar in many cases. They will typically involve a change of operating technique for existing assets, an upgrade of existing assets, or the addition of new assets. Non-network solutions are considered but must be suitable to the stakeholder both commercially and practically.

Each of the following options is carefully evaluated based on economic efficiency and technical performance. Wherever possible, capital-intensive development is delayed until absolutely necessary, and non-asset intensive solutions used where these are not incompatible with future development plans. The first three solutions listed are essentially non-asset intensive (non-network in some cases).

The options include:

- Tariff structure (Non-network)

Demand based tariffs give the end user strong incentives to reduce peak demand and maximise plant load factors. This results in less peak demand and better regulation on the EA Networks network. The demand-based tariffs set by EA Networks incentivise third parties (retailers, major industrial users) to the extent that the tariffs are reflected in final prices seen by end use consumers.

- Demand side management (Non-network)

Use of Demand Side Management is linked to the tariff structure and allows the consumer or EA Networks to control the internal demand by shedding non-essential load at peak periods. The success of demand side management is related to the value the consumer places on electricity at peak times versus the cost of supplying electrical demand at that peak time. The majority of demand side management visible to the network is provided by hot water ripple control, with EA Networks providing the ripple control injection system and the third-party ripple receiver owner providing the receiving control of the hot water cylinder, or any other load connect to the controlled supply. Other demand side management approaches are emerging, with a local electricity retailer contracting interruptible load, but this is used for their own purposes and has not been contracted by EA Networks. Other retailers and flexibility providers are providing demand side management via smart meters and demand shifting incentives such as free power periods. EA Networks is not aware of the extent of the contribution of these other demand side management approaches but has observed some low voltage network impacts that are likely attributable to free power periods.

- Energy Efficiency (Non-network)

Where a tangible benefit to EA Networks and generally the consumer can be obtained, energy efficiency measures are investigated and encouraged as a delay to asset-intensive development. Many new appliances are already much more energy efficient than previous technology (e.g. LED light bulbs). Educating consumers on the economics of energy efficiency can assist them in making smart choices. EA Networks has various programmes related to encouraging and assisting consumers with energy efficiency (e.g. LED light bulbs giveaways, home insulation assistance, energy audits). This is making a modest contribution. It is hard to quantify the contribution of consumer behaviour (residential, commercial or industrial) related to energy efficiency.

- Line-drop compensation

Line-Drop Compensation (or LDC) can be used in specific circumstances to boost the sending end voltage on a feeder to improve down line regulation. This effectively increases the available capacity on some feeders.

- Localised energy generation and/or storage (batteries) (Non-network)

The rise in availability and reduction in cost of both solar photovoltaic generation and battery storage (household level and grid level) allows various combinations of these to be a consideration for resolution of a network constraint or security issue. Solar PV alone will rarely be able to provide the necessary predictability or availability. Batteries can be used with or without local forms of generation to provide on-demand power/energy. The main constraint with battery solutions is the initial cost and the capacity they offer. The normal life expectancy of both the batteries and the power electronics (10-15 years likely maximum) must be factored into any comparison with a longer life (40+ years) conventional asset-intensive solution. EA Networks has installed circa 70kW of solar generation on the depot buildings to partially offset the office and depot demand, but this has not been employed as a non-network solution. In some small-scale distributed generation solar installations batteries are also being installed - presumably for back-up or generation/load shifting purposes. This is consumer driven and not being sought as a non-network solution to date. Within the EA Networks area there is circa 2 MW of battery capacity associated with the former Solar Zero product, that was available as a flexibility/virtual power plant. Utility scale solar generation is currently being constructed without battery capacity but allowance for future installation is being made in designs, in anticipation of economic conditions which would favour use of batteries in generation time-shifting or for flexibility services etc. At current state, the network is largely constraint-free, so flexibility services and non-network solutions have not been sought from the above providers.

EA Networks considers generation and batteries as a non-network solution against the conventional network solution on a lifecycle cost basis, while ensuring that the solutions are comparable in security and reliability. Remote Area Power Systems (RAPS) have been evaluated as a non-network solution to the renewal and replacement of overhead lines in remote areas of the network. Where a RAPS solution would be proven to be more economic, we would consult with the connected customers because of the obligation to maintain network connection unless agreement to disconnect is obtained. For a detailed description of a recent investigation, refer to section 5.4.12.

- Voltage regulation

Voltage regulators can be a useful measure if load growth can be reliably predicted. If the load exceeds the rating or boost capacity of the regulator, a new larger unit must be purchased requiring the smaller unit to be relocated, stored, or sold. Regulators can increase losses and are an increased security risk as they can fail (a spare is therefore required).

- System reconfiguration

System reconfiguration is the first choice of any asset manager in accommodating additional load. Caution must be exercised to ensure that the combination of reconfiguration and new load does not compromise the security levels offered to existing and new consumers. Typically, the capacity liberated by reconfiguration is limited.

- Reactive compensation (capacitors or power electronic devices)

Installing capacitors at strategic points in the network where voltage constraints are present or imminent can postpone the need for more asset intensive solutions. In some cases, load growth for a particular installation may require increased reactive support, and the consumer is required to contribute to the capital expenditure involved. Irrigation sourced harmonic levels on the EA Networks network make a capacitor option more expensive than on many other networks.

Recent development of lower cost power electronic devices that can provide power compensation are another option. These may be able to simultaneously provide other functions such as harmonic filtering.

- Conversion to a higher voltage

Conversion to higher voltage is a particularly effective solution. Doubling the voltage (from 11kV to 22kV as an example) provides a four-fold increase in capability when the line is voltage constrained. The cost of voltage conversion is higher than some of the other solutions, but it provides a capacity increase that none of the other options can.

- Reconductoring

Reconductoring is asset intensive and can involve significant cost if the poles supporting the existing conductor are insufficiently strong for the larger conductor. The additional capacity introduced by reconductoring depends on the pre-existing conductor size. The most one could typically expect to achieve on the same poles would be ~100% increase in capacity (for example, going from a Mink sized conductor to Dingo – an increase from 220 amps to 420 amps).

- Overlaying with a higher voltage

Overlaying with a higher voltage (LV with 11-22kV or 11-22kV with 66kV) is very asset intensive, and often cannot be justified in terms of the cost involved. In many cases this cost must be borne by the consumer requesting the new or increased supply and becomes their decision in the final analysis.

- Additional SCADA remote control or Advanced Distribution Management System (ADMS)

Automation allows timely pre-emptive or reactive responses to impending or actual events. This can effectively increase reliability and can possibly liberate additional capacity. Use of special protection schemes to allow unconstrained operation except in the case of rare fault conditions while avoiding expensive security driven upgrades is often an economically attractive approach. Functions of an Advanced Distribution Management System (ADMS) like a Distributed Energy Resources Management System (DERMS) can assist with managing the output of distributed generation or battery storage during times of network constraints.

- Load Diversity

Ensure that the diversity within and between different types of consumer groupings are accurately modelled. If the peak demands of each group do not coincide, then capacity is either liberated or not required.

- Loading Knowledge

Accurate information about the existing network loading is essential to permit accurate calculations of spare capacity and the need for upgrades or additions.

- Long-Term Planning

Every solution should be compatible with the long-term plan for network development. This will ensure minimum long-term cost and disruption.

- Coordinated Development

All the proposed projects on the EA Networks network (development, maintenance, replacement, etc) must be fully coordinated to ensure any possible synergistic benefits are realised.

The load growth estimates are used as a basis for determining the likely timing of projects which are justified by load growth and/or security.

The performance targets are used to develop strategies to accommodate both increased demand and other (presumably) improved performance targets. These strategies cover all voltage levels and asset classes and include non-asset solutions. The different strategies are evaluated against each other, and the feasible options are then presented to the Board for consideration (see section 1.7).

Network/asset performance is multidimensional. There are capacity, regulatory, cost, reliability, safety, environmental, and power quality dimensions that trade off against each other. The measurement of all network performance must be objective and complete.

The capacity of the network is the biggest issue that is debated between the regulator, funder, network designer, network owner, network operator, and consumer (all stakeholders). Too much capacity is seen as wasteful. If there is too little capacity (or it is delivered too late) then it is seen as poor service. While there are no simple ways to measure performance in this area, the Board have the desire that any small-medium consumer (typically <500 kW) that applies for a new or enhanced connection before the end of one irrigation season can expect to be connected before the next season starts (in the order of 5-6 months). It must be explained that the term *irrigation season* implies that an application received before April would be connected by September. Most other (<500 kW) urban and industrial connections are easily achieved within this timescale, provided a suitable transformer is available. In order to provide a prudent level of capacity, the estimated 5-10-year future load (as per Appendix C) is used as a minimum to size distribution assets when they are installed.

Regulatory performance is a given. All personnel are expected to be familiar with the regulations that cover their area(s) of responsibility and comply with them (see section 1.7.6). Further work to enhance this understanding via compliance reporting is currently underway. Measuring performance in this arena is as much about peer awareness and external observations (such as other organisation's performance and practices) as it is about internal processes and systems. There have been rare occasions when non-critical regulatory requirements were unable to be achieved. These are generally resolved in the shortest possible timeframe and the necessary resources engaged to prevent a recurrence. Unless the non-compliance is consequential it is not explicitly reported.

EA Networks believe that they are painstaking in their efforts to ensure the network reliability indices reported reflect all incidents that require inclusion in those indices. All outages are *traced* using the electrically connected model included in the Hexagon GIS system to obtain a list of affected connection points. All faults are then entered into the *Faults* database, and this allocates all connection points interrupted by that fault to it. This allows every connection point interruption to be identified and, if necessary, individual CAIDI and CAIFI values reported. The *Faults* database provides the storage and analysis of EA Networks' reliability data. This system will soon be supplanted by the newly implemented and automated Advanced Distribution Management System.

The financial performance indicators are as accurate as the data they are based upon. This presumes that the categorisation of all projects is precise and that allocation guidelines are followed in every instance. These financial values are subject to audit and consequently there is no reason to doubt their precision.

Safety, power quality, and environmental performance is measured and recorded in systems that are best suited to each area.

The safety performance data is integrated with competence, training and other personnel specific information in a system that runs in parallel with the asset management environment. Any safety issues that are linked to asset performance are reported via the Safety Committee to the GM - Network. The GM - Network then obtains engineering advice on available solutions to mitigate or eliminate the source of risk. Where necessary, that solution will be inserted into the asset management approval process for acceptance into the appropriate methodology by the management and/or Board.

Monitoring of network performance for capacity, voltage and power quality is an important input to determining and addressing network development needs. Refer to section 5.1.10 below for a detailed description of approaches and maturity in this area.

Environmental monitoring has been limited to compliance with the relevant legislation and Regional/District Plan rules. This particularly concerns noise, gas and liquid discharges, and District Plan aesthetic rules. EA Networks monitor and, where necessary, record the loss levels of gases (such as Sulphur Hexafluoride – SF_6) as well as fluids such as transformer and hydraulic oil, or stormwater from transformer bunds. The aesthetic rules relate to all new plant being underground in urban and fringe urban zones. These zones are well known and there have been no issues of non-compliance. A *Sustainability Plan* is in preparation for Board approval, and this will provide overarching principles that can be applied to all aspects of EA Networks' environmental impact. See section 3.9 for more details.

5.1.10 Monitoring Load and Injection Constraints

This section summarises EA Networks' approach to monitoring load and injection constraints as part of network planning and asset management. To understand the utilised capacity of the distribution network, its characteristics and loading must be measured and monitored. The data gathered in doing this provides both opportunities and challenges for both existing and new load or injection. This section describes the level of maturity EA Networks have in the various facets of predicting, finding, communicating and, where applicable, resolving network constraints.

Measuring and Monitoring

EA Networks have a comprehensive SCADA system that provides both loading and voltage data for many parts of the distribution network. The current scope of the SCADA system is limited to equipment in the 66 kV to 11 kV voltage range. The equipment within this scope will typically be monitored to provide a clear indication of capacity utilisation. These parameters are logged at relevant intervals and are available for review and historical trending. Alarms are set to identify high loading and high/low voltages. These alarms give warning of potential constraints. The monitored equipment includes:

- 66 kV circuits,
- zone substation transformers,
- 11 kV or 22 kV feeders, and
- some stand-alone 11 kV or 22 kV switchgear.

Each zone substation has a power quality meter that measures a large range of parameters including substation loading, power factor, current, and voltage measures. Many of the sites have more than ten years of data history.

Urban ground-mounted distribution substations will typically have some form of LV (Low Voltage) maximum demand indicator fitted. These include:

- analogue thermal drag hand meters,
- non-communicating multi-parameter digital meters, and
- communicating PowerPilot meters.

The non-communicating devices are typically read and reset twice a year, while the PowerPilot units are remotely read every ten minutes and provide a wealth of loading and power quality information into a logging database. The twice annual readings are of some use but do not indicate the time, frequency or duration of maximum demand, making its value much less than the continuous stream of PowerPilot data (voltage, current, kW, KVAr, THDv, THDi, voltage balance, current balance, etc).

There are plans to expand the PowerPilot LV monitoring network to include the end of LV feeder devices. This will allow lowest voltages (heavily loaded conditions) to be logged and provide some indication of highest voltages (high injection or low load conditions).

Large new injection sites (>250kW) typically have some form of dedicated power quality metering installed to ensure the connection performs as expected and no power quality issues arise for either the network or the generator.

Future budget has been allowed to source smart meter data in a third-party solution that provides immediate insight into both existing and forecast network capability/constraint at a low voltage level. Some initial contact has been undertaken with retailers and MEPs (Metering Equipment Providers) about provision of both consumption and voltage data, but no contracts have been drafted for data provision. EA Networks have identified some challenges with this process, in that the cost for providing the data sought is not inconsiderable and the contract duration proposed is significant. In EA Networks' view, many issues with distribution network power quality, capacity, and incipient faults (e.g. faulty neutral connections) could be solved by taking a year-long data extraction, addressing all the issues identified, then returning for a subsequent data extraction in several years' time. Data providers do not support this approach, and their longer contract term and high cost of data provision is imposing costs that will add to the burden on network end-use consumers.

Predicting Constraints

Constraints can occur at any level of the distribution network. They are much more obvious at higher voltages such as 66 kV and 33 kV (sub-transmission). SCADA tends to reveal sub-transmission loading in real-time and it becomes readily apparent when approaching either n or n-1 constraints. Reasonably comprehensive modelling of the sub-transmission network and zone substations ensures there are no constraints that occur without warning. The 11 kV and 22 kV distribution network are more dynamic and there can be occasions when n-1 constraints appear during back-feeding, but these are temporary and rare.

The LV network is much less predictable. Consumer choices in retail pricing options and asset purchases can dramatically impact the network without warning. Examples of this are:

- Free power hours which drive the normal diversity of appliance use out of each household and can cause sudden increases in load and/or decreases in supplied voltage. The amount of energy delivered in a day is the same, but a lot of it is provided in one or two hours. This is inefficient - a loss of network energy delivery capacity over a day driven by retailer “herding” consumption into a limited period.

- Electric vehicle charging at home during peak hours. Some owners of EVs do not yet consider time of use electricity cost when selecting EV charging timing, as electric energy is still much cheaper than petrol or diesel even at $0.30 per kWh. This is loss of peak power delivery capacity.
- Roof-mounted solar panels. Although EDBs get a few weeks warning of new domestic solar generation, the impact of a 5kW single phase array can be significant and may require alterations to the distribution transformer tap position. Lowering the LV voltage at the transformer is a permanent loss of load capacity. Instead of ±6% voltage range it changes to +3.5% to - 6% (a loss of 21% of load capacity). No revenue is obtained from solar to replace this lost load capacity – all consumers must pay for its replacement (if needed). Solar generation doesn’t typically match peak network loading conditions so will not offset peak demand to compensate for the loss of capacity due to compensating for the voltage issue described above.

It is planned to create distribution network models by extracting the connected GIS network model (to ICP level) and importing it into a third-party network analysis software that can profile both existing and future connection loading/injection. This software will highlight areas of the network that may come under pressure and potentially constrain either load or injection in the absence of network changes or flexibility options. The option to import the network model into a desktop load-flow package is also planned. This will allow detailed analysis of specific loading/injection scenarios where necessary.

EA Networks are reasonably fortunate to have an ongoing underground conversion programme that has given a significant capacity boost to the urban LV network. There are some well-known older underground reticulation areas that have smaller cables, and these will be monitored/analysed as a priority using PowerPilot devices at the distribution substation and the end of LV feeders.

Communicating Constraints

When EA Networks become aware of a potential future constraint, it is noted and any consumer that applies for information about network load or injection capacity will be advised of any relevant constraint issues at hand. More general load capacity constraints are considered for reinforcement as the need becomes imminent and these are typically not exposed to existing connected load consumers as this is simply part of the expected service provided by an EDB.

When a new injection consumer approaches EA Networks for a connection, or wishes to inject on their existing load connection, the specific scenario they present is considered and, if there is no constraint, a connection option is provided. Should a constraint exist that would prevent their proposal from proceeding, the details of the constraint are explained and the available options to resolve it presented. This may include modifying the proposal or suggesting a flexible solution involving shifting generation (using storage) to a less constrained time. The injector is made aware of the incremental cost principles of Part 6 of The Code, and they use this information to consider their proposal.

In the case of a large load connection, any constraint is communicated to the consumer and options will be presented to resolve the situation. This may involve a contribution from the consumer and some delay in completing the necessary works. Smaller load consumers expect to be able to connect in relatively short timescales, and this means EA Networks need to keep ahead of the load growth curve. Typically, any trend in load growth in a local area will trigger consideration of works for the good of all connected load customers and what benefit they may receive from any network upgrades or available flexibility solutions.

Resolving Constraints

Constraints of the supply of load are typically assessed for resolution before the load growth forecasts predict the benefits of intervention (network reinforcement or flexibility options) exceed the cost of constraint. In many cases, the revenue obtained from increasing load will justify some form of early intervention by EA Networks in advance of the constraint becoming apparent to consumers. Large step increases in load from one or a small group of large consumers will in many cases open a dialogue so that plans can be shared, and solutions discussed. Timing of solutions can have a big impact on its acceptability and flexibility will always be presented as a viable option for both the consumer(s) and the network (should such a solution be commercially viable).

Constraints on injection will always be couched in the commercial aspects of funding to resolve it. Because no revenue is obtained from most injection connections, there is no direct incentive to remove that constraint in advance of an injection proposal. Once an injection proposal presents itself, any constraint will be explained and the options for resolution detailed. Almost all of these options will have a cost to implement, and the current approach is to require the injection consumer to fund any resolution of the injection constraint. The alternative is to connect with the constraint and flexibly inject within the limitations of the existing network capacity.

Collective injection from many small consumers will ultimately cause constraint at either LV or distribution substation level, typically caused by voltage limits. Unless there is a simultaneous need for load capacity, it is unlikely there will be a commercially viable case for addressing an injection constraint unless the injectors that benefit are prepared to fund the work. In the case of domestic solar injection this is unlikely. It would be more beneficial to put the funds towards storage behind the meter.

Current and Forecast Constraints

Roof mounted solar distributed generation connections have in a limited number of instances driven high voltage complaints, and EA Networks notes these areas as potential areas of low voltage generation export constraint when assessing further generation connections. EA Networks is awaiting the potential increased low voltage regulatory upper limit change before acting on the limited high voltage issues identified.

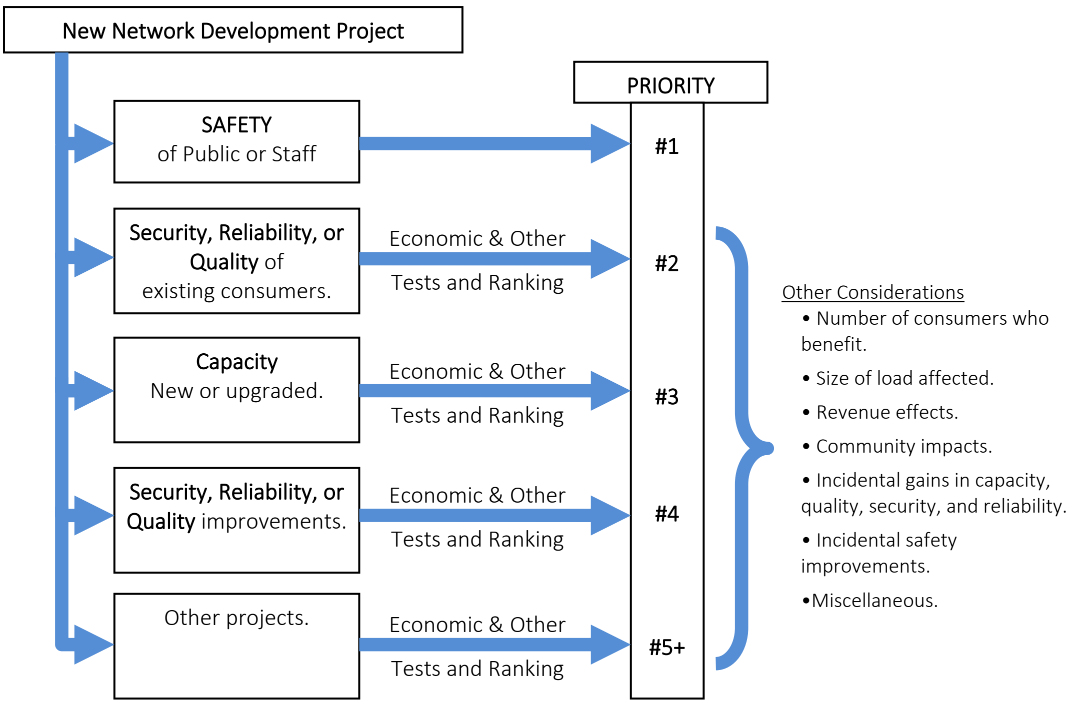
For a 22kV feeder connected solar distributed generator in the east Tinwald area, output constraints have been observed related to the upper distribution feeder voltage limit assigned to the connection. This was accepted by the generator in their final connection application. These types of constraints may be addressed with EA Networks' interconnected open radial network and the ability to change configuration to deal with voltage and export issues.

Larger utility solar DG applications are providing system connection studies that currently do not identify export constraints with all network equipment in service and all currently approved distributed generation operating.

5.1.11 Network Development Prioritisation

Particularly during periods of rapid demand growth, there is a tension between various projects that need EA Networks' available financial, physical, and intellectual resources. The resolution of which issue requires priority is not necessarily straight forward. The general methodology and criteria for the technical and financial evaluation of network development projects can be summarised in the diagram shown below.

Any capital expenditure must be justified, and in normal circumstances such a project is expected to add value to the company by providing an overall positive benefit to EA Networks, our consumers, or environment, over its lifetime. Projects are prioritised by comparing their benefits and ranked accordingly. This determines which projects are preferred for funding out of a limited capital budget.



Ultimately, it is the Board that dictates the immediate focus for the company, and they consider not only the advice offered by management but also external factors including matters such as stakeholder perspectives and overarching business strategies.

5.2 Load Forecasting

5.2.1 Introduction

EDBs across New Zealand are aware that they have a key role to play as their networks enable the decarbonisation and electrification of society, particularly in the transport and industrial sectors. As EDBs confront this challenge, they recognise the importance of providing clear signals to their customers, communities, and other stakeholders, of the likely medium to long term implications of this transition. It is important for stakeholders to understand that this is not 'just' an electric vehicle story – different EDBs will experience increased demands for investment in their networks for a range of different reasons. The drivers listed in section 5.2.3 describe what are anticipated to be the most significant sources of this demand that EA Networks anticipates will occur over the next three decades, out to ~2050. It should be noted that for many EDBs, ongoing 'business as usual' maintenance and renewal of their existing distribution network is, and will continue to be, a very significant driver of investment, however this is not presented here as it is not a 'new' driver of investment of the type the sector wishes to highlight. Lastly, readers should appreciate that while certain elements of the transition are well-understood and reasonably well-fixed (e.g. the net zero by 2050 target), political objectives may vary and other elements which may have a significant impact on EDBs (e.g. the phase-out of reticulated gas for home heating, hot water and cooking), are still uncertain. EA Networks has made an educated assessment of what might be expected on their network, but there are significant uncertainties and assumptions built into this. The EDB sector has, via its association Electricity Networks Aotearoa, developed a more rigorous and structured set of demand forecasts and scenarios out to 2050.

Future load projection is a difficult task and is based on a complex multivariate environment. A careful and rigorous approach must be taken to developing future load projections based on historical trends, available information, and estimates on future changes.

Given the climate of decarbonisation driven by climate change targets, the electricity sector expects a diversity of network investment drivers out to 2050. These drivers include the decarbonisation of transport, process heat conversion to varying degrees between biomass and electricity, population growth resulting in both greenfields and infill development, new commercial or industrial point loads (e.g. data centres, hydrogen infrastructure), residential and commercial gas conversion (only to a minor extent in Mid-Canterbury), utility scale solar generation, climate adaption requiring changes to assets, and the need for investment to improve LV visibility and implement Advanced Distribution Management System functionality to manage the influx of DER, making best use of network capacity. These are largely new drivers that the sector has not experienced before to the greater extent expected. There is still significant uncertainty related to the timing and scale of these drivers, which affects EA Networks' ability to predict load growth and investment requirements, particularly further out in the future.

5.2.2 Derivation of Forecasts

Forecasts of maximum demand on the subtransmission system have been derived from internal modelling work. Sources of information include:

- Historical demand and energy usage data,
- Discussions with real estate agents, well drilling contractors, irrigation system consultants, and other service/equipment providers for rural industries,
- Major consumers connected to the network,
- The '*Canterbury Irrigation Peak Electrical Load*' report prepared for Transpower NZ Ltd by Aqualink Research Ltd – November 2010,
- '*The economic value of potential irrigation in Canterbury*' prepared for Canterbury Development Corporation by AERU Lincoln University – September 2012,
- '*The economic impact of increased irrigation*' NZIER – November 2010,
- Environment Canterbury reports and resource consent applications.

- Electric vehicle uptake statistics from NZTA and trends in solar PV applications to EA Networks.
- '*Thermal Fuel Transition Impact Assessment*' report done by Deta Consultants for EA Networks on fossil fuelled industrial heating in Mid-Canterbury – December 2020.
- *'South Canterbury Spare Capacity and Load Site Assessment Report'* by Ergo Consulting for EECA related to decarbonisation of process heat in Mid-Canterbury and South Canterbury – Draft October 2022.
- Various Transpower strategic documents including Whakamana i Te Mauri Hiko – Empowering our Energy Future (2020)
- We are monitoring Environment Canterbury's Essential Fresh Water Package and will incorporate the findings in our future forecasts. In late 2024, the Government indicated this area will be revisited.
- EECA *'Regional Energy Transition Accelerator (RETA) Mid-South Canterbury – Phase One Report'* completed in June 2023 informed the potential for industrial process heat conversion from coal to electricity or biomass in the Mid-Canterbury region.
- DETA '*EA Networks Transport Electrification*' electric vehicle demand forecasting report, referencing the New Zealand Transport Agency registration data and the Climate Change Commission (CCC) predicted forecast for transport electrification.

These information sources have been used to generate a forecast (e*stimation*) that analyses individual zone substation maximum demands based on present demand with likely additional load allocated by each zone substation for the next ten years. This model has the advantage of locating the estimated load within the subtransmission and distribution networks allowing analysis of the capacity utilisation of many network components. The disadvantage of this forecasting technique is that unknown future loads are not accounted for.

An alternative statistical projection based upon historical demand data cannot account for the now observed downturn in irrigation load growth caused by water extraction restrictions. On the other hand, the individual load estimation reflects that downturn but does not account for unknown future load. The historical projected load growth is considered unrealistic. The estimated load growth has been revised to reflect water extraction and now nutrient run-off restrictions recently imposed by ECAN. A new issue that has been factored in is the potential for industrial process heat to be converted from fossil fuel sources (coal, diesel, and LPG) to electricity. This has provided a notable upswing in estimated demand. The summer system maximum demand will probably be more than 200+MW by 2033.

5.2.3 Significant Drivers

This section considers new connections likely to have a significant effect on network operations or asset management practices and significant drivers on load forecasts.

New Connections with Significant Effect

Demand increases generally come in three ways. The first is organic distributed growth caused by additional electrification of manually, fossil fuel, or renewable powered processes, or the addition of new electrified processes that did not previously exist. Typical examples would include heat pumps, induction hobs, electric vehicle charging, and solar generation. The second type of demand increase is a location specific step change caused by a new industry or an industry that has changed the way it works (expansion or additional electrification). Examples of these would include food processing, manufacturing, or multi-megawatt solar farms. Each of these can have a significantly different impact on the electricity network and different ways of funding the necessary work to accommodate it. The third type of demand growth that occurs is caused by behavioural changes in electricity usage. This can be caused by changes in energy pricing, either at all times or at specific times of the day. It can also be caused by choices provided by third parties such as flexibility traders or home automation systems. The most obvious example of behavioural change is the *free hour(s) of power* concept offered by some retailers that has been observed to cause complete loss of diversity in appliance usage for that hour or period, with individual ICP demand easily tripling or more for that entire period.

Organic growth tends to be slower and widely distributed, slowly consuming any additional capacity in the existing network until supply security limits are approached or breached, potentially in multiple places on the network and involving multiple voltages (HV, MV, and LV). It is possible to estimate the uptake of new or alternative electrically powered technology, but it can be an inaccurate science, and the rate of uptake is not always correctly predicted, even by experts. One of the more cost-effective ways of estimating when an issue may arise is by stress-testing a model of the electricity network and seeing what level of penetration of the technology in question will cause issues. EA Networks are investigating the feasibility of having a third-party entity model and estimate the threshold of LV network constraints for residential electric vehicle charging and rooftop solar. This analysis will, by necessity, be a statistical average and represent a likelihood rather than a certainty of successfully accommodating a particular load or generator. At higher voltage levels in the network, distribution transformer monitoring and MV feeder SCADA system monitoring allows EA Networks to plan upgrades to distribution transformers and/or MV feeders. Equally, zone substation transformers are continually monitored for loading, and any trend that shows either a pending thermal or security risk is addressed on a case-by-case basis. In most cases, when this type of demand growth triggers the need for upgraded or new assets, the cost is borne by EA Networks and passed on to all consumers who utilise those classes of asset.

Location-specific step changes in demand can come from loads, generators, and storage. Step changes in demand are not necessarily signalled well in advance and, due to their commercial nature, the proposal can be quite advanced before the issue of electrical supply is addressed with EA Networks. This can create some concern from the entity approaching EA Networks for a new or altered supply, but generally these issues are only a matter of how any asset changes are funded and the timing for delivery of the necessary capacity. A discussion about available electrical capacity at an early stage would have the potential to save the new load entity a considerable amount of money by locating themselves in proximity to an adequately sized existing source of electrical supply. Uncertainty associated with step demand increases may be caused by ill-defined needs of the entity enquiring, frequently overestimating their demand. EA Networks will respond with an estimate of the cost to provide for that demand. This cost frequently causes the entity to review their demand needs and come back with a more realistic demand estimate. Once they are satisfied with a revised approximate cost, the entity may revert to confirmation of other aspects of their development and connection negotiations may become time pressured as the stated lead-times have not been allowed for by the entity. Negotiations generally ensue to coordinate expectations and the reality of long-lead time items such as transformers.

Behavioural driven changes in demand can be very difficult to accommodate and can be triggered at very short timeframes randomly across the electricity network. This can cause a step change in demand distributed across diverse locations. The classic example of retailers offering free energy during a specific period in the evening is the most impactful illustration seen so far. It is feared that a similar, but much higher impact, situation could arise if retailers offer a time-based tariff for electric vehicle charging that would cause all vehicles to begin charging simultaneously at a specific time. EDBs have no direct control over the types of tariffs retailers can offer, even though the impact on the EDB's network loading is considerable. Well controlled electric vehicle charging will ultimately be the lowest cost option to both the vehicle owner and New Zealand's economy with little to no impact on the charging experience for the vehicle owner. This requires a coordinated all-of-industry (generator, grid, retailer, distributor, and flexibility trader) approach to work effectively.

The timing and uncertainty of demand, generation, or storage is addressed in a number of ways and some of those have already been mentioned above. In general, if developments are uncertain and therefore income from those developments are uncertain, there will be less incentive to either set aside existing capacity or install new capacity for that development. The more certain a development becomes the less risk of stranded capacity becomes, and thereby it is lower risk to reserve existing capacity or install incrementally more capacity when other planned works are underway. Assets specifically required to accommodate demand, generation, or storage are not installed until it is clear a commitment is made by a developer or organic growth trends show it to be necessary.

The potential thermal decarbonisation demand in EA Networks area is less than many other areas, and the largest single incremental thermal coal load is the equivalent of 15 MW electrical. This load has indicated they intend to delay electrification until high temperature heat pumps can provide the same thermal output as the boiler, reducing the electrical demand by a factor of two to three (5-7 MW). The total assessed coal load is equivalent to no more than 20MW. Biomass burnt in modified coal boilers remains an alternative to electricity conversion, provided reliable sourcing of biomass can be secured at a competitive price. There is no reticulated gas in Mid-Canterbury and bottled gas has some usage, but it is likely to be less than 20% of households. This means conversion to electricity would be of note, but not necessarily a direct driver of significant demand increase. The biggest decarbonisation demand will be the advent of widespread home electric vehicle charging and destination high speed electric vehicle charging. The high-speed chargers will be known in advance and the new connection can be engineered to either suit the existing network or have the necessary alterations funded by the developer of the charger. The much slower home chargers will create the potential for a large collective impact depending upon how the charging is controlled. Poorly controlled charging (creating large network demand peaks) will require significant network development to accommodate. Well controlled charging is likely to allow maximum utilisation of the existing network up to reasonable levels of home charger penetration (actual level to be further studied) and then subsequently uniform demand increases rather than new peaks.

Solar injection is currently reducing available capacity for demand. Solar typically peaks when demand is low (sunny summer weekends), and voltage must be controlled to prevent exceeding +6% voltage tolerance. This typically means the steady state voltage (transformer tapping) must be changed to a lower voltage, and when load is peaking (dark winter nights) the voltage is now lower than it used to be (maybe by 2.5%), risking lower than desirable voltage at these times. A simple resolution of this is to increase the positive voltage tolerance to +10% (as it exists in Australia) providing an additional 4% voltage rise for peak solar injection while leaving loads with the same voltage they currently receive. This involves no additional assets, increases available capacity, and reduces network *tuning* costs considerably. Large (1 MW+) solar injection is individually negotiated, and incremental cost principles are applied for any network alterations required.

There have been no significant storage (battery) inquiries received (the largest being 500 kW) and these will be negotiated on an individual basis as and when they occur. The small residential batteries (<5 kW and <20 kWh) that are commonly added with rooftop solar are generally a useful addition to the mix of generation and load. The only downside is when owners decide to use the aforementioned *free hour of power* to charge their batteries as hard as possible (typically 5 kW), and this adds to the other appliance demand on the connection, further increasing current drawn and reducing voltage.

Significant Drivers on Load Forecasting

Some factors that could significantly affect electricity consumption have been considered in the forecasting process, and these have been projected forward. They are:

Population Impact

Population projections, broken down into local supply areas, are provided by Ashburton District Council's District Plan. The impact of population growth on load is largely that of additional domestic consumption, although population-based industries such as entertainment and retailing also tend to grow. Domestic loads are typically peaking at mealtimes and early morning and are obviously concentrated in urban areas. Cold weather will also cause domestic consumption to rise, and the coldest weather typically causes the regional/national peak in electricity demand. Hot weather is also beginning to increase demand as domestic heat pump/air-conditioning units become much more ubiquitous. The impact of purely population driven demand is much lower in the EA Networks network than in many others because the irrigation demand is so dominant. There has been no measurable impact on demand post-earthquakes caused by Christchurch residents shifting to Mid-Canterbury. If house and land prices in the Christchurch area increase, demand for housing in Ashburton may be expected to increase.

Price Impact

In an efficient environment, energy prices (at least for marginal sales) should be close to marginal cost. Marginal prices have spiked very high in some years due to a shortage of fuel for generation. Electricity growth could begin slowing down as prices increase. This may not impact on the growth in system maximum demand however, since maximum demand is measured over any half-hour period – a short time for energy consumption. The use of energy may become more selective – only when the return on expenditure is high (a very dry year in the case of irrigation).

To date, the increasing price of electrical energy does not appear to have changed usage patterns or volumes to any measurable degree, linked to the high price elasticity of demand for electricity. Most people see electricity as an essential service that they cannot do without and are not currently making decisions based on doing without, except for cases of energy poverty. Industries may be looking for more efficient technologies to use electricity, but few are abandoning its use for alternatives.

Price may encourage consumers to seek alternative energy sources. The ability to generate and store electricity at home using solar PV and batteries is here. What this is likely to mean is that over time energy through the meter will drop but maximum demand in winter may remain. Daytime demand will be lower for residential consumers, but night-time and winter demand will likely remain high.

The potential closure of the Bluff aluminium smelter would have had a significant impact on electricity prices. The signing of a 20-year electricity contract (2044 term) means that is no longer happening. If closure had happened, consideration would be given to the degree of price decrease and the consequential changes in demand.

Major Industries Impact, Including Decarbonisation

Most forecast increases in load are an indirect response to economic and demographic pressures and cannot be related to any particular electricity consuming development. Some major industrial loads can be anticipated however, particularly in the food processing industry. Unfortunately, these are also the most difficult to predict or quantify as they depend on investment decisions from major industries. Historically, final commitments on these projects have been deferred to a very late stage, often involving significant last-minute load revisions, leaving EA Networks in a difficult situation from a planning perspective.

Meat processing industries and the food processing industry generally are of sufficient size (and in specific locations) to need to be studied separately. These industries are generally year-round with relatively consistent loads and are not weather dependent. The existing industrial loads greater than 1MW are limited to RX Plastics (plastic product manufacturing), ANZCO Seafield (meat processing), Talleys Ashburton (vegetable processing), Talleys Fairfield (ex-Silver Fern Farms Fairton – currently just refrigerated storage), Mt Hutt ski-field (snow making & lifts), and Manawa Energy BCI Highbank (irrigation water pumping). ANZCO is served directly via a dedicated zone substation and security is negotiated directly with them. Talleys Fairfield plant is likewise served directly via a zone substation which also serves Talleys Ashburton via a relatively short 22kV feeder. Mt Hutt ski-field has a dedicated supply from a nearby zone substation. The original large (2x950kW) air compressors for snowmaking have been replaced with a smaller set of compressors and this has decreased the ski-field load. The water pumps associated with the snow-making system can cause significant voltage depressions on the zone substation 11kV bus during starting. Other consumers can see this voltage depression. Mt Hutt is a winter only load. Manawa Energy's Highbank has six 1.5MW pumps (1.4MW loaded) that run during summer. The supply to these pumps is from a Manawa Energy owned 66/11kV transformer. EA Networks provide a single circuit 66kV supply to this transformer. All these loads have to some degree individually negotiated their capacity and security.

Talleys Group purchased the ex-Silver Fern Farms meat processing facility at Fairton and renamed it Talleys Fairfield. Talleys have indicated that they intend to develop the site which could add considerable load to the electricity network. For planning purposes, a load of 3MW has been allocated to this facility which is approximately what the previous site user consumed. It is almost certain any process heat source will be electrical.

The need to reduce fossil fuel consumption in industrial process heat generation is likely to cause a marked increase in electricity consumption. Recent enquiries from meat and vegetable processing companies have indicated that new heat sources are very unlikely to use coal and existing coal burning boilers are probably going to be converted to either electrical heating or biomass heating. There are two sites that are in the process of analysing their thermal options and for planning purposes 5+MW (high temperature heat pump) and 4MW loads have been included. The Ashburton Hospital has converted their coal-fuelled boilers to a ground water source heat pump of circa 700kW demand. It is assumed much of the industrial process heat is for hot water and not steam. Hot water can be generated using high pressure heat pump technology and a low-grade heat source from wastewater or refrigeration condensers. This process is likely to provide a 3:1 coefficient of performance (3kW thermal out for 1kW electrical in). Should the process require steam, then direct electrical heating (electrode boiler) may be required which would increase the electrical load considerably, although commercially viable steam generating heat pumps appear to be on the horizon (~2028).

There are still numbers of smaller industrial and commercial heat processes, such as heating for schools, operating at lower temperature levels, where converting to electricity from current carbon-based heat sources is viable. It is likely the additional electricity capacity required to achieve this will be drawn from the distribution network. As the pressure on business and other entities to reduce emissions increases, we see potential for higher electricity demand associated with process heat conversion, but the uptake rate for this is uncertain and the collective additional demand manageable.

Dairy farming and irrigation are the dominant industrial loads in the EA Networks network, and these have grown at a significant rate. Irrigation load has been the dominant contributor to system peak demand for many years and will continue to be so for the foreseeable future. Total chargeable irrigation load now exceeds 148MW (including almost 9MW of pumping at Highbank Power Station). It has been suggested by most informed industry commentators that conversion to spray irrigation development of farms (both dairy and cropping) is largely complete and further irrigation development is limited by both water availability and nutrient run-off issues. The other factor with potential to affect electrical irrigation load is the piping of historically open race irrigation schemes. This conversion can provide gravity pressurised water at the farm gate displacing the previous electric pumping. The BCI scheme is also predominantly a gravity pressurised piped scheme. Some pumping is required when insufficient gravity head is available. It is unknown whether the reliability of the piped schemes is sufficient for farmers to forego the back-up of a deep well electric irrigator. Only a handful of farmers have so far chosen to permanently disconnect pumps.

The irrigation load is very dependent on weather conditions. During a *wet* summer the diversity in use of irrigation plants increases considerably, which in turn lowers the simultaneous demand placed on the EA Networks network. A *dry* summer tends to remove the diversity from irrigation load and can cause very significant jumps in maximum demand from year to year. As an example, 2005-06 had a summer peak demand of 104 MW, while a year later (with the addition of 8 MW of new irrigation plants) the summer peak demand dropped to 100 MW because of a less arid summer. The 2024/25 irrigation season started in mid-October and peaked at 182.9 MW in December. Regular rainfall has limited the total energy consumption since then. In 2010-11, the summer demand peaked at 148 MW. A year later, the demand peaked at 143 MW despite the addition of 17 MW of irrigation load. In summer 2024-25, an all-time high maximum demand of 182.9 MW occurred (23.7 MW of which was supplied by solar and hydro generation). 181 MW was the previous record maximum demand and that occurred in a relatively *normal* year (2017-18) and in 2022 the peak was only 156 MW.

Large irrigation plants can range up to 300 kW in size for an individual pump (this is equivalent to about 100 residential homes). The irrigation *season* can start as early as August and last until as late as April. Once operating, an irrigation plant can typically be left to run for days or even weeks – particularly the centre pivot types. Electrically irrigated farms were historically restricted to more coastal parts of Ashburton district. Over the last two decades, deeper and deeper water wells have been funded by the improved economics of intensive farming. This has caused the load density to intensify closer to the Southern Alps which is further from EA Networks' GXP. This increases losses in the subtransmission network.

Historically, irrigators have indicated (after being consulted specifically on the issue) that they would prefer to pay higher charges than be subject to load control at times of maximum demand. The network has evolved to suit that requirement. This attitude does not appear to have changed and the returns from irrigation are sufficiently high that it has been assumed that there would have to be a major decrease in global food demand to influence prices sufficiently to make load control an acceptable option.

Two significant irrigation developments have been implemented in recent times. The schemes are generally described as the *Barrhill Chertsey Irrigation (BCI)* scheme and the *Acton* scheme.

The BCI scheme consists of a water intake from the Rakaia River supplying a pumping station lifting up to 8 m^3/s ($4m^3/s$ initially) of the water from river level to the normally empty end of the Rangitata Diversion Race (RDR) and a piped gravity-pressurised water distribution network on the plains. In electrical terms, the item of interest is the pumping load. The initial pumping station is a load of up to 9.0 MW, composed of 6 x 1.5 MW motors. More motors have been mooted, potentially taking the total load to 12 MW. The impact of this load on the subtransmission network is considerable and it has been arranged so that, if necessary, it is interruptible during subtransmission outages. The water distribution network is a gravity-pressurised pipe network which only requires small amounts of electrical pumping to boost pressure at the initial points of offtake from the RDR. The net effect has been similar in terms of the overall electrical pumping load on the EA Networks network.

The Acton scheme is a canal-based distribution network fed from a river level intake near Rakaia township. The canal required no electrical pumping, but the on-farm electrical pumping need was estimated at approximately 3 MW. This load increase has been shared across Overdale, Pendarves, and Dorie zone substations and was in addition to existing irrigation pump load.

<u>Electrification of Transport</u>

Road transport accounts for about 17% of carbon emissions in New Zealand. The electrification of these fleets, starting with passenger vehicles, is therefore another obvious focus area to reduce emissions in New Zealand. A major impact looming on the horizon is that of electric vehicles. The energy and demand impacts of widespread use of home charged electric vehicles are enormous. Most of the affordable vehicles currently on the market are useful city cars with enough range for a daily commute. The smallest battery pack on these electric cars has a capacity of 16 kWh. From flat, the specified recharging time is 7 hours from a standard 10 amp socket. At almost 100% efficiency that represents 2.3 kW of demand per vehicle. The average electric vehicle fuel consumption is between 15-20 kWh/100 km. As car and battery technology advances and becomes less expensive, larger vehicles with improved range and performance will be developed. Vehicles/batteries with 100 kWh or more are already available, and the consumer will expect to be able to recharge a significant fraction of this overnight at home or substantially more quickly at dedicated recharging facilities (350 kW fast-charging rates are a reality). A household is likely to have more than one vehicle. Considerable thought needs to go into the way electric vehicles will be integrated into both the national and local electricity infrastructure that presently adequately serves the existing load.

The impact of increasing numbers of EVs on electricity demand is highly uncertain, as it is subject to multiple factors such as:

- Number of EVs in a network area.
- Average distance travelled per day (and hence energy required to recharge).
- Use of charging infrastructure structure (public infrastructure v residential charging).
- Time of charging (off-peak charging will have little impact, but should it coincide with the early evening demand peak, it will add to total network demand).
- Energy required by the type of vehicle.
- Rate of charging.
- The expected demand increase can be largely avoided if we can encourage charging during off-peak hours. Various means of achieving this are being investigated.

To address the future EV demand forecast uncertainty, EA Networks partnered with DETA, a provider of consultancy services, to examine the impact of transport electrification on the electricity network. The goal was to understand the potential load growth and identify future network constraints as electric vehicles (EVs) become more prevalent. The resulting EV load forecast has been incorporated into EA Networks' overall load forecast modelling.

The study forecasted EV adoption based on New Zealand Transport Agency (NZTA) registration data and the Climate Change Commission (CCC) projections, with the starting point adjusted to the current slower uptake of electric vehicles in the Ashburton District. It assumed that by 2050, 88% of light vehicles and 70% of heavy vehicles will be electric in Ashburton. Two charging scenarios were considered: no load management and load management, with the latter being more likely due to price incentives for consumers to practice smart charging.

The study predicted a substantial increase in electricity demand by 2050, with over 25 MW of additional demand at evening peak hours, whilst a minimal increase of 5MW was forecast by 2035. This additional demand is primarily driven by residential charging of light EVs. The network impact of the 2035 forecast will be reviewed further, but it is expected that the increase is manageable with the investment planned within this AMP. At the 2050 forecast level, there is significant impact of light EV charging on the network, emphasizing the need to understand and manage their charging behaviour. Public charging of light EVs is projected to peak at 5pm, coinciding with existing network peaks, necessitating careful planning and management. The Ashburton and Northtown zone substations will be significantly impacted by light EV uptake due to their high concentration of residential customers. As electric vehicle uptake develops, early engagement with businesses and consumers is needed to promote smart charging practices and ensure the network can handle the growing demand. EV uptake will be monitored and the resulting network response adapted accordingly.

The design standards applied to the LV network during the overhead to underground conversion programme in urban areas has ensured that the LV network capacity is relatively robust and is expected to have sufficient thermal and voltage capacity to supply residential EV charging. Transformer upgrades and targeted feeder reinforcement may be required under higher levels of EV penetration, particularly if EV charging is not shifted to off-peak periods.

New Commercial or Industrial Point Loads

New commercial or industrial point loads may establish on the network without much lead time and can be driven by new technologies or demands that have not previously been foreseen. Examples include data centres, hydrogen generation facilities, or hydroponic farming that can result in relatively intense load densities and the need for network investment.

Regulatory Uncertainty

Environment Canterbury, Canterbury Regional Council (ECAN), has returned to a fully elected council after being run by Government appointed commissioners for a period. One of the reasons the Government took the move to appoint commissioners was to provide a clear path forward for water management in the Canterbury region. A *Canterbury Water Management Strategy* has now been prepared, facilitated by the Canterbury Mayoral Forum. The strategy has been embraced by ECAN as a suitable way forward. The *Canterbury Natural Resources Regional Plan* is a parallel process that ECAN must progress that set environmental flows in several Canterbury rivers. As the strategy matures and the recommendations of stakeholders in various district committees are presented to be enacted the impact of their decisions on EA Networks will be considered.

If the underlying assumptions about water availability and portability were changed by ECAN, it could result in another surge of irrigation demand in areas currently assumed to be fully electrically serviced for available irrigation demand. It would appear that any changes to the regulatory environment will be more restrictive to irrigation and there will be no material changes to the availability of ground water (as presently constrained by ECAN) caused by the regulatory environment (Canterbury Land & Water Regional Plan).

The *ECAN Water Regional Plan, Plan Change 7* was advertised in July 2019. This plan change places further restrictions on intensification of irrigation to address the over-allocation of water resources and nutrients generally and specifically in the Hinds/Hekeao Plains Area. This will be achieved through limits on nitrate levels in groundwater and nitrogen leaching from land areas. The outcome of this variation is that additional irrigation development south of the Ashburton River will be very limited.

Further regulatory intervention occurred in 2020 in the form of the *Essential Freshwater* package. This package of *National Environmental Standards*, Regulations, and *National Policy Statements*, has a significant impact on the farming methods used to support the current level of production. It is almost certain that significant changes will need to be made to on-farm practices and this is likely to have consequences for the electrical demand irrigation places on the EA Networks electricity network. The full implications of the package will not be known for some time, and it is possible irrigation peak demand may still occur at similar levels as currently, but energy usage overall may drop. Changes in land usage may see different irrigation patterns develop for alternative crops. As responses to the package mature, the implications will be incorporated into future plans.

Economic Uncertainty

Economic activity is difficult to predict accurately over a period of 10 years, and this will have consequential effect on electricity demand. Likewise, factors such as population, price of electricity, and the effect of other fuels are uncertain over this period.

The global and national economies continue to be uncertain due to COVID-19, the war in Ukraine, and high levels of inflation. How this affects the primary industries that EA Networks' peak load is driven by is also uncertain. It is possible that most existing load will continue to operate but the connection of new load may be delayed or cancelled. To some degree the estimated load forecast takes this downturn into account. Enquiries for new irrigation and dairy sheds has dropped to very low levels and is unlikely to increase. Given the regulatory environment, additional dairy conversion looks very unlikely.

Over time, the electricity used per unit of production will change, and automation may result in electricity replacing labour. The extent to which this will happen over the next decade is hard to predict.

Similarly, there may be improvements in energy efficiency, so that over time energy requirements (per unit of production) may diminish. This will not necessarily reduce electricity consumption, as in many instances efficient use of electricity may be a better use than the direct use of fossil fuel resources. Energy efficiency measures can also see a rise in peak demand while lowering average demand (the difference between demand cost and energy efficiency).

Demand Structure

The characteristics of the various classes of load; domestic, commercial, irrigation, and industrial are quite different. Domestic consumption has a particularly low daily load factor and is a major contributor to winter system peaks (despite the use of water heating load control). Irrigation has a high daily load factor during summer but a low annual load factor. The base load varies from commercial/domestic heating in the winter to industrial/irrigation load in the summer. Tariff structures reflect these load characteristics and allocate cost where it falls, but this does not necessarily materially affect the behaviour of consumers.

Relatively recent irrigation scheme changes have provided farmers with the option to purchase the right to use water from piped schemes that deliver pressurised water onto the farm. These schemes have provided both new water resources as well as converting existing open race schemes to piped schemes. The impact of these changes on actual and future electrical demand has been complex. Where the farmer has not had access to water previously or used flood irrigation, these schemes have had little impact on connected irrigation demand. If new irrigation water was available, there has been some additional demand from farms that converted to dairy production. A significant number of farms that signed up for pressurised water delivery already had either deep well irrigation plants or surface water pumping systems. These farmers have retained their deep well electrical pumping facilities to provide high reliability irrigation during periods of restrictions on the piped scheme water sources. A consequence is the *standby* electrical load is no longer contributing to irrigation peaks in normal years. This latent demand is a big risk for the EA Networks network as it can be simultaneously activated after being dormant for many years – potentially overloading assets that were historically adequately sized. Irrigation pumps can no longer be switched to non-irrigation rates to prevent this situation from getting any worse and to ensure adequate return on dormant assets.

The Canterbury Regional Council (ECAN) has clean air requirements for solid fuel space heaters. This strategy has aimed to reduce the quantity of airborne pollution, particularly that caused by domestic solid fuel heaters. The requirements have seen additional electrical heating demand come on to the residential portions of the EA Networks network, and most of the appliances are inverter style heat pumps. The impact on the peak demand has not been considerable and may be offset to some degree by the new heat pumps displacing resistive heating in homes that would have otherwise used resistive heating for initial comfort in the early evening or morning. Significant numbers of heat pumps have been installed in response to the clean heat strategy (61% of Mid-Canterbury homes are heated by heat pumps in 2018). The possibility of these heat pumps being used for cooling during times of peak demand in summer is of more consequence to overall system demand, and this will be monitored.

Phasing out of gas hot water, cooking and space heating is not expected to be a major contributor to demand increases in Mid-Canterbury, due to these installations being relatively uncommon and only on bottled LPG supply.

Diversity

Peak demands for different supply points do not necessarily occur simultaneously. The natural diversity among loads can be used to advantage. Since a zone substation maximum demand (MD) will be less than the sum of individual distribution substation MDs served from it, the major distribution elements can be designed to a smaller capacity than the sum of individual consumer connections. As EA Networks have only one Transpower Grid Exit Point (GXP), the expected system summer peak for the GXP will be the same as the corresponding sum of the coincident zone substation totals, plus subtransmission losses, minus any distributed generation.

Diversity can also work against the Asset Manager. The diversity in EA Networks' connected irrigation load varies considerably with the weather. During a season with average rainfall, the diversity is average. When the season is particularly dry (every five years or so), there is minimal diversity and all pumps that can be operated are. This can cause a false sense of security for the Asset Manager during the preceding four years and may have implications for emergency capacity.

Distributed Generation

Distributed generation has the potential to reduce the peak demand EA Networks impose on the Transpower grid. It must however be of such a scale and be sufficiently reliable (both mechanically/electrically and with its source of fuel) to guarantee that EA Networks can avoid investment in major system components while retaining the appropriate level of security to service load. If the distributed generation was, for example, wind powered, a calm summer day during a dry year would cause peak demand on the EA Networks network, but none of the wind turbines would be generating because of lack of wind. The Highbank hydro power station is another example that generates only during winter (off-peak for EA Networks, but presently during the period of peak regional demand). Utility scale solar generation will contribute to supporting the network during typical high irrigation periods, but during wet weather and overnight will have little or no contribution. On the converse side, if generation export causing voltage or capacity constraints is considered, maximum solar export could occur during rural low load periods (autumn, winter, spring) or in summer following sustained rain when irrigation is suppressed. These factors make planning network capacity in the context of an active network with two-way power flows complex. Only distributed generation with very high availability, some form of fuel storage (for generation on-demand), or a diverse range of independent fuel sources will offset the need for network investment.

The estimated future network demands have not assumed the existing distributed generation plants (Barrhill – 0.5 MW, Cleardale – 1.0 MW, Montalto Hydro – 1.6 MW, Gartartan Solar Farm – 6.5MW, Highbank – 26 MW and Lauriston Solar Farm 47.2MW) to be operating. The nature of the hydro plants (single penstock, run of the river, single turbine) and solar generation (poor weather or darkness) means that they can be (and sometimes are) unavailable at peak times. In terms of energy, the existing distributed generators are predicted to supply about 45% of the ~600 GWh to be delivered to consumers during an average year assuming average levels of irrigation demand. While acknowledging the difficulty in absolutely relying on solar generation mentioned above, it is likely that significant amounts of utility scale solar photovoltaic generation will probably lower the summer peak demand on the GXP and certainly lower the amount of energy supplied through the GXP. Where the solar is connected to the 22 kV distribution network it is also likely to lower the peak load demand on the zone substation concerned.

A range of generation proposals have been discussed in recent years. Two of them have proceeded (Lauriston and Gartartan), while others are approved and in the advanced stages of design (e.g. Mt Somers). Some other projects are still commercially sensitive. Section 5.4.12 has details of the type and scale of these potential developments. None of the unapproved projects are sufficiently commercially mature to be included in the load estimates, although some of them could have a meaningful effect on substation and system demand should they proceed. Once firm details are available, the impact on peak load will be assessed and included in the demand estimates.

Photovoltaic solar panels have been installed on some residential, farm, and small business premises (657 installations totalling 6550 kW as of February 2025). The distributed nature of these installations and the modest output has not yet caused any measurable impact on the distribution network. One installation highlighted the small size of overhead LV lines connecting it to the distribution transformer (since resolved with scheduled underground conversion), but the remainder are operating without any negative impact. EA Networks currently has circa 56MW of utility scale solar farm applications on hand. While no contracted commitments have yet been made, it is clear that, at this scale, there will be impacts on the flow of electricity in the network and management of voltage, particularly under subtransmission network contingency situations. Application of ADMS generation run-back schemes may be required to manage post-contingency network conditions, minimising network investment, and allowing lower levels of generation constraint pre-contingency.

Demand Management

The only form of direct demand management currently in place is that of ripple control of hot water and night storage heating facilities. Indirect demand management by signalling of price is accomplished by a tariff structure that makes night energy less expensive than day energy. EA Networks do not have in place any dynamic signalling of demand peaks to consumers. There are currently no plans to implement dynamic demand signalling to individual consumers.

Future demand management would certainly be imposed on widespread electric vehicle fast recharging.

Over time, there have been a range of network security options placed before the Board for consideration. One of the options discussed was contingency load management. This would require that certain types of load be automatically interrupted during faults. Restoration of this load would then be done by remote control (either feeder by feeder or over larger areas – depending on the type of fault). This action would, under many circumstances, allow the remaining connected loads to be supplied via un-faulted network paths while the fault is repaired. Contingency load management could be an appropriate response to a HILP (high impact low probability) event such as a zone substation transformer failure or in national emergency load shedding situations due to capacity or energy shortfalls. Well managed, contingency load control could provide capacity for all essential load and share the remaining capacity in an equitable manner. This would not be possible if the larger, non-critical, interrupted loads remained connected. No immediate commitment was made, and future plans will provide details on enabling technology and any Board decisions. EA Networks is investigating the potential to implement direct demand management for emergency purposes at a local community recreational facility, that temporarily transfers heating and cooling demand from electrical heat pumps to LPG gas supplied equipment.

In the set of forecasts that follow, no specific allowance has been made for intangible factors, other than in line with historical trends. Increasingly, it may be possible to control load so that appropriate action can be planned ahead of time. Thus, for example, as a specific subtransmission circuit approaches capacity, it may be preferable to improve the efficiency of utilisation or install local electrical storage in the area rather than immediately increase capacity.

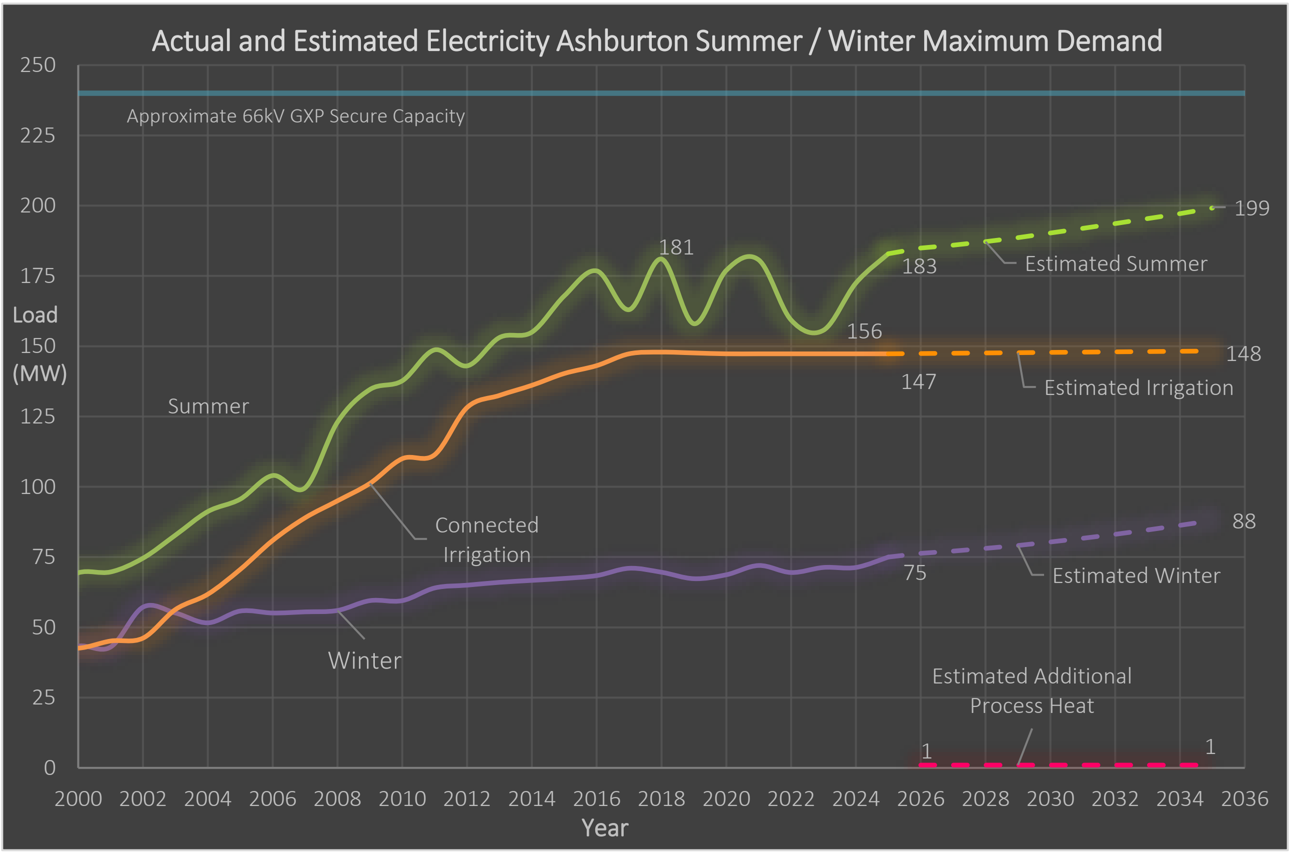
5.2.4 Future Load Projections

A forecast has been developed which does not utilise long-run historical data. Estimated load is now used. The technique is subjective and uncertainties in population, price of electricity, economic activity, and the intensity of use of electricity in industry all influence future demand.

Appendix C contains additional data used to derive this forecast plus the estimated individual zone substation maximum demands for the next ten years.

The estimated growth in individual zone substation loads is a subjective process in that it relies on the opinions of a range of people who are knowledgeable within the various industries that contribute to most of the electrical demand in the Ashburton district. For irrigation, localised trends are prepared for each zone substation and incorporated in the future load figures. A report prepared for Transpower provided some additional estimates of irrigation load and these have been considered when preparing EA Networks' internal estimates. Other industries contribute likely step load increases, and these are allocated individually to zone substations at the expected load commissioning date. Residential and general supplies are trended in percentage growth terms, and this is seen as acceptable, bearing in mind the difficulty in alternative models and the relatively low impact of this growth on the total peak loads (particularly at subtransmission levels).

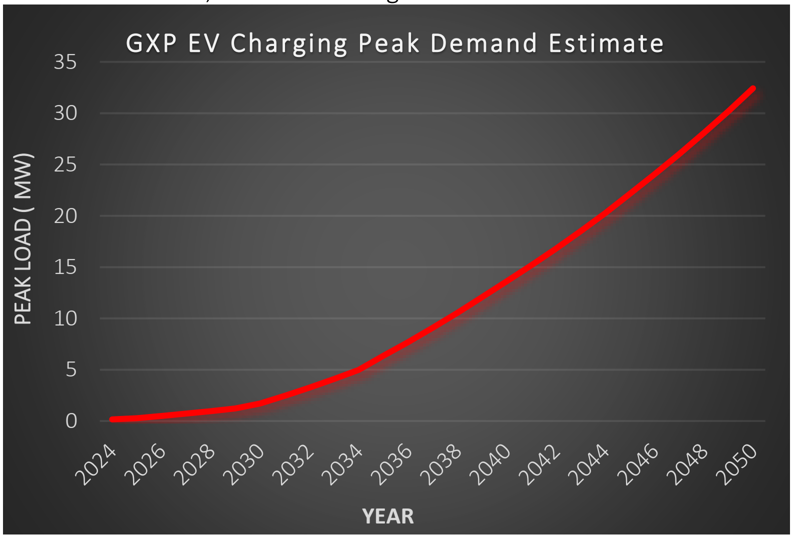
Some additional estimates of maximum regional irrigation demand were provided in the *Canterbury Irrigation*



Peak Electrical Load report. The estimates for the total irrigation demand on the EA Networks network varied between 114.4 MW to 167.4 MW depending upon the assumptions made. The highest value assumed intensive irrigation of all available area including large portions of the high-country basins. This would appear to be highly unlikely at the energy densities assumed in the report. EA Networks have used a similar technique for estimating system wide demand in the past, but the sensitivity to assumed energy intensity is so great that it is only broad quantitative indicator rather than a precise forecasting tool. EA Networks' estimate of complete consentable district irrigation using existing demand density is around 146 MW although the uncertainty surrounding this is likely to be at least ±10%. The estimated irrigation load of 14 MW in 2031 contained in the report is within this band of uncertainty. The lower regional load estimate of 114.4 MW is actually a considerable reduction in load caused by increased use of gravity pressurised pipe schemes. Several of these schemes have been installed in recent years and appear to be successful. Where they are converting an existing open-race scheme to pipes, the electrical demand of surface spray irrigators is eliminated. When a new scheme is introduced using newly consented water (or water is conserved by piping) some deep well pumps are only used as dry year backup when the surface water supply may be restricted. The potential demand still exists but is not expressed during *normal* years. If a new piped scheme proves to be reliable, the deep well consents may be sold to other interests within the same aquifer zone – shifting the electrical demand on the EA Networks network.

There is a new emphasis on removing fossil fuel heating from the industrial process heat and large space heating sectors. A report prepared by Deta Consulting for EA Networks in December 2020 has identified the likely prospects for fossil fuel to electrical conversion. The demand estimates now include the conclusions of the Deta report, as well as a subsequent report for EECA from Ergo Consulting, and it has markedly changed the likely demand in 10 years. The EECA '[Regional Energy Transition Accelerator (RETA) Mid-South Canterbury – Phase One Report]' completed in June 2023 informed the potential for industrial process heat conversion from coal to electricity or biomass in the Mid-Canterbury region. Much of this load is concentrated on two zone substations that are focused on industrial load (Fairton and Seafield).

Also incorporated is the impact of EV charging based upon the report provided by DETA in 2024. The impact is still minor at 2025, but accelerating. Growth at these estimated rates may still require some development work on the EA Networks network to accommodate the load, while continuing to meet the security standards. The chart at left is anytime peak demand and this is likely to occur at times non-coincident with existing GXP peak demand.



Forecasts of summer estimated maximum demand indicate a 10-year summer growth averaging 0.8 % p.a. in ADMD (After Diversity Maximum Demand). Winter ADMD is predicted to grow at a higher rate of about 1.6 % p.a., largely as a result of industrial growth and EV charging.

Water storage is the pervading sentiment as the way to advance irrigation water availability in the Canterbury region. The statistical summer load projection (extrapolation) is no longer a valid predictor of future demand. Underlying winter load growth is at a rate comparable with other urban networks (1.2%).

Winter peak demand growth is ultimately constrained by regional security load control strategies (Upper South Island) and the growth of uncontrolled load such as heat pumps. It is possible that widespread uptake of electric vehicles could potentially change the estimated/projected peak winter demand (increased demand) as could additional battery storage and/or distributed generation (decreased demand), depending on contribution from batteries and distributed generation at the time of the peak. The scope for decreasing demand across significant parts of the network (thereby decreasing demand on upstream assets) depends on the location and scale of any distributed generation or batteries. Energy efficiency may slow the growth rate over time until efficiency has peaked.

5.3 Network Level Development

All the following network level developments provide energy efficiency benefits. By utilising the correct voltage and larger or more numerous conductors/cables the energy efficiency of the network is measurably higher. Although the primary reason for doing the developments was not energy efficiency, it was certainly one of the influencing factors.

5.3.1 66kV Subtransmission

During the mid to late 1990s, the EA Networks 33kV subtransmission network was showing a lack of capacity and security. The incessant growth in irrigation had caused parts of the network to sag to 30kV with all circuits in service. This surge in demand caused large energy losses and meant there was zero security should a 33kV line fault occur. Some zone substation transformers were also operating on maximum boost tap. It was obviously time to reconsider the subtransmission development at EA Networks. The peak load then was a little over 60MW.

A range of options were investigated, and the option of using 66kV as a subtransmission voltage was immediately appealing. The ability to supply the scale of loads EA Networks were anticipating would occur and the distance from the GXP they would occur at was a good match. The techniques used to construct 66kV lines were similar to those used at 33kV so EA Networks personnel could build and maintain them without major reskilling or retooling. The cost of major components for 66kV were only 15-20% more costly than 33kV items. In some cases, the cost was virtually the same. The increase in capacity was almost 400% for the voltage constrained parts of the network and 200+% for the thermally constrained parts.

So, the options (including approximate costs) were presented to the Board for discussion, and it concluded with a request to provide an estimate of cost for a conversion of a significant portion of the 33kV subtransmission network to 66kV. A project to solve the immediate 33kV problem with 66kV operation was approved. Once that commitment had been made, the Asset Management Plan became the vehicle to communicate future subtransmission plans to the Board. In subsequent years, as the pace of irrigation load growth accelerated even further, the Board further endorsed the principle that the future of the subtransmission network was with 66kV. In the long-term future, as the 66kV subtransmission system begins to reach its limits, reinforcing the 220/66kV transformer capacity at the existing Transpower Ashburton GXP combined with more 66kV circuits, a second 66kV GXP, widespread battery storage, or diverse distributed generation could provide immediate and on-going relief.

5.3.2 22kV Rural Distribution

The late 1980s had already seen significant irrigation load growth occurring on the EA Networks distribution network. This was putting the 11kV distribution voltage under stress in a number of places on the network with multiple regulators in service. Energy losses were high, and power factor was dropping (high kVAr losses in the reactive overhead lines). In some cases, the measured distribution voltage was as low as 10.3 kV (minus 6.5%) which made motor starting and running very difficult and the voltage range consumers were experiencing was exceeding the standard range that EA Networks had prescribed as acceptable. In some cases, attempting to start one motor would stop an adjacent one. The 11kV fault levels were becoming inadequate for the increasing size of individual loads being supplied. Back-feeding during faults was impractical.

A solution to this issue was required. Forecast load growth was increasing and these voltage regulation issues were going to be very widespread if nothing was done. A range of potential solutions were considered including the following options that were analysed in detail:

- 11kV reconductoring

The most obvious option was to increase the size of the conductor on the existing pole lines. This results in a relatively small incremental change in capacity as the existing poles can typically only double the area of conductor at best. So, a line carrying Mink conductor (75 mm^2) may be able to be restrung with Dog (120 mm^2) but this results in a 40% increase in capacity at best (if the entire line is restrung) with no further options for size increase without reconstructing the entire line with stronger poles (expensive). The extent of the potential voltage problems were sufficiently widespread that a lot of restringing would have been required with a capacity increase ceiling at the conclusion. The restrung network would still have very limited back-feeding capacity at times of peak demand (distribution security levels would not increase appreciably). The distribution system fault levels would perceptibly increase with this solution but motor starting would still be limited in many cases. Although this option was certainly viable, it was not the long-term solution that would solve the issues facing EA Networks. This solution was not preferred or recommended to the Board.

- 11kV regulators

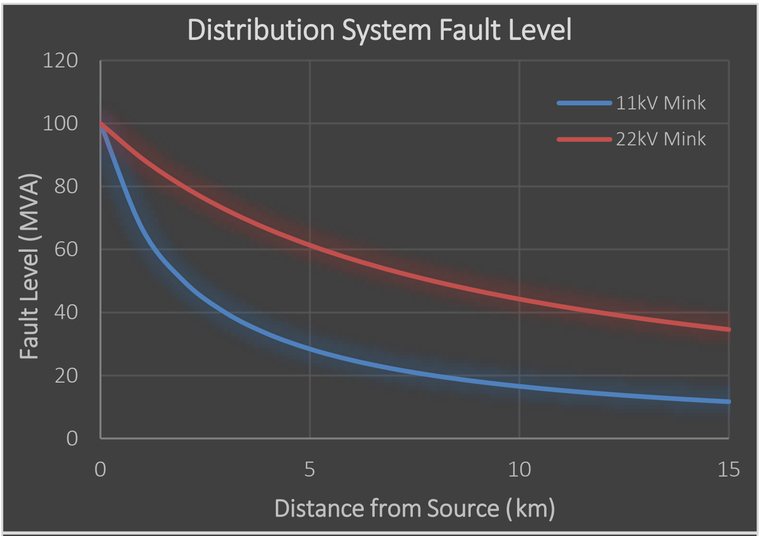
Another method of boosting voltage was the in-line voltage regulator. This is essentially a localised solution for maintaining voltage on a distribution feeder. It does not increase fault levels (in fact they slightly reduce), so motor starting is still difficult for larger loads. It is a relatively low risk option, in that the regulator can be relocated if necessary or additional ones can be installed to further boost voltage. On the downside, system losses begin to increase and back-feeding through a regulator is not always straight-forward. The extent of distribution system reinforcement required would have involved the purchase of dozens of voltage regulators and this would essentially be solving one of the symptoms of an overloaded distribution network without solving the underlying problem. This solution was not preferred or recommended to the Board.

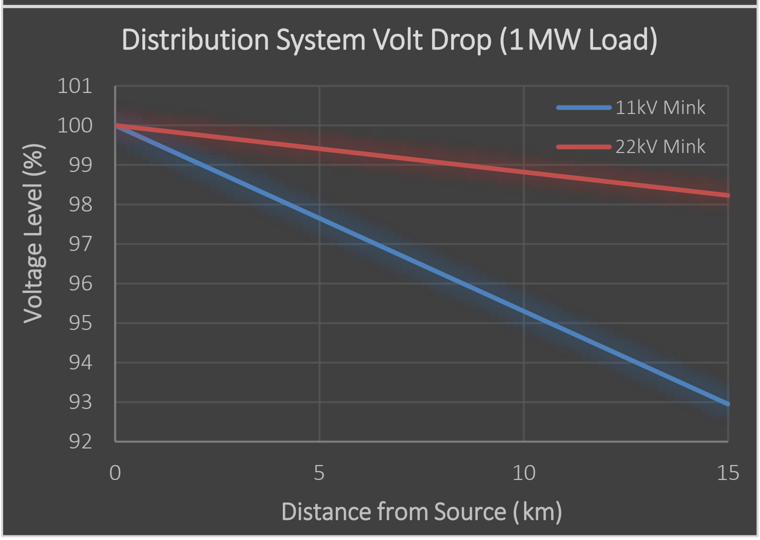
- Additional zone substations

An expensive, but technically viable, option would be to build additional zone substations between the existing ones thereby shortening the 11kV feeder length by approximately 50%. This has a number of technical advantages but is very costly. It doubles the number of 11kV feeders, each with half the number of consumers per feeder, which means any distribution fault only affects half the number of connections. The load per feeder is halved, which solves the voltage drop issues, and the fault level increases as a consequence of shorter line lengths from the 11kV source. It seems to be a good solution, but the downside is certainly the cost and complexity of many more zone substations of half the size that would otherwise be required. A loss of load diversity means that each smaller zone substation would actually be more heavily loaded than 50% of the one that originally supplied the entire load. The 33kV network was showing signs of duress, and 66kV was already being contemplated as an option. This meant that the cost of building twice the number of new 66kV substations was not appealing economically. This solution was not preferred or recommended to the Board.

- 22 kV conversion

Although the option of converting to 22 kV seemed costly, in reality there was little waste in the exercise. The main costs are in reinsulating existing overhead lines (a relatively low cost of three insulators for most poles) and replacing the existing distribution transformers with 22 kV units. The transformers can be reused on 11 kV portions of the network or sold to other networks. In the worst case, the very old ones are scrapped. The overwhelming technical advantages of 22 kV were plain to see. The percentage voltage drop on the same conductor falls by 75% allowing 4 times the load for the same voltage drop as 11 kV. Line energy losses fall by 75%. The fault level also increases considerably and stays much higher over the entire feeder length. This allows much larger motors to be started without causing interference with neighbouring consumers. Existing poles and conductor could be retained and the only things needing replacement were the insulators, the fuses and switchgear, and any surge arrestors. The incremental cost of 22 kV equipment over 11 kV equipment varies from zero to at most 20% (overall 8%). In many cases, the equipment is the same as it is not cost effective to manufacture both voltage classes of equipment. The source of 22 kV could be provided by 11/22 kV star connected autotransformers which maintained zero phase shift and allowed them to be moved along a feeder as conversion proceeded. This solution was recommended to the Board as a solution that could be applied where 11 kV was likely to no longer be adequate for the loads being served.





The Board were presented with the various options that had been considered and were content that 22 kV conversion offered the best long-term value for money. It was pointed out that within a decade or so the subtransmission network and a portion of the rural distribution network could be renewed and the opportunity to migrate to what is generally accepted as the modern distribution voltage class of 24 kV was one that should not be missed. The fact that the subtransmission voltage at the time was 33 kV (only 50% higher than 22 kV) tended to reinforce the notion that it too was under pressure. Ultimately, the Board agreed that 22 kV was the best choice overall for stakeholders where significant distribution system voltage regulation was an issue.

In hindsight, had the move to 22 kV not occurred, the dramatic load growth that occurred from 2000 to 2010 would have overwhelmed the 11 kV network and loads would have been turned away. This would not have been a good situation for the local or national economy. The combination of 66 kV subtransmission and 22 kV distribution seems to be close to the perfect match for the scale and distribution of loads presently on the EA Networks network.

5.3.3 Urban Underground Conversion

As a cooperative company, the ownership structure of EA Networks encourages the Board to make decisions that are in the long-term best interests of the shareholders/consumers and other stakeholders that use or interact with EA Networks network. One of the areas that EA Networks Board have chosen to reinvest in the community that they serve (and where almost all shareholders reside), is by continuing to convert end-of-life urban overhead lines to underground reticulation. The Board are well aware of the alternative, which is to rebuild the network as overhead lines. Overhead lines are certainly less costly, but they provide very few of the other benefits of underground cables:

- Underground cables are immune to the frequent snow and windstorms that Mid-Canterbury experiences. One such snowstorm in the 1970s caused most poles in Methven to fail and consequently power was not restored for many weeks.
- The safety of an underground system is several powers of magnitude greater than overhead lines due to its largely buried situation. The exposed nature of overhead lines (particularly in an urban area) is a significant risk and adverse weather, trees, vehicles, kites, fireworks, vandalism etc. can all place the urban dweller at greater risk of accessible or damaged overhead conductors.
- The capacity of a low voltage underground cable is typically much greater than the equivalent overhead line as it serves only half the number of consumers and is usually of greater cross section (lower voltage drop).
- The flexibility of interconnected underground cable systems normally means planned outages are very infrequent as the various parts of the network can be isolated without interrupting supply.
- The aesthetic benefits cannot be ignored. Residents are much more satisfied with underground reticulation.
- The reliability of underground networks is significantly higher than overhead networks, so the consumer has better power quality and lower outage duration. When a fault does occur, restoration is typically much faster also.
- Energy losses are typically much lower in underground networks, largely because of the larger conductors and greater number / lighter loading of individual LV circuits.
- Fewer (but larger) distribution transformers are required (all of which are ground-mounted). This minimises the potential oil spill risk.
- One notable potential downside is the exposure of underground cables to seismic events. Liquefaction is not expected to be a significant factor in urban areas.

Feedback from consumers has shown that they are very satisfied with the continuing underground conversion programme. The Shareholders' Committee (the elected/appointed shareholder representatives) have also supported the urban underground conversion philosophy. In addition to the technical and service benefits, there are on-going strategic drivers. As a cooperative company, the return to shareholders needs to be distributed in a fair manner, and with considerable investment in the rural area to support irrigation and farming generally, there needs to be a counterbalance for the urban consumer/shareholders. All conversion programs are driven by the need to replace existing overhead lines owing to diminished capabilities and condition.

An underground conversion programme has now been included in the plan which provides for the removal of all distribution voltage power poles from the townships within the Ashburton District. The programme identifies projects by specific streets. These projects are based upon assessed overhead line condition and the timing of each line replacement with underground cable is scheduled to ensure the risk of pole failure before conversion is acceptably low.

5.3.4 Core Urban 11 kV Network

The EA Networks *Reliability by Design* guidelines put greater emphasis on the number of consumers supplied from (or affected by) any particular electrical asset. Of critical importance is the number of consumers supplied from a zone substation feeder circuit breaker. Currently, there are a number of individual urban 11 kV feeders supplying more than 1 000 consumers each and consequently nearing their thermal rating limit. As of 2025, a 1 000 consumer feeder represents about 4.5% of the total EA Networks consumer count. A fault causing this circuit-breaker to operate will rapidly impact on the reliability measures such as SAIDI and SAIFI as well as inconvenience 1 000+ households or businesses. A 20 minute outage for 1 000 consumers represents 1 minute of SAIDI and 0.05 of SAIFI (1.1% and 4.0% of the respective compliance targets).

The Ashburton urban area has about 9 000 consumers supplied from two zone substations. The two substations have about 26 existing or potential 11 kV feeders. This is an average of more than 340 consumers per feeder. To bring this down to the design guideline of 200 consumers would require another 19 feeders (a total of 45 feeders).

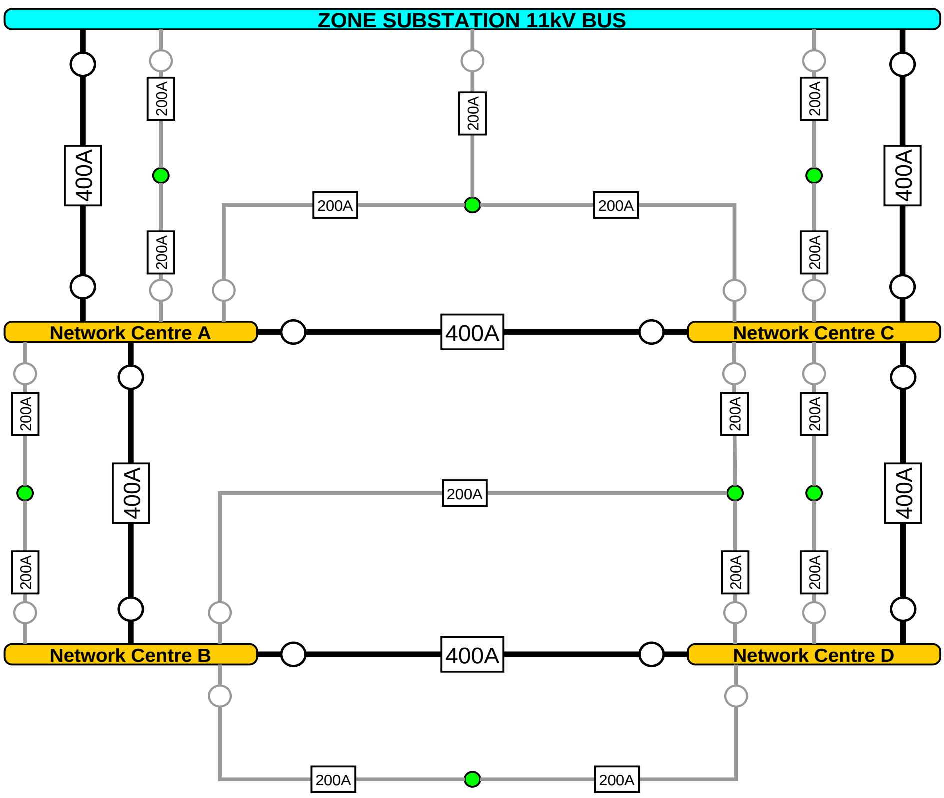
To comply with the new guidelines on maximum number of consumers per feeder, there are several possible approaches.

1) **Nineteen additional 11 kV feeders from existing zone substations**. Although this is possible, it is particularly asset intensive. New switchboards are required, and cabling will have to be installed and extended to a location in the existing network where it can create new, smaller, feeders. The new switchboards will require enlarged or additional buildings on the zone substation sites, and this may involve obtaining additional land which could be a difficult prospect in an urban setting. This option is not the preferred option.

2) **Two new zone substations in urban locations distant from Ashburton and Northtown zone substations**. This is also possible, but even more asset intensive than option (1). This would require significant underground subtransmission, two new sites, at least four new transformers, new buildings, switchboards, protection, and supporting infrastructure. New 11 kV cables would also need to be run from the new sites to integrate with existing 11 kV cabling forming the 19 new feeders. Initial estimates place the cost of this option at several times that of the other options with no quantifiable benefits other than a doubling of the already adequate total 11 kV infeed capacity. This option is not the preferred option.

3) **An additional layer of high capacity 11 kV distribution**. This option involves a new network of *core* 11 kV circuits that do not directly connect to distribution transformers, effectively extending the zone substation 11kV busbar in a distributed manner. The core 11 kV would be a transport level only. An 11 kV circuit breaker switchboard at a network centre or zone substation would provide the termination point for each end of a core 11 kV circuit. Core 11 kV circuits will form closed rings (the core circuits operating in parallel) between network centres and zone substations. Several spare (or repurposed existing) circuit breakers would be required at each existing zone substation. The initial assessment of Ashburton and Northtown substations suggests there are sufficient circuit breakers to fulfil the requirements. New network centres would need to be constructed at various locations in the urban area and obtaining small amounts of land for these may be an issue. Each network centre would have at least two core circuits terminating at it, and between three and five lower capacity 11 kV feeders radiating from it. After careful consideration, this solution was chosen as the preferred option.

Ashburton Township 11 kV Reinforcement



The diagram above gives some idea of the core 11 kV network concept. The bold black lines are the high-capacity circuits. The grey lines are the lower-capacity feeders. The orange objects are network centres. The larger circles are circuit-breakers. The smaller green circles are open ring main unit (RMU) switches at distribution substations.

The scale of this core network development is significant. It will take most of the planning period to fully implement, and a commitment is needed to continue the work to completion. Partial implementation would not achieve the desired improvements and could make the impact of some faults more extensive. The Board have indicated that it is appropriate to make provision for the core network when doing other works.

Previous Asset Management Plans had allowed a programme to cover this work starting in 2020 and continuing until at least 2028. This programme now runs from 2025 until 2031. The first two network centres are now complete (Melcombe and Glassey). Protection relay commissioning is ongoing. Once commissioning is complete, core and feeder cables newly terminated on the switchboards can be used in a fully secure core network configuration.

5.4 Strategic Plans by Asset

Once the security standards have been set, the rate of growth has been predicted, and assumptions have been made about the location of the additional load, decisions must be made on how to accommodate it on the network. This section identifies each major voltage level and functional grouping and then goes on to describe what impact the additional load will have and what changes will be necessary to cater for it.

Please note that the [10045] type reference in each project title is the project code for reference to financial detail in Appendix B. Project costs can be seen in Appendix B – referenced by the year and project code. A year in [red] indicates that the project has unexpectedly carried over from the previous year without budget allowance.

5.4.1 Transpower Grid Exit Points

EA Networks has one Grid Exit Point (GXP) that is at the Transpower Ashburton Substation – a site approximately 7 km south-east of Ashburton township. Transpower call this substation Ashburton Substation, but for clarity (EA Networks also have an Ashburton Substation in Ashburton township), it is known as Ashburton220 (220 kV is the highest voltage on Transpower’s Ashburton site).

Ashburton220 provides EA Networks with a 66 kV GXP. Until 2019, there was also a 33 kV GXP on the same site. Immediately adjacent to Ashburton220 is an EA Networks substation called Elgin. This provides two major functions. Firstly, it takes the three 66 kV supplies from Transpower and splits them into the seven individual circuits that form the 66 kV subtransmission network. Secondly, it historically provided a (normally open) link between the 33 kV GXP and the 66 kV GXP in the form of a 60 MVA autotransformer. This autotransformer currently allows a 33 kV ripple injection plant to serve the 66 kV network and has been reconfigured to also provide a 20 MVA 22 kV supply to the distribution network.

The capacity and configuration of the Ashburton220 substation largely determines the security and reliability of the GXP at that site. It is the responsibility of EA Networks to plan the configuration of the GXP and the way the connections to the GXP are made to promote high performance and good value. The cost of Transpower assets that are dedicated to supplying EA Networks are passed on to EA Networks in the form of an annual charge that reflects a rate of return and some assessment of maintenance requirements. This charge is in turn passed on to the consumers that use the EA Networks network.

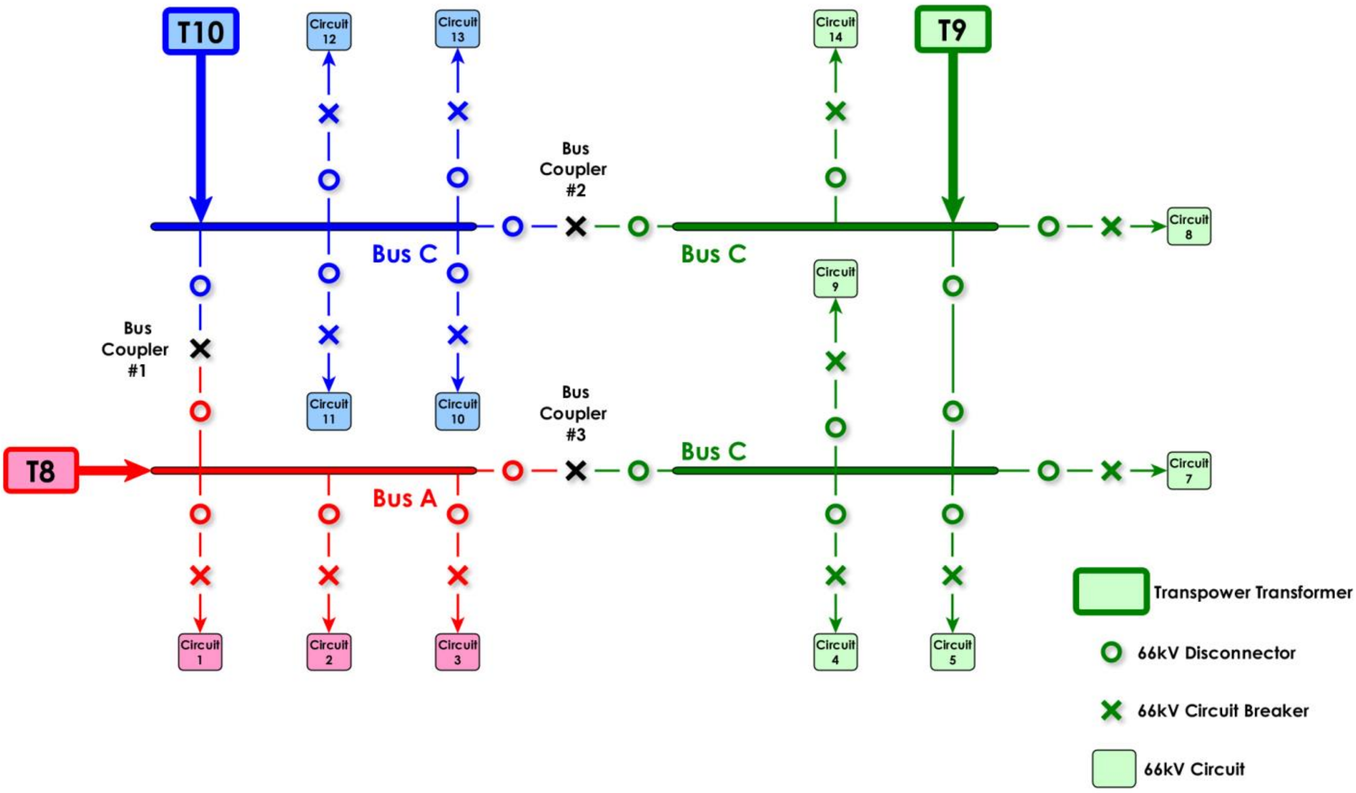
The existing arrangement meets the security standards at peak load times and for the foreseeable future. The addition of a third 220/66 kV transformer during 2013-14 enabled full security policy compliance. The all-time maximum of 183 MW is within the steady state firm no-break 66 kV GXP capacity of 220 MVA or 250 MVA cyclic.

Capacity of New Equipment

The security standards effectively set the requirements for immediate capacity and security (section 3.6.3). The margin allowed for growth is the only parameter that is not predetermined by the security standard.

The AMP 2023 included a second 220/66kV GXP that would be developed connected to the Transpower Islington – Livingston circuit (Roxborough – Islington A single circuit line) in the vicinity of Mitcham. Also included in AMP 2023 was the expenditure for associated 66kV circuits to connect the new GXP into the 66kV sub-transmission.

<u>Elgin 66kV Bus Configuration</u>



By evaluating a number of factors, this AMP update has concluded that the second GXP is not required within the ten-year time frame of this plan, so the projects and expenditure have been excluded from the forecast. The factors considered included:

- The existing Transpower Ashburton 220/66kV GXP is very secure, with four circuits connected to a robust high-capacity double circuit transmission line and three 220/66kV supply transformers connected to the Elgin multi-zone, ring 66kV bus.
- Discussions with Transpower confirmed that the risk of tower failure on this 220kV double circuit line is very low, whether from earthquakes or river foundation washouts.
- The 220/66kV supply transformers provide a nominal 220 MVA of firm capacity, which increases to around 250 MVA when cyclical short-term contingency overload ratings are applied (as would be the case following the loss of one of the 120 MVA transformers).
- Transpower has a prudent 10-year load forecast of 254 MVA which significantly exceeds EA Networks' expectation for load growth over the period.

Taking these factors into account has led EA Networks to the conclusion that the second 220kV GXP is not required within the 10-year forecast period of this AMP.

5.4.2 Subtransmission Network

The 66kV subtransmission network is the backbone of the EA Networks network. The capabilities of a 66kV network are in keeping with the scale of loads that EA Networks serve. All EA Networks load is presently supplied from a single Transpower substation. At 66kV, the subtransmission network capacity is thermally limited in some sections close to the GXP and generally voltage limited in other sections more remote from the GXP.

Capacity of New Equipment

The capacity of any new subtransmission line is determined by a combination of required mechanical strength, thermal rating constraints, and voltage drop considerations. The specification of these parameters is as follows:

For all foreseeable n-1 contingencies the thermal rating of any subtransmission line must not be *continuously exceeded and the voltage at any point on the subtransmission network must not drop below 90% of its nominal value.*

A load considered to be probable 10 years into the future will be applied to a model of the entire subtransmission network (as it is planned to be in 10 years into the future) to measure compliance with these parameters.

The mechanical strength of all subtransmission lines will be such that it adequately resists all reasonable environmental influences for the duration of its life.

The Ashburton District Plan contains a rule that makes upgrading any line to 66kV a non-compliant activity. This does not mean that it cannot be changed, but it does flag that a resource consent is required in non-rural settings. Resource consent applications can be a difficult, time consuming, and costly process. It is likely that additional subtransmission reinforcement would be justified, thereby meeting the security standards, if load grows significantly beyond that used to test compliance with security standards.

Other considerations will also come into play when determining new subtransmission equipment capacity including: energy losses, expected equipment life, pollution resistance, aesthetic impact, etc.

Projects & Programmes

Most of the projects in this subtransmission section are in some way linked. As an example, if 66kV supply is introduced at the source of a subtransmission circuit, the need to convert existing lines connected to the same source line or build new alternative ones becomes unavoidable.

Around 1997, before the first 66kV line was built or the first 66kV substation was even designed, a broad concept was provided to the EA Networks Board for their consideration. It showed the evolution of the then overloaded 33kV and 11kV networks to a predominantly 66kV and 22kV system. Budgetary estimates of the cost to develop the 66kV aspect of the concept were provided and the benefits in capacity and security were outlined. After evaluating the alternatives (massive increase in size and quantity of 33kV lines, 110kV & 33kV, or not supplying the new load), the Board provided an endorsement to proceed with system development keeping this ultimate 66kV concept in mind. This initial endorsement has been subsequently reinforced by approval of many projects that fit into the concept. This must be borne in mind when considering many of the subtransmission projects identified below. The substantive alternatives have already been considered as part of a much larger *all of network* concept and EA Networks are not aware of any new technologies or opportunities to use non-network options that would provide an adequate substitute for the solution included in the initial concept. Should an alternative solution become apparent it will be evaluated and the decision documented in future plans.

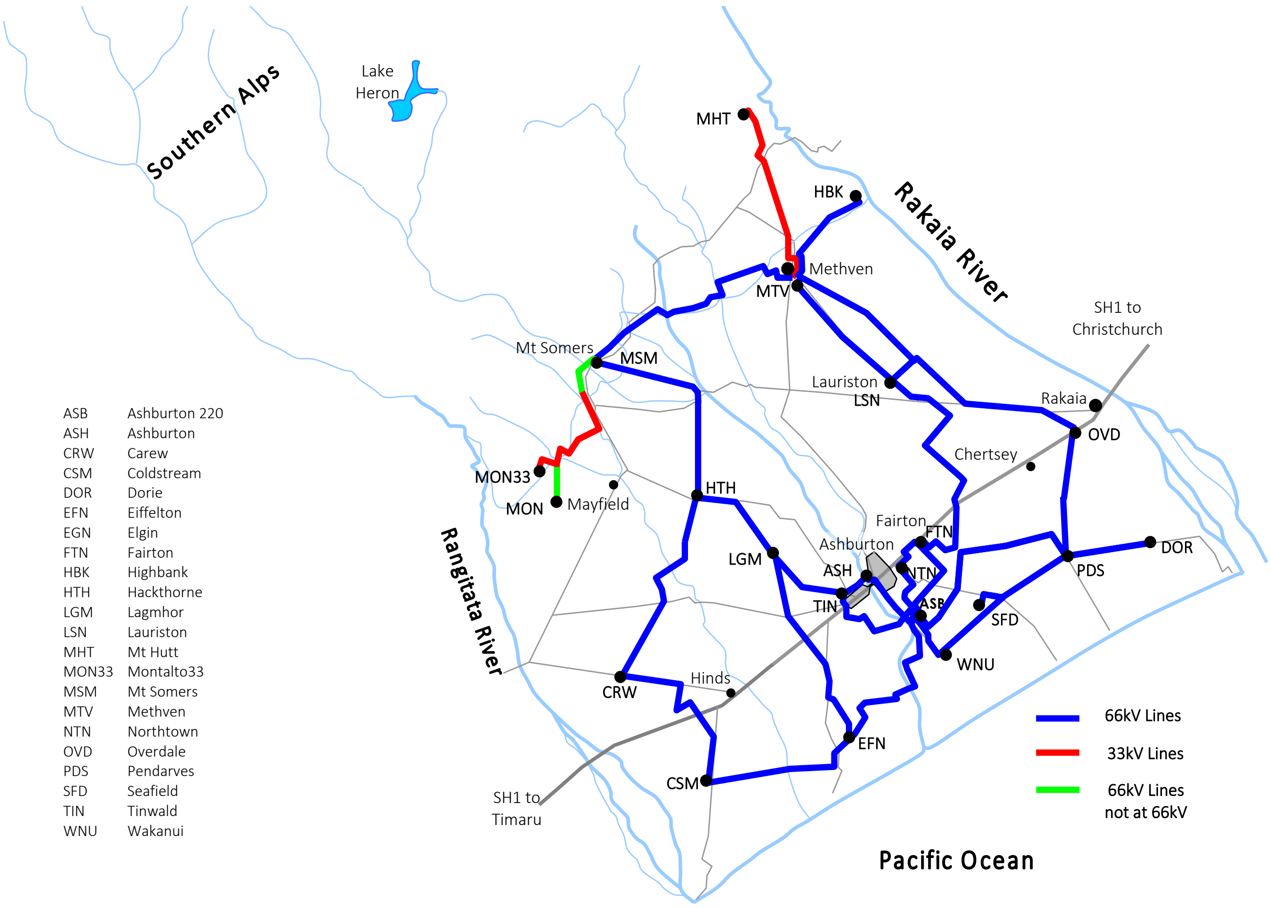
To provide a sense of where all the individual projects are taking the network, a series of diagrams have been included. Each one represents a stage in the evolution of the subtransmission network from where it is now in 2025, to where it will be during 2026, to the end of the planning period – where it is entirely 66kV with a second 66kV GXP.

The first diagram (2026 below) shows the network with a single Transpower GXP at 66kV. The 66kV network consists of:

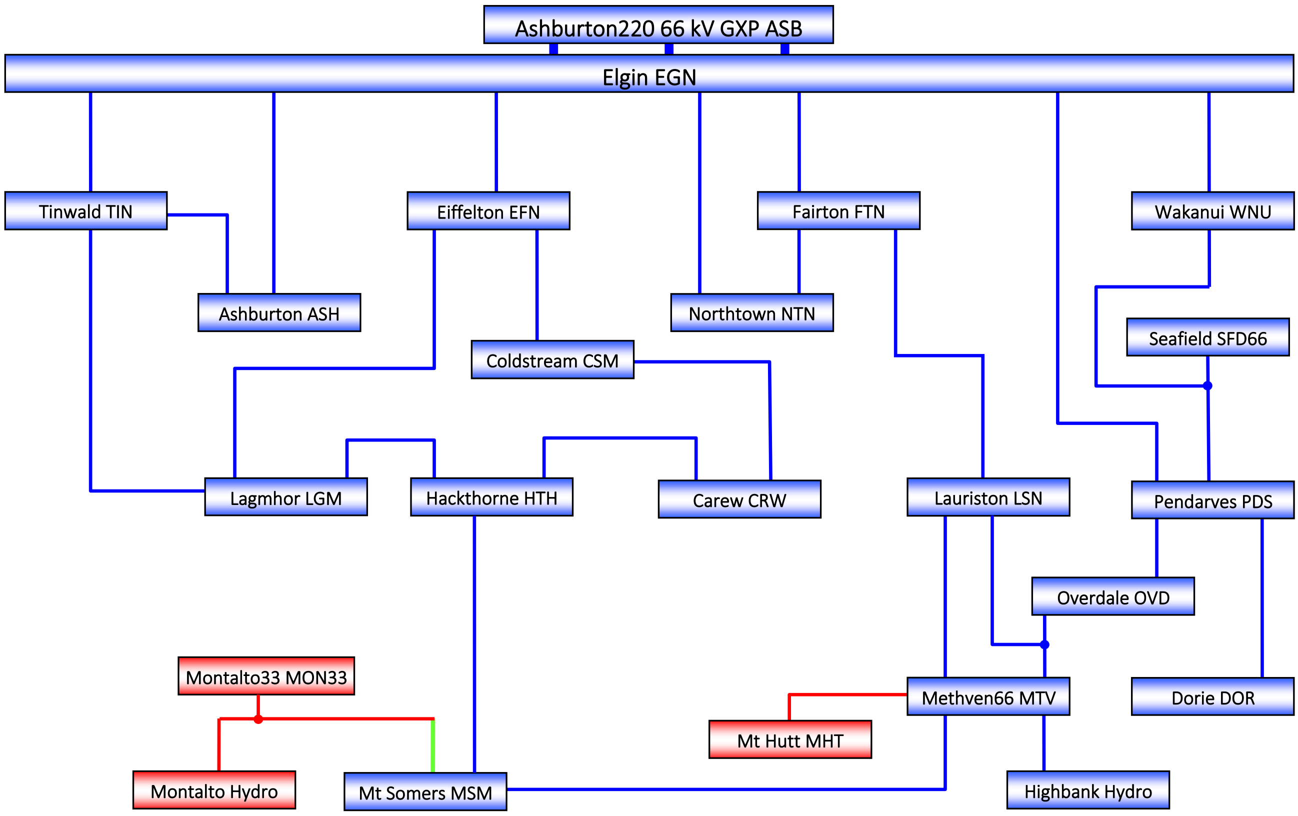
- a northern interconnected closed ring supplied by four circuits with several radial lines supplying individual sites,
- a southern closed ring supplied from three circuits.
- A single circuit between Methven 66 and Mt Somers providing increased security to Mt Somers and Methven by connecting the southern 66kV circuits to the northern 66kV circuits

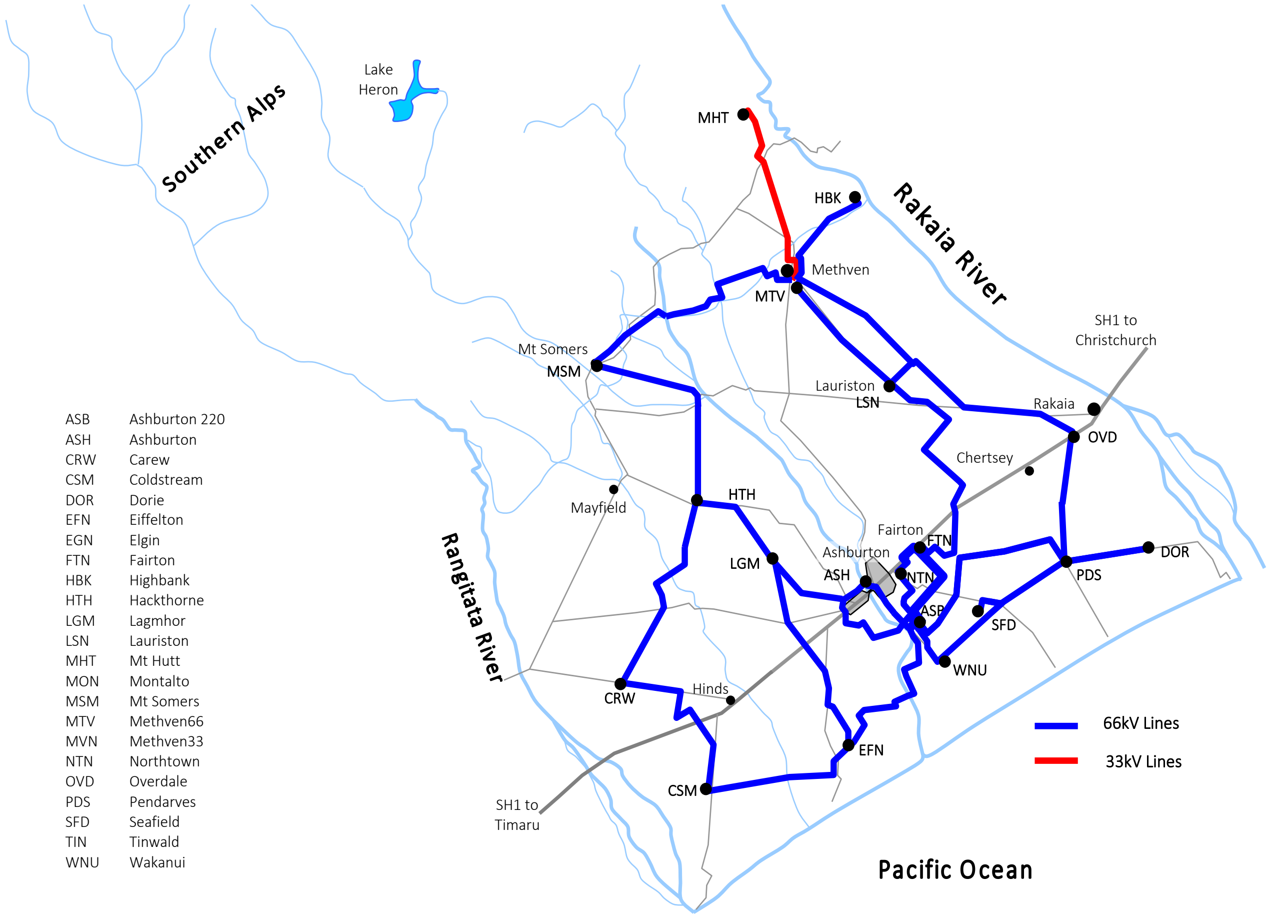
The associated geographic map provides the location of each of the sites described in the schematic diagram.

The remaining steps to change from 33kV to 66kV are limited to two lines, one of which is not scheduled for conversion within the planning period, and three zone substations, two of which will be decommissioned or converted to 22kV within the planning period.

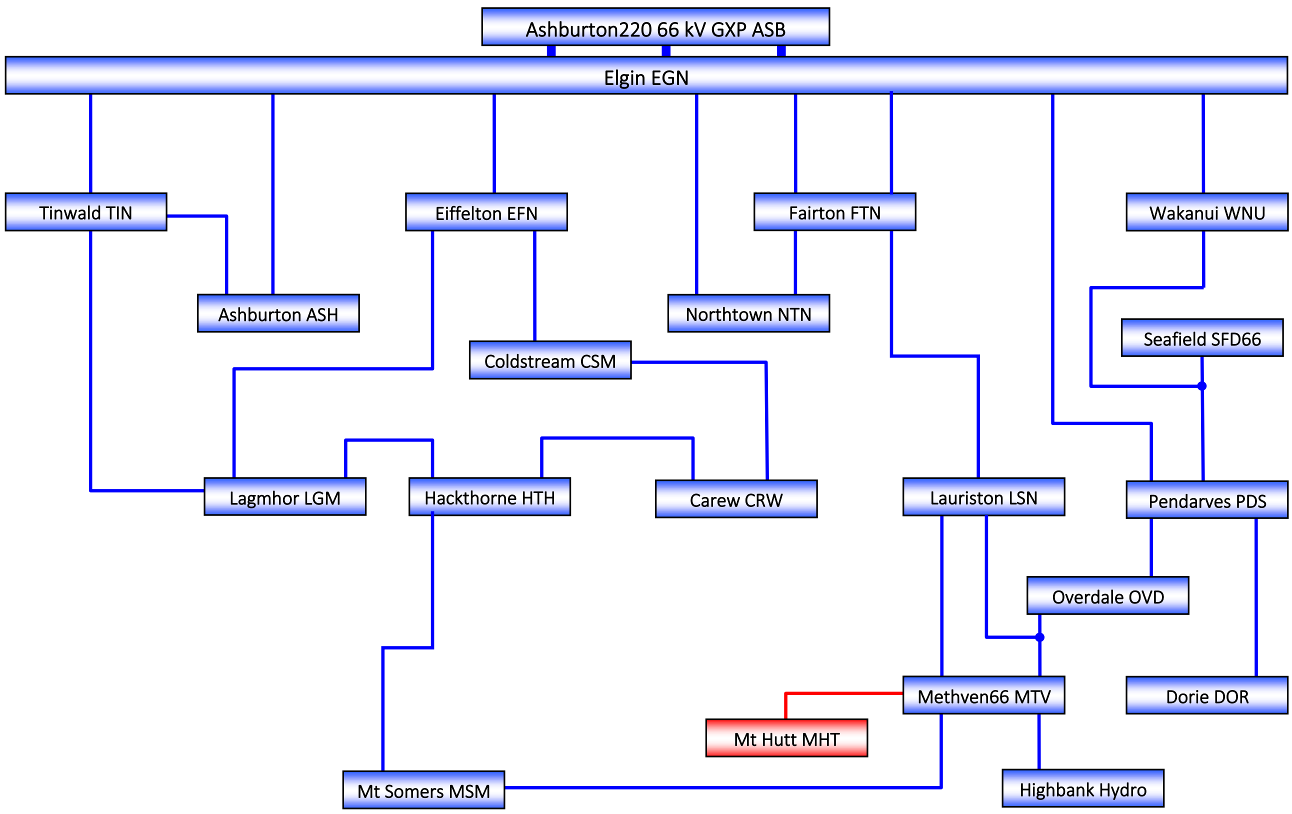


2026 EA Networks Subtransmission Network





2030 EA Networks Subtransmission Network



Project	Year	Name	Category
1037	2026	LSN to LSNT New 66kV Line Stage 1 (0.5 km)	System Growth

During certain 66kV line outages, the supply to Lauriston and Overdale zone substations can experience lower than desirable 66kV voltages which can in turn offer lower than acceptable 22kV and 400V supply voltages to consumers. This is caused by the long 66kV route required to supply them. During an outage of the PDS-OVD 66kV circuit, the supply must travel from Elgin all the way to Methven and then back to Overdale. During an outage of the FTN-LSN 66kV circuit, the supply must travel from Elgin to Overdale to Methven and then to Lauriston. This 66kV line has been delayed by Line Road's realignment uncertainty (Ashburton District Council – delayed by several years) but is largely finished and will now be completed in 2025-26. The associated 66kV line bay at Lauriston has already been completed.

Programme	2027, 2029	Overhead Line Replacement 33kV	Asset Replacement

This project is a rebuild of the Methven – Mt Hutt 33kV line related to asset condition.

	2027	33kV OH Rebuild - MTV-MHT Line (7km)	Asset Replacement
	2029	33kV OH Rebuild - MTV-MHT Line (7km)	Asset Replacement

Project	Year	Name	Category
700	2028-29	Additional 66kV and 22kV capacity at Fairton 66kV OH New – EGN-FTN	System Growth

This project is to provide a second 66kV overhead line from Elgin to Fairton to enable additional intensive industrial development in the Fairton area should signalled demand emerge. It is linked to zone substation expenditure to rearrange Fairton ZSS for 22kV loading. This programme is a specific allocation of capex within the Decarbonisation and Smart Technology Programme allowance (see below).

5.4.3 Zone Substations

The development at zone substations is typically a very costly and important part of network development. The drivers for doing this work are generally load growth and security.

EA Networks currently has 18 sites operating at 66kV. The 2 zone substations operating at 33kV are less secure with less capacity than the ones operating at 66kV. Once 22kV conversion is more developed, one of the 33kV sites will be decommissioned (MON33).

Capacity of New Equipment

A range of equipment is introduced when a new zone substation is constructed. The most critical and high cost items are the power transformers and the circuit-breakers.

The capacity of a new power transformer is influenced by a range of parameters, some of which relate directly to the load being served and some of which are externally derived. The only power transformers that EA Networks now purchase are units with 66kV primary voltage. The secondary voltage is either 11kV or 22kV. Almost all units purchased so far have been capable of both secondary voltages using a series/parallel connection of the windings. This configuration allows operation at 66/22kV, 66/11kV, and 33/11kV. The transformer power rating is based on the minimum economical size of 66kV transformer while keeping a degree of standardisation amongst the installed population. To date, two sizes of unit have been purchased, 10/15MVA and 10/20MVA, with the exception of the 35MVA unit installed at Lauriston in 2024 to cater for export from the Lauriston Solar Farm. The 10/15MVA and 10/20MVA units share the same impedance as well as a common external electrical and mechanical connection arrangement which allows any unit to be exchanged with any other unit. The security standard (section 3.6.6) dictates the combination of single or dual transformers that are required to be installed to serve particular sizes and types of load. 10-20MVA units are a close match to these security requirements.

Circuit-breakers and disconnectors are a simpler specification. At both 66kV and 22kV the continuous thermal and short circuit ratings of almost all available equipment exceed the requirements at both voltage levels. Minimum ratings of 630 amps continuous and 16 kA fault break are easily met by virtually all equipment. Except for urban Ashburton sites, all new distribution equipment is 22kV rated. All new subtransmission equipment is 66kV rated.

Projects & Programmes

Project	Year	Name	Category
700	2025-26	**ANZCO Security of Supply & Capacity Upgrade**	Consumer Connection - Other

This project was to provide an additional 1.5 MVA of industrial network capacity to ANZCO for a decarbonisation project, by providing an indoor 11kV switchboard and a new feeder connection at Seafield ZSS. This has improved security and capacity to ANZCO's industrial network.

-1126	2027	**Mt Somers to Montalto 22kV Feeder Protection (Montalto Hydro Injection at 22kV)**	RSE Quality of Supply

The reason the existing Montalto Hydro generation station (33/3.3kV) will require conversion to 22/3.3kV is the planned conversion of the Montalto area to 22kV. This will permit the decommissioning of Montalto33 33/11kV substation, the decommissioning of the Mt Somers 22/33kV step-up transformers and the reuse of the existing Montalto33 to Mt Somers 33kV line at 22kV. It will not be viable to commit to maintaining the infrastructure to allow Montalto Hydro to continue injection at 33kV.

This involves changing the existing (Manawa Energy owned) 33/3.3kV transformer to a 22/3.3kV unit and connecting it into a 22kV feeder.

700	2028-29	**Additional 66kV and 22kV capacity at Fairton** **New EGN-FTN 66kV Line Bay** **New EGN-FTN 66kV Line Bay** **FTN - Rearrange for 22kV loading**	System Growth

This project is to provide line bays for second 66kV overhead line from Elgin to Fairton to enable additional intensive industrial development in the Fairton area should signalled demand emerge. Zone substation expenditure is required to rearrange Fairton ZSS for 22kV loading. This programme is a specific allocation of capex within the Decarbonisation and Smart Technology Programme allowance (see below).

-1149	2030	**Tinwald Substation 66/11kV Transformer**	System Growth

Presuming the load in Ashburton continues to grow, there will be a need to provide additional firm capacity within urban Ashburton. It is sensible to have geographically diverse 11kV supply points and the Tinwald 66kV switching station will be available to house a 66/11kV 10/20MVA transformer supplying the existing 11kV switchboard. A transformer, 66kV circuit-breaker & disconnector, protection, and concrete pads will be required.

There may be ways to delay the need for the transformer using demand side management, energy efficiency measures, or grid/domestic batteries, and these will be examined for economic efficiency nearer the time.

700	2027-35	**Decarbonisation and Smart Technology Programme**	System Growth

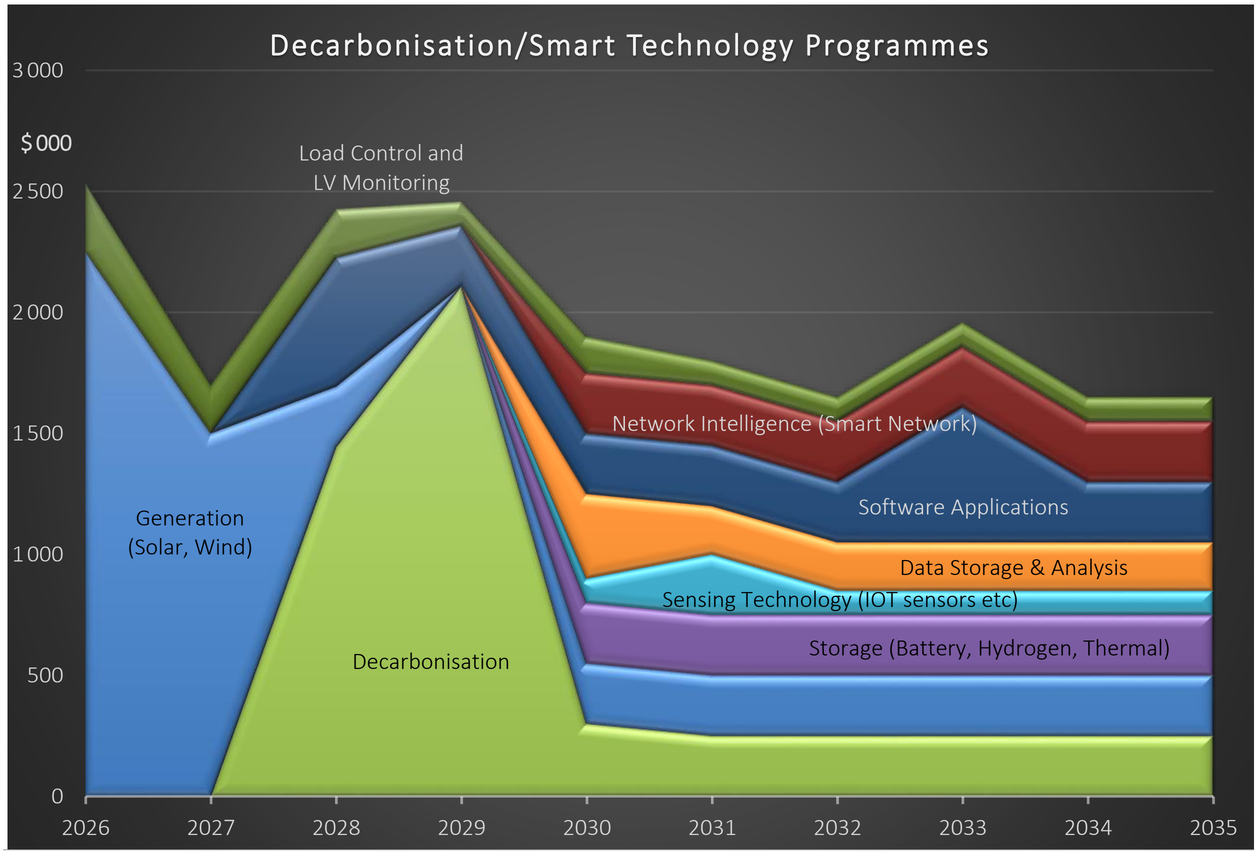
Decarbonisation of process heat and transport will impose new demand on the network, requiring investment to accommodate it. The rate of demand increase and the uptake and location of the new energy use technologies is difficult to predict and convert into concrete network projects and budget requirements. As a result, a broad-brush allowance for reinforcement of the network has been allowed for. In some cases, it may be possible to accommodate new load increases with technology to manage the available capacity and avoid conventional network upgrades, hence the conflation of this budget allowance with smart technology.

The range of technology applicable to the electricity distribution sector and related areas is expanding at a rapid rate. Broad areas with potential for rapid evolution include:

- Generation connections (Solar PV, Wind, etc),
- Storage technologies (batteries, hydrogen, solar thermal etc),
- Sensing technology (internet of things sensors, IP connected equipment, etc),
- Data storage and manipulation (energy use/availability, environmental, demographic, etc),
- Software applications (peer-to-peer trading, consumer portals, etc),
- Network intelligence (self-healing networks, continuous asset health monitoring, active capacity optimisation, management of distributed energy resources, etc).
- Enabling decarbonisation (creating capacity to allow electrification of carbon-based fuels).

It is inevitable that some of these technologies will be introduced into the EA Networks system at some stage within the planning horizon. One or two of them are already under active consideration.

Many of these technologies are changing rapidly and ten years is a long time within which major changes in capability and affordability are likely. Bearing in mind much of the change is likely to be based upon technology EA Networks are now only seeing glimpses of, it is not yet possible to determine which options EA Networks will be commercially compelled to implement.



The Decarbonisation and Smart Technology programme is planned to research and implement these types of technology projects at relatively short notice without specifically identifying them at this early stage.

Ultimately, any of the options that are chosen will be driven by consumer demand for a product, a service, or a consumer benefit that EA Networks can foresee will provide an appropriate return on investment - be it in retaining/expanding energy delivery market share or finding ways to utilise existing or new assets in new and novel ways.

The preceding diagram shows a possible spread of technologies that may be implemented with purely indicative costs (particularly in the latter stages). The Load Control and LV Monitoring programme is included here as it forms a foundation for many of the other technologies shown.

5.4.4 Rural 11 kV and 22 kV Distribution Network

The loading, security, and load growth on each of EA Networks' rural distribution feeders is assessed annually and this assists in preparing enhancement and development projects for this plan. The need for reinforcement is typically driven by the security standards and how the HV distribution network would cope with loss of an overhead line segment. Once a candidate feeder has been identified, the potential solutions are developed and then rigorously analysed to select the option offering best value.

Rural feeders are almost always limited by voltage drop. There are a range of solutions that can be applied to reinforce these feeders to meet the security standards. These include (but are not limited to):

- increase the conductor size
- reconfigure the network
- install capacitors
- install voltage regulator(s)
- convert to higher operating voltage
- install additional inter-feeder tie lines
- install additional feeders from the zone substation
- install additional line reclosers to increase segmentation

Almost all rural load is summer peaking irrigation or dairy shed load. Although peak demand load determines the feeder capacity, it may not determine the feeder configuration or its compliance with security standards. A lightly loaded rural feeder with little irrigation load may have many consumers supplied from it and consumer numbers rather than load may dictate the appropriate level of security.

Capacity of New Equipment

The capacity of new rural distribution lines is nearly always determined by voltage drop and mechanical considerations. The primary requirement in sizing rural overhead lines is to ensure that:

> *no part of the feeder in question experiences a voltage below 95 % of nominal during a foreseeable n-1 security event using the load probable 5+ years into the future.*

Thermal constraints can exist in the portion of line immediately beyond the feeder circuit-breaker. These are considered on a case-by-case basis but generally will not require a rating exceeding 300 amps (11 MVA at 22 kV).

Rural distribution transformers are sized based upon the scale and type of load being served. Small domestic and non-irrigation loads will be provided with transformers closely matched to the load. Irrigation pumps were historically provided with transformers that were larger than normal due to the harmonic derating effect of variable speed drives (compulsory harmonic limits now preclude the need for derating).

Projects & Programmes

Project	Year	Name	Category
11136	2026-35	**Consumer Connections – Rural LV/Rural Transformer**	Consumer Connections

When a new connection is supplied there is typically some modification or extension to the distribution network. This can range from a replacement pole through to a significant 22 kV extension of a kilometre or more with one or more new substations.

Being unscheduled, this work is essentially completed on demand (assuming the new or altered connection load is advantageous to EA Networks). The solution chosen to supply a new/altered load is typically agreed during consultation with the consumer to determine a price/quality/security trade-off they are happy with.

Project	Year	Name	Category
-1002	2025-35	22 kV OH Unscheduled Reconductoring	Asset Replacement

Unplanned replacement of inferior conductors or conductors at the end of useful life.

Some conductor condition is not obvious until either a fault or planned work identifies deterioration that is not obvious from ground level inspection. If this is found and needs timely attention the work is completed from this budget allocation.

When required, significant reconductoring works are identified as individual projects separate from this programme.

Programme	2024-33	Overhead Line Replacement 22 kV	Asset Replacement

The programme of rebuilding rural overhead lines when they reach the end of their useful structural life is an accepted routine activity. With a legal requirement to maintain the supply to existing consumers in place there is no option but to replace the old line with a modern equivalent overhead line using 22 kV components and a standard conductor size/type. The following schedule identifies those lines that have been identified as needing replacement within the next few years. Underground cable can be used more often now as, depending on circumstances, it can be of comparable cost.

	2026	Bruces Rd (0.4km)
	2026	Dicksons Rd (0.6km)
-1195	2026	Hardys Rd (East of Baker Rd) (0.25km)
	2026	Highbank School Rd (1.2km)
	2026	Jaines Rd (Hackthorne Rd East) (1.5km)
	2026	Kyle Rd (1.5km)
	2026	Longs Rd (1.8km)
	2026	Muckles Rd (0.8km)
	2026	Normanby & Sheehans Rds (0.4km)
	2026	Rushford Rd (1.4km)
	2026	Swamp Rd - Section 1 (Maronan Rd to Scales Rd) (2.4km)
	2026	Unnamed Rd Ealing (0.2km)
	2026	Unnamed Rd off River Rd (0.5km)
	2026	Wards Rd (0.7km)
-1180	2027	Klondyke Tce to Rangitata River Crossing (1.7km)
-1015	2027	Rangitata Gorge Bluffs (0.5km)
	2027	Ashburton Staveley Rd (2.2km)
	2027	Blacks Rd (0.8km)
	2027	Chertsey Kyle Rd (2.4km)
	2027	Christys Rd (0.5km)
-1092	2027	Copley Rd (Chertsey Kyle Rd East to end) (1.4km)
-1116	2027	Mayfield Klondyke Rd (RDR) (0.6km)
	2027	Swamp Rd. - Section 3 (Winslow Rd to Hendersons Rd) (3.3km)
	2027	Trevors Rd (0.7km)
	2027	Wakanui School Rd (0.7km)
	2028	Anama School Rd & Blairs Rd (Hekeao Rd to Lower Downs Rd) (2.5km)

Project	Year	Name
	2028	Anama School Rd (ARG Rd to Hekeao Rd) (2.1km)
	2028	Emersons Rd (4.1km but partial rebuild)
	2028	Longbeach Rd. (Grahams Rd to Lower Beach Rd) (2.6km)
	2028	Lower Downs Rd & Mayfield Klondyke Rd (2.8km)
	2028	Rangitata Hwy - Section 1 (Frisbys Rd to Giddings Rd) (5km)
	2028	Rangitata Hwy - Section 2 (Giddings Rd to Ealing Rd) (4km)
	2028	Swamp Rd. - Section 2 (Scales Rd to Winslow Rd) (3.2km)
11704	2026-35	Unscheduled Asset Replacement and Renewal

Programme	2026	Overhead Line Replacement 11kV	Asset Replacement

The programme of rebuilding rural overhead lines on the edge of the urban 11kV area when they reach the end of their useful structural life is an accepted routine activity. With a legal requirement to maintain the supply to existing consumers in place there is no option but to replace the old line with a modern equivalent overhead line using 11kV components and a standard conductor size/type. The following schedule identifies those lines that have been identified as needing replacement within the next few years. Underground cable could be used more often now as, depending on circumstances, it can be of comparable cost.

	2026	11kV OH Rebuild - Company Rd. (Seafield Rd to Ashford Ave) (2.0km)
	2026	11kV OH Rebuild - Quarry Rd (2.2km)
	2026	11kV OH Rebuild - Seafield Rd (Bridge St East to end.) (1.4km)

The overhead rebuild programme is still being researched to give an accurate year 4-10 assessment. By using the stored age of overhead lines, a provisional assessment has been made of the quantity of lines needed to be rebuilt within the planning period. This assessment has been costed and included in the plan as an average annual cost. Future plans will continue to develop our assessment of the 5-year programme.

1000	2026-35	22-11kV OH Scheduled Pole Replacements

A programme of planned minor replacement works that typically involve replacing one or two poles at a time. Prior year's inspection programme is likely to have identified the target poles.

-1001	2026-35	22-11kV-LV OH Unscheduled Pole Replacement

A programme of unplanned minor replacement works that typically involve replacing one pole at a time. Current year's routine inspection will typically drive this programme.

	2026-35	22-11kV Transformer Pole Replacements

In order to ensure EA Networks' on-property pole-mounted distribution transformers are safe to work on and are not exposed to undue risk of pole failure, a programme of pole replacements has been initiated. Where EA Networks deem the pole to be end-of-life and the owner is not prepared to replace the pole, EA Networks will negotiate with the land-owner to replace the pole and subsequently take ownership of that pole. During the free private line inspection process that EA Networks offers, suspect transformer poles will be identified and scheduled for replacement. There are approximately 1500 privately owned transformer poles that will need to be inspected for this programme. Not all will need replacement, and not all will end up in EA Networks' ownership.

	2026-35	22-11kV SOPL Rebuild Programme

The Private Property Existing Shared Service Lines policy enables the transfer of these pole types when agreed with affected landowners. This policy seeks to progressively enable ownership of shared service lines to be transferred to EA Networks from landowners at a nominal cost of $1. Ownership transfer will only occur after an inspection and contractual agreement with the affected landowners.

Depending on when a private line was installed, and the related agreements struck at the time, ownership can be hard to determine. Since EA Networks has always maintained that the private property boundary is the 'network supply point' (the demarcation point for asset ownership of poles, conductors, and cable) and the landowner was invoiced and consequently paid for all on-property works, our view is that all private lines are owned by the landowner from the network connection point.

We have received legal advice supporting this view, though it is recognised that each installation should be treated on a case-by-case basis. Where lines are shared (supplying more than one landowner) our private ownership position is more difficult. Regulation makes clear that these private lines should be owned and maintained by the network up to the point of common coupling (the point where a 1:1 relationship with a landowner can be identified). In general, there is a lack of good documentation that supports any ownership conversation, particularly when we look more than circa 15 years into the past. Reliance is placed on our prevailing connection policies, asset records, and our approach to asset inspections on private property. At no time has EA Networks claimed ownership of poles, conductor, or cable on private property.

Project	Year	Name	Category
Programme	2026-35	**Rural Underground Conversion**	Asset Replacement

The state highway network through Mid-Canterbury covers about 100km of rural road. EA Networks have electricity network along the side of a significant length of this highway network. Waka Kotahi (NZTA) have road safety as a primary goal. To achieve this, they have indicated the desire to remove roadside obstacles including power poles and, in the past, EA Networks has had an arrangement with Waka Kotahi to part-fund the removal of poles from any state highway when the opportunity arises. Currently, no further Waka Kotahi funding is available.

Rural Underground Conversion is typically considered when the line in question reaches the end of its useful structural life. EA Networks is currently considering the replacement decision in a qualitative safety, reliability, and lifecycle cost basis, where the higher initial installation cost of an underground solution is balanced by the higher lifecycle costs of an overhead line (equipment repairs and maintenance, vegetation management). The initial cost of overhead and underground installation can be cost comparative, provided the number of customer connections on the route is not large. Rural conversion projects will be considered on a case-by-case basis over the period of this plan.

Rural Underground Conversion obviously has some pros and cons for the line owner. The principal requirement is to replace the existing end-of-life overhead line with a line of the same or similar functionality.

A new overhead line would achieve this but would not improve the fault resistance of the line (weather, wildlife, vehicles, vandalism etc would still pose a threat). No road safety benefits result, and in fact the roadside pole hazard is extended for another 40 or more years. This option is the least expensive option but the least safe for the public.

Placed underground, the line is almost entirely immune to traditional (and common) sources of rural faults. It is exposed to the hazard of someone digging into it in ignorance (the law is not on the side of the person excavating) and the infrequent above ground portions can be exposed to vehicles, heavy flooding, and vandalism. The line will typically be of larger cross section and lower voltage drop than the overhead line it replaces. It is certain that during the following 40 years, multiple lives will be saved by avoiding a high-speed car versus pole collision. This option is more expensive than the overhead alternative.

Sub-Programme	2026	**Rural State Highway Underground Conversion**	Varies

2026 will see the completion of a series of projects that rebuild the existing end-of-life overhead line on the Ashburton-Methven Highway as underground cable. The projects will replace the existing overhead line with underground cable and connect existing overhead spur lines using either ring main units or three-way disconnectable joints (*elbow* connectors). This programme is most suited to sparsely populated highways which minimise the number of relatively costly tap-off connections to on-property lines.

EA Networks decided to proceed with the undergrounding of the remaining feeder sections in the interests of public safety, and that the incremental cost of undergrounding the feeder was justified based on the lower lifecycle cost and improved reliability and safety of the asset.

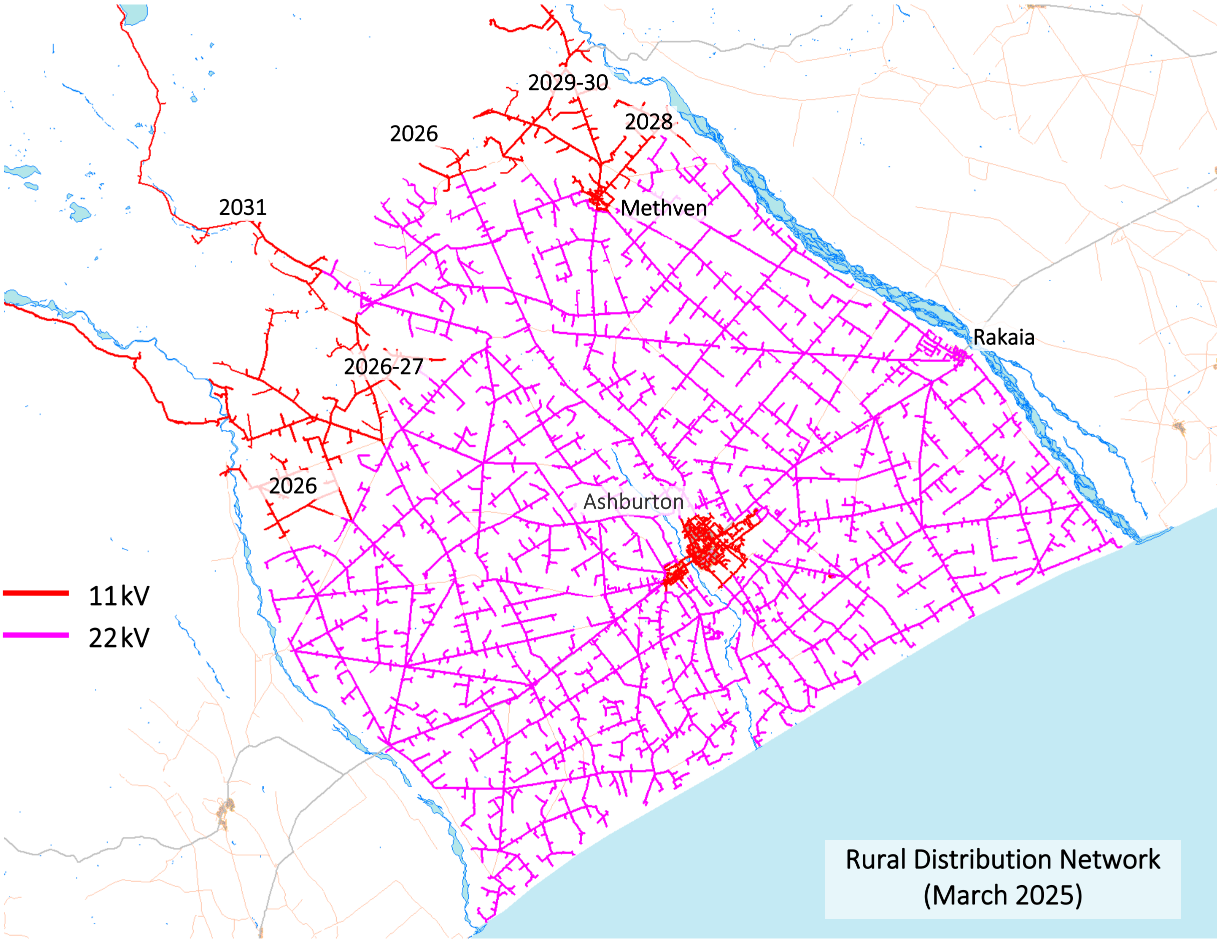
-1121	2025	**Methven Hwy (Shearers Rd to Springfield Rd (7km)**	Asset Replacement
Sub-Programme	2021	**Other Rural Underground Conversion Projects**	Varies
	2026	**Lake Heron Line (25.0km)**	Asset Replacement

-1059	2026	**Longbeach Rd, Hinds Hwy to east (0.7km)**	Asset Replacement
	2026	**Upper Downs Rd (2.2km)**	Asset Replacement
	2026	**Quarry Rd (1.9km)**	Asset Replacement
	2029	**Mt Hutt Station Road (Holmes Rd to Back Track) (1.7km)**	Asset Replacement

The Lake Heron Line is a large project to replace a remote high-country feeder with a more reliable and cost-effective cable solution. The evaluation of this project versus a non-network solution is discussed in section 5.4.12.

The Longbeach Rd project replaces a section of EA Networks 22kV line crossing private property to reroute it and supply it from the now 22kV underground Hinds Highway. The Upper Downs Rd and Quarry Rd projects are overhead replacements that have been found to be cost comparable to an underground solution. The Mt Hutt Station Rd project is a further section of SH77 overhead line that will be evaluated for underground conversion.

Programme	2026-31	**Upgrade Rural Network 11kV to 22kV**	Varies



The 22kV conversion programme in rural areas has been established to provide a significant step increase in capacity or additional back-feeding capacity. The rationale for this selection is discussed in section 5.3.2. The exceptions to this are that the supply from Orion in the upper Rakaia is likely to always be 11kV as will the Mt Hutt skifield supply (2 x 11kV cable circuits of about 7km length).

-1089	2026	**Methven Highway Springfield Rd to Methven, Alford Forest to Newtons Corner**	Quality of Supply

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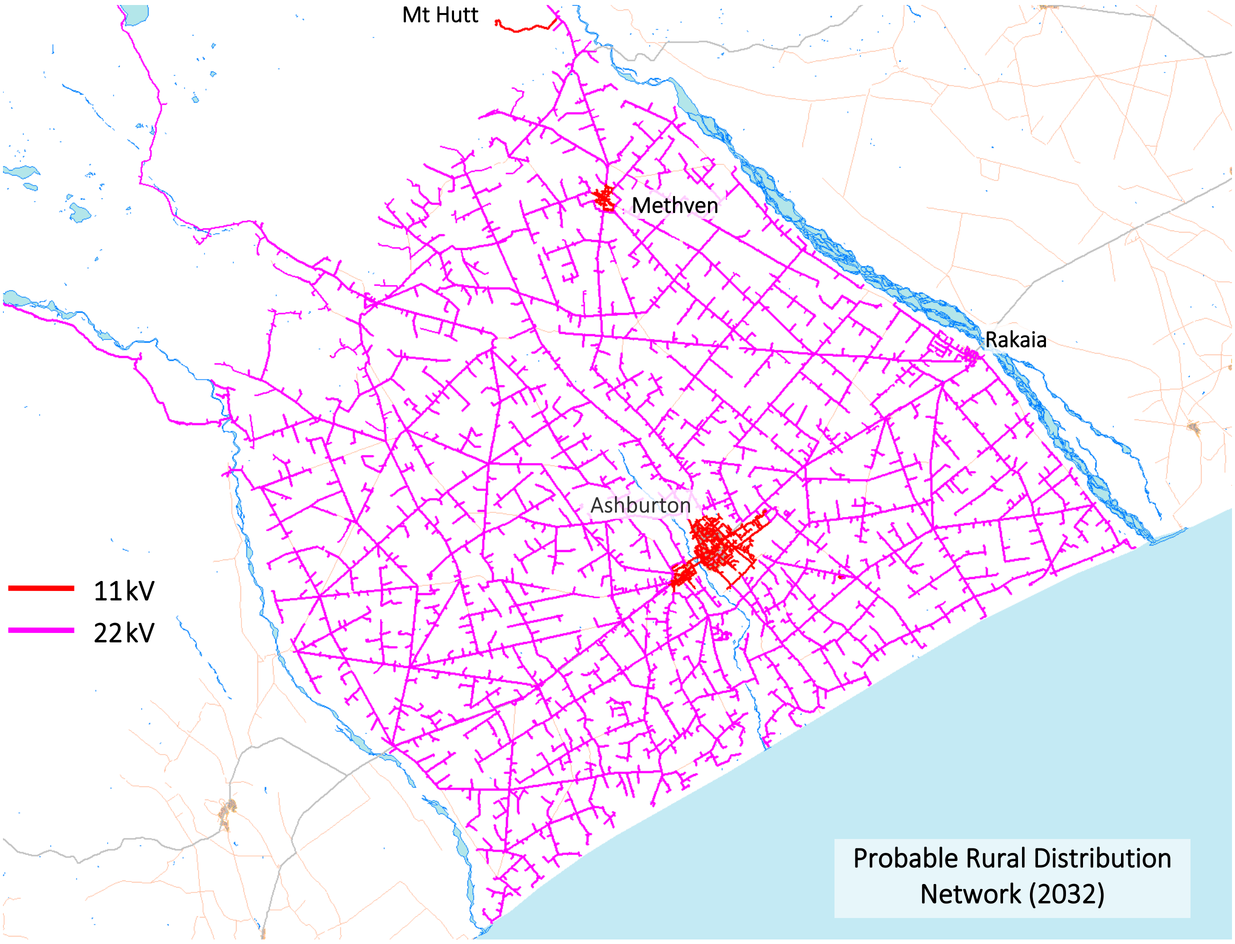
-1172	2026	**Montalto / Rangitata**	System Growth
-1133	2027	**Anama**	System Growth
	2027	**Quarry Rd**	System Growth
-1139	2028	**Highbank**	System Growth
-1150	2029-30	**Waimarama / Mt Hutt / Lower Rakaia Gorge**	System Growth
-1154	2031	**Ashburton Gorge**	System Growth



Probable Rural Distribution Network (2032)

Several of the projects are large areas of 11 kV that are supplied by a single 11 kV line bordered by 22 kV network. The circuit will have more than 250 consumers on it and no back-feeding options for a fault at the root of the feeder. The only viable solution is 22 kV conversion as 22/11 kV interconnecting autotransformers are technically not an acceptable long-term solution.

The 2026-27 conversion will permit a partly overloaded 2.5 MVA 33/11 kV zone substation transformer at Montalto33 to be decommissioned and provide much needed back-feeding capability into the area.

The projects will provide a significant boost to the security and reliability of the connected consumers as well as boosting the capacity significantly. Compliance with the *Reliability by Design* guidelines will be greatly assisted by the work.

It should be noted that load growth which occurred over the previous decade or more has prompted the security issues that these projects resolve.

5.4.5 Urban 11 kV Distribution Network

Urban distribution feeders are restricted to Ashburton, Methven, Mt Somers, and Rakaia townships. Other townships are typically connected to a rural overhead feeder with additional network segregation using line reclosers to offer the township a more secure supply.

In recent times, a third 11 kV feeder cable has been laid to secure the supply from the Methven66 zone substation to the Methven urban area. A new 11 kV inter-feeder cable was also installed to provide balance between the feeders and increased back-feed capacity during a cable fault.

Urban reinforcement solutions are typically implemented by adding additional cable routes from a zone substation, although a point is reached when congestion makes this impractical. Around 2005, Ashburton substation reached that situation, and the chosen solution was to introduce Northtown substation.

To meet both the capacity and security standards in place, the need has arisen to provide reinforced 11 kV ties and distributors from both Northtown and Ashburton substations. Some circuits are close to reaching thermal capacity and consequently security suffers (no capacity to back-feed during a fault or some planned outages). To resolve this, and thereby increase security and capacity, a decision has been made to introduce an additional layer of 11 kV cabling within the Ashburton urban area instead of adding many long, smaller cables. These large capacity cables (400+ amps) will be used to transport energy away from the zone substations to other nodes and between those nodes. Normal capacity distribution feeders (200 amps) would then radiate from these nodes, interconnecting with existing feeders.

Capacity of New Equipment

The capacity of a new urban 11 kV underground distribution feeder circuit is typically sized between 200 amps and 300 amps. The exact sizing is determined by likely feeder loading and its function during *n-1* security events. Typically, this will mean:

> *The peak load will be no more than 50% of the thermal capacity to allow for growth and adjacent feeder back-feeding during n-1 events.*

Urban distribution transformers are sized using either an average diversified load for domestic consumers (4 kVA) or assessed load information from industrial/commercial consumers. Maximum demand meters in the distribution substation ensure calculated values can be readily confirmed.

Projects & Programmes

Project	Year	Name	Category
Programme	2026-35	**Unscheduled Urban Works**	Varies

A small amount of budget is set aside for unscheduled work that occasionally occurs. This could involve one or many classes of asset. It has been included in the urban distribution section as a significant proportion of EA Networks' consumers reside there. It is therefore likely that some of the demand for unscheduled work would come from these areas.

It should be noted that the Ashburton District Plan does not permit the installation of additional poles in the urban and fringe urban zones and replacement poles must be of the same or similar height and scale and in the same or similar location. This precludes significant changes to any overhead line if it was going to be rebuilt.

Project	Year	Name	Category
11059	2026-35	**Unscheduled System Growth**	System Growth
11078	2026-35	**Unscheduled Quality of Supply**	Quality of Supply
11079	2026-35	**Unscheduled Other Reliability Safety Environment**	RSE
11704	2026-35	**Unscheduled Replacement and Renewal**	Replacement & Renewal

Project	Year	Name	Category
Programme	2026-35	**Urban Consumer Connections**	Consumer Connections

When a new connection is supplied, there is typically some modification or extension to the distribution network. This can range from a new pillar box through to a significant 11 kV or 22 kV extension of several hundred metres with a new substation. Typically, the new consumer will be required to contribute to the cost of the work.

Being unscheduled, this work is essentially completed on demand (assuming the new or altered connection load is advantageous to EA Networks). The solution chosen to supply a new/altered load is typically agreed during consultation with the consumer to determine a price/quality/security trade-off they are happy with.

Although subdivision work is categorised as Consumer Connection – Other (as it is triggered by the desire to take additional electrical connections to the network), it does not immediately create any new ICPs. In fact, the bulk of new connections generally occur a year or so later as the marketing takes effect. A consequence of this is that there are generally no new ICPs reported next to subdivision work in the disclosure documentation. Other types of new connections are charged directly against the project creating them and can be resolved back to the relevant connection category.

Project	Year	Name	Category
11058	2026-35	**Urban Connections – Transformer**	Consumer Connections
11058	2026-35	**Urban Connections – LV**	Consumer Connections
11058	2026-35	**Urban Connections – Alteration**	Consumer Connections
11058	2026-35	**Urban Connections – Other**	Consumer Connections

Programme	2027-34	**Ashburton Core Urban 11 kV Network**	System Growth

The adoption of the indicative [Reliability by Design] guidelines by EAN Networks and approved by the Board has added impetus to the need to reduce the scale of urban 11 kV feeders. The new guidelines have a maximum of 250 consumers per feeder before action is deemed necessary to reduce that number to below 200. There are many urban feeders that exceed that number by a significant margin and a range of initiatives are underway to close the gap to complying with the guidelines. This *Core Urban 11 kV Network* programme (Section 5.3.4) is one of the most significant ones, and it will provide additional feeders from new Network Centres (switching centres) embedded within the urban areas. The planned reinforcement would take the form of relatively few, new, high capacity (7 MW) 11 kV Core Network circuits radiating from both Ashburton and Northtown substations. These circuits would terminate in new switching centres that would supply (via circuit-breakers) portions of some smaller (4 MW) existing zone substation feeders and additional feeders (created by utilising existing and new 11 kV cables). Distribution substations would not be directly connected to the new Core Network circuits. These high-capacity Core Network circuits would then interconnect between Network Centres to provide an 11 kV backbone which could be used to shift increased load during cable faults and zone substation transformer outages. An added benefit is that the existing smaller feeders would be more than halved in length and load, so any cable fault should affect less than half as many consumers and restoration to the un-faulted sections would be significantly faster.

With the continuing use of heat pumps to displace solid/liquid/gas fuel heating, the introduction of home electric car charging, continued housing infill, and as the general growth in electricity demand continues, it is very likely that additional distribution system capacity will be needed in the Ashburton urban area. In some places it is already required. This programme will increase the capacity to supply load under both normal and contingency conditions.

This programme of works will only be undertaken as necessary. The addition of unforeseen load may accelerate the programme and, equally, a prolonged period of low growth may postpone parts of the programme. Once started, there will be key points where a pause can take place, but these points must be reached, as incomplete closure of a ring of the core 11 kV circuits would heavily compromise security. The progress of the programme will be optimised by coordinating with the urban underground conversion programme.

Alternative distribution architectures may yet surface that provide part of a viable solution. These new technologies will be considered as part of any solution as will future load shifting, distributed generation, or energy storage technologies.

This part of the programme identifies the roughly 17 km of new 11 kV cabling required. Much of the new cable will be run in existing ducts or new ducts installed during the UG conversion programme. The network centres are identified in Section 5.4.8. The commencement of the future Core Network Cables and Network Centres projects has been deferred to 2027 while selection of switchgear and access to sites are confirmed.

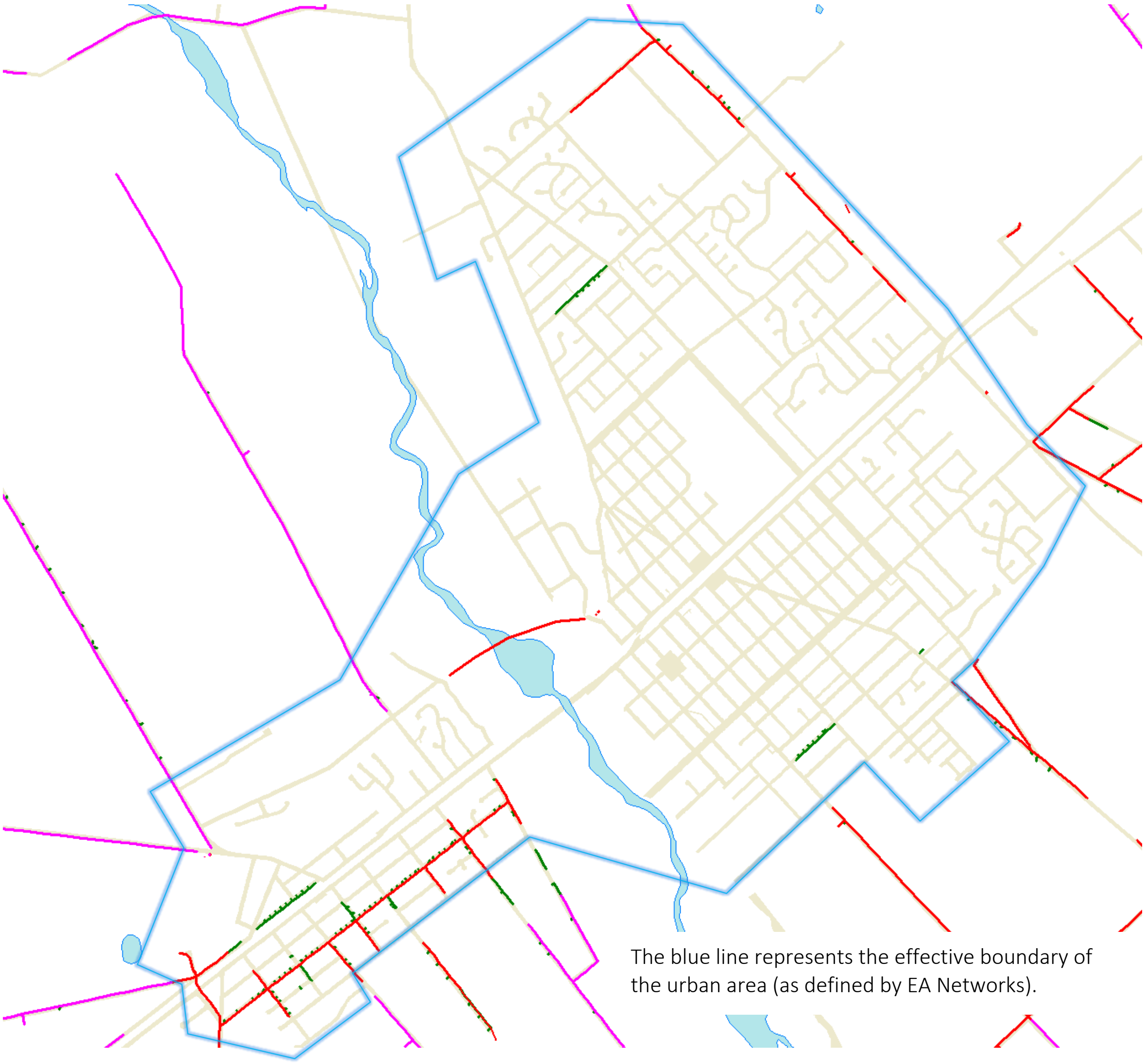
-1010	2027-34	**11 kV Core Network Cables**	System Growth

- Northtown [NTN] to Racecourse [RCS] Network Centre (1.5 km).
- Netherby [NBY] to Domain [DMN] Network Centre (0.9 km).
- Domain [DMN] to Allenton [ATN] Network Centre (2.1 km).
- Domain [DMN] to Allenton [ATN] Network Centre (2.1 km).
- Racecourse [RCS] to Allenton [ATN] Network Centre (1.0 km).
- Ashburton zone substation [ASH] to Western [WST] Network Centre (2.9 km).
- Dobson [DBN] to Beach [BCH] Network Centre (1.3 km).
- Western [WST] to Allenton [ATN] Network Centre (1.6 km).
- Chalmers [CMR] to Beach [BCH] Network Centre (1.1 km).
- Hollands [HLD] to Melcombe [MCB] Network Centre (0.7 km).
- Netherby [NBY] to Beach [BCH] Network Centre (2.1 km).

Programme	2026-32	**Urban Underground Conversion**	Asset Replacement

During the 1960s and 1970s a significant amount of the urban electricity network was (re)built to service the new influx of electric ranges, electric heaters, electric washing machines, fridges, and freezers. The network has lasted very well but is now due for replacement. The last urban overhead line that was rebuilt in 1993 is now 32 years old, other lines are considerably older. Although the Ashburton District Plan allows the replacement of overhead lines with the same or similar type of construction, there are no additional new poles allowed, and all extensions and subdivisions are required to be completely underground. EA Networks

March 2025 – Remaining 11 kV and LV Overhead Lines in Ashburton



The blue line represents the effective boundary of the urban area (as defined by EA Networks).

has a policy that all new network connections are required to connect via underground cable.

As discussed elsewhere in this plan, the stakeholders and Board have shown considerable support for the progressive removal of overhead lines from the urban areas. The widespread support of the consumers/shareholders lends additional weight to the other less obvious advantages that accrue from this work. The additional quality of supply, security, capacity, flexibility, and low maintenance characteristics all contribute to greater consumer/shareholder satisfaction. Other stakeholders are also encouraging of this work.

The individual projects funded by this programme are prioritised by the following factors:

- the condition of the existing overhead lines and therefore the safety of them,
- the benefits to reliability and security obtained by underground conversion,
- the need to increase line or transformer capacity in an urban area.

This programme targets the lines in poorest condition as a priority and has been assessed to ensure public safety is maintained. Once they have been replaced with underground network the remaining overhead lines will be continuously aging and at the end of the programme the major components of the final line to be removed will be circa 40 years old. Areas with concrete poles have been phased at the end of the programme given their longer life.

The map above shows remaining overhead lines in Ashburton (11 kV and LV) stored in the GIS database at the time of writing. There are some shown that may not be in service and are awaiting removal following underground conversion. Additionally, there is presently a delay in processing as-built information and some of the lines shown may have already been physically removed.

March 2025 – Remaining 22 kV and LV Overhead Lines in Rakaia

The map above shows remaining overhead lines in Rakaia (22 kV and LV) stored in the GIS database at the time of writing. There are some shown that are not in service and are awaiting removal following underground conversion.

Project	Year	Name	Category
-1142	2026	Jane St (McMurdo St - Grove St)	Asset Replacement
-1171	2026	Carters Tce (SH1 - Grove St)	Asset Replacement
-1151	2026	Lower Hakatere Huts Stage 3B	Asset Replacement
-1132	2026	Oxford St (Beach Rd - Wellington St)	Asset Replacement
-1124	2026	South Town Belt East (Bridge St - Burrowes Rd)	Asset Replacement
-1129	2027	Melcombe St (Anne St - Lagmhor Rd)	Asset Replacement
-1145	2027	Rakaia Huts	Asset Replacement
-1136	2028	Farm Rd (Middle Rd - Racecourse Rd)	Asset Replacement
-1157	2028	Graham Street (Thomson St to McMurdo St)	Asset Replacement
-1187	2028	Line Rd Methven (200m LV)	Asset Replacement
-1152	2028	Rolleston Street (Tancred St - Burrowes Rd)	Asset Replacement
-1153	2028	South Town Belt - West (West Town Belt - SH1)	Asset Replacement
-1147	2028	Wilkin St (McMurdo St - Millibrook Pl)	Asset Replacement

-1204	2029	**Racecourse Rd (Creek Rd - Allens Rd)**	Asset Replacement
-1162	2029	**Shearman St**	Asset Replacement
-1134	2030	**Allens Road (Harrison St - Alford Forest Rd)**	Asset Replacement
-1158	2030	**Thomson St (Carter Tce - Wilkin St)**	Asset Replacement
-1160	2031	**Agnes St (McMurdo St - Grove St)**	Asset Replacement
-1158	2031	**Thomson St (Wilkin St - Graham St)**	Asset Replacement
-1138	2032	**Racecourse Rd (Allens Rd to Farm Rd)**	Asset Replacement
-1158	2032	**Thomson St (Grahams St - Hassel St)**	Asset Replacement

5.4.6 Industrial 11 kV Distribution Network

The major industrial zoned areas of Ashburton, Methven, and Rakaia are generally close to existing or proposed zone substations. This has made planning for the security and capacity requirements of these areas relatively straightforward. As necessary, additional feeders will be taken into these areas to ensure adequate capacity and compliance with the security and power quality standards. The most recent industrial park that been developed to the northeast of Ashburton township is in close proximity to both Fairton and Northtown substations.

A number of industrial plants are directly connected to EA Networks' HV distribution network and these consumers have individual arrangements with regards the security, reliability, and quality of supply they wish to receive. Most of these consumers are adjacent to a zone substation and they take ownership of the HV distribution network (generally excluding RMUs & transformers) as it enters the plant boundary. Any alteration of the supply up to the boundary is done either at the request of the consumer or by negotiation with the consumer. Any alteration to the HV network within the plant boundary is the responsibility of the consumer and although EA Networks can offer advice on solutions, it is up to the consumer to ensure adequate capacity and performance.

Capacity of New Equipment

The majority of equipment is sized to suit individual industrial consumers. Consumers are asked to reveal any expansion plans so this can be factored into the sizing calculation. Most industrial consumers of note are served by one or more dedicated distribution substations and the cost to the consumer indirectly reflects the investment in these assets i.e. the consumer gets the capacity and security they pay for.

Projects & Programmes

Project	Year	Name	Category
Programme	2026-35	**Unscheduled Industrial Works**	Varies

Projects as per reference to Unscheduled Works in section 5.4.5.

Any work identified here is typically to secure industrial load as part of the underground conversion programme. Most of this load is on a radial feed, and work would typically increase security while relieving feeders that are heavily loaded.

Occasionally, an industrial customer may approach EA Networks to either reconfigure or enhance their supply and if this work is minor it would fall under this programme. Significant alterations or enhancements would trigger a specific project to provide the requested level of connection.

Programme	2026-35	**Industrial Consumer Connections**	Consumer Connections

Projects as per reference to Consumer Connections in section 5.4.5.

When a new connection is supplied there is typically some modification or extension to the distribution network. This can range from a replacement pole through to a significant 11 kV or 22 kV underground extension of several hundred metres with a new distribution substation.

Being unscheduled, this work is essentially completed on demand (assuming the new or altered connection load is advantageous to EA Networks). The solution chosen to supply a new/altered load is typically agreed during consultation with the consumer to determine a price/quality/security trade-off they are happy with.

5.4.7 Low Voltage Network

The LV distribution network is heavily interconnected in the urban area. This generally permits reconfiguration to solve simple capacity problems. If a new consumer load exceeds the additional capacity reconfiguration can liberate, a new cable is normally run from the either a suitable distribution substation or higher capacity LV node. Should the load exceed the ability of the LV network to meet the security standard, a new distribution substation is the most common alternative. Essentially, the LV network is extended or installed on demand.

The low consumer count on each LV segment typically precludes a high level of security at the individual connection. Some larger consumers will be supplied from a switching point from which two supplies can be selected. This allows restoration of supply relatively quickly after an LV segment faults, while others directly connected to the faulted segment will have to wait for either physical disconnection of the faulted cable or the full repair time.

The LV network in Ashburton is approximately 94% underground by conductor/cable length. The underground area is largely fault-free. Occasional terminal or connector problems arise and there have been some instances of older single core PVC insulated aluminium cables corroding causing an open circuit fault. Third parties cause most faults.

The capacity of the LV underground network is adequate for the planning period except for a few very early underground subdivisions where the cables were undersized by modern standards. These are not currently causing a problem but could become an issue (with new loads such as electric vehicle charging) before the end of the planning period as both the thermal rating and guideline voltage drop limits are exceeded.

Widespread adoption of long-range electric vehicles requiring 10 kW+ home charging facilities would cause issues for the existing network. The present design of the urban LV network is conservative and allows for 5 kW of diverse loading per household. The addition of 10 kW or more (even off-peak) would obviously compromise the original design limits by quite a significant margin. It is assumed that vehicles with large battery storage will not be prepared to pay for the network capacity to charge from flat at home overnight and they will instead visit a faster charging station to obtain at least 80% of their charge (this could be at locally available fast chargers already established in central Ashburton with additional geographical and capacity expansion driven by EV demand)). The remaining top-up could be serviced by a slow charger in their garage overnight (3.5 kW over 6 hours is 20 kWh ~ 100 km+).

Should peer-to-peer trading of electricity become widespread, then solar PV may be another challenge for the urban LV network. Currently, the buy-back rate for solar PV is low enough to discourage high-capacity export to the network. In future, should a peer wish to purchase that electricity for their electric vehicle, they could pay enough for the solar PV owner to export much of their peak generation to the peer. This may cause large network import spikes during the sunniest days that will cause voltage rise on the LV network. Modern solar PV inverters can provide some control over this voltage rise, but it is limited and has other impacts that may ultimately restrict its widespread use. Until solar PV penetration exceeds 5-10% (currently ~2%), it is unlikely the issue will have a major asset management impact.

Urban Methven has been completely underground for several years and has a low-maintenance LV network. Load growth within the existing network is typically caused by hotels, accommodation houses, restaurants, or smaller industrial loads. The accommodation houses and restaurants are usually supplied from the LV network and have consumed much of the extra capacity built into the LV network at the design stage. Fortunately, the density of these developments has peaked, and it appears that as a new one opens another tends to close. The larger hotel and industrial loads are supplied from a dedicated distribution substation in most cases. When they are supplied from the LV network, care has been taken that the additional source impedance does not permit inrush loads such as motors to interfere with other consumers on the same LV segment.

Rural LV distribution is traditionally overhead and serves one or two consumers on each segment. New connections are now all underground. Other than conversion to underground cable (normally at the consumer's cost), there is little that can be done collectively and economically to improve the security of these lines.

Capacity of New Equipment

The value of the cable is typically a relatively minor component of the total cost of LV underground network construction. The standard cable in use at EA Networks is either 185 mm^2 aluminium or 240 mm^2 aluminium 4 core XLPE insulated cable. This allows optimal spacing of distribution substations while ensuring adequate capacity to allow for adjacent distribution substation outages caused by maintenance or fault. The key parameter is that:

> *the voltage at any connection point must not drop below 95% of the nominal value during a foreseeable n-1 security event. The thermal rating of the cable must not be continuously exceeded at any time.*

Projects & Programmes

See the projects listed under section 5.4.5 as they contain the majority of new LV network – installed in conjunction with MV work.

Project	Year	Name	Category
Programme	2026-35	**LV Consumer Connections**	Consumer Connections

Projects as per reference to Consumer Connections in section 5.4.5.

Programme	2026-32	**Urban Underground Conversion**	Asset Replacement

Projects as per reference to Urban Underground Conversion in section 5.4.5.

As the urban underground conversion programme progressively covers the urban areas, the security and capacity of the LV distribution network improves significantly. This programme is the only identifiable initiative to reinforce this section of the network to accommodate future demand and security objectives. The modern cable designs and installation techniques will offer a long trouble-free life for this plant. The consumer/shareholder enthusiasm for this programme is very high. All stakeholders in this plan are satisfied that the urban underground conversion programme is the best solution for an aging urban overhead network.

5.4.8 High Voltage Switchgear

The range of high voltage switchgear in use at EA Networks covers multiple voltages (66 kV, 33 kV, 22 kV, and 11 kV), multiple types (circuit breakers, disconnectors, load-break switches, fuse switches, fuses, and links), and is in multiple locations (on poles, ground-mounted, inside kiosks, inside buildings, and inside zone substations). Although the voltage, type, and location of the devices vary greatly they are all electromechanical in nature and share common asset attributes and maintenance requirements.

Generally, new switchgear is installed as an adjunct to subtransmission, distribution, or zone substation projects. There are a few projects and programmes that are explicitly switchgear focussed, and they are described here.

Capacity of New Equipment

Switchgear capacity is typically sized to comfortably exceed the load rating forecast for ten years into the future. Most high voltage switchgear has minimum ratings that significantly exceed EA Networks' requirements. The required fault ratings are determined by the parameters detailed in Section 5.1.1.

Operational safety requirements are considered when new types of switchgear are evaluated for introduction into the EA Networks network.

Projects & Programmes

Programme	2027-34	**Ashburton Core Urban 11kV Network**	Quality of Supply

See section 5.3.4 and section 5.4.5 for details on the Ashburton Core 11kV Network.

A total of seven network centres will be required in the Ashburton township and two of three now exist in Tinwald. The commencement of the future Core Network Cables and Network Centres projects has been deferred to 2027 while selection of switchgear and access to sites are confirmed.

Project	Year	Name	Category
-1011	2027-34	**11kV Core Network Centres**	Quality of Supply

- Allenton [ATN] Network Centre.
- Hollands [HLD] Network Centre.
- Domain [DMN] Network Centre.
- Netherby [NBY] Network Centre.
- Racecourse [RCS] Network Centre.
- Dobson [DBN] Network Centre.
- Beach [BCH] Network Centre.
- Western [WST] Network Centre.

5.4.9 Protection Systems

The demands of the security standards and increased load require that the protection systems not only detect faults but also, whenever possible, prevent overloading of network components. As technology advances this is becoming more achievable. Devices now exist that can monitor and model many different power system components while offering fault protection functionality as their primary purpose. With an accurate model, many power system components can be run at higher than rated capacity for short periods without any detrimental effects. This can liberate previously unavailable capacity to supply either additional short-term peaking load or offer higher security to consumers reliant on that component as an alternative supply.

Functionality of New Equipment

When any network is made more secure, there is normally a protection relay that is providing the logic to keep the supply on to consumers. At subtransmission voltages this involves isolating the faulted path, leaving the unfaulted path(s) to carry the full load. This philosophy may also exist in heavily loaded HV distribution networks. In HV distribution the goal is usually to:

1) ensure the fault is not transient (a branch touching a line then burning away) – in which case the line will be automatically relivened (this is not used for underground cable circuits),
2) if the fault is permanent, interrupt only the faulted segment of network in the fastest possible time,
3) if it is possible to reconfigure the network to resupply consumers that are not connected to the faulted segment, do so in the shortest possible time.

All these goals are to some degree achievable and, if implemented, can help increase compliance with security standards as load grows.

Projects & Programmes

The zone substation replacement, development, and enhancement projects all contain aspects of protection technology. Although it is possible that protection will be upgraded independently of these projects, most new protection will be introduced as a result of zone substation work.

The introduction of closed 66kV rings required some form of directional, distance, or differential protection scheme to take full advantage of the additional security two 66kV lines per substation offers. EA Networks standard approach is to use line differential protection with a distance backup on all 66 kV line terminals, and high impedance bus differential protection on each 66 kV busbar. The line differential protection uses the EA Networks inter-substation fibre optic network. The 3-zone distance protection will also be the master control device for the line bay (marshalling or controlling items such as: status, analogue values, reclosing, and remote control etc). Once complete, all equipment from the 66 kV GXP to the zone substation 22 kV (or 11 kV) busbar will be covered by differential protection zones. This arrangement will provide selective operation of all circuit-breakers in the fastest possible way – minimising voltage depressions and outages experienced by consumers.

There are a range of alternative protection schemes that could possibly be engineered to perform a similar function (at significant engineering cost both initially and for maintenance) but none would offer the same level of performance on offer by the differential/distance combination. Also, none of the alternative protection schemes would scale up as easily or be as stable with the level of interconnectivity that the 66 kV system exhibits.

Project	Year	Name	Category
10988	2026	**Synchrophasors (66 kV System Sync-Check)**	Quality of Supply

The hydro generator at Highbank is a synchronous machine that can create an island situation if the 66 kV subtransmission network clears a fault that trips all of the in service 66 kV lines that interconnect MTV substation with the EGN/ASB GXP. A phase angle difference occurs the moment the last circuit-breaker opens. This situation can be catastrophic to the generator if the network is reconnected to the Highbank supplied island when it is out of phase with the EGN supplied network. The generator can suffer irreparable damage. Currently, there is no automatic reclosing on the 66 kV network. With the commissioning of the Methven - Mt Somers 66kV circuit, there are now three 66kV circuits to ensure connection from Highbank back to EGN/ASB GXP which has improved the situation. However, when one of those 66kV circuits is out of service and another trips, the controller-initiated closures to reliven the tripped circuit, Manawa Energy shuts down the Highbank generator to guard against out of synchronism events. The disadvantages of this mode of operation are clear. The affected 66 kV circuit breaker fault operations must be patrolled before any thoughts of closing the circuit breaker and, before that can occur, Highbank must be shut down. This all adds to delays and inefficiency.

This project is to provide a mechanism that guarantees that synchronism exists between EGN and MTV and communicates this to all the nodes on the 66 kV network. The approach that EA Networks intend to take is to install a device at EGN and another at MTV that sense the 66 kV voltage and communicate samples of this with a very accurate time stamp (Synchrophasors) to a calculation device. The calculation device checks the absolute and relative phase angle of the two signals to see if it is stable and within acceptable bounds. If it is, a signal is propagated across the network to indicate that it is permissible to close a 66 kV circuit breaker. The absence of this signal will be used to inhibit closing of all 66 kV line circuit breakers. Initial evaluation of the synchrophasors approach is that it may also assist with the network management of higher levels of utility scale solar farms.

Discussion with Manawa Energy has begun to ensure they are satisfied with the degree of security that this check offers and, if agreement is reached, the project will proceed.

The alternative of the status quo, while safe and low risk, it is very inefficient and cumbersome. The only additional option would be to fit 66 kV line VTs and synchronising relays to all line terminals in the EA Networks 66 kV network. This would cost a lot more and is unlikely to be any more secure than the proposed solution.

This project has been postponed until 2026 - until engineering resource is available.

-1011	2027-34	**Ashburton Core Urban 11 kV Network**	Quality of Supply

This programme will include a significant quantity of 11 kV protection relays. They will be line differential relays operating across core 11 kV circuits which will utilise interconnecting fibre optic links. There will also be a number of simple overcurrent feeder relays.

All the projects, costs and associated work are included in the 11 kV network centre developments (Section 5.4.8).

-1075	2026-34	**Replace 20+ year old Numeric Protection Relays**	Asset Replacement

The relays that were installed when the first 66 kV lines were constructed in 1999 are above 20 years of age. Any electronic device that is 20 years old is more prone to failure than one that is 2 years old. Having consulted with various manufacturers of numeric relays, they all say that a 20-year old relay is end-of-life in critical applications. 20-25 years is the typical lifespan of a numeric relay. Most manufacturers now have 10-year warranties of their relays which gives confidence to that age. Assuming they have built in a safety margin to the expected point of failure it is not unreasonable to add 50-100% to the 10-year warranty. A paper published in 2010 backed up these estimates (albeit for relays made in the 1990s). The critical safety role of a protection relay means that running it to the point of failure because of age is not an option.

This programme will replace various relays each year over the duration of the programme. The recovered relays will be either scrapped or retained for spares.

There was a 2016 programme to upgrade older numeric relays involved in transformer and 11-22 kV feeder protection which replaced all the electronic components in the relays and provided a 10-year warranty from that point onwards.

As the relay population ages, there may be additional cost introduced to upgrade or replace numeric relays.

5.4.10 SCADA, Communications and Control

SCADA is an acronym for **S**upervisory **C**ontrol **A**nd **D**ata **A**cquisition, which essentially means remote control of power system equipment and getting information back from remote power system equipment. In this case *remote* is anywhere other than *here*. SCADA systems are not new and have existed for many decades in various forms. The most rapidly changing aspect of SCADA systems is the devices they connect to in the substation and at other points on the network. Microprocessor-based protection relays and modern electronically controlled reclosers have a wealth of information on offer to SCADA systems about power system conditions and faults. It is now possible to look at real-time values of current, voltage, power, thermal demand, harmonic currents and voltages, virtually any other measurable power system quantity, as well as historical logs of any of these values. If a fault has occurred, the relay can provide a surprisingly accurate estimate of distance to the fault and data to display the waveform of the currents and voltages before, during, and after the event. All this information can assist in planning a more responsive power system that can provide higher levels of fault immunity and assist in locating faults quickly and identifying under-utilised capacity such as when power factor is too low at peak times.

A SCADA system can also be used to schedule events such as switching on or off capacitors, batteries, or generation that prevents overloading of a piece of equipment during a period of normal peak loading or during fault events when being used to supply load above normal levels.

Any reasoned decision that a human can make can now be programmed into a server application and it can then reproduce that logic for similar situations. In the future, with sufficient processing power, communications, data gathering, and remote control, it will be possible to provide a much faster response to loading and fault situations than is presently the case. It may even prove possible to reliably predict loading minutes or hours in advance (given sufficient data to derive an accurate model). These capabilities can be used to dynamically configure the network so that overloading is avoided, and faults impact fewer consumers. This concept is the next step in a system called distribution automation and *smart grid*. Distribution automation is currently a predominantly reactive process which attempts to restore supply once it has been lost.

The current SCADA system is now maturing in fundamental control capability, having been commissioned in 2020 and is being extended into more advanced ADMS functions as discussed below. It is part of the Aspentech advanced distribution management system and includes all existing zone substations, as well as many smaller switching and data gathering locations. Data communication to all zone substations was dramatically improved by using the fibre optic network and allows reliable data, video, and voice communication. The fibre optic communication service provision is occurring as a separate commercial development by EA Networks which is not suitable for inclusion in this electricity network asset management plan.

Projects & Programmes

No SCADA-specific projects have been identified. As new sites are developed, they will incorporate SCADA functionality and will contribute to a more complete automation system. There are a small number of projects related to communications and control.

Project	Year	Name	Category
11074	2026-33	Advanced Distribution Management System	Non-Network Assets

An **A**dvanced **D**istribution **M**anagement **S**ystem (ADMS) is in the process of being fully commissioned at EA Networks. Most core components are functional, but some of the advanced modules are still being configured.

An ADMS incorporates all the features of a SCADA system but also adds the idea of electricity network modelling into the mix. This means that there is a degree of *intelligence* that the DMS can have about what the context is for the information it is receiving and the actions it is being asked to undertake.

The ADMS incorporates the following features/subsystems:

- A SCADA subsystem that interfaces to devices of all types in the physical world (protection relays, remote controlled switchgear, power meters, load control devices, weather collection devices, asset condition monitors, GPS location devices, etc).
- A mapping subsystem that can show both:
  - Traditional location maps of assets, SCADA information about those assets, the physical environment, personnel location (assuming GPS equipped radio).
  - Interactive schematic views of the connected electricity network including most of the static and real-time information about assets.
- An outage management subsystem that reports in real time the consumers and portions of the electricity network that are without supply and predicts the fuse or circuit-breaker (if it is not on the SCADA system) that is likely to have operated. This subsystem also provides SAIDI and SAIFI statistics over timescales varying from the last 5 minutes to the last 5 years. This system has been substantially developed and is in the last stages of enhancement.
- A network analysis engine that can calculate/estimate the existing power flows, voltages, and fault levels in the electricity network as well as predict the electrical consequences of operating a device in advance of doing so. Given sufficient information, the engine can also estimate the location(s) of a fault.
- A distribution automation engine that can suggest a restoration sequence for a human controller to implement. Optionally, the restoration sequence can be automatically executed using SCADA control in full automation mode.
- A Distributed Energy Resources Management System (DERMS)subsystem that provides demand side management of load/generation to ensure regional, GXP, zone substation, and even feeder loading limits are respected. This system is under evaluation for potential future application, particularly related to enabling optimal solar generation connection and apply export constraints only as required and avoiding costly network capacity increases. This is indicatively forecast in two stages in 2028 and 2033, with the intention of recovering the cost of development from network customers who benefit from the system.
- A customer interface subsystem that can receive and send messages from/to email, SMS, web site submission, dedicated smartphone app's, interactive phone call (with caller id), last gasp messages from meters identifying outages, etc. This allows the DMS to estimate the extent of an outage based upon the known location of the customer on the electrical network. The customer communications aspect of this system is being progressively actioned, refer to section 3.5.2.
- A crew management package to assign a piece of work to a crew/truck and monitor their status and workload.

The ADMS has obvious benefits to the asset owner and network customers. Power could be restored within tens of seconds (unless you are supplied from the faulted segment) and the asset owner does not necessarily have to initially spend time manually finding and isolating the fault. This type of system relies on sensing the fault location by passage of fault current through devices and communicating the information to a central point and the ADMS then making the logic decisions.

The ADMS acts to firstly gather fault detection data and then to control the distribution system to isolate the fault. There is no need for additional hardware in the field. The ADMS is essentially software running on a series of secure servers that are configured to respond in a particular manner should a fault be detected. If necessary, the ADMS can be overridden by the controller.

This project provides for the continuing implementation of the ADMS subject to a business cost/benefit test to achieve many of the features detailed above using internal engineering resources and supplier support as required.

Project	Year	Name	Category
11636	2026-30	**Distribution Automation Programme**	Quality of Supply

This is a programme of works to progressively add both SCADA and fault detection/isolation features to existing rural ring main units and pole-top switchgear that are ready for automation.

A typical implementation will be the additional of a modern protection relay that permits direct integration with a SCADA protocol, giving a raft of information and control capabilities. The communication will be either by fibre optic (if it is within easy reach) or DMR (utilising a small **D**igital **M**obile **R**adio data transceiver). Once implemented, the relay can be used to provide full protection and reclosing on ring main unit circuit-breaker(s) or sectionalising capabilities on a pole-top, CT-equipped, load-break switch.

The DMR radio system that EA Networks use can transport data packets transparently. This feature can be used to support using a piece of DMR hardware that acts as a combined radio and RTU (Remote Terminal Unit – a device that measures real-world parameters and converts them into a standard digital protocol). The DMR radio supplier that provisioned the voice system has developed this product. A DMR repeater has been added to provide coverage up into the Ashburton and Rangitata Gorges so that workers can be confident of radio reception at all parts of the power system they may be working on. These repeaters also provide the ability to remote-control circuit-breakers and switchgear in these distant areas. Even without controlled switchgear, the DMR RTU will notify EA Networks of outages that would otherwise require a consumer to phone in about the issue.

The remote-control hardware used can be utilised by any master control system that uses a modern SCADA protocol (such as the ADMS).

This programme has been forecast for a five- year period ending in 2030, prioritising suitable candidates for switchgear automation. Since the inception of the programme, 45 rural RMU's have been automated with four planned to be automated in FY26. The automation of the pole-top switchgear is handled on a case-by-case basis with criteria being developed to assist with the automation prioritisation. The programme will be periodically reviewed to ensure correct prioritisation and benefits are being obtained.

5.4.11 Ripple Injection Plants

The ripple control system is a proven way to control the maximum load at any given time. This system can be used in a variety of ways but is predominantly employed to shift water-heating and space-heating load to off-peak times. This limits the maximum load that the EA Networks electrical network must supply at peak times. Another term for the ripple control system is *demand side management*.

During summer, the rural irrigation load causes the annual system peak to occur (currently about 183 MW). Somewhat uniquely, EA Networks has a summer peak demand and until recently it has been only during winter that the regional peak occurs. This is changing and the growth in irrigation throughout Canterbury along with increased air-conditioning loads has caused some of the highest regional peaks to occur during summer. During regional peaks, EA Networks use the ripple control system to minimise the demand placed on the Transpower GXP to coordinate keeping the regional demand below the 220 kV system voltage stability limit[5]. This has the coincident benefits of reducing total losses and lowering the required average capacity of EA Networks equipment. The urban network is comparatively lightly loaded during summer and ripple control during summer does not assist in optimising urban network capacity.

EA Networks provides reduced price controllable categories to encourage hot water load to be connected to the ripple control system. During winter, this control has the by-product of keeping urban distribution peak demand lower than it otherwise would be, which frees up additional capacity for uncontrolled loads such as lighting, cooking, and other household appliances. This peak control can also reduce the need for reinforcement of the urban network, although EA Networks do not currently control load for that reason.

Should a fault occur that limits the supply capacity into a specific portion of the network, ripple control could be used reduce the load to a level where all consumers have supply, but only if they accept that controlled load is off until a repair is completed. This could be a useful method to help achieve the security standards without dramatically inconveniencing consumers. EA Networks have not yet implemented this strategy, largely because of limited ripple channel granularity and system capacity being adequate under most *n-1* scenarios.

[5] The *voltage stability limit* is the Upper South Island load value that, if exceeded and a 220 kV circuit should trip, would see the 220 kV voltage drop below acceptable and stable values.

Capacity of New Equipment

Because the investment in plant is relatively expensive and typically non-recoverable, the sizing calculation is very important for ripple injection facilities. The probable future network configuration is ascertained and a plant capable of injecting signal successfully across that proposed network will be specified.

Projects & Programmes

Until 2005, there had been no firm projects planned to enhance the capability of the ripple control system. Failure of a critical component on one of the ripple injection plants in late 2005 caused a rethink as the age of the technology was such that it could not be fixed. The failed piece of equipment was replaced with a modern equivalent, sized to suit potential future use at 66 kV.

The single 66 kV GXP now in use has prompted the reconfiguration of the two in-service ripple plants. The ex-33 kV unit at Ashburton 66/11 kV substation has been reconfigured to operate as an 11 kV plant. The pre-existing 33 kV plant (stepped up to 66 kV by an autotransformer) at Ashburton 220/66 kV GXP has been retuned and the two plants (11 kV and 33 kV) now inject synchronously which provides some signal reinforcement.

The signal level from the Ashburton 220/66 kV GXP 33kV plant has been declining over recent years due to a cracked air-cored reactor. By March 2025 the replacement of the 66 kV GXP ripple plant primary coupling cell connected at 22kV will be completed, resolving the signal level issue and providing redundancy between the ripple plants at the 66kV GXP and Ashburton Substation 11kV.

The converter panels for both ripple control plants are circa 15 years old, with an expected end of life replacement at 20 years. The units are no longer supported, so critical spares have been purchased. In the event of a converter panel failure, a maintenance support agreement gives access to a replacement panel on hire from the supplier. This panel would be in place within a few days while a new converter panel was ordered, but there is a significant lead time. The ASB 66kV GXP Ripple Injection Generator Replacement project below will replace the complete converter panel at that site, providing one completely new ripple plant alongside the legacy Ashburton Substation 11kV ripple plant.

It is possible that other technology (retailer or flexibility aggregators, smart meter technology) may supersede the ripple injection signalling in future, so this progressive replacement approach is considered a prudent asset management strategy to maintain secure functionality from the ripple control system but not commit to a full system replacement until it is necessary.

-1148	2026-27	**ASB - Ripple Injection Generator Replacement**	Asset Renewal

The ASB 66kV GXP Ripple Injection Generator Replacement project will replace the complete converter panel at that site, providing one completely new ripple plant alongside the legacy Ashburton Substation 11kV ripple plant.

As discussed in section 6.15 and above, the increasing age of the ripple injectors is such that a replacement plan needs to be in place. This project will replace the earlier (2007) injector as it approaches 20 years old and free up the decommissioned injector as a contingency spare for the Ashburton 11kV ripple plant.

5.4.12 Distributed Generation & Storage

Distributed generation can be broadly described as any type of electrical generator that is completely embedded within the network of a lines company. A distributed generator can range in size from a photovoltaic panel on a domestic rooftop that has an output of several hundred watts, to hydroelectric or wind generators of several tens of megawatts. Every generator has a different impact on the security and capacity of the network depending upon the size and location of its connection and its generation pattern.

A distributed generator can provide additional security/capacity to the EA Networks network, but it also has security and capacity requirements of its own. A generator which can always operate during peak demand periods can reduce the required capacity of a portion of the immediate network. If an individual generator is not available, it cannot offset the need to provide network capacity for consumers without breaching security standards. Alternatively, a generator which is unable to dispatch its available generating capacity because a long-duration network fault either disconnects it from sufficient consumers, or limits its ability to inject into the network, is less likely to satisfy the generator's desired security. The commercial loss may be insufficient to promote additional investment by the generator in security.

EA Networks encourage connection of new distributed generation. The general philosophy is that generators do not pay any on-going asset charge to connect to existing network (provided it has the capacity to absorb the generation without alteration). Only the additional or upgraded assets required to connect the generation are considered for cost recovery (incremental cost principle). Any fiscal benefits from coincident demand reduction cannot be shared with the generator they have been deemed by the Electricity Authority to be a customer benefit and must be passed to the Retailers. If the network is not loaded sufficiently, export into Transpower can occur, which could result in some (export) charges related to the Transpower TPM (transmission Pricing Methodology). If they occur, these charges are passed back to the generator(s). By arrangement, during low load periods, the export risk can be signalled to the generator before export occurs.

If distributed generation becomes a widespread phenomenon, the diversity amongst a group of generators can make it a useful alternative to network reinforcement. This assumes that the generators do not have similar generation or fuel availability patterns that cause minimum generation at times of peak demand.

EA Networks already has significant distributed generation in the form of four hydroelectric generation plants: one at Cleardale in the Upper Rakaia (1.0 MW), one at Montalto Hydro (1.6 MW), one at Barrhill (0.5 MW), and one at Highbank (26 MW). New distributed generation of any scale is encouraged and will be connected subject to suitable commercial and technical arrangements made according to industry rules and guidelines governing these activities. The connection of distributed generation is regulated by Part 6 of the Electricity Industry Participation Code and requires all lines companies to publish guidelines for the connection of distributed generation to their respective networks. EA Networks have done this (https://www.eanetworks.co.nz). Several potential developments are detailed in the projects section below. The clarity these regulations provide is useful for all participants.

EA Networks are always reviewing the feasibility of locally connected distributed generation that would enhance the security and profitability of both the company and the community. Several preliminary studies have been undertaken and this has identified some promising options that will be detailed in the Asset Management Plan if they become a commercial proposal.

The photo above shows a distributed generation system which injects into the EA Networks distribution network. This project made use of previously wasted energy from drops in a medium sized irrigation race that ran parallel to the property boundary. At 200 kW maximum output, it is sufficiently large to provide all the on-farm energy requirements at times, plus a small surplus. It does not supply all the farm's power requirements and in mid-summer it will often have zero output while the farmer is irrigating at 100%. Like most of these types of small schemes it has no storage and can only generate when the energy source arrives (water in this case, but equally the sun in the case of solar panels and a wind in the case of wind turbines). Without storage of the energy they produce or the fuel that feeds them, peak system load on the EA Networks network may not be reduced significantly by distributed generation (consider a cold, calm, frosty, dark winter morning).

Capacity of New Equipment

All equipment installed for generation plant is sized in agreement with the generation owner, although this is usually only required where the generation exceeds 100 kW.

Projects & Programmes

The opportunity for discussion with third parties who are interested in developing a wide range of small and large generation projects in the Mid-Canterbury region has continued in recent times.

Cleardale Hydro resulted from a farmer in the Rakaia Gorge deciding to irrigate his farm and, in the process, provided the opportunity for Mainpower to install a 1MW pelton wheel turbine. The electrical output of the installation varies considerably during the year and there are times when it is unable to run at all through lack of water. The installation is connected to the 11kV network and feeds into Mt Hutt substation. There have been no problems with its operation on the 11kV network. The generation has since been sold to the farmer.

BCI was commissioned in early 2016. It is a crossflow turbine and operates in conjunction with an irrigation scheme and provides a modest output throughout the year. It is injected into the EA Networks 22kV network via a feeder from Lauriston substation. As irrigation demand builds, the summer output drops as the summer water is diverted to irrigation. It is advantageous that this generation is generally operating at the same time as the electric irrigation pumps as it reduces the peak demand on the 22kV feeders, zone substation, subtransmission network, and GXP, although 2017 showed its output is zero at times of peak irrigation.

Some time ago, an interesting discussion was held with a proponent of oceanic wave power. The area off the Canterbury coast is apparently well suited to the type of device that the organisation was considering. The commercial and technical viability of wave power may be in its infancy, but if a commercially competitive product evolves it could hold a great degree of promise for an island nation such as New Zealand.

There have been no firm proposals for connection of non-solar forms of distributed generation to the EA Networks network that would prudently affect the predicted maximum demand.

There are some very small-scale distributed run-of-the-river hydro generation opportunities that have been discussed historically, and have in one case been developed, but their collective output accounts for only two or three typical irrigation pumps and in drought years they are unlikely to be generating because of water restrictions on river off-takes. It is also possible that the hydro turbine mechanical output will be used directly for mechanical water pumping with no electrical generation or pumping.

The economics for new generation investment have improved of late, with a firm commitment that the Tiwai Point aluminium smelter will remain in operation. Government commitments to decarbonisation of the economy and targets for a fully renewable generation sector have provided increased incentives for new renewable generation. Demand is forecast to increase because of EV charging and process heat demand, requiring new generation development coupled with investment in transmission and distribution infrastructure. However, the timing and specifics for these requirements are difficult to forecast at this point.

No specific projects or programmes have been allowed for regarding the impact of medium-large scale (50kW+) distributed generation.

Solar Photovoltaic

Solar PV is continuing to be adopted by a small, but increasing, percentage of consumers. At the time of writing 676 ICPs are known to have solar PV (3.1% of consumers) and the approved peak output totals 61.9MW (7.4MW excluding 500kW+ installations). It is probable that more consumers will adopt solar and the complimentary technology of batteries as the price decreases. Initial investigations into the impact of solar PV show that it will take significantly more widespread adoption before significant network issues arise. The newer (2016+) inverters also provide much better mitigation of those network impacts by providing facilities for volt/watt/var responses that reduce output or change the power factor of the output to control network loading and voltage.

Grid/utility scale solar PV (multi-MW) has happened. The cost benefit of scale makes the per MWh (energy) cost lower than a multitude of smaller installations. Recent work by researchers has shown the most viable areas in New Zealand for this type of operation, and the Canterbury Plains is one of the more economic locations. EA Networks' rural 22kV network can absorb multiple MW output, and during summer it would be consumed within the local area by irrigators. During winter, the peak solar output would be lower, and it would have to be transmitted to urban areas for consumption. Solar PV can be used in conjunction with some forms of dry land grazing as the panels do not entirely prevent grass growth underneath them and provide shelter in summer and winter.

The attraction of larger utility scale solar PV farms has recently increased dramatically, due to improved economics and the desirability of renewable generation. As a result, a significant number of large solar farm applications have been received and processed by EA Networks (~110 MW), in line with similar activity nationwide. As of 2025, multiple solar farms have been commissioned on the EA Networks system. The additional/modified assets used to connect them are fully funded by the generator using the incremental cost principle.

Project	Energy Source	Timescale [1]	Estimated Capacity [2]	Likelihood [3]
M	Solar	Commissioned	47.2 MW	100%
N	Solar	Commissioned	6.5 MW	100%
O	Solar	1-2 year	4.4 MW	90%
P	Solar	1-2 year	4.4 MW	80%
Q	Solar	1-2 year	15 MW	90%
R	Solar	2-3 year	30 MW	65%
S	Solar	1 year	999 kW	100%
T	Solar	1-2 year	999 kW	65%

[1] Timescale is an estimate by EA Networks based on generalised discussion with third parties.

[2] Capacity is either based on third party disclosure or, for larger proposals, an estimate by EA Networks.

[3] Likelihood is an entirely subjective assessment by EA Networks which does not imply any evaluation of feasibility or commercial viability. 0% likelihood means EA Networks believe the option is no longer feasible or even physically possible.

No specific projects or programmes have been allowed for regarding the impact of distributed kW-scale solar PV, although there is scope for this scale of solar PV to become quite disruptive. There are a multitude of 40-200 kW sized solar installations occurring, typically at existing load sites with no additional/modified network required. It is hoped that the addition of storage batteries when installing solar PV will become the norm in future, as this will absorb solar output within the home during the middle of the day (charging the batteries) while decreasing the evening peak (discharging the batteries – supplying domestic load).

With the significant quantity of utility-scale solar PV already commissioned or under application, there will be parts of the 66 kV sub-transmission network that will become congested if it all connects. Other parts of the 66 kV network will still have injection capacity available. It is probable that new solar associated with a load in congested areas will have strict export limits (possibly as low as zero) applied to them. Solar not associated with a comparable sized load in the congested areas will be given the option of network reinforcement to connect, but this may prove to be quite uneconomic. The option of using solar purely to charge batteries and then discharge the batteries at night could allow new solar in congested areas.

Storage Batteries

Although not generation in the traditional sense, battery storage is a significant factor that may address a range of issues for both networks and consumers. The ability to charge batteries at times when excess generation and/or network capacity is available and then discharge them to directly supply load or provide distributed energy resource (DER) capacity to the network is attractive. The present hurdle is cost. It is not economically viable for consumers to provide battery storage solely to reduce their network demand. The possibilities of electric vehicles (EVs) filling that role is beginning to evolve. There may be very specific network issues that could be resolved by using battery storage that are close to economically viability, but none have been identified by EA Networks at this stage.

A provider of a combined solar and battery installation product has demonstrated residential peak load management using a strategy of battery discharging over the morning and evening peaks and charging overnight and in the afternoon trough. This service could be useful for network peak load management to defer network investment if sufficient uptake of the solar and batter installations can be achieved. Improved resilience of the residential customer to network outages is an additional benefit, particularly valuable to work-from-home businesses. The provider of this product derives value from the retail residential customer, and “value stacking” various revenue streams resulting from the discharge of the battery, for example for instantaneous reserves, demand side management, forming a virtual power plant etc.

EA Networks believe the energy role of batteries is going to be as daily or inter-daily load levelling rather than as seasonal *power stations*. A battery can only store energy that is provided to it – it does not create or convert energy. If people expect to be able to store their summer solar PV output for use in winter, they will be very disappointed. The storage requirements for seasonal energy storage are so vast that it will never be possible using the current scale and technology of battery storage. The chances of mass disconnection from the urban distribution network are low, as the diverse interconnection of generation, storage, and load that it facilitates are what is required to maximise the value of each consumer's investment in solar PV, storage, and EVs. Without the distribution network, every disconnected consumer would need to invest in enough generation and storage to be fully self-sufficient at all times of the day and year. The distribution network could facilitate peer-to-peer trading of energy to and from all energy sources and loads.

EA Networks have yet to formulate a strategy for utilising either domestic or grid scale batteries to resolve existing or future issues on the network. There is an awareness that change will occur and that before it begins to impact the network it will be critical to adapt to the needs of consumers quickly and effectively or risk becoming less relevant.

Projects are now examined at the preliminary stages for suitability of using batteries to either resolve or delay the capacity issue being addressed. Several spreadsheets to assist in this examination have been created and will continue to mature as battery prices drop and the market for ancillary battery services evolves beyond energy arbitrage.

No specific projects or programmes have been included regarding the direct impact of storage batteries, although the Decarbonisation and Smart Technology programme is likely to involve battery technology in some form.

The type of project that could be deferred by using batteries would be equipment that is difficult to upgrade, is loaded to just over rated capacity, and does not have significant load growth forecast. This could be long underground cables, long 22 kV overhead lines, or small urban LV underground cables. Overall, the best location for batteries is behind the meter where it can assist consumers to reduce their demand but also reduce the peak demand on the network assets supplying them. The key is ensuring that incentives are in place to encourage battery charge/discharge behaviour that benefits both parties.

Remote Area Power Supplies

Where an individual consumer (or a small group of consumers) is supplied by a very long (many kilometre) line and they are the only users of that line, it may be cost effective to provide them with a **R**emote **A**rea **P**ower **S**ystem (RAPS). A RAPS is a combination of generation and storage that allows off-grid electricity supply. Typically, a RAPS would combine solar, wind, and diesel generation with battery storage so that all non-diesel generation is stored and then used rather than wasted. The diesel would be used sparingly to fill energy gaps in solar, wind, and stored energy. A small microgrid may also be applicable where there are a small group of customers nearby that can be supplied from a RAPS and short lengths of network, to replace a long spur of line previously used to supply them.

There are few locations within the EA Networks distribution network that would be considered remote, and even less that have just a few consumers on them. When the lines supplying these locations are considered for renewal, close examination will be given to offering the consumer(s) a RAPS if the economics show it is viable. An investigation was done in 2018 to consider RAPS for the upper Rakaia Gorge and it showed a negative return.

The Lake Heron Road 11 kV line is another candidate for RAPS that has been examined, comparing the lifecycle cost of a conventional network solution to a RAPS non-network solution. The remote Lake Heron area is a mix of high-country farming and conservation land, with 12 network connections clustered in six locations along the network route. The existing overhead line requires renewal, with the least cost network solution being a 25km underground cable installed largely by mole plough. The non-network solution was evaluated using RAPS systems with solar PV panels, a battery and a diesel generator provided by EA Networks in lieu of a network connection. The RAPS lifecycle cost calculated from the Net Present Value (NPV) of operating, maintaining and replacing components of the RAPS system. Consumers would pay their current line charges, and the diesel fuel required to supply electricity when there was insufficient solar or battery electricity available. The RAPS NPV cost was calculated at $1.8m and the Lake Heron Road cable solution at $2.1m, meaning that both solutions are within the margin of error for the cost calculation. The RAPS solution has several disadvantages; customer capacity upgrades (currently being sought) require further incremental upgrades of the RAPS, the remote area means that maintenance and faults have a high cost travel time to resolve, operating solar systems in winter with snow and poor weather will result in high operating hours of diesel generation in the sensitive alpine environment and the repeated replacement of components of the system over the comparison 50 year life of the network solution. The network solution provides a long-term asset with capacity for foreseeable load increases and avoids the issue of obtaining customer agreement to implement the non-network solution. It has been necessary to evaluate the solution for all customers accepting a non-network solution compared to a network solution, because unless all customers agree the network solution cannot be fully avoided.

5.4.13 Electric Vehicles

The relationship of electric vehicles (EVs) with the electricity distribution network has the potential to become quite revolutionary. Today, the smallest new EV on the market has a 24kWh battery in it. This is the equivalent of the average household's peak electrical use for at least 6 hours. The largest EV batteries are in the vicinity of 100kWh for electric cars but can exceed this value for SUVs and trucks. According to the Ministry of Transport, 90% of car trips are less than 90km. Most EVs use between 15 and 20kWh to travel 100km. Given these numbers, very few EVs will be heavily discharged when they arrive home in the evening and a portion of this excess energy could be used around the home.

Charging Electric Vehicles

In typical daily use, it is likely most EVs will be recharged at home overnight. A standard 10amp, 230 volt socket offers 2.3kW of capacity. During 7-8 hours of charging this can provide 15+kWh of charge for the battery. Should the EV be discharged more deeply, it would be prudent to go to a *fast charger* of 50kW or more capacity and recharge to 80% in a few tens of minutes. If so desired, the remaining 20% charge could then be topped up at home.

EA Networks see no immediate challenge in the controlled overnight charging of EVs at the rate of 2.3kW. EA Networks' provision of three 50kW fast chargers around the Mid-Canterbury district means most EVs have the necessary facilities to travel where they need to go without huge range anxiety. Other companies such as ChargeNet NZ, BP Charge, Meridian Energy, and Z Energy are also providing fast charging networks within the Ashburton District that increases convenience for EV owners.

If EV owners see the need to begin charging at higher rates in the home (say 7kW), this could begin to provide a challenge to the network within the Ashburton urban area. This uptake in demand will have a significant impact on the Ashburton and Northtown zone substations which account for over 50% of all residential ICPs on the network. Network impacts at rural centres such as Methven and Rakaia may be more muted depending on uptake but must be expected. The coincident inception of charging would provide a large peak demand that could see residential voltages at the lower end of the acceptable range and smaller LV network cables coming under thermal stress. Some form of intelligent charging control would be necessary to ensure network constraints are adhered to. In the longer term it could be that network reinforcement may be required to meet the demand, provided there is a return on that investment.

As EV adoption rates increase, it is probable that more medium rate chargers (20-30kW) may appear at retail outlets and significantly larger chargers (such as the 300kW ChargeNet NZ charging station located at an existing retail outlet). Again, EA Networks see that this is relatively easy to adapt to, as many of these facilities will have distribution substations nearby that can be uprated to supply the new load or will be specifically built for the new demand. Newer battery technologies are likely to offer significantly faster charging rates that could lessen the 20% to 80% (60%) charging time to a few minutes, but this would also mean the chargers would increase to around 700kW to allow this. These chargers would need to be placed close to existing 11kV or 22kV cabling.

Fortunately, Mid-Canterbury does not have a significant week-end tourist destination. It can be envisaged that on long weekends, some destinations such as Hanmer Springs, Tekapo, Wanaka, and the likes could have a large influx of Christchurch EVs that have been heavily discharged on the trip there, all wanting recharging before the return trip in two days' time. The recent study revealed that public charging peaks, in Ashburton, over the past year occur between 1pm and 4pm. The highest peak demand profiles occur in December and April, on the day before Christmas Eve and on Good Friday. This could create a significant demand on both the charging facilities available and the local electrical network. However, a South Island EV Journey Charging Research by DETA Consultants is reflecting that the current 2024 charging capacity within Ashburton is sufficient to cater for a 2030 90th percentile forecasted demand. The forecast predicts only an additional 23kW demand by 2030 within the Methven township. This additional journey charging demand is insignificant and would be catered for within the network.

Some people presume that solar PV will be the answer to charging their EV. However, if they are working away from their residence, it is likely they will have driven their EV to work and the only way to use the home solar will be to pay for the transport of the energy though the distribution network. This may or may not be economic and will require some smart technology to resolve who gets charged for what. The ideal scenario is that the EV is home during the day and can be 100% charged by solar. Alternatively, they could purchase a separate domestic battery to store their solar PV energy in. While this is possible, it essentially duplicates the battery in the EV (which is resource inefficient) and leads to the next scenario.

Discharging Electric Vehicles

An EV is pretty much a very large battery with four wheels, some electronics, and a powerful electric motor. The electronics in some of the newer EVs allow the EV to discharge into the house and/or electricity grid. This makes it a mobile electricity generator (once it is charged). You can take a reasonably large amount of electric energy and transport it both in time and space. This can be beneficial to the EV owner. They can buy and then use or sell the stored energy when and where they can get best advantage from it.

If they choose to charge the EV at work, they can take that energy home and potentially use some of it in the house to limit their on-peak electricity use by *plugging the EV into the house*. This is also of benefit to the network owner as they see a reduced peak demand on the electricity network.

Batteries could be able to provide other ancillary services to both distribution network operators and transmission network operators. Such things as frequency support, demand response, and so-called synthetic inertia are all possible services that an EV could participate in. It would take quite an amount of coordination and some guarantee of the available response, but the eventual collective scale of EV batteries will make this type of service possible.

The comments above relating to storage batteries also relate to EV batteries with the addition of mobility.

Network Impact

EVs will initially be a load on the network that could increase demand at peak times. In the study by EA Networks, by 2035, an extra 5 MW of demand at 6pm was predicted, increasing to over 25 MW by 2050 assuming charging load management behaviour. It will require careful tariff design to ensure most charging takes place overnight and is progressive in how it both starts and is controlled. There is a risk with crude binary tariff signalling that the feared EV-driven demand peak may be shifted to late evening or early morning instead of simply filling the demand trough in the midnight to 6:00 am period.

Some of the projects included in this Plan intend to explore the possibility of providing a level of granular control to each customer so that *smart* charging decisions can be made to keep the customer happy (an 80-100% charged EV at 7:00 am) and the electricity network well utilised, without causing asset overloading or power quality issues.

The other side of EVs is the potential for the EV battery to offer network support during peak demand. It would be the ideal scenario if a portion of the EV's charge could be redirected to reduce each household's demand and thereby reduce residential network demand in the morning and evening. This could preclude the need for network upgrades and provide additional value to the customer by selling a demand reduction service back to EA Networks. The level of granularity would need to be high, and the response of the customer's battery guaranteed by monitoring/metering the discharge. The next level of sophistication would be to provide net export of electricity back to the network (supply the household load entirely and export additional energy to the network). This would allow the customer to gain from both selling electricity at a high unit price but also optionally gaining income from EA Networks to support the network in a specific area or reduce GXP demand.

The activities described above are already technically possible, ignoring the commercial aspects. To make it a reality will require a lot of coordination between electricity industry players and at its heart must ensure everyone can continue to remain as viable commercial entities. This will mean that lines companies will probably remain as regulated entities for the foreseeable future to ensure they cannot take advantage of their monopoly position. Other entities will be able to freely compete for customers as service/product providers over the distribution network. This is where the idea of a Distribution System Operator (DSO) becomes a possibility. To manage the level of complexity that arises from many participants attempting to buy and sell demand, energy, generation, and other services from EVs, batteries, and solar PV, there needs to be an overarching coordinator and the evolving term for that is a DSO. The nature of a DSO and who they will be is still open to debate but, as it becomes clearer, EA Networks will make a strategic decision as to whether they wish to be an asset owner and a DSO or not.

5.4.14 Innovation Practices

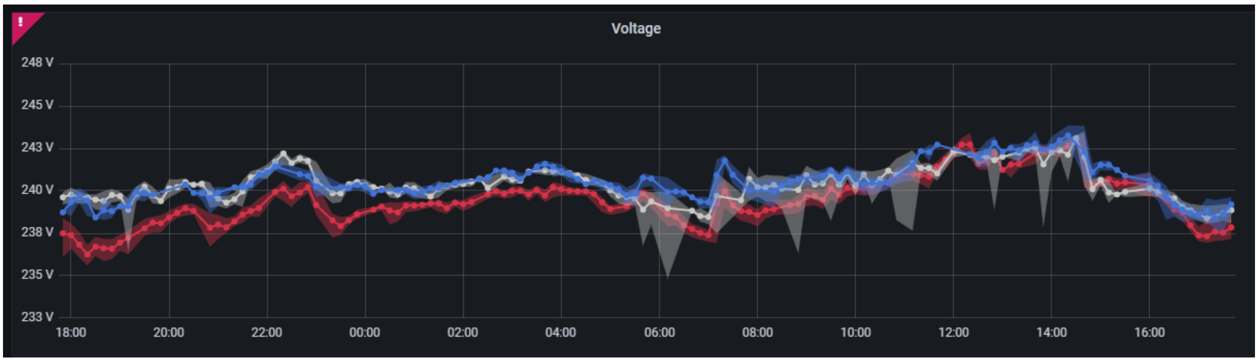
EA Networks consider a number of the practices they undertake to be quite innovative. These vary in scale, cost, and impact, with some having immediate benefits while others are an investment in the future.

Rural underground conversion

For some years, EA Networks have been using innovative mole-ploughing techniques to convert strategic rural overhead lines to underground cable. Some of these have been the high traffic State Highways which have been progressed with the assistance of Waka Kotahi (NZTA) as pole lines reach the end of their useful life. The desire to reduce serious injuries and fatalities caused by vehicle versus pole collisions was a large driver for the decision to remove poles from the roads. The incidental impact on reliability of not only vehicle collisions, but also weather and overhead equipment failure (which tends to be significantly higher than underground or ground-mounted equipment) was the next aspect that swayed EA Networks in the direction of completing the rebuild with underground cable. The final consideration was the relatively small increment in cost over an overhead line rebuild of a mole-ploughed underground cable rebuild. The traditional factor of three for underground versus overhead no longer holds true in many cases. While not directly a factor, the aesthetic benefit of not having poles and wires on a road is a non-commercial advantage that both Mid-Canterbury residents and people passing through the district appreciate. There are no power poles left in the State Highway One road reserve between the Rakaia and Rangitata rivers. Underway is the continued underground conversion of Methven Highway, and it is planned to complete the section between Ashburton and Methven within 2026. There have been no deaths or serious injuries on State Highway One caused by collision with EA Networks assets since the completion of the underground rebuild. Reliability of customers served from this section of the network is appreciably higher than that historically experienced.

LV and Transformer Monitoring

EA Networks have been trialling and now are routinely installing innovative PowerPilot monitoring devices at kiosk distribution substations to provide accurate transformer loading and power quality data. A PowerPilot continuously monitors all major electrical parameter and sends back the minimum, maximum and average of each of these measures every ten minutes over LoraWan communications. This provides a clear picture of transformer utilisation and, if necessary, the same device can be equipped to monitor all of the LV feeders from the distribution substation providing individual cable loading, phase balance, and power factor data to manage LV feeder utilisation. The following diagram shows an example of 24 hours of voltage data from a PowerPilot unit fitted to a transformer with significant residential solar penetration.



There are also some PowerPilot units fitted to customer connections on a trial basis, and these provide useful data further down the LV system. While fitting a PowerPilot to every LV connection is not a viable strategy, it is possible that a PowerPilot at end-of-feeder open points may be a useful way to track worst case voltages on any LV feeder. This will be trialled in 2026 and may end up being used more as a mobile power quality sampling exercise, rather than a lot of permanent PowerPilot installations. LV modelling could pinpoint targets for this type of monitoring.

The PowerPilot devices are a development of the Electronet group of companies who also manage the Westpower network. EA Networks have a very cooperative relationship with Electronet and find them to be very like-minded on many aspects of network operation and development.

Advanced Distribution Management System (ADMS)

EA Networks have undertaken to implement an ADMS in the last few years. It is currently working well in its base configuration and additional features are likely to be configured/developed as they become worthwhile from a network utilisation or consumer benefit aspect. Two features in particular are likely to become attractive in the next few years.

Distributed Energy Resource Management System (DERMS) is a module of the ADMS that controls the interaction of generation, storage, load, and third-party flexibility traders with the ability of the network to accommodate the fast changing (and bidirectional) dynamics of these consumer owned facilities. At the smaller end of the consumer spectrum are <10kW solar and EV charging that can collectively overload cables and transformers if not managed to take best advantage of the available capacity over any 24-hour period. Influencing the behaviour of these resources so that the consumer gets what they want, and the network is utilised to its fullest without overloading it is a win-win which reduces cost to all parties. At the other end of the spectrum are large multi-megawatt generators and loads that can respond to static network limitations, operational limitations, and contingent events. A DERMS can dynamically signal these consumers so that they retain supply by reducing their injection or load to levels that the network can handle for the duration of the event or increasing their injection to supply load for the duration of the event. This response would also be true of flexibility traders, who can control large numbers of smaller consumers behaviour and signalling them for a response would be done by a DERMS. The need for a DERMS will largely be determined by how consumers adapt to the new realm of flexibility and what commercial imperative or operational restriction it takes to sway them.

Fault Location, Isolation, and Service Restoration (FLISR) is a module of the ADMS that in its simplest form applies logic to determine the likely location of a fault using data gathered from protection relays and other fault passage detecting devices. This can accelerate the isolation of a fault and restore the remaining consumers' power in a timelier manner than manual fault location actions. The next step of FLISR system is to have it suggest and prepare a sequence of isolation and restoration steps for action by a controller. This can save a useful amount of time, especially after-hours when a single controller is receiving consumer calls, operating SCADA, coordinating fault staff, and trying to diagnose the likely fault cause and location. Once the FLISR system can reliably propose appropriate actions, the final step is to allow the system to remotely control the automated devices, isolating the fault and restoring supply, while pausing for manual actions where they are necessary. This has the potential to reduce some restoration times to less than one minute and consequently improve consumer experience which will be reflected in improved SAIDI and SAIFI measures. There are a considerable number of SCADA controlled devices in the field at present and more are being converted or added every year. This makes the implementation of FLISR more an ADMS configuration effort than an asset intensive field equipment installation exercise. The bones of the FLISR are already in place and it is anticipated that a progressive refinement of data and software functionality needed for the decision process will lead to commissioning of the system within a few years, subject to a business case.

Industry Cooperation

EA Networks participate in the Future Networks Forum and keep abreast of other industry working groups that are anticipating the rapidly evolving environment EDBs are in. Staff attend a multitude of electricity and associated industry conferences and read international publications to ensure innovative solutions to the problems EDBs face across the world are considered when tackling issues that confront EA Networks.

Non-network Solutions

There have been several situations where the sparseness and remoteness of overhead lines in the foothills of the Southern Alps have resulted in consideration of alternative means of electrical supply rather than rebuilding the end-of-life overhead line. A Remote Area Power System (RAPS) tends to be economic when there are small loads that are distant from one another and/or from the nearest network connection. RAPS consist of a combination of solar, wind, and diesel generation, plus inverters and batteries. Collectively these generate and store enough energy to allow the consumer to experience the same convenience of electrical supply as if they were grid-connected. There are two situations where RAPS have been considered as an alternative to renewing the network assets currently supplying remote customers. The first did not have universal acceptance by the consumers and consequently the 11 kV line had to be rebuilt to keep them grid connected. This meant the remaining customers could continue to be inexpensively supplied from the rebuilt line. At the time (several years ago), the cost of RAPs was also not competitive with a rebuilt 11 kV network. The second circumstance is the Lake Heron Road 11 kV line where the non-network solution was found to be unfavourable compared to the network solution, as described in section 5.4.12.

Urban capacity constraints have yet to be adequately addressed by extensive non-network solutions. The relatively low cost of asset-based solutions in urban settings versus widespread batteries or flexibility control mean that there have been no projects that could be compared to a non-network solution that offered a similar level of cost or service to the consumer. In the future, there is potential for peak management by flexibility services or battery solutions sited at distribution level that can avoid costly investment at both MV and HV that may be attractive.

Approaches to tender for non-network solutions are now well developed by EDBs such as Aurora, Powerco, and Vector. Through collaboration, the process and documentation used in these tenders is available to EA Networks should an opportunity be identified.

Decision Process

When contemplating an innovative approach to an issue that has a readily available conventional asset-based solution there are a range of key considerations that take place.

(a) What is the issue that needs addressing?

(b) What are the service levels that the consumers are prepared to accept with either a conventional or innovative solution? Are they the same?

(c) What are the relative merits of each solution from safety, consumer satisfaction, maintenance, future capacity, up-front and ongoing cost, reliability, and likelihood of success perspectives? A conventional solution is well known from these perspectives.

(d) Does the solution offer future options for other services and capabilities that a conventional solution may not be able to achieve? For example, a flexibility option may provide a communication pathway to the consumer that could be utilised for signalling requests for response from appliances that are not yet enabled for this functionality.

(e) What does the consumer want?

(f) What is the consumer prepared to pay for?

Once it has been decided to trial an innovative approach, the scope of the trial is set, and the key performance metrics established to signal success. These metrics include cost, flexibility system reliability and repeatability, consumer experience, and any other measures considered appropriate. When the trial is completed, and the results analysed, it is generally quite apparent if the trial has been successful or not. If it has been successful, then a proposal to adopt the solution as a standard option will be prepared for consideration by management or the Board (if the scale is new or a material change from the conventional solution). If accepted, it becomes either a standard approach for all similar issues or an approved option for consideration whenever an issue that could be resolved using it arises.

To inform the decision process, information/experience from other EDBs and vendors of suitable solutions is gathered and compared. When a likely candidate for consideration arises, much further research into the topic is undertaken to ensure all options are surfaced in the area of interest. Other stakeholders have valuable information to contribute to the decision process. Ensuring that the relevant stakeholders can offer their perspective should lead to better decisions and less duplication or wastage of effort on a solution that does not meet stakeholder requirements or duplicates another party's efforts.

The electricity/energy industry is going through a period of rapid change and not all decisions that will be made in this time will be proven correct by history. All that can be asked is that the decisions are made using the best information available at the time and in the best interests of the consumer (who happen to also be the shareholder in EA Networks' case).

MANAGING OUR ASSETS

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6 MANAGING OUR ASSETS

6.1 Introduction

This section is where the detailed asset-specific management issues are discussed. It describes each asset by category and details quantities, condition, performance, maintenance, and the operational standards of each in turn.

The management plans for each asset category detail how EA Networks intends to operate and manage the assets so that they meet the required performance standards. The focus on optimising lifecycle costs shapes all the processes involved.

EA Networks owns electricity reticulation assets that are used to provide distribution and connection services to electricity retailers and generators. These assets generally comprise equipment that is common to all New Zealand electricity lines businesses and, wherever possible, industry standard assets have been employed. The Asset Management Plan covers the electrical reticulation assets and associated systems owned by EA Networks.

For the purposes of managing the assets that EA Networks own, logical groupings of assets are required. These groups may have members that are geographically distant or installed in a different application, but they are most effectively managed as a single population. These groupings comprise the following:

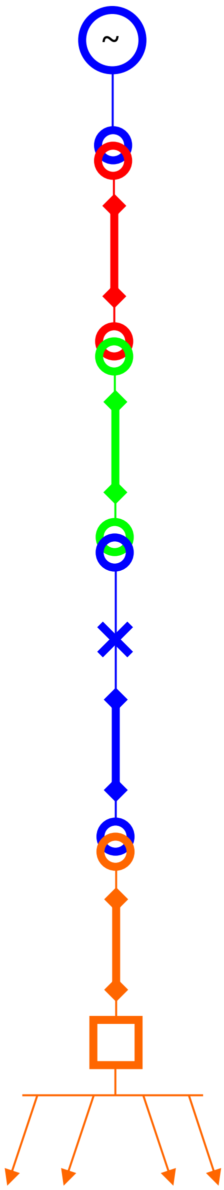
- *Subtransmission Line Assets* – Electric lines and cables, including associated easements and access ways operating at voltages of 33 kV and 66 kV.
- *Overhead HV Distribution Line Assets* – Electric overhead lines, including associated easements and access ways operating at a voltage of 11 kV or 22 kV.
- *Underground Cable HV Distribution Assets* – Electric underground cables, including associated easements and access ways operating at a voltage of 11 kV or 22 kV.
- *Overhead Low Voltage Line Assets* – 400 V electric overhead lines, including associated easements and access ways.
- *Underground Cable Low Voltage Assets* – 400 V electric underground cables, including associated easements and access ways.
- *Service Lines* – Connection assets at any voltage owned by EA Networks for the purpose of supplying a single consumer (not including the line on the consumer's premises, but including any portion of the service line in, on, or above the legal roadway).
- *Zone Substations* – High voltage substations connected to the subtransmission network. This includes plant and equipment within the substations such as power transformers, foundations, support structures and buswork, oil interception equipment, and incidental equipment such as DC batteries and chargers together with station land and buildings. Other items such as switchgear, earthing, SCADA, and protection are covered by other definitions.
- *Distribution Substations* – Substations connected to the distribution network. This includes plant and equipment within the substations such as foundations, platforms, electronic data monitoring (if installed) and Maximum Demand Indicators, together with land and kiosk covers, but excludes transformers, MV and LV switchgear, and earthing.
- *Distribution Transformers* – Standard transformers used in distribution substations ranging from 5 kVA to 1000 kVA and generally having a primary voltage of 11 kV or 22 kV. Also includes MV regulators or autotransformers up to 5 000 kVA.
- *High Voltage Switchgear* – Circuit-breakers, reclosers, sectionalisers, disconnectors, ring-main units, expulsion drop-out fuses, structures and buswork used in the distribution and subtransmission systems.
- *LV Switchgear* – Load-break switches, fuse switches, fuses, support frames, busbars, and capacitors used in the LV line and cable systems.
- *Protection Systems* – *Fault protection* includes all protection relays, associated panels, metering devices, current transformers, voltage transformers, and control cabling.
  – *Over-voltage protection* includes surge arrestors and spark-gap devices.
- *Earthing Systems* – All earthing systems that are owned by EA Networks and connected to EA Networks

equipment.

- *SCADA, Communications and Control Equipment* – SCADA, Communications Equipment and associated facilities installed at any location. This includes Control Room equipment, Remote Terminal Units, radio repeaters and dedicated fibre optic systems installed, owned, and maintained by EA Networks.
- *Ripple Control* – Ripple Injection Equipment.

The size and complexity of EA Networks' fixed asset base is considerable when compared to other businesses such as retail chains and serves as a major differentiator for this company and other utility organisations. Below is a diagram illustrating some of the different asset categories and typical ownership involved in the electricity supply industry.

Asset Owner	Voltage(s)	Equipment
Generator/ Retailer	11kV or similar	Generator (Wind, Hydro, Gas, Solar, Battery Storage etc)
Generator/ Transpower	11kV and 220kV	Generator Transformer
Transpower	220kV (Transmission)	Transmission Overhead Line(s)
Transpower	220kV and 66kV	GXP Substation Transformer(s)
EA Networks	66-33kV (Subtransmission)	Subtransmission Overhead Line(s)
EA Networks	66/22-11kV or 33/11kV	Zone Substation Transformer(s)
EA Networks	22-11kV	Zone Substation Feeder Circuit-Breaker and Protection Relay
EA Networks	22-11kV (Distribution)	Distribution Overhead Line or Underground Cable
EA Networks	22-11kV and 400V (LV)	Distribution Substation Transformer
EA Networks	LV (Low Voltage)	LV Distribution Overhead Line or Underground Cable
EA Networks	LV	Consumer Connection Point (Pillar Box or Pole Fuse)
Private	LV	Consumer Service Line (Load, Batteries, and Solar)



Variations on this ownership structure exist, particularly in industrial or rural situations, where the consumer is likely to own 22-11kV lines on private property which are dedicated to servicing their property. In addition, distributed generation is connected within all voltages of the network and battery storage is being connected within consumer private networks.

6.2 *Overview*

This section outlines the lifecycle management plan required to maintain, enhance, and develop the operating capability of the system. The programmes are outlined by asset type and, within this, according to area and then by maintenance activity.

- Maintenance
  - servicing, inspections, and testing.
  - fault repairs.
  - planned repairs and refurbishment (including replacement at the component level).
  - planned replacement programmes (at the asset level).
- Enhancement
- Development

Section 8.1 – Appendix A has a more complete series of activity definitions.

For the purposes of lifecycle management, the Enhancement and Development categories can be seen as the asset creation/acquisition phase of the cycle. The Replacement category will introduce new equipment of similar function at a similar location and have a similar purpose as the existing asset.

Each category of asset has a *Standards* subsection that details the documentation available for each activity undertaken on that category. This is one area that still requires some work to complete. Many categories do not have documentation to cover post-commissioning activities such as inspection and maintenance. The actual work is done to an acceptable standard, but the methodology is not yet formally recorded.

Asset disposal is typically done only at the end of an asset's useful life. Most of these assets are equipment that is only suitable for scrap, and it is normally disposed of in an appropriate manner as part of the activity replacing it. Any asset that becomes surplus and is not at the end of its service life will have a specific disposal plan. As at the time of writing there are relatively few assets that have been identified that will require disposal in this manner and only those asset categories will contain a Disposal activity.

6.2.1 Maintenance

Maintenance work is largely based on the condition of the assets.

The scope of work planned under each maintenance activity is quantified wherever possible to assist in reviewing EA Networks' achievement in future years. The estimated maintenance expenditure is projected in this section and where relevant, the consequences of the proposed maintenance programmes are noted. It should be noted that analysis of maintenance strategies and programmes is an on-going process and the most cost-effective means of maintaining the network is constantly under review. In some instances (e.g. pole replacement) further investigation and analysis is required to determine an optimal strategy.

The maintenance requirements are influenced by development projects, many of which, if they proceed, will lead to dismantling and decommissioning of assets that would otherwise require significant repairs and/or replacement. The maintenance programmes described in this section cover the anticipated situation where all the planned development projects proceed.

The base-line planned maintenance expenditure projections assume, for consistency within this plan, that development projects take place as projected in Section 5 – Planning our Network. It will be necessary to monitor closely the likelihood of each project proceeding and additional remedial work will need to be programmed if certain projects do not proceed or are significantly delayed.

6.2.2 Replacement

When an asset reaches the end of its useful life and economic maintenance options have been exhausted, the only remaining options are scrapping the asset without replacing it or replacing it with a modern equivalent asset. Under most circumstances, assets will be replaced with an asset that exhibits the best price/performance ratio. Each individual case will be examined for the economic efficiency of the options.

Replacement work does not intentionally increase the asset's design capacity but restores, replaces, or renews an existing asset's function to its original capacity and lifespan.

6.2.3 Enhancement

This activity outlines work that is planned to enhance the system. By this, it means that this increases the capacity of the asset to:

- supply increased load,
- enhance voltage regulation,
- improve security and reliability,
- reduce electrical losses,

or

- increases the expected lifespan of the asset significantly beyond its original end of life date.

It includes projects (at specific sites) and programmes of related work covering several sites. Project numbers (e.g. [10023]) are used to identify individual projects or programmes. Appendix B has a complete list of these, including costs and categorisation.

Specific enhancement projects are detailed in Section 5 – Planning our Network.

6.2.4 Development

Specific development projects and programmes are described in Section 5 – Planning our Network, which outlines the projects currently anticipated over the planning period. The nature of each project is briefly described along with the reason why it appears to be required. The justifications for including each of the projects in the plan are categorised as follows:

- safety-related issues,
- specific consumer requests (and commitment to incur project-related charges),
- anticipated demand growth,
- to meet security planning guidelines,
- economics (i.e. where the project produces overall cost savings),
- reduce electrical losses.

The projects described in this document represent an indicative plan based on the best information currently available. There is currently no commitment by EA Networks to undertake all or any of the specific projects listed, nor should consumer commitment be inferred from the inclusion of any project in this plan, except where they are described as already committed. Further, it should be noted that more detailed investigations will undoubtedly lead to changes in the scope of projects that do proceed. There may be considerable scope for integrated subtransmission/distribution system planning to achieve the required results by somewhat different means.

Because of the need for consumer consultation and, in many cases, agreement, as well as uncertainty in the fickle prediction of future load growth, it is likely that some projects in the first half of the planning period will not proceed or will proceed later than indicated in this plan. Secondly, because investigations tend to be more focused on the short-to-medium term, it is likely that additional required projects will arise, particularly towards the end of the planning period.

6.2.5 Asset Renewal Processes

The general renewal strategy is to rehabilitate or replace assets when justified by:

- *Safety*

  The asset represents an unacceptably elevated risk to the safety of people or property.

- *Asset performance*

  Renewal of an asset is where it fails to meet the required level of service. The monitoring of asset reliability, capacity, and efficiency during planned maintenance inspections and operational activity identifies non-performing assets. Indicators of non-performing assets include:

- Structural life
- Repeated failure
- Ineffective and/or uneconomic operation

- *Economics*

  Renewals are programmed with the objective of achieving:

  - The lowest life cycle cost for the asset (uneconomic to continue repairing), or
  - An affordable medium-term cash flow, or
  - Savings by co-ordinating renewal works with other planned works.

- *Risk*

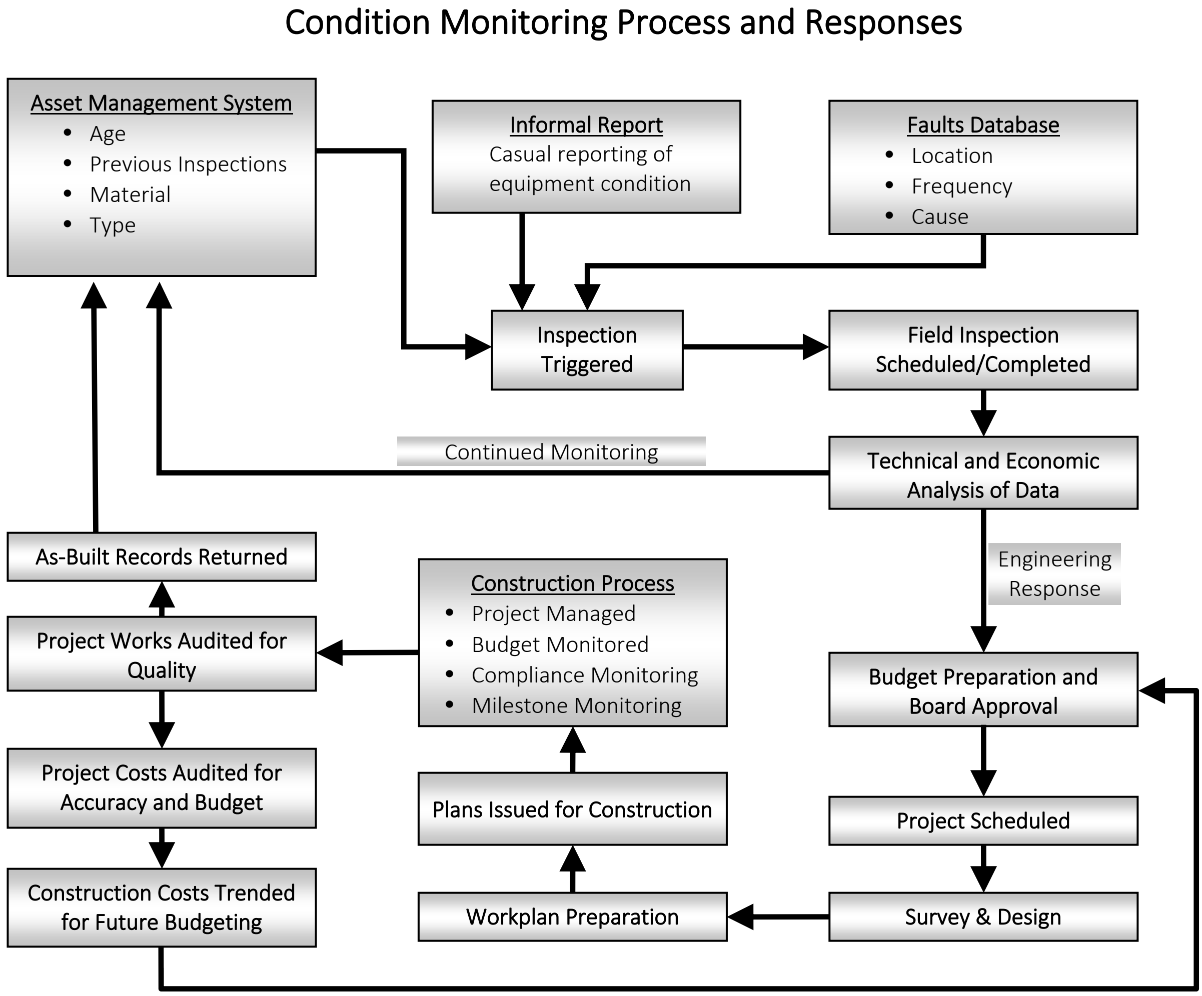
  The risk of failure and associated environmental, public health, financial, or social impact justifies proactive action (e.g. impact and extent of supply discontinuation, probable extent of property damage, health risk etc)

Selection Criteria for Asset Renewal	
Priority	**Renewal Criteria**
1 (High)	• Safety concerns • Asset failure has occurred. • Asset failure of critical system component is imminent. • Regular maintenance required. • Complaints that are assessed as justified
2	• Failure of non-critical asset is imminent, and renewal is the most efficient life cycle cost alternative. • Maintenance requiring more than six visits per year.
3	• Reticulation maintenance involving two to three visits annually. • Difficult to repair, due to nature of material, obsolescence. • Environmental risk reduction.
4	• Existing assets have low level of flexibility and efficiency compared with replacement alternative.
5 (Low)	• Existing asset materials or types are such that known problems will develop in time

Planned and reactive replacement works can be prioritised in accordance with the priority ranking shown in the above table.

The process of asset renewal is generally triggered and managed according to the flow-chart shown below. The asset management system is used to examine candidates for inspection based on a combination of age, material of construction, make or type of equipment, and any previous inspections. Other triggers for inspection include information from the Faults database and ad-hoc reports from either field staff or the public describing a potential condition-related problem.

A system for assigning asset condition scores that produce asset health indicators for specific assets is under development, comprising asset health surveys for a number of asset types, that will be used for condition surveying. Asset health data will then be used to assess asset fleets as a population, and to generate individual assets that require maintenance or renewal. As such, asset health data based on condition does not yet exist, but as a proxy, age-derived asset health condition scores for asset fleets are used to assess the future renewal needs and capital expenditure required within the planning period. Refer to 10.5 Appendix E – Disclosure Schedule 12A.



The inspection is scheduled and completed using the appropriate personnel (internal for routine inspections or external specialists for some unique or critical equipment). The results of the inspection are passed to engineering staff for evaluation. Consideration is given to all stakeholders' interests when evaluating possible replacement equipment. If the inspection reveals an acceptable level of remaining life in the equipment the inspection details are recorded against the equipment in the asset management system database and scheduled for reinspection at a future date. If the economic test is passed, other considerations are introduced to ensure opportunities for security or capacity improvements at little or no extra cost are not lost. The best value option is ultimately selected where the *value* is not only financial but, on occasion, also relates to less tangible stakeholder interests. The project budget is prepared and submitted to the Board or appropriate management for approval. If approved, the project is scheduled for construction and detailed design occurs, ultimately leading to the issue of workplans to the chosen contractor (by default internal). Project timing, budget monitoring, spot auditing, compliance with the specification, and adherence to normal contractor standards (safety and contractual) are the common areas attended to by the project manager.

Once notified as complete, the works are audited by the appropriate inspection staff to ensure quality and completeness are acceptable. The as-built records are incorporated into the GIS and asset management systems so that the dismantled assets are removed, and any new assets are added. The completed project is then financially analysed to ensure accuracy and the cost compared to budget and any discrepancies investigated. The actual costs are used to refine the budgeting process for future project costing.

6.2.6 Line Maintenance – General Observations

Line Repairs and Refurbishment

All line repairs are carried out to the requirements laid down in EA Networks' line maintenance standards. These are based on international practice combined with local knowledge and New Zealand legislative requirements.

Major Refurbishment

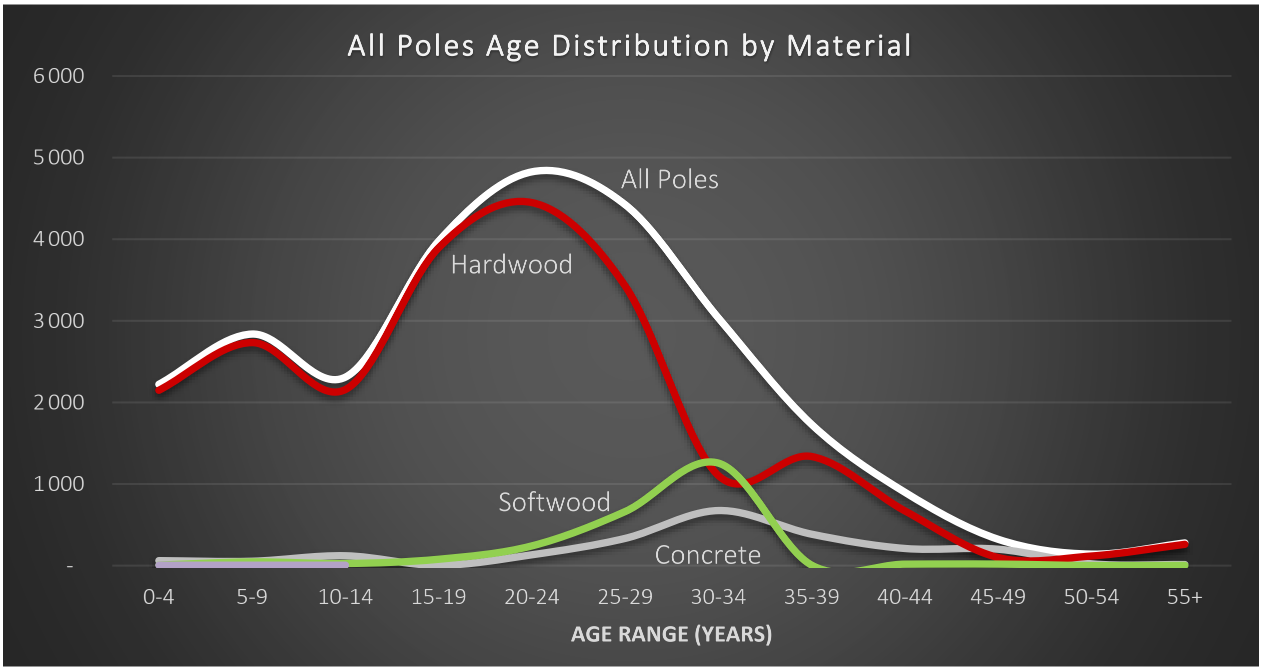
Multiple HV overhead lines will require refurbishment or replacement during the planning interval. Known candidates are explicitly identified in scheduled overhead rebuild projects for the first 3 years based upon pole condition inspections. Beyond that time the projects are pooled into the Unscheduled Replacement and Renewal programme, and this is allocated an expenditure value based on pole inspections, known distribution pole age profiles and historical trends.

Beyond the scheduled overhead rebuild projects, the Unscheduled Replacement and Renewal programme allowance for rebuilding is fixed until 2030. It is then increased by about 6% per annum for the remaining years, as the impact of the aging pole population results in additional condition-based rebuilding. Additional inspection, analysis, and assessment will take place to refine this forecast. The diagram below illustrates the issue (note that the poles over 50 years old are predominantly urban poles awaiting removal once underground conversion takes place).

The subtransmission lines that are approaching the end of their structural life within the 10-year period are identified by line section and a Project number.

Untreated hardwood pole lines can be expected to last between 40 and 50 years. Some of the "second growth" hardwood poles supplied during the 1980s are showing signs of premature decay. Not all poles are affected, and future pole inspections will reveal if the issue causes a shift in rebuild cost timing. The use of concrete and treated softwood poles during the 1980s and 1990s will dampen the rebuild requirements as they have a longer life than the untreated hardwood poles. During the late 1990s and beyond, the hardwood poles used were treated with preservative compounds that should increase their useful life beyond 40-50 years.

Referring to the age profile for recently installed poles (age 0-4 years and 5-9 years) in the chart below shows that approximately 2 300 poles are currently being installed every 5 years (460 poles per annum) and at a rate appropriate for the current pole population. The expenditure within this plan is expected to be appropriate for pole condition-driven replacement.



Forecasting forward beyond the 10-year period and considering overall pole population, if the average pole life is 45 years and there are 28 000 poles, then the long-run average pole replacement rate needs to be about 3 100 poles every five years (620 poles per annum). Noting the age profile of current 30-year-old poles, in about 10-15 years, an increased need for pole replacements could begin to occur at circa 50-60% more than current rates, depending on the performance of both the treated hardwood and softwood poles in this population. Current

20-year-old poles could result in a pole replacement rate of 1,000 poles per annum. This can be managed with careful consideration of pole types, risk, and individual pole condition and forecasting of replacement expenditure and adequate construction resourcing.

Wood Poles and Crossarms

Approximately 1 150 hardwood poles are over 40 years old (another 1 337 are 35-40 years old). It is currently projected that approximately 460 poles per year would need either changing or replacing with underground cable over the next 5 years to cope with defects. However, this number will gradually decrease as lengths of very old wood pole lines are dismantled. Towards the very end of the planning period an upswing in hardwood pole replacements is expected as the age profiles illustrate a greater annual construction rate occurred 30-35 years ago (late 1980s irrigation development).

Conductors and Accessories

As a policy, all replacement **A**luminium **C**onductor **S**teel **R**einforced (ACSR) is being purchased with a greased core wire. Some aluminium wrap splices have failed, with a variety of failure modes including corrosion and driven by through-fault current. Line splices are now being proactively replaced when other line maintenance or overhead renewal is being carried out on a feeder section, or reactively when a small number of failures in an area indicates that line splice condition warrants replacement. Some single strand conductor types are considered deficient and have been targeted for replacement.

Insulators and Insulator Fittings

Neoprene wrap-lock ties were used for a period but have proven troublesome by loosening the grip from wire to insulator when exposed to normal wind vibration. Replacement of these ties is occurring as a moderate priority – as other conductor work is required at that location. EA Networks' current standard practice is to bind the conductor to the insulator with wire of the same metal as the conductor.

Diagnostic Techniques

The purchase of an infrared thermographic video camera allows EA Networks personnel to regularly inspect overhead lines for failing or overloaded connections or equipment. This is a very good preventative measure that has already saved several fault outages (albeit that a planned outage took its place). A second, high-resolution, camera has been purchased to allow a faster *drive-by* scan of equipment.

A digital acoustic pole condition assessment instrument is used to objectively measure the remnant strength of poles which are being examined for condition. As more data is gathered from this instrument, patterns may emerge of different pole deterioration rates based upon location, age, supplier, and type.

6.2.7 Present Planning Priorities

Load growth caused by increased consumer demand and consumer expectations of reliability, security, and power quality, as well as the regulatory and statutory environment set by central, regional, and district government all guide the planning priorities of EA Networks.

In the last two and a half decades, the principal focus had been on providing capacity for the dramatic pumped irrigation load growth in rural areas. In conjunction with this stimulus there were other security and capacity issues that required resolution. As a result of these combined pressures, 66 kV was implemented as a subtransmission voltage. Eighteen zone substations have now been built and operate at 66 kV. One zone substation remains to be converted to 22 kV (MON33 - 2027). Almost all the subtransmission network by length is now insulated at 66 kV.

The development focus is also on the Ashburton urban area and the capacity and security requirements of the township. At Ashburton substation, the transformers are now 66/11 kV, and all switchgear is less than 20 years old. Northtown zone substation was constructed to provide additional capacity and supply security to Ashburton township consumers. Northtown has been commissioned for approximately eleven years and has proven to be very beneficial. An allowance has been made for a 66/11 kV transformer at Tinwald zone substation to accommodate urban load growth and security.

In Ashburton township, the 11 kV feeders have a high connection count per feeder, and some are approaching the limit of secure thermal loading. To restore security and capacity into the urban 11 kV network, a programme to add an upper *core* 11 kV network is in place. This programme will ensure the security standards are met and provide additional capacity for urban growth.

At the rural HV distribution level, conversion from 11 kV operation to 22 kV operation has been the chosen option for many of the areas facing the need for reinforcement associated with additional pumped irrigation load. This form of reinforcement has proven to be very successful and is likely to continue as the preferred option where significant rural HV distribution reinforcement is required to supply load growth or restore supply security which was reduced because of recent historical load increases and 22 kV conversion.

EA Networks continue to monitor and assess the condition of all network equipment and, where necessary, this equipment is replaced or maintained depending upon the risk it presents and the whole life economics of repair versus replacement. The risk each piece of equipment represents is assessed according to the methodology outlined in Section 2 – Managing Risk & Resilience.

June 2006 Snow Storm Review

In the aftermath of the damaging snow storm of June 2006, several reviews were done to assess the adequacy of the existing network and of the suitability of the current line design standards. The review of the existing network identified some component types that appeared to be inadequate to meet current security standards. A full report was prepared, and recommendations were submitted to the Board for consideration. The major items that have been identified as needing attention are:

- Long spans (>100 m) of small conductors such as squirrel (lower priority)
- One, two or three strand conductors such as #8 galvanised steel (number 8 standard wire gauge fencing wire), 3/10 copper (relatively high priority). See section 6.4.1.
- Older, low strand count, copper conductors (of any span length) that appear to have become more brittle over time (relatively high priority). See section 6.4.1.
- 1940s vintage steel poles (so called *Bates* poles) which do not have adequate strength reserves (higher priority). See section 6.4.1.
- Understrength mechanical fittings (particularly near the historically lightly snow loaded coast) which cannot withstand the weight of conductor when loaded with snow (lower priority).

The Canterbury-wide review of the existing line design standards showed that they were very close to the suggested level. The line design standards remain largely unchanged, but the specification of equipment used to build lines has been raised to ensure all components are rated and applied to meet these design standards. The main change has been the use of Flounder conductor in place of Squirrel conductor for new and rebuilt lines. A further review of line design standards in conjunction with Network Waitaki and Alpine Energy is underway considering climate change predictions and targeting design standardisation.

September 2010 and February 2011 Earthquakes

The earthquakes of 2010-11 were a tragedy for Christchurch and provided a severe test for all utilities serving the affected population. The severity of the shaking felt in Ashburton was significantly less than that felt in Christchurch during both major events. During the September earthquake, the peak recorded ground acceleration anywhere in the Ashburton District was less than 0.2 g. This compares with acceleration of more than 0.3 g in most of Christchurch and more than 0.7 g in rural areas closer to the Greendale fault. The February earthquake was further from Ashburton than the September one and Ashburton District ground acceleration was less than 0.1 g. The Christchurch urban area experienced ground acceleration between 0.5 g to 0.9 g with one recorder peaking at 1.5 g.

The experience of the earthquake has refocused EA Networks. Preparedness is essential to prevent catastrophic equipment failure. EA Networks have observed and learned from the information Christchurch-based lines company Orion have shared about risk preparedness and recovery. EA Networks are well aware of the many natural and man-made risks that are faced by an electricity utility and have begun to progress risk and recovery planning into formal documentation that could be called upon in an emergency.

The seismic design standards that EA Networks use are considered and robust. This should ensure that modern equipment is largely serviceable after a significant seismic event. The main area of concern is likely to be the significant quantity of older equipment that was installed prior to the adoption of current standards.

December 2019 Rangitata River Flood

A large flood occurred in December 2019 that washed away two 11kV Rangitata River crossings that EA Networks use to supply 56 consumers. The restoration of these assets took months (generators supplied the consumers while this happened). The larger of the two crossings (47 consumers) was restored with a new design that is clear of the flood risk zone of the river (outside the active river bed). The other crossing (9 consumers) has been reinstated using a similarly long span, but one end remains at risk of erosion. This mitigation is considered adequate for the likely flood return period.

Future plans will address in greater detail the additional planning required for high impact low probability events and the impact they have on an electricity utility.

6.3 Subtransmission Assets

6.3.1 66kV Subtransmission Lines

Description

EA Networks own significantly more 66kV insulated overhead line than 33kV overhead line (372km vs 39km). The 66kV network (see Section 4.2.2 for a map of the layout) is in two distinct rings. The northern section is an interconnected ring directly supplying Northtown (NTN), Fairton (FTN), Wakanui (WNU), Pendarves (PDS), Dorie (DOR), Overdale (OVD), Lauriston (LSN), and Methven66 (MTV) zone substations. Highbank (HBK) power station is connected on a 66kV spur line beyond Methven66. To the south of Ashburton, a southern 66kV ring supplies Ashburton66 (ASH), Eiffelton (EFN), Coldstream (CSM), Carew (CRW), Hackthorne (HTH), Tinwald (TIN), Mt Somers (MSM), and Lagmhor (LGM) zone substations. The two distinct rings are connected by a 66kV circuit between Mt Somers (MSM) and Methven66 (MTV) zone substations.

Two types of construction have been used to build 66kV overhead lines. The first type is brand new Jaguar, Lemon, or Dog ACSR line constructed with treated hardwood poles and polymer insulators. The second type is reinsulation of older, pre-existing, 33kV lines on hardwood poles. Steel extensions were used to provide adequate clearance to the under-built 22kV circuit on these polymer reinsulated lines (these lines are currently being rebuilt as new standard 66 kV lines). There are only ex-33kV poles three of this type on Line Road Methven that will managed with normal condition monitoring and will be replaced as required.

The capacity of the conductors in use is:

- Jaguar (low snow loading areas) or Lemon (heavy snow loading areas) which both have a *nominal* thermal rating of approximately 500 amps (summer) and 600 amps (winter),
- Dog has a *nominal* thermal rating of about 320 amps (summer) and 400 amps (winter).

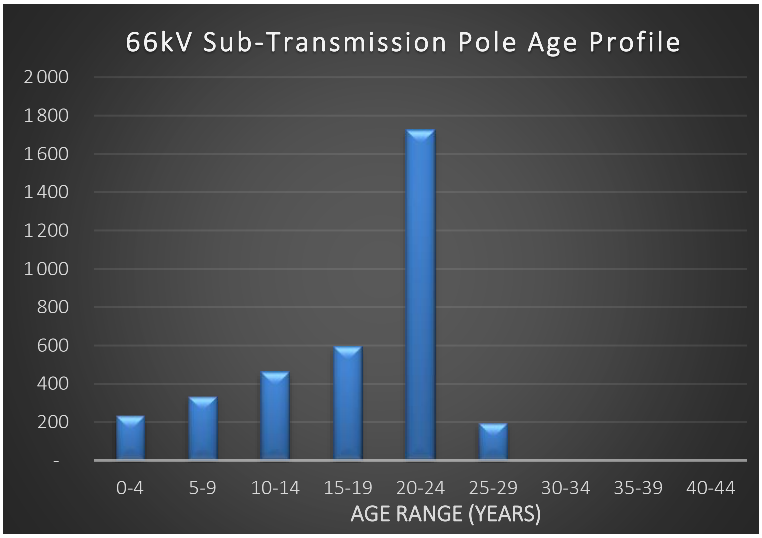
All 66kV insulators are manufactured using polymer materials (synthetic rubber) with a clamp top rather than the traditional porcelain and binder. This allows construction of new lines without crossarms (see adjacent photo).

One 2km length of 66kV cable has been installed between Ashburton Zone Substation and the edge of urban Ashburton. This replaced an overhead 33kV line at the end of its life that was largely on private property and very difficult to access. There are some short sections of 66kV underground cable that have been used to provide egress from sites at Methven, Pendarves, and Elgin (adjacent to ASB). The 66kV subtransmission cables located at the Pendarves substation are copper conductor / XLPE insulation / HDPE sheathed cables and they were installed in 1999 and 2001. Other short sections of 66kV cable have been installed from Elgin substation to the overhead lines which supply Coldstream and Northtown substations. At the request (and partial funding) of a landowner, a 300m section of 66kV cable has been installed across private property allowing the removal of a section of 33kV overhead line. These cables have a thermal rating to match the connected 66kV overhead line and are expected to have a lifetime in excess of 50 years.

Condition

Poles

The condition of the 66kV subtransmission assets largely reflects their age and the quality of materials used in construction. The vast majority of the poles are less than 30 years old, and a cluster of older poles represented the lines that were converted from 33kV and have been removed. All the poles have a life expectancy of at least 40 years from new, and almost all are CCA (**C**opper **C**hromium **A**rsenate) treated which may have significantly longer lives.



Insulators

The 66kV insulation has no known issues.

Fittings

Fitting of vibration dampers as standard to all new 66kV circuits has reduced aeolian vibration effects to an acceptable level. A few 66kV circuits are still to be retrospectively fitted with dampers. Wedge connectors are universally used for conductor junctions and have proven to be very reliable.

There are no known issues with the condition of any of the 66kV lines currently in service and there are three ex-33kV poles on Line Road Methven that will be managed with normal condition monitoring and will be replaced as required.

Standards

Documentation of standards presently used for testing, inspection, and maintenance of the 66kV subtransmission network is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

The condition of the 66kV subtransmission network is monitored using the following techniques:

- corona camera survey (insulators and cable terminations),
- complete visual inspection every 5 years (mainly roadside location assists in reporting of any uncharacteristic behaviour),
- periodic infra-red scanning (typically every two years),
- analysis of fault information,
- visual tree control inspections every 3 or 6 months (also detect obvious pole hardware issues).

Fault Repairs

There have been very few faults on the 66kV subtransmission network. The only issues that have arisen are occasional instances of loose bolts holding the 66kV insulator subsequently causing a pole fire (necessitating pole replacement) and several instances of old 33kV insulator (used at 22kV) failure on the under-built circuit causing pole fires. The majority of 66kV faults have been caused by vehicles, wildlife, or trees.

Planned Repairs and Refurbishment

Other than routine tree cutting, there is only one remedial project planned. No other repairs or refurbishment is scheduled.

Retrofitting of 66kV Vibration Dampers

During the early periods of 66kV line construction, it was not obvious that 100m+ length spans would cause aoelian vibration of conductors. A significant programme revisited early 66kV circuits and fitted vibration dampers to the conductors. The dampers prevent the vibrations from damaging the insulators and other pole fittings, extending the life of the line considerably. This programme is nearing completion and there is no additional damper installation retrofitting planned beyond 2028.

Replacement

There are plans to replace the ex-33kV poles as condition assessment determines.

Enhancement

See section 5.4.2 – Planning Our Network for details.

Development

See section 5.4.2 – Planning Our Network for details.

6.3.2 33kV Subtransmission Lines

Description

EA Networks have a rapidly shrinking 33kV subtransmission network, having relinquished the Transpower 33kV GXP – Ashburton (ASB) (see Section 4.2.2 for a map of the layout). There are now only two radial 33kV lines suppling two zone substations; Montalto33 from Mt Somers 66kV zone substation) and Mt Hutt from Methven 66kV zone substation. This arrangement has evolved as 66kV subtransmission has been introduced and 33kV line length will continue to shrink as the Montalto area 22kV conversion occurs (16km). The total route length of the 33kV rated network is 37km.

The remaining 33kV lines have a standard construction form. The lines are on hardwood poles with porcelain insulators. Pin insulators are exclusively porcelain, but the strain insulators are a mixture of porcelain and polymer materials. Conductor types are exclusively ACSR and AAC. The most common sizes are Jaguar, Lemon, and Dog.

The capacity of the conductors in use is:

- Jaguar/Lemon have a *nominal* thermal rating of approximately 500 amps (summer) and 600 amps (winter),
- Dog has a *nominal* thermal rating of about 320 amps (summer) and 400 amps (winter).

EA Networks have approximately 4.5km of 33kV underground cable in various locations around the district, only a small amount of which is still in service at 33kV (1.1km). All 33kV cables are XLPE insulated with heat-shrink terminations and joints.

The most significant 33kV cable length (3km) is installed between Ashburton township zone substation in Dobson Street (ASH) and the northern end of Ashburton urban area. This cable is single core 185 mm² aluminium conductor with XLPE insulation, aluminium wire screen and PVC oversheath (conservatively rated at 295 amps). This cable is now redundant for use at 33kV and has been reused at 11kV as part of the Ashburton 11kV Core Network. Subsequent plans will manage this cable as 11kV.

Other 33kV cables were installed at ASB and ASH to connect from substation busbars to overhead lines. The cable used was single core 400 mm² aluminium conductor XLPE insulated, copper wire screened with an

HDPE/LDPE oversheath (rated at 500 amps). These cables are up to 200 metres long. These cables have been retired from 33 kV use, in some cases recovered for scrap, others still in place may be reused at 22 kV in some cases.

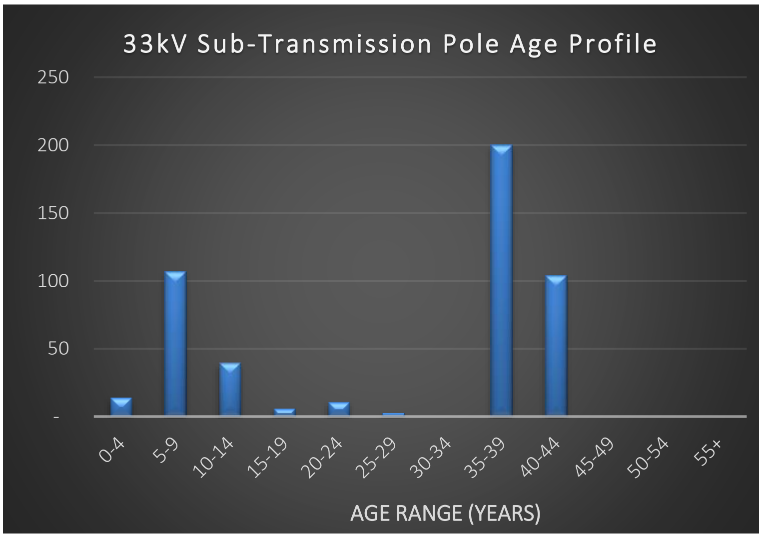
There are a variety of other short 33 kV cable lengths installed (typically 185 mm² aluminium) that overcome height restrictions under Transpower lines and glideslopes at airstrips.

Condition

Poles

The age profile of the 33 kV subtransmission poles shows that the only new poles that have been installed since 66 kV subtransmission became the preferred voltage, are to either replace defective ones or those damaged in car crashes. One exception is a section of line that has been built to retain supply to Montalto Hydro and Montalto33 substation. The condition of the line was such that replacement was required and the portion with underbuilt 11 kV line could not be relinquished. Within the planning period this line will be repurposed as a 22 kV distribution circuit.

A portion of the Mt Somers to Montalto33 circuit has been rebuilt at 66 kV to supply the proposed but now shelved Montalto66 substation (shelved due to future irrigation load now unlikely to eventuate). The remaining portion of the 33 kV line will be rebuilt as 22 kV-only once the Montalto area has been converted from 11 kV to 22 kV. This will remove the need for 33 kV in the area and some 200 old 33 kV poles will be removed from the network.



As of March 2023, the 33 kV system involved approximately 65 Concrete poles and 465 hardwood poles. Of these, it is estimated 322 hardwood poles (69% of total) will need replacing within 5 years. Approximately another 65 are estimated to need replacement closer to the end of the planning period (subject to further evaluation). Some of these poles are now operating at lower voltages such as 22 kV.

If the EA Networks network evolves as described in this plan, the 33 kV network will be almost entirely superseded with a new 66 kV network by the middle of the planning period leaving only one 33 kV line (MTV to MHT) in service. This obviously solves most 33 kV line conditions issues identified above. The 33 kV line from MTV to MHT has some poles showing evidence of aging and a project has been included in this plan to rebuild the line. Many 33 kV poles have underbuilt distribution lines on them, and they will continue in service beyond the end of the planning period. These poles will be managed as distribution poles once they operate at 22 kV or 11 kV only.

Fittings

There is a mixture of old technology (porcelain) and new technology (polymeric) insulation used on the 33 kV subtransmission system. Due to the low pollution environment in Mid-Canterbury and the replacement of failed first generation polymeric (cycloaliphatic) insulation some years ago, it is not envisaged there will be a need for a widespread insulation replacement programme before retirement or conversion to a lower voltage.

Termination or connector practices have varied over the years ranging from parallel groove (PG) connectors, line taps, and over recent times, a policy of using only wedge connector clamping has been implemented. The existing PG clamps are prone to overheating and/or corrosion and subsequent failure when poorly installed. The line tap arrangement was subject to failure during through-fault conditions. While the PG connectors and line taps still exist in the EA Networks system, it is not intended to undertake a mass replacement programme. However, the PG clamps will be monitored on a regular basis by thermographic methods and individual clamps replaced as and when necessary.

Underground Cables

The 33 kV single core cables laid from the Ashburton zone substation out to Racecourse Road are some 3 km in route length and have an Aluminium/ XLPE insulated PVC sheath with an aluminium screen. This cable was installed in 1986 and has been the subject of several failures due to water between the aluminium screen and the sheath entering joints. It is suspected that the water problem occurred both during the manufacturing process and prior to installation (poorly fitting end caps). Further analysis revealed a problem that required attention. The issue that was identified was that of excessive circulating currents in the cable screens. The cable has now been mid-point earthed and cable screen voltage limiting devices installed at each end of the cable. This work permits the full cable rating to be sustained without excessive heating.

Partial discharge tests, wire screen continuity/impedance tests and insulation tests would suggest that the cable itself is unlikely to fail catastrophically within its useful lifetime of operation at 33 kV. This cable has been de-rated to 11 kV operation as Northtown and Ashburton substations are both operating at 66 kV. This cable has now been incorporated into the core 11 kV network as an 11 kV circuit between Ashburton and Northtown zone substations.

Standards

Documentation of standards presently used for testing, inspection, and maintenance of the 33 kV subtransmission network are a lower priority given the small number of remaining assets but will be developed given the retention of the Mt Hutt supply. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

The condition of the 33 kV subtransmission network is monitored using the following techniques:

- corona camera survey (insulators and cable terminations)
- complete visual inspection every 5 years (roadside location assists in reporting of any uncharacteristic behaviour)
- periodic infra-red scanning (typically every two years)
- analysis of fault information

As with the entire 33 kV network, inspection and patrols are important to reduce fault incidents. The 33 kV network has a higher impact on reported statistics than lower voltage lines and this encourages more preventative action and research. The majority of the 33 kV network is on public road reserve (as are most EA Networks lines) and this fact tends to encourage both staff and the public to report components that are causing concern. The Lines Inspector will examine the 33 kV network at least once during the planning period.

Fault Repairs

The history of faults on the 33 kV network would suggest that one or two a year would occur on average. This rate could increase slightly up until the date the oldest lines have been either replaced or refurbished.

The 33 kV lines have had a variety of faults affecting them over the years. It is very difficult to predict the number of faults from year to year due to climatic conditions. An estimate for fault work is provided based on historical fault data for the entire 33 kV network.

Planned Repairs and Refurbishment

Other than regular tree cutting, there are no scheduled plans for repairs or refurbishment of portions of the 33 kV network.

Replacement

Should the need arise, any replacement of 33 kV lines will be with 33 kV lines unless future development plans dictate, in a location compatible with future requirements. A voltage or location change would make the work enhancement rather than replacement.

Enhancement

See section 5.4.2 – Planning Our Network for details.

Development

See section 5.4.2 – Planning Our Network for details.

6.4 *Distribution Assets*

Electric lines and cables operating at a voltage of 11 kV and 22 kV, including associated easements and access ways, make up the bulk of EA Networks' infrastructure assets in terms of both value and number. The extent of the distribution network is such that it covers virtually all of the plains in Mid-Canterbury and three long spur lines reach 35 km into the foothills of the Southern Alps via the Rangitata, Ashburton, and Rakaia Gorges.

6.4.1 11 kV and 22 kV Overhead Distribution Lines

Description

EA Networks have extensive 11 kV and 22 kV distribution networks. Until the late 1990s, EA Networks only used 11 kV as a distribution voltage. The rapid increase in irrigation load caused steady state 11 kV voltage to drop to intolerably low levels. The security of the distribution network also fell, since back-feeding was not an option, as it would have resulted in an unacceptably low voltage. A rigorous investigation of the various solutions led to the adoption of 22 kV as the preferred solution to the raft of capacity and security problems.

The 22 kV network is proving to be an excellent distribution voltage. As an example, most people in the industry are familiar with conductor sizes by code names. Swan or Squirrel ACSR conductor run at 22 kV has a lower percentage volt drop for a given kW load than Dog ACSR run at 11 kV. Ferret conductor at 22 kV has 21% less voltage drop than Jaguar ACSR at 11 kV. These capabilities ideally suit a rural voltage-constrained network. The two-fold increase in thermal capacity (absolute power rating) of all conductors is merely a useful by-product of the conversion work.

11-22 kV construction types are many and varied with lines that cover various materials, ages, and designs. Pole types include hardwood, treated hardwood, treated softwood, prestressed concrete, mass reinforced concrete, and steel (expanded I-beam *Bates* poles). All these different poles have their strengths and weaknesses. Crossarms are predominantly hardwood. Historically, a small number of steel crossarms were used and some are still used for special high strength applications.

Major insulation hardware has always been, and continues to be, porcelain pin insulators because of competitive pricing and a respectable track record. Strain insulators of choice have changed from being porcelain to universal adoption of polymer strain insulators at 11 kV and 22 kV.

Current standard construction employs hardwood poles and crossarms in a conventional style with porcelain pin insulators and polymer strain insulators.

The table at right details the route length of the overhead distribution assets owned by EA Networks using a rough guideline capacity class (a simple indication of capacity). It should be noted that a significant quantity of the lines categorised as 22 kV will be insulated at 22 kV but operating at 11 kV due to a policy of completing 22kV re-insulation ahead of future conversion, justified by low additional cost (circa 7%).

Capacity Class	11 kV Circuit Length (km)	22 kV Circuit Length (km)
Light	129	660
Medium	49	970
Heavy	0	37
TOTAL	178	1667

The HV overhead distribution lines that radiate from rural zone substations are what most people see running along the rural roadsides. EA Networks own a total of 1864 km of 11 kV and 22 kV overhead lines that are predominantly located on the roadside. Some of the poles that carry these lines also carry subtransmission or LV lines. The highest voltage the pole was constructed to carry provides the asset category that is responsible for the structure's asset management.

Other line owners supplied by EA Networks own about 440 km (457 km in previous plan) of HV overhead line which is all on private property.

As of the date of this plan, the data available for management of pole hardware is incomplete. The total number and age of poles is known from work-plan information however the hardware fitted to these poles has not been captured. The relatively low incidence of ancillary component failure on poles and the ability to repair failures quickly means that there is a low return on gathering and maintaining this data. At this point in time, data on components other than poles may be gathered if and when personnel visit the host pole. It should be noted that replacement of any existing pole will result in brand new pole hardware being fitted.

Distribution Components		Type	Quantity
Distribution Structures (not overbuilt)			
	Wood	- Hardwood	16 639
		- Softwood	2 162
	Concrete		2 059
	Steel Poles		5
	TOTAL		**20 865**
Distribution Pole Supports			
	Guy Wires	- Aerial	225
		- Single Down	2 270
		- Double Down	1 314
	In-Ground Pole Blocks		5 461
Conductor			
	Conductor Length (km)	- 11 kV	476
	(Span length x No of wires)	- 22 kV (inc. 22 kV at 11 kV)	4 938
	TOTAL (km)		**5 414**

The next stage in data capture will be determining and recording older outstanding structure types (almost all less than 25 years old are already captured). This data permits the use of standard bill of material schedules to determine total quantities of cross arms, insulators braces and even nuts, bolts, and screws. This will also tie into costing, budgeting, asset valuation, stores management, asset management, and financial reporting.

Condition

The present condition of any distribution line is largely a factor of its age, the quality and type of materials used and the climatic conditions the lines are exposed to in various areas. EA Networks' location is largely free from corrosive airborne contaminants such as salt. The major life accelerating factors are sun (attacks insulation and protective coverings), wind (vibration and cyclic stress) and pole resilience to fungal or insect attack. At this stage, relatively few young poles have been individually inspected. The older poles have been inspected and those in need of attention replaced. The age profile would suggest that the bulk of the backlog maintenance has been attended to.

Hardwood Poles

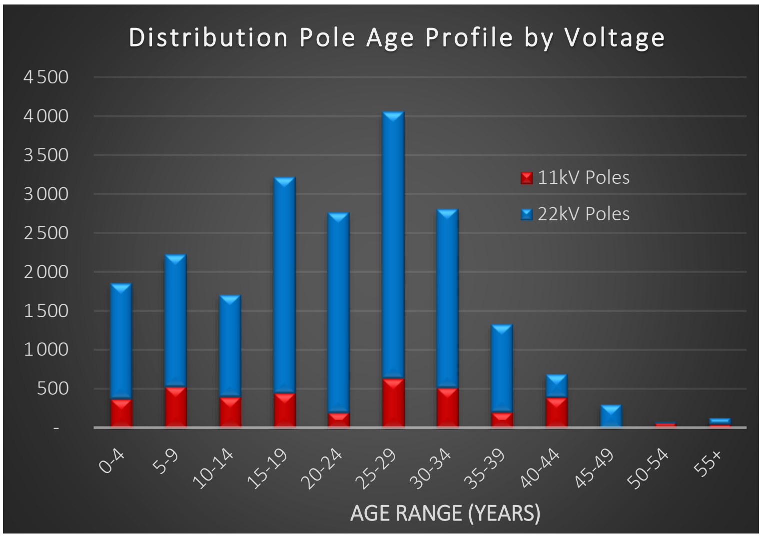
There are approximately 16 639 hardwood poles (80% of total distribution poles) in the overhead distribution network. The distribution lines are 22 kV or 11 kV single circuit and double circuit construction with an age ranging from new to around 50 years old. Many of the older lines have been replaced over recent years, but this has still left a small but significant percentage of poles exceeding 45 years old. Several of these lines are scheduled for replacement over the next two years. Over the years, three styles of hardwood poles have been used in the EA Networks system. These styles are – natural round (first generation pole), desapped hardwoods, and more recently CCA treated hardwood poles. The average age of the hardwood distribution poles is 20.3 years.

Concrete Pole Lines

Concrete poles make up approximately 10% of the total distribution poles used in EA Networks' system.

There are two types of concrete poles used:

- Pre-Stressed concrete poles – these various pre-stressed types of concrete poles were first installed around the late '60s and therefore not expected to need to replacement during the planning period. An early type of pre-stressed pole (called *Burnett*) was deemed defective and dangerous and these have all been replaced with other manufacturer's pre-stressed concrete poles, softwoods, and hardwood poles.
- Mass-reinforced concrete poles – these are in excellent condition and are likely to last well beyond 40 years.



The average age of the concrete distribution poles is 32.2 years.

Treated Softwood Pole Lines

Construction of treated softwood pole lines began in the early 1990s for economic reasons, and continued through until 1997, when the cost differential between hardwood and treated softwood poles became less and the quality of the softwood poles received deteriorated. These poles make up approximately 10% of the total system poles.

The green (damp) nature of the poles when first installed has seen the pole tops in many cases setting with a twist as the timber dried out causing the conductor to become unevenly sagged. This in turn leads to the possibility of conductor clash during turbulent wind flows. Large cracks have also appeared during the drying process in some poles that may pose a problem if the poles continue to split especially around any bolt holes. The splits also allow moisture into the untreated pole interior.

Due to the varying diameters of the poles, they can be susceptible to birds resting between the centre insulator and pole causing a current to earth and the resulting burning-out of the top portion of the pole.

It is not envisaged a widespread remedial maintenance programme be set in place during the planning period. Repair work will be expected in some cases, but this will occur as and when problems develop. Each specific case will be examined at that time to determine if it is symptomatic of a wider problem. The expected life of these poles is greater than 30 years.

The use of these poles may be reconsidered, as a refined treatment process now produces a higher quality pole. The technical/economic balance will determine future softwood pole usage.

These lines are typically wired in ACSR conductor.

The average age of the softwood distribution poles is 29.9 years.

Bates' Steel Pole Lines

These poles were installed in the mid-1940s and account for about 0.06% of the system total (0.1% in previous plan). These poles are rapidly approaching the end of their life with all poles requiring replacement within 5 years.

The rapid deterioration through rusting has seen a programme introduced to replace almost all these poles within the planning period. The June 2006 snowstorm reinforced this opinion as some steel poles failed during this severe weather event.

As of March 2025, four *Bates*' Steel poles remain standing operating at 22 kV. These poles were scheduled for removal in 2022, but the commercial development associated with three of them did not proceed. Irrespective of the commercial development, these poles will be removed by March 2026.

The average age of the steel distribution poles is 60 years.

Conductors and Conductor Accessories

A variety of conductor types have been used over the years ranging from galvanised steel, Aluminium Conductor Steel Reinforced (ACSR), All Aluminium Conductor (AAC), #8 copper (solid high strength copper), and stranded copper.

Most of the ACSR and all AAC installed are in a good condition and there is no intended replacement programme for any of these conductors. After the recent snowstorms it was decided that the small relatively low strength *Squirrel* conductor would not be used for new or rebuilt lines. In its place a much stronger smooth body conductor *Flounder* will be used.

Galvanised steel conductors make up approximately 0.4% of the total distribution conductor length. Some galvanised steel conductors are beginning to rust (in some cases quite significantly). It is anticipated that most of these conductors will require replacement during the planning period and there has already been significant progress along this path – a reduction of about 4 km since the last plan was published. This leaves approximately 21 km of these conductors in service at 11 kV or 22 kV. Almost all of this conductor length is the first span of an on-property extension owned by others (which is partly in the road corridor – estimated to be about 19.3 km of conductor length).

Line splices have started to cause an increase in faults, with a variety of failure modes including corrosion and driven by through-fault current. Line splices are now being proactively replaced when other line maintenance or overhead renewal is being carried out on a feeder section, or reactively when a small number of failures in an area indicates that line splice condition warrants replacement.

Wire termination and connector practices have been amended as per the current practice for subtransmission lines (see section 6.3.2 – Fittings).

Insulators and Insulator Fittings

A majority of the insulation used on the distribution system is porcelain and generally considered in reasonable condition. Given the relatively low pollution environment it is not envisaged that any major replacement programme will need to be implemented in the near future.

Wrap-lock ties were also used at 11 kV and the situation described in section 6.3.2 – Fittings also applies to a proportion of 11 kV lines.

The June 2006 snow storm identified that in some cases mechanical fittings were inadequate and they failed prematurely, dropping conductors onto the ground. The application and use of these types of fittings has been reconsidered and provided they are applied correctly they are adequate.

Standards

Documentation of the standards presently used for testing, inspection, and maintenance of the HV overhead distribution network is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

HV distribution assets comprise most of EA Networks' asset base by distance, value, and most other measures. Consequently, the asset type also accounts for the greatest share of maintenance and enhancement expenditure.

The value of distribution lines included in projects that are triggered by subtransmission development is beginning to reduce. These lines were incidentally reconstructed on the route of new 66 kV subtransmission lines (or existing 33 kV lines being converted to 66 kV). The cost of these rebuilt distribution lines has been estimated and allocated so that a true indication of increasing asset value can be obtained.

Any line in the 22 kV network is at worst a lightly refurbished line and at best a brand new one. This situation has arisen from the 11 kV to 22 kV conversion programme. Lines are generally reinsulated without full replacement work being necessary, however, if any faulty components are discovered they are replaced. This process effectively extends the planned maintenance-free period on 22 kV lines, typically for ten years from the date of conversion.

Inspections, Servicing and Testing

The rural 22-11 kV network is the area that consumes most of the Lines Inspector's time. Much of the inspection budget is spent assessing poles and hardware on these lines. A gradual accumulation of information on lines is being achieved with inspections targeting the oldest lines first. Future plans may allocate the inspection time more systematically.

The refurbished nature of the recently converted 22 kV network has relegated it down the priority list for patrols and inspections. It is anticipated that the data gathered during the conversion work so far will be used to assess the refurbished lines, looking for inspection candidates towards the end of the planning period.

Fault Repairs

This section of the network absorbs the biggest portion of the fault budget every year. The usual culprits are wind, wildlife, cars, trees, snow, irrigators (large rotating aluminium/steel booms), occasionally aircraft (top dressing), vandalism, equipment failure, consumer earth faults intruding into the distribution network causing protection to trip a feeder, and completely unknown causes. The projected costs are based on historical values adjusted for major replacement, refurbishment, and development projects.

A surprising statistic has come from the fault data gathered since 22 kV conversion was started. There appears to be an irreducible lower level of faults that exist for all open wire distribution lines. Asset management staff were hoping to see the number of faults fall to low levels in the 22 kV areas, but this was not the case. The fault level certainly dropped, with aged equipment failure virtually eliminated (faulty or damaged new components accounted for most equipment failures). Seemingly, provided there are people, birds, exotic marsupials, and trees (including blue gum trees with bark streamers), faults will occur. Dramatic reductions in this base level of faults will require alternative construction techniques.

The fault repairs on the HV distribution network have been estimated from the pool of fault maintenance done in previous years.

Planned Repairs and Refurbishment

The various repairs and refurbishments have not been identified individually. The present rate of maintenance is likely to reduce over the planning period as the average pole age decreases.

Single Strand Galvanised Steel Conductor (on-going)

The single strand galvanised steel conductor (predominantly #8 galvanised steel fencing wire) historically used in the 11 kV network is considered deficient. It has corroded and during wind and snow events is prone to failure which will drop a conductor onto the ground in many cases. A conscious decision has been made to eliminate this conductor from the distribution network. It has been progressively replaced with the minimum modern equivalent conductor for the structure/line to survive until the pole is at the end of its useful life. A maintenance programme is almost complete to give effect to this strategy. The remaining conductors are the first span leaving the roadside network onto private lines and, as they are rebuilt by the owner, it will be replaced.

Replacement

The rural HV distribution network is decreasing in average age. A considerable effort has been made in recent years to catch up on backlog maintenance that was postponed during times of major enhancement and development. This has reduced the level of annual maintenance required to a more routine amount. Routine amounts would be 2.0 to 2.5% (40 to 50-year average lives) of the total pole population per year needing replacement. With a distribution pole population of approximately 21 000 this represents approximately 500 poles per annum. This of course assumes a flat age curve, and this is not the case. The present rate of replacement would be about half this number (250 per annum). Towards the end of the planning period, the pole replacement rate may begin to increase as the age profile indicates more aging poles reaching about 40 years old.

Bates Steel Poles (on-going)

The *Bates* steel poles, which have given long service, are reaching the end of their mechanical life and are being progressively replaced, with six in service (at all voltages). The rural underground conversion programme has decommissioned many of these poles. The remaining poles are being closely monitored. All five remaining 22 kV poles will be removed by 2026, leaving only one relatively low risk poles supporting Chorus in service which will be reported to Chorus for attention.

Enhancement

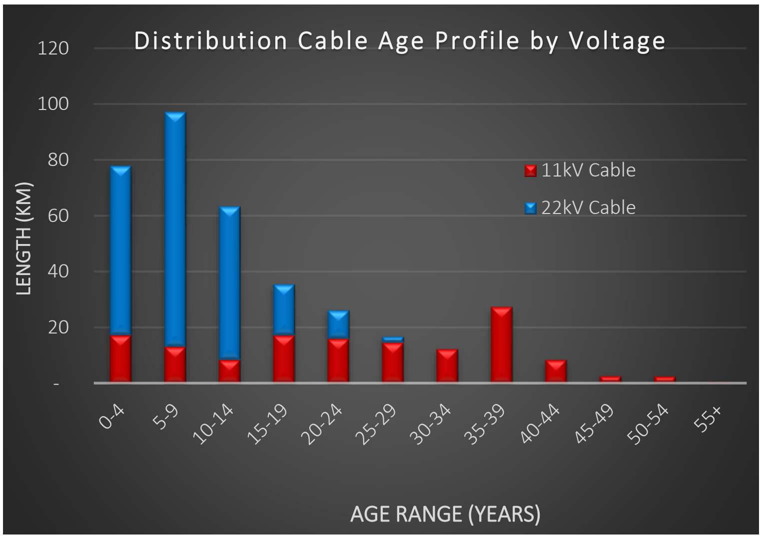
See section 5.4.4 – Planning Our Network for details.

Development

See section 5.4.4 – Planning Our Network for details.

6.4.2 11 kV and 22 kV Underground Distribution Cables

Description



Underground cable is a significant asset for EA Networks. It is being used to service any new urban development as well as replacing urban overhead plant when it requires rebuilding. The Methven urban area is completely underground. The decision to proceed with undergrounding Methven was taken after a disastrous snowstorm in the 1970s that left many poles and wires lying in the streets. It took many weeks to repair the damage sufficiently to return supply to all consumers. The Hinds township has been recently undergrounded.

Urban Ashburton is being progressively converted to underground cable as the condition of the existing overhead lines deteriorate, demanding replacement. When prioritisation is required because of limited resources, the HV distribution voltage lines are chosen before the LV reticulation as they have a higher public safety risk and a more dramatic impact on reliability.

It is not only urban areas that benefit from underground cable installation. Where necessary, short sections of rural distribution lines have been placed underground to avoid conflict with Transpower transmission lines, airstrips, and to get around problematic obstacles. Distribution feeder entry and exit from zone substations is also normally achieved with short lengths of underground cable. More extensive rural underground distribution is being undertaken with approximately 38.5 km of end-of-life overhead line being replaced with underground cable during the planning period. State highways are being targeted for rural underground conversion. An assessment of the actual costs and operational experience will determine how commonplace rural underground becomes, although in some cases the cost is now equal to or lower than the overhead equivalent and the differential is, in general, reducing.

It should be noted that EA Networks has a policy that all new connections to the EA Networks network must be made using underground cable (up to and including 22 kV).

The distribution voltage cables used by EA Networks are almost entirely XLPE insulated. The cables in common use at EA Networks are shown in the table below.

Since about 1995, the cable specification changed from a copper tape screen with PVC over-sheath to a copper wire screen with HDPE over-sheath.

EA Networks presently have about 139 km of 11 kV cable installed (an increase of 5 km from the last plan and 44% of all 11 kV) and 230 km of 22 kV cable (an increase of 30 km from the last plan and 12.1% of all 22 kV).

Condition

EA Networks have a mixture of some old and mostly new technology cables throughout the system, and these are generally in good condition and trouble free. As with most electrical networks, failures are typically associated with joint and termination problems or mechanical damage. The spike in cable 35-39 years old is a consequence of 14 km of 11 kV cable being installed onto Mt Hutt ski-field in the late 1980s.

Cable Accessories

Any remaining pre-1975 11 kV cable terminations are of concern from a reliability point of view. EA Networks target these for prompt replacement as soon as they are found.

Historically, a series of joint failures occurred in an 11 kV cable in William Street, Ashburton. A thorough investigation was less conclusive than was hoped. It is suspected that a crimp connector failed and caused a heavy current fault. This fault may have weakened similar crimped connectors in other joints in the same cable. Additional care is now being taken during application of crimp connectors and where possible existing and new joints are being minimised in the cable system. Where possible, new distribution cable installations use shear-bolt connectors, which appear to be more tolerant of cyclical heating. Where possible, screened elbow terminations are used to terminate cables, as they are impervious to dust, vermin, and moisture.

Voltage (kV)	Description	Current Rating (amps)	Capacity (MVA)
11	3 core 95 mm² XLPE aluminium (urban feeder distribution)	200	3.8
11	3 core 150mm² XLPE aluminium (distribution feeder root)	255	4.9
11	3 core 300mm² XLPE aluminium (*Core* distribution)	400	7.6
22	3 core 35mm² XLPE aluminium (rural consumer connection)	120	4.6
22	3 core 95mm² XLPE aluminium (general distribution)	200	7.6
22	3 core 120mm² XLPE aluminium (distribution feeder root)	240	9.1

Standards

Documentation of the standards presently used for testing, inspection, and maintenance of the HV underground distribution network are well underway. Construction standards are fully documented, and all new work is audited for compliance. Review and documentation of design standards is commencing in 2026.

Maintenance

The maintenance requirement of underground cable is virtually nil, and the urban Ashburton 11 kV network is being placed underground based on condition, solving the problem for the foreseeable future. The other township area that has some 22-11 kV overhead distribution, namely Rakaia, is being actively converted to underground – the overhead condition demands it. There will be no urban overhead lines remaining at the end of the planning period provided the underground conversion programme proceeds as programmed. This approach provides for medium to long-term cost minimisation.

Inspections, Servicing and Testing

There is limited inspection and testing work that can be done on any buried equipment. Periodically, electrical tests are done on cable segments that are out of service for other reasons, but condition is predominantly ascertained by tracking fault information. Some tests using partial discharge mapping were trialled after a series of faults occurred in quick succession. The results of the testing were not particularly compelling, and it was decided widespread adoption of the technique would not offer good value.

Fault Repairs

There is a very low frequency of faults on the HV distribution cable network. A small allowance is made for fault repairs annually.

Planned Repairs and Refurbishment

There are no planned repairs or refurbishment scheduled.

Replacement

There are no plans to proceed with any replacement work.

Enhancement

See section 5.4.5 and 5.4.6 – Planning Our Network for details.

Development

See section 5.4.5 and 5.4.6 – Planning Our Network for details.

6.5 Low Voltage Line Assets

These assets include 400 V overhead lines and cables used to reticulate electricity to the boundary of consumer's premises where it connects to the service line.

6.5.1 400 V Overhead Distribution Lines

Description

EA Networks uses a conventional overhead low voltage configuration with covered conductors and wooden crossarms. Aerial Bundled Cable (ABC) construction techniques are not employed. The total length of line in this category is approximately 39 km (a decrease of 15 km from the previous plan). This quantity has reduced significantly from the last plan - largely through removal of lines associated with underground conversion. These LV lines are in both urban areas and on the rural roadside. The urban lines will typically be heavier construction with larger conductor and almost always three phases. The rural lines are likely to be lighter and commonly will be only single phase. A significant proportion of the circuit length identified here is likely to be road crossings and the first span leaving the road to service a consumer's property. Despite being dedicated to each consumer, these short spans are all owned by EA Networks as they are fully or partially over the public roadway.

Copper conductor was used extensively until the mid-1970s but was gradually replaced with PVC covered aluminium because of economic and constructability considerations. The last large-scale urban overhead reconstruction was completed in the early 1990s and used PVC covered Weke AAC conductor. Since then, there has been no significant urban LV reconstruction undertaken. The present policy of EA Networks is to convert to underground cable whenever an urban overhead distribution reconstruction becomes necessary because of the line's condition.

The smaller rural villages, settlements, and townships of: Rakaia, Hakatere Huts, and Rakaia Huts all have some LV overhead reticulation, much of which is approaching the end of its useful life. All other townships and villages except Ashburton are completely underground. The urban underground conversion programme is scheduled to place the remaining township reticulation underground before the end of the planning period, based upon condition.

The supply to some of these settlements is via long overhead distribution lines, which is the most significant risk in the overall security to the consumer. Underground conversion has been selectively applied in these areas where it is truly advantageous to all stakeholders. An example of this is at the Rangitata Huts where (with the assistance of EA Networks) the *Rangitata Hutholders' Association* organised the conversion of both HV and LV overhead lines to underground cable (photo above). This solved safety, capacity, and reliability issues within the settlement and provided a much more aesthetically pleasing environment.

There is very little truly rural LV network. The majority of this is single spans leaving or crossing the road reserve.

Service Poles

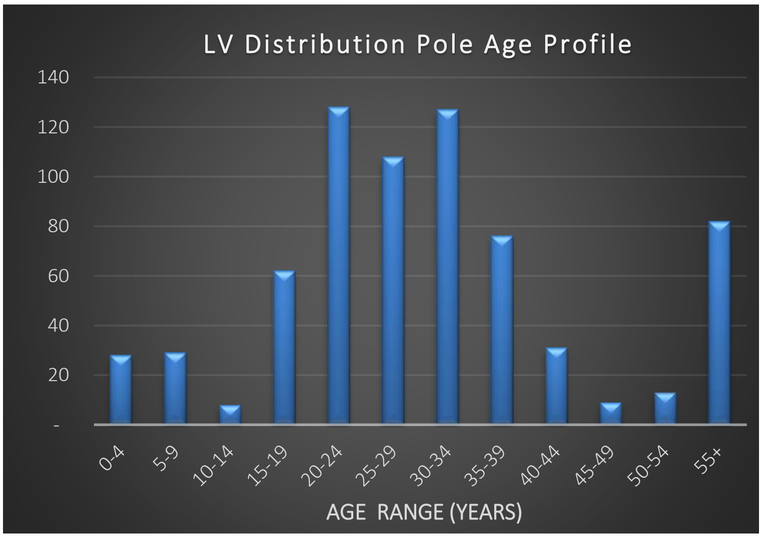
Service lines on consumer's premises are generally owned and maintained by the individual consumers – irrespective of voltage. The only ownership interest EA Networks maintains is in the span leaving EA Networks' network pole (while it is above the road reserve) and poles in the road reserve that only support one or more services. Service poles can be likened to aerial pillar boxes.

Street Lighting

A network of street lighting pilot wires has been run to supply street lighting. These pilots are switched at distribution substations by a ripple control relay that is signalled at dusk (on) and dawn (off). This conductor is typically 16 mm² copper in overhead reticulated areas. EA Networks own 16 km of overhead street lighting pilot line. The overhead pilot network is generally as reliable as the other LV overhead distribution and malfunctions/faults are generally caused by clashing wires or a faulty ripple control relay.

When EA Networks convert to underground reticulation and make available an underground cable street lighting pilot, the Ashburton District Council install new street lighting columns. This makes for a win-win outcome as EA Networks can remove the old poles supporting the outdated streetlight fittings and the council have new steel columns that they own, are safer for the public, in the best optical position, and the columns will last for many decades. Public street lighting is now LED except Waka Kotahi roads (where renewal is LED) and a number of subdivisions with special decorative heads. LEDs have reduced street lighting electrical loads considerably.

Condition



The age-based condition profile of LV overhead lines is relatively evenly distributed. The distribution represents all LV poles, and these are distributed in both rural and urban areas. The poles less than 20 years old are mostly located in the rural area. Then urban lines are split between much older lines that will be converted to underground within the next ten years and relatively new lines that were rebuilt in the 1980s and early 1990s. These newer lines will generally be in very good condition. The older lines (>40 years) are one of the principal targets of underground conversion, and the lines are regularly inspected for public safety and condition. They will typically be smaller conductors with either no covering, or failed covering, that offers little protection against conductor clash or accidental contact. The conversion to underground will eliminate any condition related issues.

EA Networks policy change to enforce all new network connections be underground has caused a dramatic drop in the number of LV poles under 15 years old. This will become even more apparent in future years.

The overhead lines constructed over the last twenty years consist mainly of PVC covered All Aluminium Conductor (AAC) or PVC covered hard drawn copper and are in generally good condition.

The policy that all new connections to the network will be via underground cable will see a gradual reduction in the quantity of overhead LV network although its average age is likely to increase. 92% of existing service mains use underground cable.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of the LV overhead distribution network is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

Major inspections were performed during 2007, 2013, and 2019, and inspections of urban Ashburton has resumed in 2025 in light of the revised urban OHUG programme. This ascertained the condition of all urban poles including LV and service poles. This data is being used to further prioritise and schedule reinspections and the urban underground conversion effort. Each year, the reducing number of urban LV lines are closely watched to ensure there are no preventable failures. In rural townships, this data may promote some replacement activity of individual poles to smooth the underground conversion demand. Rural LV lines are only reinspected if the associated HV distribution line has triggered a visit.

Fault Repairs

The frequency of LV faults on the EA Networks network is very low. This is reflected in the relatively low cost of LV faults overall.

Of the sum allowed for LV faults system-wide, Rakaia takes a slightly higher than average proportion. This is purely age related and reflects the *minor maintenance until converted to underground* approach considered as prudent by EA Networks. Refer to section 5.4.5 and 5.4.7 related to the progression of underground conversion of Rakaia township.

Planned Repairs and Refurbishment

No substantial repairs or refurbishment are proposed during the planning period. Most maintenance work is on an as-required basis.

Replacement

There are no plans to replace any LV overhead network in urban areas during the planning period. Rural areas are likely to have some replacement work completed as part of HV distribution replacement or enhancement work.

Where individual poles are close to failure, in an otherwise sound line, a pole replacement will occur, generally with a pole that matches the remaining life of the rest of the line.

Enhancement

See section 5.4.7 – Planning Our Network for details.

Development

See section 5.4.7 – Planning Our Network for details. The Ashburton District Council’s District Plan has rules that make additional pole locations in urban areas a non-compliant activity.

6.5.2 400V Underground Distribution Cables

Description

As has been already mentioned, EA Networks has a significant amount of underground cable and this is increasing as LV overhead lines require reconstruction. The Methven, Chertsey, Fairton, Mt Somers, Mayfield, Barrhill, Lauriston, Rangitata Huts, and Hinds urban areas are completely underground. Hakatere Huts is partially undergrounded, expected to complete in 2026. Approximately 96% of Ashburton, and 95% of Rakaia are underground by circuit length.

Various cable types were used during early underground installations. This included PVC insulated single solid aluminium core cable. The present standard types are:

Description	Current Rating (amps)	Capacity (kVA)*
3 core 16mm² XLPE copper (standard urban connection)	85	60
3 core 25mm² XLPE copper (larger urban connection)	120	85
3 core 35mm² XLPE copper (pillar box to main cable)	150	107
3 core N/S 95mm² XLPE aluminium (light duty LV distribution)	200	142
3 core N/S 185mm² XLPE aluminium (standard LV distribution)	300	213
4 core 185mm² XLPE aluminium (old standard LV distribution)	300	213
4 core 240mm² XLPE aluminium (heavy duty LV distribution)	360	256

* It should be noted that distribution LV cable circuits are typically limited by voltage drop not thermal rating.

In many cases the ability to supply load with a LV cable is determined by voltage drop rather than thermal capacity. The total distance of LV cable presently installed and owned by EA Networks is approximately 456 km. This includes all cable sizes from 16 mm² to 500 mm².

Currently, all new urban subdivisions are reticulated underground as a requirement of the appropriate District Plan (and consumer preference). District Plan provisions ensure that no new poles (where one does not already exist) can be located in urban areas. This means that any new urban reticulation is typically underground.

Various roadside boxes are required to complete the LV cable system. These vary in size and are categorised as follows:

- Pillar box — Residential pillar box that can accommodate up to six single phase or two three phase connections,
- Link box — This is typically at a junction in the LV network and provides network reconfiguration capabilities or supplies a larger three phase load,
- Distribution box — This is the largest LV box and can provide up to four 400 amp three phase connections and its typically used in commercial and industrial areas.

The typical configuration of urban LV underground distribution is that a cable will be run on each side of the street in individually fused feeders from a distribution substation. The cables either loop between pillar boxes or are tapped off to pillar boxes that are used to connect the consumer’s service cable via fuses. At the end of a cable run, a link box or distribution box will allow interconnection to adjacent LV cables that may be from a neighbouring substation. This arrangement allows reconfiguration to accommodate changes in load or back-feeding during cable failure or distribution transformer replacement.

Box Type	Quantity
Pillar Box	6 021
Link Box	671
Distribution Box	476
TOTAL	7 168

Service Cables

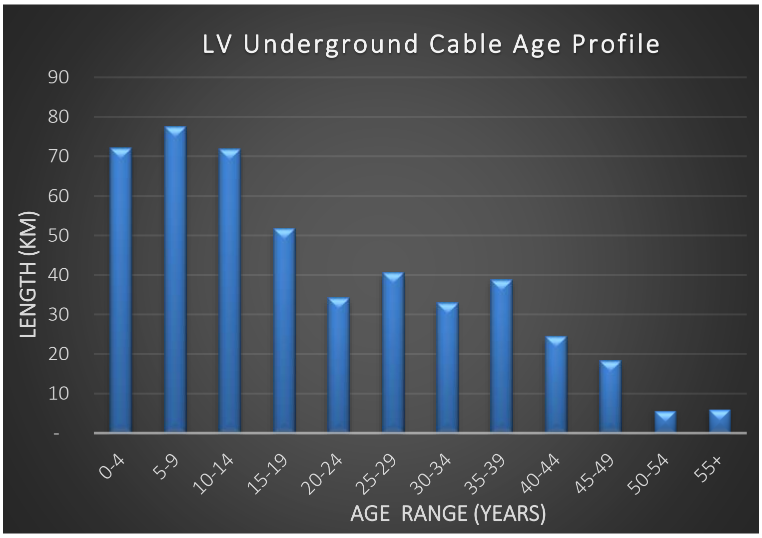
The cable from pillar box to house or business does not always exit directly from the pillar box across the property boundary. Often during underground conversion, the most cost-effective and least disruptive route is along the footpath and then across the boundary. EA Networks retain ownership of the portion within the road reserve. The underground service cable is generally very reliable in the roadside unless excavated by other utilities or contractors. There are no known problems with this portion of the LV network.

Street Lighting

As mentioned above, a parallel network of street lighting pilot cables has been run to supply street lighting. This cable is typically 16 mm² copper neutral screened cable in underground areas. EA Networks own 340km of underground street lighting pilot cable. The pilot cable network is very reliable, and malfunctions/faults are generally at the ripple control relay or caused by third party damage.

Condition

EA Networks has a mixture of early generation PVC and modern XLPE insulated, PVC covered, low voltage cables in the low voltage network. Generally, these are all very reliable excepting some early single core aluminium cables that have a very thin plastic sheath and are therefore prone to mechanical damage from stones etc. These cables only form a small percentage of the total low voltage cable population – about 1%. It is intended to replace these cables as they begin to fail at an unacceptably high rate or as replaced by underground conversion in the area.



The age distribution shows the effect of more than 35 years of underground conversion and new urban subdivision. This chart has all EA Networks owned underground cable including small in-road service cables. The underground LV cable system is generally in excellent condition. The exposed part s of the network, such as boxes, can be subject to vandalism and vehicle damage but the frequency of damage is very low and there are no known outstanding condition-related issues.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of the LV underground distribution network is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

Five-yearly visual inspections of LV boxes, cables up poles, and cable terminations are undertaken. Individual site inspections are instigated when damage is noticed or reports of unusual appearance are received.

During 2017-18 a survey of all pillar boxes in Ashburton township was undertaken and a programme of remedial maintenance has been undertaken to resolve a range of condition-related issues. This programme is now complete, and a very low amount of remedial work was necessary. In 2021-22 every urban pillar box was checked for security, access issues, and a label with EA Networks contact details was attached. Since then, the lack of LV box labels has been monitored, with some 2023 new installation areas needing to be retrofitted with labels, and minor areas identified as without labels.

Fault Repairs

Fault repairs are typically very low in frequency and in many cases are chargeable to the party causing the fault.

Planned Repairs and Refurbishment

There was one historical problem with a small portion of the LV network in urban Ashburton. The phasing of different parts of the network were not necessarily the same. That is, the *red* phase wire could not be guaranteed to have the same absolute phase angle as another *red* phase wire in an adjacent substation area. Correct phasing is necessary when using LV ties between substations. The last year has seen the few LV links labelled *Do Not Operate* become fully operational because the phase difference across them has been rectified. This situation arose from the historical lack of LV interconnectivity. The overhead LV network was built in a substation-by-substation manner with no reference to adjacent or absolute phase angle. A survey of phase angle is complete and each Magnefix ring-main unit has been labelled with the known and true, red, yellow, and blue phase conductors. This gives all personnel the information needed to correctly connect a standard Dyn11 distribution transformer as HV RYB ABC and LV ryb abc. Phasing correction work in Ashburton is now complete. In Tinwald, work is proceeding to physically correct the phasing in one final substation area as a stand-alone project. This will occur during periods of reduced workload for high priority tasks as well as in association with the remaining OHUG programme and other routine projects or tasks. Methven township has uniform, but incorrect, phasing thoughout. This does not represent a safety risk or operational impediment, as this is well known to field workers. The outage inconvenience to customers, cost, and the safety risks introduced during a re-phasing programme weighed against correcting the Methven area. All other townships with interconnected LV have correct phasing.

No other repairs are planned.

Replacement

There are no plans to replace any significant portion of underground LV network during the planning period.

Enhancement

See section 5.4.7 – Planning Our Network for details.

Development

See section 5.4.7 – Planning Our Network for details.

6.6 Service Line Connection Assets

Description

This asset consists of the equipment used to interface approximately 21 160 connections to the EA Networks distribution network.

The major component of this asset is the service protective device, which may be one of the following:

- 400 V re-wireable pole fuse
- 400 V HRC pole fuse
- 400 V HRC pillar box or distribution box fuse
- 11-22 kV drop-out fuse
- 11-22 kV disconnector
- 11-22 kV circuit-breaker

The service line on the premises of the consumer is owned and maintained by the consumer. There are circumstances where EA Networks will contribute towards consumer owned service lines. One example would be during underground conversion. EA Networks fund the first 20 metres of underground service line conversion onto private property. This ends up in consumer ownership but is a cost against the project and therefore against the LV network assets. Any portions of service line assets on the road reserve are considered EA Networks' asset as a private landowner has no explicit right to own equipment in the road reserve.

Condition

The connection assets are largely in sound order with the most common condition related issue being gradual deterioration of the fuse link as fault current (interrupted by on-property equipment) passes through the fuse. Occasionally, the fuse link carrier may deteriorate through corrosion or thermal (overloading) damage and this is replaced as and when required.

Standards

Documentation of the standards presently used for testing, inspection, and maintenance of service line connection assets is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

In general, EA Networks does not carry out maintenance on consumer owned service lines unless contracted to do so. These are the responsibility of the consumer to maintain, and they can use any competent contractor to do so.

The situations where EA Networks do maintain service line related equipment include:

- damaged pillar boxes,
- replacement of blown service fuses due to faults,
- replacement of service main poles on the street where these are sub-standard,
- repairs to network connection equipment,
- repairs to service spans across road reserve (any asset located in the road corridor is assumed to be EA Networks' responsibility unless informed otherwise).

Financial control procedures mean that only approved work is carried out and that the consumer will be required to pay for most work on consumer-owned service lines.

Inspections, Servicing and Testing

There are no scheduled inspections of the LV service asset category apart from periodic visual inspections of pillar boxes.

EA Networks, as an electricity network operator, offers free inspection and advice to consumers about their 11-22 kV service lines. Consequently, a lines inspector visits private on-property lines to assess them and advise the owner of any remedial work that is required. Currently there is no charge for this inspection. The relatively few HV service lines connected via a circuit-breaker are subject to regular inspection and servicing as per section 6.10. MV EDO fuses connecting MV service lines are examined whenever they are operated.

Fault Repairs

Service lines are generally owned by the end consumer and as such are not maintained by EA Networks. The only maintenance item of note is the occasional replacement of a defective service fuse carrier, cartridge, or base.

Planned Repairs and Refurbishment

No repairs or refurbishments are planned.

Replacement

The gradual replacement of re-wireable fuses with HRC types as part of LV replacement projects is expected to reduce the number of premature service fuse failures, which should be reflected in a reduced cost of fault work.

Enhancement

There are no enhancement proposals.

Development

There are no development proposals. It should be noted that all new connections to the EA Networks network are required to be made using underground cable (at all reticulated voltages below 33 kV). This will lower the mechanical burden on the service line connections and should decrease further the impact of failed service lines on the EA Networks network.

6.7 *Zone Substation Assets*

Description

Zone Substations are used to transform power from subtransmission voltages of 66kV or 33kV down to EA Networks' standard distribution voltages of 11kV or 22kV.

These substations comprise buildings, switchyard structures and associated hardware, high voltage circuit-breakers, power transformers, instrument transformers, and a multitude of other associated power supply cabling and support equipment. Furthermore, the substations range in size from 5MVA to 55MVA and are used to feed all areas of EA Networks' network, thus playing a critical role in the overall reliability of EA Networks' network. Section 5.4.2 shows the location of EA Networks' 21 Zone Substations. Highbank is not shown as it is owned by Manawa Energy although it both injects winter generation and consumes summer pump load. EGN is adjacent to the Transpower 66kV GXP and now supplies distribution load via 22kV feeders.

Abbreviations have been used to keep substation descriptions concise. The substations are listed below along with some vital statistics. Note that firm capacity in this context relates to the loss of a power transformer.

Each site has its own unique characteristics that tend to relate to the design and technology at the time of construction. The full details of each site are too much to describe here, but a brief overview follows. The distribution load details in each title line are pre-diversity and non-seasonal. The *General* category will include a lot of commercial users such as retail, accommodation, dairy sheds, and warehousing while the majority is residential. The actual peak load is in the summary description that follows.

Code	Name	Transformer Count	Peak Load (MW)	Sub-transmission Line Security	Firm Capacity (MW)	Firm (Break) Capacity (MW)	ICP Count
ASH	Ashburton 66/11	2x10/20MVA	21	*n-1*	20	30	4300
CRW	Carew 66/22	1x10/15MVA 1x10/20MVA	16	*n-1*	15	9	975
CSM	Coldstream 66/22	1x10/15MVA	12	*n-1*	0	9	859
DOR	Dorie 66/22	1x10/15MVA	11	*n*	0	9	450
EFN	Eiffelton 66/11	1x10/20MVA	13	*n-2*	0	4	289
EGN**	Elgin 66/22	1x20MVA	4.4	*n-1*	0	10	214
FTN	Fairton 66/22	1x10/20MVA	9	*n-1*	10	15	439
	Fairton 66/11	1 x 10/20MVA	4	*n-1*	10	15	312
HTH	Hackthorne 66/22	1x10/20MVA	15	*n-1*	0	9	810
LGM	Lagmhor 66/11	1x10/15MVA	11	*n-2*	0	6	726
LSN	Lauriston 66/22	1x10/20MVA 1 x 24/35 MVA	15 (-46)	*n-1*	0	7	919

MHT	Mt Hutt 33/11	1x5MVA	3	*n**	0	2	123
MON33	Montalto 33/11	1x2.5MVA	2.5	*n*	0	1	166
MSM	Mt Somers 66/22	1x10/15MVA	3/6	*n*	0	5	435
	Mt Somers 22/33	1x5MVA	3	*n*	0	5	(166)
MTV**	Methven 66/11	1x10/15MVA	5	*n-1*	0	5	1630
	Methven 66/22	1x18/25MVA	4	*n-1*	0	5	290/1920
	Methven 22/33	1 x 5MVA	3	*n-1*	0	0	(123)
NTN	Northtown 66/11	2x10/20MVA	14	*n-1*	20	30	5080
OVD	Overdale 66/22	1x10/20MVA	13	*n-1*	0	10	1210
PDS	Pendarves 66/22	2x10/20MVA	17	*n-1*	20	30	420
SFD22	Seafield 22/11	1x5MVA	-	*n**	0	5	0/1
SFD66	Seafield 66/11	1x10/15MVA	8	*n**	0	10	1/0
TIN**	Tinwald 66 (22/11)	1x6/8MVA	-	*n-2*	0	10	0
WNU	Wakanui 66/11	1x10/15MVA	8	*n-1*	0	13	790

n* – these substations are dedicated to one industrial consumer each and security levels have been negotiated with that consumer. SFD22 is essentially hot standby for SFD66.

** EGN has been converted to 20MVA 66/22kV operation for serving load while continuing to provide 22kV ripple injection to 66kV.
MTV 66/22 also provides 33kV via a 22/33kV step up transformer
MTV 66/22/33 normally supplies MHT.

Ashburton (ASH) General: 16MW Industrial: 4.0MW Irrigation: 1.1MW

This site used to be Transpower's supply point into Ashburton. The site is expansive and well fenced. The 66kV switchyard is well laid out, easily maintained, and has new equipment (2016-2019). Two 10/20MVA 66/11kV transformers are new (2019). The main building dates from the late 1940s but was extended in 2003 to accommodate two 11kV switchrooms. The 11kV load is served from two 11kV switchboards. All protection uses numeric relays. Full SCADA functionality exists. An old 25 tonne gantry crane has been removed to eliminate seismic risk. During 2020, the opportunity to increase building strength to Importance Level 4 (IL4) was taken during internal alterations. The site currently supplies 60% of urban Ashburton and some outlying areas. The load has a winter peak consisting almost entirely of residential dwellings. Northtown and Lagmhor zone substations offer additional switched firm capacity. Total switched firm capacity matches load. Fibre connected.

Carew (CRW) General: 2.3MW Industrial: 0MW Irrigation: 15.6 MW

A 66/22kV site established in 2002. Two 66kV circuits forming a closed ring serve this site. The 66kV numeric line protection is line differential with backup distance. The site has modern numeric transformer and 22kV feeder relays fitted and SCADA. The site is proving to be low maintenance. The load is summer peaking and irrigation based. The high general demand is a consequence of the large number and size of dairy sheds. Firm capacity exceeds load. The site has a 10/20 MVA and a 10/15 MVA transformer fitted to provide a spare system transformer, more firm capacity than load, and adequate back-feed capacity to adjacent sites (CSM, HTH & LGM). A fire barrier is installed between the two 66/22 kV transformers. Fibre connected.

Coldstream (CSM)	General: 1.7 MW	Industrial: 0 MW	Irrigation: 15.6 MW

A relatively new site that operates at 66/22 kV and serves an area that experienced significant growth in irrigation requirements. Two 66 kV circuits from a closed ring serve this site. Line distance and differential protection is fitted. Modern electronic relays are fitted, and SCADA is fully operational. Load exceeds firm capacity. The high general demand is a consequence of the large number and size of dairy sheds. The dominant load is irrigation pumps which are summer peaking. A 10/20 MVA transformer is utilised. Fibre connected.

Dorie (DOR)	General: 1.8 MW	Industrial: 0 MW	Irrigation: 10.1 MW

This site is compact and originally housed a 33/11 kV substation. Rebuilt as a 66/22 kV site around 2000, it has a concrete block building, and all electrical equipment is modern. A single 66 kV circuit serves this site. Indoor 22 kV circuit-breakers are utilised. 22 kV feeder protection and the 66 kV transformer inter-trip signalling (no 66 kV circuit-breaker at Dorie) has been updated to fibre in 2013-14. The site summer peaks with irrigation load. The higher general demand is a consequence of the large number and size of dairy sheds. SCADA system installation covers 66/22 kV transformer and 22 kV feeder protection. Firm capacity via 22 kV interconnections exceeds load. Fibre connected.

Eiffelton (EFN)	General: 3.0 MW	Industrial: 0 MW	Irrigation: 11.0 MW

Eiffelton is a newer site with a 66/11 kV 10/20 MVA transformer, 22 kV indoor switchboard, numeric 22 kV feeder, transformer, 66 kV bus, and 66 kV line protection. SCADA control is available. The three 66 kV circuits that are connected provide excellent security. Firm capacity meets load with 22 kV back-feed capability from adjacent substations (CSM, EGN, and WNU). Fibre connected.

Elgin (EGN)	General: 1.0 MW	Industrial: 0 MW	Irrigation: 2.5 MW

A site that is located adjacent to the Transpower Ashburton GXP. This site houses EA Networks' main 66 kV supply bus and a large (60 MVA) 66/33/22 kV autotransformer to allow 22kV ripple plant signalling on the 66 kV network (also previously used to provide security to the 66 kV bus). Significant changes occurred during 2012-13 to make the 66 kV bus more secure. The 66 kV bus has three sections with independent bus zone circuit-breakers and protection over each section. 22kV distribution feeders have recently been supplied from this site using a 22 kV tertiary winding from the autotransformer. Firm capacity and load is dependent on Transpower GXP configuration. The 60 MVA 66/33/12.7 kV YNa0d1 autotransformer was reconfigured as a YNayn0 66(33)/22 kV transformer. This allowed 22 kV load to be served directly off the EGN 66 kV bus which provides some steady state demand relief and significant back-feed capacity to Wakanui, Eiffelton, Ashburton (in future), Northtown (in future), Fairton, and Seafield substations. Fibre connected.

Fairton 66 (FTN)	General: 2.6 MW	Industrial: 5.5 MW	Irrigation: 3.6 MW

Fully commissioned in 2017, this is a site that provides capacity for rural residential, industrial, and irrigation load. It supersedes the Fairton 33/11 kV site which was about 100m away. The site has: three 66 kV circuits, a 66/22 kV 10/20 MVA transformer, a 66/11 kV 10/20 MVA transformer, a 6/8 MVA 22/11 kV transformer, a 10-way 11 kV (22 kV rated) switchboard in two sections, and a 10-way 22 kV switchboard in two sections. The ex-Silver Fern Farm meat-works are now owned by a vegetable processing company, and indications have been given that the site will be developed for vegetable processing and other commercial tenants. Currently, the site's cool store facilities are being utilised by the new owner with limited electrical demand (<1 MVA). Previously, the industrial load was non-seasonal, but total load peaked in summer with irrigation load. Another vegetable processing plant forms the base load. Fibre connected.

Hackthorne (HTH)	General: 2.5 MW	Industrial: 0 MW	Irrigation: 14.5 MW

A modern site configured for 66/22 kV operation. Two 66 kV subtransmission circuits are connected in a closed ring with a third circuit supplying Mount Somers substation. The site has modern numeric relays fitted and SCADA. Full 66 kV line protection is fitted (differential & distance). The site is proving to have low maintenance requirements. The load is summer peaking and irrigation based. The high general demand is a consequence of the large number and size of dairy sheds. Maximum load currently exceeds firm capacity. 22 kV incomer cables have been replaced to obtain full 20 MVA rating from the transformer. The addition of a three-way switchboard extension increased the feeder count to six (up from four) with a spare way for a second transformer. Additional 22 kV conversion has increased firm capacity as from Mount Somers 66/22 kV substation. Fibre connected.

Lagmhor (LGM)	General: 0.5 MW	Industrial: 0 MW	Irrigation: 10.4 MW

This site was developed in 2006. 2012 saw conversion from 33/11 kV operation to 66/11 kV operation. During late 2012, the site was converted to 66/22 kV operation. Three 66 kV subtransmission circuits are connected which gives excellent security. A 10/15 MVA transformer is moderately loaded. Numeric 22 kV feeder and transformer protection are installed. 66 kV bus differential and full 66 kV line protection is installed. Indoor fixed pattern 22 kV vacuum circuit-breaker switchboard. Full SCADA facilities. Firm capacity exceeds maximum load. Fibre connected.

Lauriston (LSN)	General: 4.0 MW	Industrial: 0 MW	Irrigation: 15.0 MW

Rebuilt in 2000 and now operating at 66/22 kV. The site was established in the 1980s anticipating a surge in irrigation demand that didn't arrive until ten years later. Two full capacity 66 kV circuits offer *n-1* security. Load has seemingly reached a plateau with limits on new water extraction. Irrigation pumps are large in this area due to depth of wells (200m+). SCADA system is operational on all relays. Maximum load exceeds firm capacity. Summer peaking due to irrigation demand. The high general demand is a consequence of the large number and size of dairy sheds. Recent 22 kV conversion has largely secured most load. Recent conversion of the 66/33 kV transformer at Methven to 66/22 kV has secured all distribution load. In 2024 the Lauriston (LAU) 47MW solar farm was connected at 22 kV via 3 cable feeders, with additional 24/35 MVA transformer and additional 22kV switchboard to suit. Fibre connected.

Methven33 (MVN)	Decommissioned

A site that was developed in the 1970s on the edge of Methven to offer reliable service to this tourist village. Chalet style A-frame building. Outdoor 33 kV switchgear in a compact pole-mounted arrangement. Decommissioning during 2024-25. The site may be retained as a remote storage, network training, and backup network control centre facility. Fibre connected.

Methven66 (MTV)	General: 5.0 MW	Industrial: 0.2 MW	Irrigation: 2.3 MW

A site that was established as part of the initial 66 kV ring development and Highbank generation embedding. Four 66 kV lines terminate at this site, three of which are high-capacity alternatives. The fourth (radial) circuit serves Highbank power station. This site serves as a 66/22/33 kV transformation to supply Mt Hutt substation. There is also a 66/11 kV transformer, which offers Methven township *n-1* levels of security on an entirely underground 11 kV network. Load is winter peaking because of the tourist/skiing influx and residential/commercial predominance. SCADA system is fully functional. A 10 MVA 22/11 kV YNyn0(d) transformer offers bidirectional fast-switched firm capacity to the 11 kV and 22 kV buses. Firm capacity of 11 kV exceeds maximum load. 33 kV firm capacity is zero. All 33 kV switched firm capacity is via the distribution network. An 18/25 MVA 66/33 kV transformer has recently been converted to 66/22 kV operation and a 5 MVA 22/33 kV unit provides the supply to Mt Hutt 33/11 kV substation. Fibre connected.

Montalto33 (MON33)	General: 0.5 MW	Industrial: 0 MW	Irrigation: 2.3 MW

This site has been in service for a few years. It is currently a temporary substation located near the Montalto Hydro power station. If more irrigation water becomes available, a future project could possibly construct a brand new Montalto66 66 kV substation at a permanent site about 3 km away. The new substation is dependent on new irrigation load or generation occurring which appears unlikely, so it has been removed from the ten-year plan. Land for the new substation has been secured. DMR data radio connected.

Conversion of the surrounding distribution network to 22 kV will make the temporary substation redundant in 2027.

Mt Hutt (MHT)	General: 0.4 MW	Industrial: 2.6 MW	Generation: 1.0 MW

A 1980s site with indoor SF_6 11 kV switchgear and a compact outdoor 33 kV bus arrangement for the single incoming 33 kV feeder. Small concrete block building. Fully functional SCADA system using IP digital microwave link. Load peaks in winter associated with ski-field activities. Maximum load exceeds firm capacity. Negligible irrigation. Cleardale hydro generation is connected at 11 kV. Modern numeric protection is fitted. Switched firm capacity is sufficient for essential services of the major consumer. Any increase in security is by negotiation. General refurbishment of building and fence, along with replacing aged 33/11 kV transformer and 33 kV circuit-breaker with newer items from other decommissioned sites occurred in 2019. Replacement transformer pad with bunding and new 66 kV rated disconnector installed in 2024. Digital microwave link connected.

22 kV conversion will significantly increase switched firm capacity in 2029-30.

Mount Somers (MSM)	General: 1.7 MW	Industrial: 0.7 MW	Irrigation: 2.2 MW

A site established in the 1970s. Rebuilt in 2019-20 with two 66 kV circuits from Hackthorne and Methven. The 33 kV circuit supplies Montalto33 substation and Montalto Hydro. New 66 kV switchyard. Fully functional SCADA system. Firm capacity exceeds maximum load. A new building has been constructed, and a new 22 kV switchboard has been commissioned along with modern transformer and feeder protection. Fibre-optic is connected. A 66/22 kV 10/15 MVA transformer is installed for 22kV supply, and a 33/11 kV 5/10 MVA transformer in conjunction with an 11/22 kV 5 MVA autotransformer provides a 5 MVA 33kV connection for Montalto33 substation and Montalto Hydro. The load is balanced between extensive rural farms, Mt Somers township, and a couple of lime quarries. The load is slightly summer peaking due to the irrigation but remains close to the summer peak during winter due to the residential demand. The 66 kV circuit between Methven and Mt Somers was commissioned in 2024. Fibre connected.

Northtown (NTN)	General: 17MW	Industrial: 2.6MW	Irrigation: 0.3 MW

A site completed in 2006 that operates at 66/11 kV. Two 66 kV subtransmission circuits supply an outdoor

66 kV switchyard. Two 10/20 MVA 66/11 kV transformers. The 11 kV switchgear is configured as two switchboards, each with a bus-coupler and two incomers, in two separate rooms giving four bus sections with one incomer and four outgoing feeders on each section. Modern numeric protection relays and SCADA. This site is intended to complement Ashburton (ASH) substation providing additional capacity and security to Ashburton township and immediate surrounds. Firm capacity exceeds maximum load. Load is winter peaking in line with residential demand. Fibre connected.

Overdale (OVD)	General: 5.0 MW	Industrial: 0.3 MW	Irrigation: 12.2 MW

A site constructed in 2004. Two full capacity 66 kV circuits offer *n-1* security. The site has a 10/20 MVA transformer (upgraded in 2014), indoor 22 kV vacuum circuit-breaker switchboard, modern numeric relays fitted and SCADA. The site is exhibiting low maintenance requirements. The load is summer peaking and irrigation based, although Rakaia township with its residential/commercial demand causes higher base loads than some other irrigation-serving substations. Firm capacity exceeded by maximum load. New FTN 66/22 kV substation has increased switched firm capacity. Fibre connected.

Pendarves (PDS)	General: 1.6 MW	Industrial: 0.2 MW	Irrigation: 17.0 MW

Two full capacity 66 kV circuits offer *n-1* security, a third offers limited back-feed ability. A fourth 66 kV radial circuit feeds Dorie substation. All modern equipment with a newly replaced/enlarged building. Outdoor 66 kV bus and circuit-breakers. New 22 kV circuit-breakers. Irrigation load causes this site to summer peak at 10 times its winter peak. Full SCADA system functionality. Firm capacity is available to all load as the site has two 10/20 MVA transformers (one of these is considered as a system spare). A fire barrier has been installed between the two 66/22 kV transformers. Fibre connected.

Seafield (SFD22 & SFD66)	General: 0 MW	Industrial: 8.0 MW	Irrigation: 0 MW

These sites are dedicated to ANZCO's meat-works.

SFD66 is a new site (separate to SFD22) and is supplied from a single *T* connected 66 kV line. A single 66/11 kV 10/15 MVA transformer. A concrete building with the facility for indoor 11 kV switchgear. One outdoor 11 kV circuit-breaker feeds a 500 amp capacity overhead line to SFD22. Maximum load exceeds firm capacity (contracted terms imply limited backup capacity). Fibre connected.

At SFD22, a single 22 kV line feeds onto an outdoor bus via an outdoor circuit-breaker. From there it passes into a 5 MVA 22/11 kV autotransformer and then into a (normally open) 11 kV incomer. SFD66 normally supplies the industrial load via the other 11 kV incomer at SFD22. The indoor 11 kV switchgear feeds into a consumer-owned 11 kV cable network. Concrete block building. Non-seasonal peak load. Limited SCADA system to permit switching load between SFD22 and SFD66.

In 2025-26 an upgrade project will be completed to install a new 5-way indoor 11kV switchboard at SFD66. This new switchboard will connect two 66/11kV transformer incomers, the existing 11kV feeder to the SFD22 site indoor 11kV switchgear, a new feeder to provide additional capacity into the ANZCO 11kV cable network, and a spare feeder circuit breaker for future expansion. WiFi radio link to SFD66.

Tinwald (TIN)	General: 0MW	Industrial: 0 MW	Irrigation: 0 MW

A site commissioned in 2017 to provide 66 kV switching and 22/11 kV transformation between the 22 kV rural area and the 11 kV urban area using a 6/8 MVA transformer. 6-way 22 kV indoor vacuum switchboard, 9-way 11 kV indoor vacuum switchboard, and numeric 66 kV line, 66 kV bus, transformer, and feeder protection relays. Facility to accommodate a 66/22 kV and a 66/11 kV transformer in future. 22/11 kV transformer operated in hot standby mode (capable of supply in either direction). Fibre connected.

Wakanui (WNU)	General: 2.5 MW	Industrial: 0.2 MW	Irrigation: 11.8 MW

A 66/22 kV site with a summer peak load. Is unique in the EA Networks network as a split-level site. Two full capacity 66 kV lines serve a single 10/15 MVA 66/22 kV transformer and 22 kV indoor vacuum switchgear. The site has modern numeric relays fitted and SCADA. With Elgin 66/22 kV and Eiffelton 66/22 kV now available, switched firm capacity is sufficient to secure all load. Fibre connected.

Power Transformers

EA Networks has 28 power transformers (24 x 66 kV and 4 x 33 kV primary voltage) installed at its Zone Substations, (as opposed to distribution transformers, which are used in distribution substations). There are 6 other units in storage either as spares or awaiting reuse or disposal.

All the power transformers are three phase units fitted with on-load tap-changers. A mixture of tap-changers have been used, including:

- 66 kV Easun MR (Reinhausen)
- 66 kV MR (Reinhausen)
- 66 kV ABB
- 33 kV Ferranti (33 kV – most transformers no longer in service)
- 33 kV ATL (33 kV – both transformers no longer in service)
- 33 kV Fuller (33 kV only – most transformers no longer in service)

Oil Containment

Oil containment facilities have been installed at all major substations constructed since 1991. EA Networks' policy is to install these facilities at all new sites where single vessels contain 1 500 litres or more of mineral oil and at existing sites where there is a risk to the environment.

Other Equipment

Almost all of EA Networks zone substations have 11 kV and/or 22 kV neutral earthing resistors (NERs) installed. These devices are simple pieces of equipment that limit the amount of current that can flow when one of the conductors of an overhead line or underground cable directly encounters the earth. Without an NER there is the possibility of several thousand amps of current to flow, while with the NER a maximum of 320 amps can flow. The presence of an NER offers numerous advantages: low circuit-breaker duty, much reduced voltage depression during earth faults, reduced interference with telecommunications circuits, much lower arc-flash energy (reducing public and employee risk), much lower thermal stress on the distribution network, and reduced step and touch voltages around power system earths. NERs are almost maintenance free.

Three revenue energy meters owned by EA Networks are installed at Transpower's Ashburton220 substation (one on each supply transformer) and these are used as *check* meters for comparison with Transpower's meters. The only other energy meters installed on the network are principally used for power quality monitoring at zone substation bus distribution voltages.

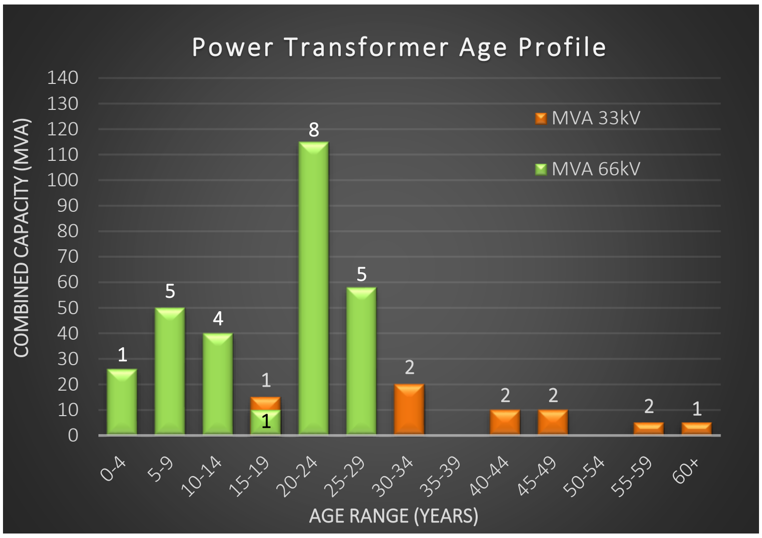
EA Networks do not own or operate any power factor correction equipment at any voltage.

Condition

The 20 zone substations that EA Networks operate range in age from circa 11 years old to portions being almost 40 years old. The newer sites are obviously in excellent order while older, typically smaller, sites such as Mt Hutt (MHT) have historically required more maintenance.

Transformers

The population of zone substation power transformers are generally in very good order. A proportion of the units could be said to have entered middle age, and, like anything in middle-age, it pays to monitor certain critical parameters more closely. Dissolved Gas Analysis (DGA) has allowed EA Networks to monitor the internal condition of its power transformer population and demonstrate that, in general, there is little evidence of accelerated insulation ageing or deterioration. The age chart clearly shows the younger and larger 66 kV transformers versus the older and smaller 33 kV transformers.



Four smaller (2.5 MVA) 33/11 kV units, manufactured by ECC in the mid-1960s, have all been de-tanked after a design flaw was exposed as a result of an 11 kV fault. No major damage was done (an exposed tertiary inter-phase conductor had touched the tank) and some minor corrective engineering achieved an acceptable solution. While de-tanked, the core and winding clamps were tightened, and a general internal wash (with clean oil) refurbished the units. Only one of these units is currently in service, and it is planned to be decommissioned in 2027. One other unit is being held as a spare. Once decommissioned, both units will be disposed of.

With the conversion to 66 kV at some sites, newer 33/11 kV units have been reused at other sites facing either increased loading, or the existing transformer reaching end of life. Most 33 kV transformers are currently in storage awaiting disposal.

Oil Containment

All oil containment bunds installed at Zone Substations are in excellent condition. Some of the bund field drains have become clogged with detritus from bird's nests and leaves. These will be renovated and are likely to be converted to the more modern surface drain type permitting much simpler maintenance. EA Networks have trialled polymer filter devices to allow direct drainage of stormwater from the bund without a normally closed valve. Unfortunately, they appear to be prone to clogging with dust and detritus which makes them impermeable. These units have been returned to manually operated gate valves.

Other Station Equipment

Batteries at all stations are now monitored with portable specialist equipment and analysis of the data obtained has kept the batteries in good order. HV switchgear is considered in section 6.10 and protection in section 6.12.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of zone substations is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

All Zone substations are routinely inspected, tested, and maintained regularly in accordance with EA Networks' standard requirements. Maintenance is categorised as either minor (non-invasive) or major (invasive). Visual Inspections are categorised as minor.

Inspections, Servicing and Testing

Visual Inspections

All Zone substations are visually inspected monthly as a minimum, increasing to fortnightly during high load periods. Visual inspections incorporate the checking of oil levels, voltage regulation, switchgear condition, battery test, and security. A detailed report is made of load and equipment operation. This information is used to assist with forward planning and maintenance.

Battery Banks

While the modern battery is considered virtually maintenance free, high importance is placed on the reliability of substation batteries, as many of the new protection devices are reliant on stable DC supply for correct operation. Batteries and chargers are visually examined at each monthly inspection and every three months a non-intrusive battery impedance test is carried out and recorded for comparison with previous values. Regular analysis of the trend can used to determine battery replacement criteria.

Most sites have dual battery banks to guard against individual cell failure causing loss of protection functions. Dual battery banks are standard at new sites.

Infrared Camera Thermal Inspection

Inspections using a sensitive thermal infrared digital camera are carried out on most equipment on at least an annual basis.

Ultrasonic

Ultrasonic outdoor inspections are performed when needed to detect high levels of discharge.

Other Station Equipment

Other switchyard equipment such as local service transformers, surge arrestors, cables, etc is maintained as necessary when the associated circuit is taken out of service.

Power Transformer Testing

As part of EA Networks' maintenance programmes, all major power transformers have an annual minor maintenance service which encompasses a visual inspection, routine diagnostic tests, and minor repair work in accordance with EA Networks standards which incorporate manufacturers' recommendations and EA Networks' experience.

In general, maintenance on the transformers consists of maintaining oil within acceptable dielectric and acidity standards, patching up corrosion, fixing oil leaks, annual diagnostic tests on the insulating oil, and a suite of standardised diagnostic tests using a recently purchased high voltage/current test set. In addition, the units fitted with oil-switched on-load tap-changers require periodic (4 yearly) inspection of the tap-changers and the contacts are dressed or replaced as necessary during the annual maintenance. Additional remedial work required outside the scope of the maintenance standard is referred to the asset management team for further action, which is budgeted as repairs and refurbishment.

Oil Testing – Dissolved Gas Analysis

For two decades, all Zone Substations have had annual dissolved gas analysis tests carried out and this has helped identify potential problems that need monitoring. A baseline Dissolved Gas Analysis (DGA) test was carried out on most power transformers in 1996 (the remainder in 1997 or when purchased). Trends revealed by this analysis give some indication of internal condition. After a period, the frequency of testing may be reduced on units showing no discouraging trends.

Costing for minor maintenance is very dependent on location and based on historical maintenance expenditure.

Costing for major maintenance, i.e. on-load tap-changers, is not only dependent on the location of the site but also the usage and types of unit and is such that some units are scheduled to be serviced every four years and others (vacuum switched units) only when operation count exceeds manufacturer's recommendation.

In future, the above condition monitoring techniques will be incorporated into generating an asset health indicator score for zone substation equipment.

Fault Repairs

Equipment failures tend to occur randomly and generally without warning. These range from a simple battery failure or a faulty resistor, to a costly transformer winding failure. The cost budgeted is the cost to restore supply or the service following the failure, not the cost of any repair work after supply or service has been restored.

The projected expenditure is based on actual expenditure incurred in recent years. It is not practicable to allocate projected expenditure against each substation asset category given the range of faults which can occur.

Planned Repairs and Refurbishment

This area of expenditure includes corrective work identified during inspections and tests while undertaking routine maintenance or following equipment failures. The magnitude of costs can vary significantly.

Planned expenditure also includes the cost of materials and spares.

Power Transformers

Major causes of power transformer failures to date have been winding, internal connection faults, and on-load tap-changer mechanism failure. No faults to power transformers have been caused by lightning to date, however, surge arrestors are installed at all zone substations as a precaution.

The other major internal maintenance on a power transformer is oil refurbishment, which is carried out as required based on oil acidity and moisture test results. It is not expected that this will be required on any EA Networks units within the planning period. Some older transformers do require regular maintenance for oil leaking around radiator connection fittings. This work is usually combined with other maintenance such as painting.

Repainting

Painting is carried out on a regular basis at a period of generally between 20 to 25 years depending on site conditions. It is planned to paint approximately 0.5 site/transformer per year over the period 2026 – 2035.

General

The general condition of most zone substation sites is good to excellent. Having been recently rebuilt as 66kV sites, nearly all sites are to a modern standard and very old sites have been decommissioned.

Replacement

There are no plans to replace any of the existing power transformers during the planning period based on the age and condition of the units. The recent 66kV subtransmission expansion has introduced a significant number of newer transformers (less than 25 years old) that help decrease the average age of power transformers. Within the plan horizon, 22kV conversion in the Montalto area will ensure all near end-of-life transformers are retired from 33kV service, and the 33kV transformers that remain in alternative applications will have suitable replacements available.

The 33kV transformers that are significantly older than 40 years are likely to be scrapped. Newer 33kV transformers will be either kept as spares or sold. The 33/11kV units available for reuse have provided an opportunity to decrease the average age of 33kV transformers. A few of these 33/11kV transformers will be reused as 11/33kV step-up transformers (at MSM temporarily and at MTV as a contingency plan) and as a spare (MHT).

Regardless of whether a pre-emptive replacement programme is undertaken in future, it seems likely that the oldest units will eventually fail at an increasing rate, and this will force replacement. Provided sufficient diagnostic tests are undertaken to identify imminent failure and some suitable spare units are available, this should not lead to a noticeable decrease in consumer supply reliability and could be a cost-effective replacement strategy option.

Enhancement

See section 5.4.3 – Planning Our Network for details.

Development

See section 5.4.3 – Planning Our Network for details.

Disposal

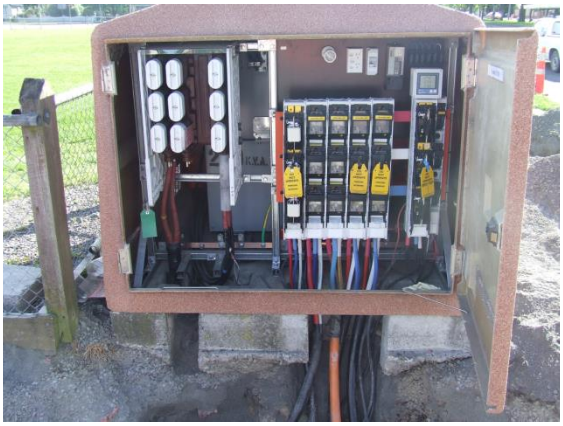
When zone substation equipment becomes surplus to requirements it is either scrapped in a commercially and environmentally appropriate way or, if it is saleable, it will be offered to other electricity network companies. Should a serviceable unit not sell, it is likely to be stored for use as spares or until it is certain no third parties are interested. At this point, depending upon the value of the item, consideration will be given to selling the item as scrap.

Zone substations represent some of the larger single location land holdings of a network operator and there have been occasions where some site rationalisation has occurred. It is typically impractical to offer the result of small boundary adjustments to anyone other than the adjacent landowner. Each situation is treated on its merits. Should an entire site require disposal, a real estate company would value it then market it.

6.8 Distribution Substation Assets

Description

Pole-mounted substations generally consist of a distribution transformer (defined elsewhere) and associated equipment including:



- 11 or 22 kV Drop Out Fuses
- Surge Arrestors
- Low Voltage Fuses
- Support Crossarms

In addition to these items, larger substations rated at 100 kVA or 150 kVA will often have the following additional components:

- Galvanised Steel Cantilever Platform
- Maximum Demand Indicator

In some applications, transformers as large as 300 kVA have been placed on a pole-mounted platform consisting of two poles with broad beams between them, upon which the transformer sits (this is no longer done for reasons of seismic security and the borderline economic advantage of pole mounting). Any new pole mounted transformers (maximum 100 kVA) reside on one pole only.

All new substations greater than 100 kVA use pad-mounted construction, where the transformer is placed on the ground. One such site is shown at right. EA Networks have a *New Connections and Extensions Policy* that requires all new connections to the EA Networks network to be via underground cable at less than subtransmission voltages. In addition, the policy requires that all new on-property transformers (>100kVA) are ground-mounted. This means that the only new pole-mounted substations are those that are established on EA Networks owned poles on the rural roadside and are less than 150 kVA capacity.

Distribution Substation Type	Quantity
Ground-Mounted	2 180
Pole-Mounted	4 587
22/11 kV Autotransformer	5

Generally, EA Networks provides the recoverable substation assets without a capital contribution from the consumer. This policy has caused a significant increase in the number of ground-mounted substations.

Extra assets required for ground mounted substations usually include:

- Concrete pad (precast where possible)
- Fibreglass or steel cover
- HV and LV Feeder Cables
- HV ring main unit (when part of a cable network)
- DIN LV Fusegear
- Anti-ferroresonance capacitors (when single phase switched at a distance) or three-phase remote switching

- Land purchase or easement.

Condition

The condition of these assets covers the whole range from needing replacement to brand new. The assets in need of prompt replacement are generally either smaller, very old, or rural sites and most are 11 kV, as 22 kV sites are newer. No seismically less secure two pole substations remain in urban settings. Remaining urban single pole substations will be replaced with a pad-mounted sites as condition dictates. The small rural sites will be prioritised for refurbishment.

The volume of transformer replacement and upgrading caused by load growth has ensured that most substation sites have been at least proven mechanically sound during the last 15-20 years.

Standards

Documentation of the standards presently used for testing, inspection, and maintenance of distribution substations is still being developed. Construction standards are fully documented, and all new work is audited for compliance.

Maintenance

Inspections, Servicing and Testing

All distribution substations are required to be tested every five years for safety reasons in accordance with the Electricity Regulations. At the same time, the general condition of the transformer is checked.

Fault Repairs

Lightning damage, pole failure, or ingress of water causes most transformer faults.

Regular inspection of transformers and covers reduces the number of failures due to water ingress caused by deterioration such as rusty tanks as these are generally obvious to the naked eye.

Pad-mounted substations have relatively few faults and usually the substation itself is not damaged (other components such as transformers or HV and LV switchgear tend to be at fault). Occasional vehicle crashes can damage this asset type.

Planned Repairs and Refurbishment

There are very few substations that are known to be needing repairs or refurbishment. Those that are will be attended to under a general repair budget set aside for this and other minor repairs.

Replacement

The urban underground conversion programme will often revisit substations that were first installed in the 1970s or earlier. These tend to be either pole-mounted on a platform (not suitable for re-installation during underground conversion) or *tin box* style units that cannot accommodate the modern style of HV and LV switchboards used by EA Networks. The result is a rebuilt substation that has the same capacity but is dramatically more flexible/functional and achieves much higher levels of operator and public safety.

Enhancement

See sections 5.4.4, 5.4.5 and 5.4.6 for details.

Development

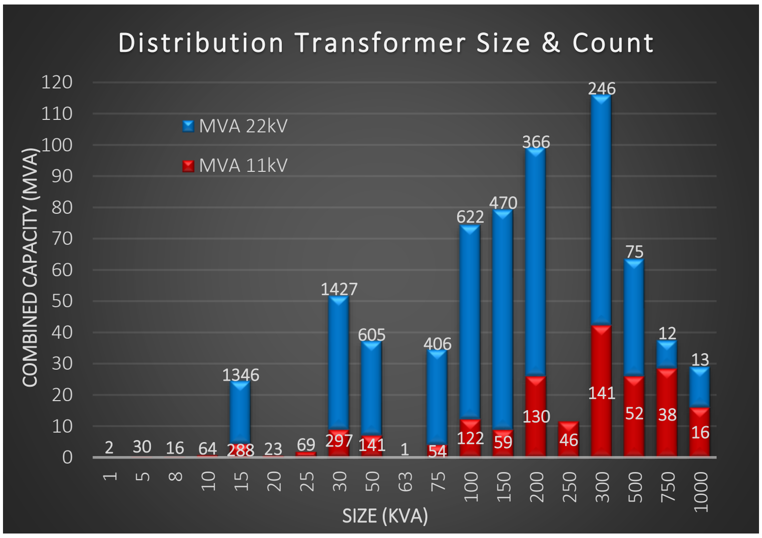
See sections 5.4.4, 5.4.5 and 5.4.6 for details.

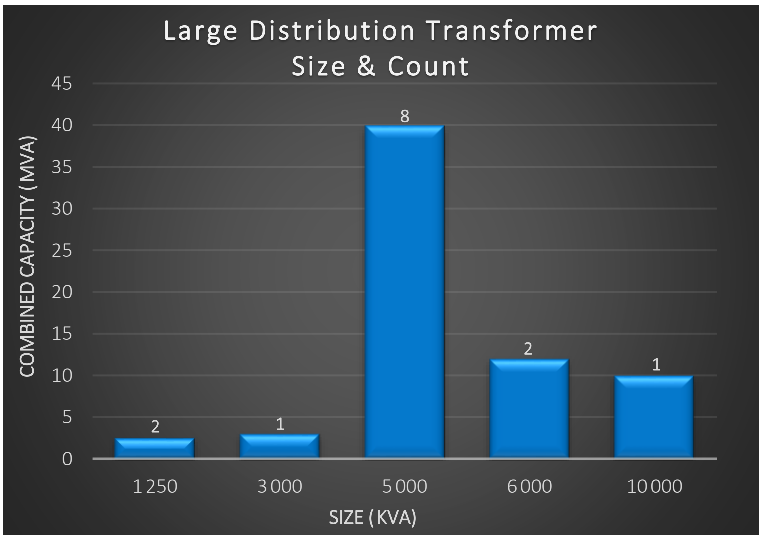
6.9 *Distribution Transformer Assets*

Description

Distribution transformers come in a variety of forms suited to particular applications. Many small transformers (<75 kVA) are mounted on a single pole by a hanger bracket and suited to rural situations such as a farmhouse, dairy-shed or workshop. A significant proportion of these small transformers are now mounted on the ground in accordance with EA Networks' *New Connections and Extensions Policy*. Modern low-maintenance specifications require galvanised steel tanks supplied as standard for all pole-mounted distribution transformers.

Larger distribution transformers take a similar form when they are designed for pole mounting (up to 100 kVA), but tend not to have hangers, as the mass is too great for a single crossarm. All new transformers larger than 100 kVA are now ground mounted to ensure adequate seismic security and immunity to pole condition. When the transformer is designed for ground mounting there are several options, of which EA Networks has at least one example of each. EA Networks' standard specification for transformers has facilities to fit HV and LV cable boxes and wall mounted HV bushing wells (which allow screened cable termination elbows to be connected). The lid is fitted with outdoor porcelain bushings as standard, and these are removed and blanked-off when ground mounting is required. Other types of transformers in use include pre-packaged *mini/micro-subs* which have integral equipment cubicles at each end and specialist kiosk mounting units which have the HV and LV bushings adjacent to each other on one wall of the tank.





All new ground-mounted transformers are fitted with in-tank HV fuses. These allow multiple transformers to be installed on an unfused underground cable without the need to consider each transformer's fault rating or single-phase fuse operation causing ferroresonance issues.

The chart above shows the total MVA of each different standard distribution transformer size and the number of each. The chart excludes regulators and autotransformers.

Extra-large distribution transformers are those that operate at distribution voltages on both primary and secondary. Examples of these in use at EA Networks are a 3 MVA 11 kV regulator, eight 5 MVA 11/22 kV autotransformers (several containerised), and two older 1.25 MVA 11/22 kV transformers. There are also three 6-10 MVA dual-wound 22/11 kV transformers permanently located at zone substations. These transformers are designed, constructed, and operated in a similar fashion to *large* ground-mounted distribution transformers and hence they are covered by this description. A regulator was used on only one portion of the 11 kV network. After conversion to 22 kV, the regulator has now been recovered and is awaiting redeployment, sale, or scrapping. 11/22 kV autotransformers are temporarily used at locations where the 11 kV network and 22 kV network meet mid-feeder or at zone substations to provide a source of 22 kV or 11 kV depending on the substation bus voltage. Exhibiting low impedance, bi-directional power flow (maintains neutral earth reference), portability (housed in 6 metre shipping containers with cable connections), and low losses are some of the appealing features of the autotransformers. There are 67.5 MVA

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of 11/22 kV transformers and one 11 kV regulator on the network, all of which are in good order.

The tanks of most distribution transformers have in recent times been supplied with bolted lids. This is important, with widespread use of in-tank fuses. All new units have an off-load tap-changer with a boost capability of 7.5% and a buck capability of at least 2.5% to account for heavy voltage regulation.

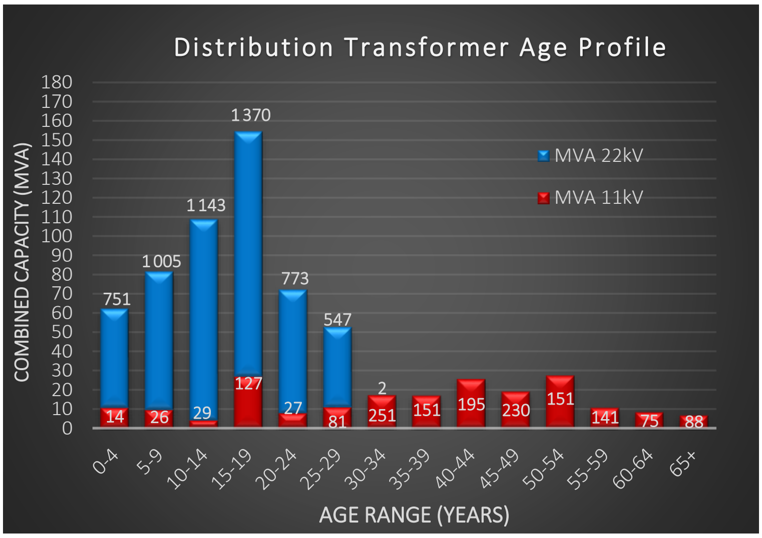
All substation data, including servicing records, is stored in the asset management system. This system will include links to the GIS, which can locate substations and electrically trace upstream to feeder circuit-breakers or downstream to consumers (ICPs) for the purposes of outage notices and fault statistics.

Condition

In the past three decades, and particularly in recent years, EA Networks has purchased significant quantities of distribution transformers at both 22 kV and 11 kV. The main driver for this either directly, or indirectly (via 22 kV conversion), is the growth in load. A population of transformers with low average unit age of 23.8 years (average kVA-weighted age is 20.7 years) is a relatively low fault and maintenance asset. The average transformer size is about 90 kVA.

There are a number of transformers that are very old, and these are normally retired when they either fault or are removed from service for other reasons. It must be said that many of the older transformers were built to last and consequently they have a longer life expectancy than the newer units.

The total population of in-service distribution transformers numbers 7 177 (7 228 previous plan) and the combined capacity is 662 MVA (653 MVA previous plan). There tend to be a large number of transformers in storage either ready for service or ready for assessment/servicing. Many of these are related to 11 kV to 22 kV conversion work. These stored transformers are now included in the age profiles and can account for some of the annual count and capacity variations. The increase from the previous year is a consequnce of commissioning a number of new 22 kV transformers while still having the replaced 11 kV transformers in the asset register.



Standards

Documentation of the standards presently used for testing, inspection and maintenance of distribution transformers is still being developed. Purchasing specifications are fully documented, and all transformers are inspected for compliance.

Maintenance

The population of distribution transformers covers a diverse range of sizes, types, and ages. As such, it is important that a comprehensive management plan is put in place, as the condition of the asset is not always easily discernible on a population-wide basis.

EA Networks' policy is to extend the life of distribution transformers where this is economically feasible. In support of this policy, many distribution transformers run well below their rated values for much of the time, resulting in long lives for the cores and windings. Provided that the tanks and oil are well maintained, the overall unit may be kept in service for up to 55 years or more. In this way, the maximum return can be leveraged from these high value assets.

Inspections, Servicing and Testing

Smaller pole-mounted distribution transformers are regularly inspected on a rolling five-year basis in conjunction with EA Networks' substation earth testing programme.

The inspection includes checks for:

- tank corrosion.
- paint chips/rust.
- Breakdown.
- oil leaks.
- insulator damage.
- breather condition (where fitted).
- termination faults.

On larger transformers, the oil level is checked and recorded and if an oil sample valve is available (standard issue on all new transformers), a sample of the oil is taken and checked for dielectric breakdown.

Pad-mount units larger than 200 kVA typically have Maximum Demand Indicators (MDIs) which are read every 12 months. This indicates loading trends to be monitored and that allows for early intervention should a unit become overloaded or optimisation if it is underloaded. It is now standard practice on ground mounted transformers to install a *PowerPilot* distribution transformer monitor (superseding the MDI) that provides on-line and continuous (10-minute min/max/average) current, voltage, and harmonics measurements.

Large transformers (>500 kVA) in areas such as the CBD of Ashburton or industrial sites such as ANZCO have periodic thermograph surveys carried out to check the tank and termination temperatures as well as to identify any other potential hotspots.

Any indications suggesting that the transformer requires attention results in prompt on-site repairs, or if this is not possible, the transformer is swapped with a spare unit from the store and sent back to the transformer workshop for refurbishment.

In future, the above condition monitoring techniques will be incorporated into generating an asset health indicator score for distribution transformer equipment.

Fault Repairs

A lot of the faults in distribution transformers are caused by lightning damage. Because of the regular inspection and servicing carried out, it is very rare for a unit to fail because of old age or deterioration.

Most faults are handled by swapping the transformer with a spare and sending the damaged unit back to the transformer workshop for inspection and repair – or scrapping if the damage is too severe.

An exception to this is bushing faults on large units – where the bushing can be easily repaired or replaced on site.

A result of 11 kV to 22 kV conversion is that many 11 kV transformers are returned into stock. Some of these units have reached the end of their useful life and they are scrapped. The remainder are either sold or refurbished for use elsewhere on the remaining 11 kV distribution network.

EA Networks have a limited stock of *emergency spares* which are used only under the circumstances of unexpected failure. A single dual voltage (22-11 kV), 1 000 kVA unit covers all large pad-mounted situations and is equipped with 15m flexible HV and LV cables to permit installation adjacent to the failed unit.

Planned Repairs and Refurbishment

Repairs can range from a minor paint touch-up on earlier painted units through to insulator repairs and bolt replacements. Refurbishment may include oil changes, rewinds, and even tank replacements.

Rewinds are only attempted on relatively modern units where modular replacement windings are readily available.

Tanks can be subject to corrosion, especially in the case of older (ungalvanized) painted units. At the same time however, the internal core and windings may be in excellent condition. For this reason, tanks are often repaired or replaced if the unit is otherwise in good condition.

Each unit is assessed on its age, loss characteristics, condition, and service history in determining whether to repair or replace the unit.

Generally, it is necessary to refurbish a heavily loaded transformer's oil initially after a 25-year period then approximately every 10 years which, with EA Networks' in-service distribution transformer population, means oil refurbishment will be required on a number of units throughout the planning period. With an estimated life of 55 years, this means a large heavily loaded distribution transformer may have its oil refurbished 3 times in its life.

It is expected that in the future, because of the high-quality specification of the insulating oil in transformers now being purchased, the oil refurbishment will be less than the historic requirements.

Replacement

Very old transformers that require extensive refurbishment or transformers that have been extensively damaged due to say a lightning strike, are often replaced rather than repaired. This is a purely economic decision. The tank of a newer electrically condemned unit may be salvaged to allow rehousing of the core and windings of an older unit with a condemned/corroded tank.

All replacement units are purchased to EA Networks' specifications, which prescribe galvanised tanks, stainless steel fixings, and oil sampling valves to minimise the cost of future maintenance.

The 22 kV conversion programme ensures that a steady flow of used 11 kV transformers return to stock. This is in addition to those units that have failed because of old age or lightning damage. The transformer technician individually assesses each transformer when returned to the store and estimates the likely cost of repair/refurbishment and subsequent life. If the 11 kV transformer is obviously at end-of-life, the decision is made to scrap it. Most other 11 kV transformers with some life remaining are retained until storage becomes an issue, and then potential buyers are canvassed for interest. If no buyer can be found, beginning with the smaller pole-mounted units, the transformers with least remaining life are sold for scrap. Almost all larger (≥100kVA) 11 kV transformers are retained and reused in urban settings. All 22 kV transformers are retained unless they are irreparably damaged.

This economic decision-making process is a means of prudently managing the asset and ensuring that an appropriate age profile is maintained. The asset management system records all available information about transformer condition and history. This data will be used in future plans as a basis for maintenance cost projection.

Enhancement

Often, the need arises for a pad-mounted cable box style of transformer. The EA Networks distribution transformer specification allows for conversion of a pole-mounted unit 150 kVA or larger to a pad-mountable arrangement. The cost of doing so is typically $500-$600. This capability is used regularly, but this work is done on demand rather than as a planned activity. While this is being done, in-tank HV fuses will be retrofitted.

A standard seismically designed and precast concrete foundation pad is now in use for all uncovered ground mounted distribution transformers. These pads allow very accurate location of holding-down bolts cast into the pad. All transformers larger than 100 kVA that are cycled through the store for reuse are modified to accommodate the standard mounting template. This process ensures that all transformers will over time adopt a rigorously designed and standardised hold-down arrangement.

In some cases, the rehousing of the core and windings of smaller (<100 kVA) pole-mounted transformers in good condition into new ground-mounted tanks is viable. This is only commercially feasible because of the price of the materials that are used in the core and windings. The value of the New Zealand dollar also impacts the economy of this approach.

Other than this capability, little enhancement work is carried out on distribution transformers, as these are essentially a standard module with no capacity for upgrading.

Development

EA Networks provide most distribution transformer assets as part of the network line charging mechanism. Any new development of note will require a suitable transformer. The 22 kV conversion projects have liberated a reasonable quantity of 11 kV transformers which are used whenever possible. At 22 kV, or if no used 11 kV units are available, a new unit will be purchased, or a second-hand unit may be sourced from other network companies.

Disposal

When EA Networks regularly undertakes 11 kV to 22 kV conversion, a significant quantity of older 11 kV transformers become surplus to requirements. Any transformer returned to stock has an evaluation completed to determine its remaining life and value. Any units that are considered saleable are offered to other electricity network companies at a cost that reflects the remaining life and maintenance costs required to return it to service. Any transformers that are unsaleable are disposed of as scrap after removal of insulating oil.

6.10 High Voltage Switchgear Assets

Description

This class of equipment includes all of the following items regardless of location:

- Disconnectors (66, 33, 22, and 11 kV).
- Gas (SF_6) Switches (22 and 11 kV).
- Circuit-breakers (66, 33, 22, and 11 kV, indoor and outdoor).
- Voltage Transformers (66, 22, and 11 kV, indoor and outdoor).
- Reclosers (22, and 11 kV).
- Sectionalisers (22 and 11 kV).
- Ring Main Units (22 and 11 kV).
- Expulsion Drop-out fuses (22 and 11 kV).
- Structures and Buswork (66, 33, 22, and 11 kV).

Disconnectors

Units at all voltages other than 66 kV are a rocking post design. Some units operating at 33 kV and below are fitted with load-break heads where load current exceeds the small interrupting capacity of the bare disconnector. The 66 kV disconnectors are a double-break centre rotating design. Most purchases of 66 kV disconnectors have been sourced from offshore. Several early disconnectors were unsuccessfully fitted with remote operating mechanisms, which have now been removed. The rating of these disconnectors well exceeds the rating of the circuits they are installed on. Typical ratings are 630, 800, and 2 000 amps. A few older 33 kV and 11 kV disconnectors are still in use, and they are more prone to failure than the modern designs. The decision has been made not to purchase any new 11 kV or 22 kV disconnectors for in-line use – buying gas switches instead. Disconnectors are still used to connect consumer's 11 kV and 22 kV cables to the network.

Gas (SF_6) Switches

A very worthwhile addition to the EA Networks network is SF_6 load break switches designed for pole mounting. They offer very reliable operation when compared to a load-break disconnector. The decision to purchase these devices was a balance between the additional cost and the significant benefits in distribution automation, operator safety, and lower future maintenance. The units that are being purchased are 24kV 400 amp rated and have: stainless steel tanks, manual and motorised operation, internal current transformers (for measuring load or fault current), more recent ones have internal voltage indication, and all can be converted to sectionaliser operation where required. The design of these units allows them to be used as isolation for working on lines, so no additional devices are required in series. To protect the unit and guarantee the insulation characteristics of an open switch, six surge arrestors are fitted to every gas switch (one per bushing). A photo of an installed gas switch (with surge arresters fitted) is shown above.

Circuit-Breakers and Reclosers

EA Networks have historically used a large range of circuit-breaker/recloser, indoor/outdoor equipment over the last fifty years, and this caused difficulty in training personnel and maintenance. EA Networks have now intentionally limited the different makes/models of circuit-breaker in operation at the various system voltages. The philosophy taken is that two different makes of each category of equipment will be selected and, on each occasion, either make will be awarded a contract for equipment supply. This limits the variety of equipment to two, while ensuring a competitive contract price.

Still in use today at 33kV and 11kV are three bulk oil circuit-breakers manufactured by AEI and Yorkshire. These units are in the process of either planned removal or are disabled to prevent the need to operate or disturb them.

An addition to the ranks of circuit-breakers are what have traditionally been considered ring-main units. Some manufacturers have produced competitively priced ring main units that contain vacuum circuit-breakers instead of fuses. This has created possibilities for additional fault-breaking isolation in both urban and rural settings. Many of the installed ring main unit circuit-breakers do not currently have protection enabled and are categorised as ring main unit switches. SCADA and auto-reclosing has now been standardised, and the protection will be enabled on many - enabling operation as true circuit-breakers.

HV Switchgear Summary by Type					
Type	66kV	33kV	22kV	11kV	Total Units
Disconnectors	90	4	640	18	752
Load Break Disconnectors	0	0	120	3	123
Circuit-Breakers or Reclosers	75	7	159	69	310
Voltage Transformers	20	0	28	15	63
Gas Switches	0	0	80	0	80
Sectionaliser	0	0	32	1	33
Drop-out Fuses	0	0	5516	984	6500
Pacific Glass Fuses	0	0	0	15	15
Ring Main Unit Circuit-Breakers	0	0	402	2	404
Ring Main Unit Switches	0	0	231	1167	1398
Total Units:	185	11	7208	2274	9678
Resin/Air Ring Main Units			195	366	561

This table summarises the presently documented population of high voltage switchgear.
There are quantities of switchgear that are in storage awaiting reuse, disposal, or refurbishment.
The stored switchgear is not necessarily counted in these totals.

Voltage Transformers

Voltage transformers are not actually capable of switching anything. They are however closely associated to switchgear. 11kV and 22kV voltage transformers are fitted to most indoor circuit-breaker switchboards and are used to control and monitor voltage and calculate feeder power in modern protection relays. The gas switches purchased for 11kV and 22kV are also fitted with a 500VA 3% accuracy voltage transformer when remote control is required (the voltage transformer provides 230V power to charge the batteries for the switch as well as providing an indication of the phase-to-phase voltage). 66kV voltage transformers are mounted outdoor on stands and these are used to monitor voltage and provide a reference for directional and/or distance protection relays protecting subtransmission lines.

Sectionalisers

EA Networks own two 11 kV oil-filled sectionalisers and only one remains in service located on a line that cannot justify a recloser but requires the ability to detect earth-faults (fuses cannot). The unit is in use to supply a relatively short length of feeder beyond Montalto into the foothills. When converted to 22 kV, these will be retired and replaced with a gas switch sectionaliser. At least 32 gas switches have had sectionaliser functionality enabled or added and now provide automatic fault isolation during recloser sequences.

Ring-Main Units

Four different models of ring-main unit (RMU) are owned and used by EA Networks. All bar one are resin/air insulated 12 kV Eaton Holec Magnefix units or 24 kV Eaton Holec Xiria units. The other brand of unit is a single Felten & Guillaume 24 kV SF_6 unit. The majority of ground-mounted 11 kV kiosk substations have a Magnefix unit installed. All brands of RMU have the option of either fuses, or more recently, circuit-breakers installed in certain models. It is now possible to purchase a reasonably priced vacuum circuit-breaker in a Magnefix unit and this option has been used on two locations. The fourth (resin insulated) RMU model (Halo) was introduced in 2022 for use in the Ashburton 11 kV core network. The additional model is being introduced because of its ability to be mounted outdoors without additional weather protection, making it much more compact/flexible than alternative circuit-breaker type RMUs which require a kiosk cover. The function of these Halo circuit-breakers is to act as ring and feeder circuit-breakers and, as such, are not considered RMUs.

Expulsion Drop-out Fuses

The most common HV protective device in the distribution network is the EDO (expulsion drop-out) fuse. Manufactured by many companies, most fuse-link carriers tend to be compatible with one another, and the simplicity of operation, low price (for bases and replacement fuse-links) and relative reliability and safety make them very attractive. EA Networks have significant quantities of these type of fuses (22 kV and 11 kV) as well as a rapidly diminishing number of *Pacific* glass tube fuses (11 kV only) which are being replaced by EDO fuses as required.

EDO fuses are located at (or on the supply to) every pole-mounted transformer providing fault and heavy overload protection and at strategic locations on the distribution network (line fuses) to sectionalise faults.

Note that the drop-out fuse quantities are an estimate of transformer fuses plus an accurate inventory of system-numbered devices. Fuses supplying transformers directly (on the same pole) are presumed to be one per transformer in this total. The quantities are the number of installations not the number of individual phase items.

Structures and Buswork

At many locations where HV switchgear is located, an outdoor busbar system is also present. These busbars and associated switchgear require support and interconnection. EA Networks have a range of structural supports and busbar types. These range from simple wooden poles on the roadside with flexible jumpers as the bus, to galvanised steel flange-mounting posts in zone substations, supporting post insulators and 75 mm diameter hollow aluminium buswork. Other supports are made of reinforced concrete or short wooden poles. The bus systems can also be made from tubular copper or stranded AAC/ACSR conductor. Both these methods are in use at EA Networks.

Condition

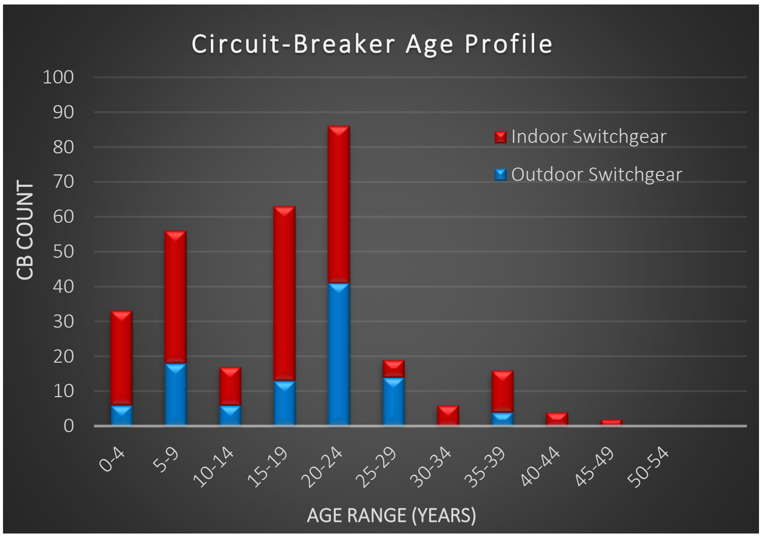
Circuit-Breakers

Ground-mounted outdoor and indoor circuit-breakers in use at EA Networks are all in reasonable condition.

Metal-clad switchgear eventually deteriorates with age resulting in degraded insulation materials, such as formation of voids and penetration of moisture. Corona and/or partial discharge often accompany this.

Replacement is justified primarily on reliability/risk of failure grounds and consumer service operating limitations. There is potential for explosive failure, which has occurred very infrequently. Historically, approximately one such failure every ten years (two in total – both non-catastrophic) – caused by one specific model of older, indoor, oil insulated, withdrawable switchgear (now retired).

As personnel work near the equipment there is an increased risk of personnel injury. Best practice appears to suggest that adopting designs such that oil-filled equipment is avoided, withdrawable components that expose primary conductors are avoided, and substantial walls are installed between old equipment and places where personnel are required to work for extended periods. The last indoor oil-filled switchgear has been disabled to prevent live operation, but not yet decommissioned.



EA Networks' switchgear selection has adopted safety by design features including modern SF_6/vacuum replacement switchboards, with SF_6, air, or resin insulated bus chambers, separate switch rooms, remote control operation of switchgear with workers away from the equipment where possible, and PPE requirements when switching to manage safety exposure.

The conversion of several zone substations from 33 kV to 66 kV has liberated some 33 kV SF_6 circuit-breakers for redeployment in place of oil-filled units. As worthwhile 33 kV equipment is decommissioned it may be redeployed at 22 kV.

Modern SF_6/vacuum replacement switchboards, with SF_6, air, or resin insulated bus chambers (rather than the old oil or compound insulated types) are virtually maintenance free. There has been a high cost associated with maintenance of old oil filled and compound insulated equipment, which usually required major service after faults.

The typical economic life of EA Networks' indoor 11 kV metal-clad switchgear installations has been assessed to be 50 years based on experience. At present, more than 56% of indoor circuit-breakers are less than 19 years old and 84% less than 24 years old. As 66 kV and 22 kV conversion proceeded, the older indoor circuit-breakers have been progressively replaced with modern equivalent assets, decreasing the average age. The few remaining older units (25+ years old) are either SF_6 and in good order, or in the process of being retired.

The bulk-oil indoor 11 kV SoHi units have had failures at other power companies. EA Networks has experienced two non-catastrophic failures in the past. The two remaining SoHi units have been disabled (one has been withdrawn from its bay) and are in series with a modern circuit-breaker. The ex-Silver Fern Farms site they service has been sold and the new owner plans to demolish most of the site and discussions continue about how these units may be decommissioned from their supply arrangement.

The population of outdoor circuit-breakers has been largely trouble-free, with wildlife (birds and possums) usually the principal cause of damage.

Pole-Mounted Reclosers

The range of pole-mounted reclosers that EA Networks own covers two voltage levels (22 kV and 11 kV) and two technologies (SF_6 and vacuum). These units have not caused any significant problems.

The more recent 22 kV reclosers have been largely trouble-free with no problems on the high-voltage side of the devices. A minor technical problem with the control circuitry was attended to by one manufacturer at no cost to EA Networks. Some early 22 kV reclosers are starting to show signs of aging as electronics embedded in them begins to fail. A program of replacing aged 22 kV reclosers has begun, and the cost of a new recloser now makes it viable to replace rather than repair some units.

Voltage Transformers

The population of voltage transformers at EA Networks had historically proven to be trouble-free until about 2006. A make of 66 kV voltage transformer failed on three occasions and based on the post-fault analysis it appeared that the manufacture of the units was at fault. An inspection of all the suspect units occurred and all of them have been replaced. One set of the recovered units has been kept as emergency spares but will not be placed in service under normal circumstances. After assessment, some of the additional recovered units may be reused at a lower voltage (monitoring 22 kV NER voltages – where they are not exposed to voltage unless an earth fault occurs).

Sectionalisers

The single 11 kV sectionaliser in service with EA Networks is aging (1992), but will remain in service until planned decommissioning in 2027. The 22 kV sectionalisers are all relatively new and trouble-free.

Disconnectors

The disconnectors in use at all voltages have been reasonably reliable in the low-pollution environment of Mid-Canterbury. Some of the older disconnectors have had problems with failing insulators, but the occurrence of this type of failure has been infrequent enough not to require a special replacement programme. Remedial action will be taken on these affected units as they come to notice. There are some very old two insulator disconnectors that are in a state of decline and at this stage they have not proven to be particularly unreliable, but they are subject to operational restrictions on breaking load. As 22 kV conversion proceeds any 11 kV disconnectors (which includes all old units) are recovered.

The population of 22 kV and 66 kV units is new and as such are in good condition.

Expulsion Drop Out (EDO) Fuses

The population of EDOs in the EA Networks network includes 22 kV and 11 kV variants. The different makes of 11 kV fuse bases and carriers have at times contributed to different reliability issues. A type manufactured locally for many years experienced some problems at EA Networks and other power companies. EA Networks have moved to alternative suppliers who manufacture to an international design standard.

The 22 kV EDO (24 kV class) is the only voltage rating of EDO now purchased. The unit is in some cases the same as is offered for 11 kV use. These have been trouble-free and are expected to remain so for the duration of the planning period.

The glass *Pacific* fuse is prone to failure when interrupting heavy faults or when it is exposed to contamination. The contaminant covers the glass tube and when the element melts, tracking occurs down the outside of the glass tube gradually causing heating until either it fails catastrophically or disintegrates when an attempt is made to remove it. Rated at 11 kV, these have almost all been eliminated as the rural area converts to 22 kV.

Gas (SF_6) Switches

This type of switch has been installed from 2003 to 2010 and more recently in 2020. They are in very good condition. The ruggedness of the switch and mounting arrangement was shown during the 2006 snowstorm when one switch's bushings had to support the three wires of an entire span of snow laden conductor after the crossarm failed. The only damage to the switch was the bushing terminals were bent. No gas leaked, and the unit has returned to service. The switches have become attractive for nesting birds and a remedial programme of fitting bird resistance features has started. Since 2020, additional new gas switches have been purchased to provide enhanced feeder segregation and automation.

Ring Main Units

Three different types of ring-main unit are in service. All types are in satisfactory condition and should remain so (with suitable servicing) for the duration of the planning period. A decision was made to replace the solitary remaining oil-insulated ring main unit with a modern resin insulated item in 2015. This reduced the number of types of ring main units to three and increased operator familiarity and safety.

Structures and Buswork

The structures and bus-work that form switchyards and switching locations come in many forms and represent different risks. The majority of 66 kV and 33 kV bus structures are very sound and in satisfactory condition.

The support structures put in place in recent times are all steel with a hot-dip galvanised coating. This will ensure that they remain in service for many decades with no major maintenance work required.

An unanticipated issue arose with the 66 kV buswork used at all the 66 kV sites. Aeolian vibration occurred on the longer unsupported spans of 75mm diameter tubular aluminium buswork. A vibration logger was installed, and it determined that the installation of some suitably sized ACSR conductor inside the tube effectively damped the motion. This ACSR solution has been applied to all affected spans as outage opportunities arose.

Standards

Documentation of the standards presently used for testing, inspection, and maintenance of HV switchgear is still being developed. Purchasing specifications are fully documented and all new HV switchgear is audited for compliance.

Maintenance

Inspections, Servicing and Testing

Circuit-Breakers

Circuit-breakers are subjected to minor and/or major maintenance routines in accordance with the requirements of the manufacturer's maintenance standards. Maintenance is also carried out on SF_6 circuit-breakers when a unit has completed a specified number of fault trippings.

Modern vacuum circuit-breakers are subjected to minor services and condition monitoring tests only at 4-5 yearly intervals. Invasive major servicing/adjustment is not scheduled and would be carried out only if required and indicated by condition monitoring tests.

As with power transformers, there are two levels of servicing:

- minor servicing, involving external servicing (non-invasive),
- major servicing, which involves invasive servicing.

The frequency and scope of servicing is defined uniquely for each type, make and model of circuit-breaker, and costs per breaker vary significantly. Typically, minor servicing is carried out as recommended by the manufacturer at a relatively low cost per service. While major servicing is typically undertaken when condition monitoring tests determine it to be necessary (at a more significant cost per service). Most of the vacuum switchgear in use has sealed HV components and only the mechanism requires periodic lubrication.

The tests performed as part of zone substation inspection and testing cover indoor switchgear.

Other

Disconnectors, ring-main units, sectionalisers, and drop-out fuses are operated sufficiently regularly to identify any servicing requirements. Generally, this is limited to lubrication and cleaning.

The gas (SF_6) switches have caused several faults when birds nest in the support frame. Over time the nesting material spills out and either catches fire or causes a flashover. When the opportunity arises, such as during a planned shutdown, a barrier is added to the frame to prevent the birds accessing the problem areas. The recent batches of new gas switches purchased permit rotation of existing gas switches out of service for bird-proofing.

In future, the above condition monitoring techniques will be incorporated into generating an asset health indicator score for high voltage switchgear equipment.

Fault Repairs

Circuit-Breakers

Fault repairs to switchgear take place as required, but as the population of old bulk-oil reclosers diminishes in line with the 66 kV and 22 kV conversion sequence, the occurrence of these faults has greatly diminished. There are oil-filled circuit-breakers at Montalto and ex-Fairton 33. Within two years there will be no 33 kV oil-filled circuit-breakers in use at EA Networks. Decommissioning the remaining 11 kV oil-filled circuit-breakers is dependent on a customer transferring 11 kV loads to 22 kV.

Failures in indoor switchgear are also relatively rare, and with the 22 kV conversion programme replacing zone substation units prone to failure largely complete, it is expected that the fault rate will remain very low over the next five years. There have been no failures during the intervening period since the last plan.

Disconnectors

Disconnectors normally fail due to deterioration of the operating arms with corrosion, misaligned contacts developing, terminal overheating, contacts welding shut due to through faults, or from an arc developing across two or more phases. By identifying old under-rated disconnectors and replacing these with gas switches, the incidence of arcing faults has been significantly reduced. Where the disconnector is required to interrupt more than a minor amount of load, a gas switch will replace it.

Expulsion Drop-out Fuses and *Pacific* Glass Fuses

Pacific glass fuses are subject to pollution contamination and fragility when operating. Any fault in these fuses will result in replacement with modern EDO fuses. They are also replaced when any planned work takes place in the vicinity. Being 11 kV, they will be eliminated within the plan horizon as 22 kV conversion is completed.

Resin Ring-Main Units (RMU)

One issue occurred with some RMUs that resulted in a component failing in a safe manner. The manufacturer has provided replacement units at no cost to EA Networks. A recent RMU failure was traced back to contamination that was not adequately cleaned off cable terminations (due to Covid separation protocols applying to the work party) from a LV heater connection wire failure. The standard for LV heater connections has been improved and contamination cleaning requirements reinforced. Maintenance checks include an acoustic camera sensor before and after maintenance cleaning is completed.

Planned Repairs and Refurbishment

Planned repair work in respect to circuit-breakers relates to additional corrective work and refurbishment identified during routine services, inspections, tests, or following failures. Refurbishment work planned includes overhaul of recovered disconnectors and EDO fuse bases prior to placing in stores.

Replacement

EA Networks has determined its replacement programme for high voltage switchgear based on the following criteria:

Safety

Where equipment presents a higher-than-normal risk to personnel during operating or maintaining the equipment e.g.

- generic types of aged bulk oil circuit-breakers with history of failures,
- circuit-breakers requiring local hand closing.

Technical Suitability

This applies to equipment that is no longer suitable for its service application e.g.

- disconnectors and circuit-breakers unreliable or inconsistent in performing their functions due to excessively worn mechanisms or intrinsic functional issues,
- equipment which fails to meet EA Networks' seismic requirements,
- electrically under-rated equipment,
- where the existing circuit-breaker is not able to be remotely controlled,
- where there is a need to obtain more metering information.

Economics

This is where replacement is justified purely for economic reasons, e.g.

- equipment is excessively expensive to maintain or repair,
- high cost of spares or where spares can no longer be purchased,
- maintenance intensive equipment installed at a sensitive supply location,
- critical location of equipment requires higher reliability than existing device can offer.

Circuit-Breakers

In line with the practice of overseas utilities as reported by CIGRE, EA Networks has a policy, subject to project-specific economic analysis, of replacement rather than life extension of aged deficient bulk oil and minimum oil circuit-breakers by major refurbishment.

Circuit-breakers are also replaced for the following reasons:

- where they have high maintenance costs.
- where they are unreliable due to an increased defect rate.
- where a system node requires a maintenance-free circuit-breaker i.e. maintenance outages cannot be tolerated.

It is internationally recognised that forty years is generally the *time expired* life of oil circuit-breakers. Some types have an economic life greater or less than this figure. Bulk oil breakers generally have a longer life, while minimum oil breakers typically last only 30-35 years.

While age is not itself a criterion for replacement, analysis based on likely total economic lives for each type, make and model of circuit-breaker provides a means of assessing likely future replacement requirements. The replacements themselves would be determined by safety, economics, and reliability assessments at the time.

Following several incidents involving a specific make and model of indoor bulk-oil circuit-breaker, a decision was made to replace all such units within the EA Networks network. This work has been completed with one exception which has been locked closed to prevent operation (it is in series with a modern circuit-breaker).

In total, there are two oil-filled circuit-breakers still in service. Montalto33 zone substation will be decommissioned in 2027 once 22 kV conversion has taken place, and the inoperable SoHi unit at ex-Fairton 33 awaits the connected industrial customer decommissioning their 11 kV reticulation (a new 22kV supply has been provided).

Voltage Transformers

Following two catastrophic failures, a thorough inspection of 66 kV voltage transformers confirmed that one make/model was substandard and needed replacement because of poor quality control during manufacture. All the potentially faulty units have been replaced. EA Networks are not currently aware of any other issues with voltage transformers.

Ring Main Units

The last oil-filled RMU was replaced with a modern resin insulated RMU during 2015-16. This reduced the models of RMU in use to three and eliminated aged equipment that represented an operating limitation and operator risk.

Other

None of the other high voltage switchgear identified in this plan meets the criteria for replacement within the planning period.

Disconnectors are scheduled for replacement when they develop a history of unreliability or failures, when their maintenance costs become unacceptably high, or when they are identified as being electrically under-rated. Should a disconnector require replacement, current policy would see it replaced with a gas switch.

Aged instrument transformers are only replaced when they fail, or when they are about to fail as diagnosed by testing. They are then replaced with a similar unit, usually a spare. Other replacements occur during site development works and depending on whether the condition and ratings etc. of the transformer are suitable for use at another site, they may be scrapped.

Enhancement

See sections 5.4.3, 5.4.4, 5.4.5 and 5.4.6 for details.

A substantial population of resin/air insulated 12 kV Eaton Holec Magnefix units have been used as switches for connection of distribution transformers, without high voltage fusing within the RMU. The current design relies on the transformer in-tank fuse that has been found not to provide fast clearance of faults on the transformer low voltage switchboard. This introduces arc flash safety risk. To manage arc flash safety risk, a programme to implement a new design solution (retrofit high voltage elbow fuses to transformer bushings) will be implemented. Refer to section 9.3.4.

The installation design from 2025 onwards for Eaton Holec Magnefix units will include high voltage fusing units for RMU transformer connections.

Development

A significant amount of high voltage switchgear has been purchased in the last two decades and a some more will be purchased during the planning period. This is predominantly RMUs, fuses, and disconnectors associated with the 22 kV conversion programme. See section 5.4 – Planning Our Network for details.

6.11 Low Voltage Switchgear Assets

Description

Housed in various enclosures are a range of LV switchgear, which perform various protective and operational functions. The simplest item in this category is a fuse connecting a consumer to the LV network from a pole or pillar box. Most pole-mounted substations will have a single set of fuses on the LV side to protect the connected cable or conductor from fault. These have traditionally been porcelain bases with HRC fuses. Extensive use has now been made of underhung DIN style fuse-disconnectors where loads have approached the rating of the porcelain equivalent.

The most extensive use of LV switchgear is in kiosk distribution substations and roadside link/distribution boxes. DIN fuse disconnectors of various sizes ranging from 100 amp to 1 200 amp ratings form the LV switchboard in these applications. Two standard types are used, a full-size DIN unit for substations and a proprietary compact unit for roadside boxes.

A full inventory of all LV switchgear types, locations, and quantities is gradually being gathered. Once complete, additional quantitative details will be given in the plan. An estimate of these quantities is as shown in the table below. Additional locations and types will be detailed once the data is available.

Condition

Low voltage switchgear is dispersed widely across the area EA Networks service. Almost all of these devices are in good order. Some link boxes and distribution substation switchboards use a specific type of fuse base and porcelain carrier (JW3) that is prone to overheating when approaching its rated current. Under normal loading conditions they are very reliable. The condition of heavily loaded JW3 installations will be monitored closely for deterioration. The JW3 also has exposed live terminals on it and is not touch-safe in the open or closed position. A combination of barrier mitigations, operating restrictions and improved PPE operator protection is applied to manage inspection, switching and working on low voltage switchgear to manage arc flash risk, with particular attention to the JW3 type.

LV Switchgear by Type & Location	
Switchgear Location & Type	**Number 3ph**
Link Box (JW3 Porcelain Fuse)	179
Link Box (Switch/Fuse Switch)	2 744
Distribution Substation (JW3)	254
Distribution Substation (DIN)	2 193
Total 3ph (Estimated)	**5 370**

The modern DIN switchgear used in most distribution substation switchboards since 1988 is very reliable and no electrical failures have been recorded. Several failures of link box LV DIN fuse units have been recorded. After research, it was noted that the loads had exceeded the unit rating after the derating of multiple adjacent units in a small enclosure. Derating had not been considered. Awareness of derating impacts, and more proactive monitoring is taking place. These devices can be described as in very good condition.

Standards

Documentation of the standards presently used for testing, inspection, and maintenance of LV switchgear is still being developed. Purchasing specifications are fully documented and all new LV switchgear is audited for compliance.

Maintenance

Inspections, Servicing and Testing

This asset requires only low-level inspection and servicing. The sites where these items are located tend to be visited for operational reasons and this is when the very infrequent problems are found. An infra-red non-contact thermometer and/or camera is routinely used to check for thermal issues.

Fault Repairs

There is a minimal amount of fault repair work required on this asset class. Fault repair generally falls into the replacement category.

Planned Repairs and Refurbishment

These assets tend not to be repairable as such. The value and construction of the items generally involves complete replacement of the asset.

Replacement

Some of the larger distribution substations (500kVA and larger) have a type of low voltage fuse (JW3) that is known to cause problems as it approaches its maximum rating. These are being progressively replaced with DIN type switchboards at the rate of one per year. The safety of the JW3 switchboards is also suspect and this provides additional justification for replacement. The cost of this is part of the general scheduled underground work.

Enhancement

The ability to enhance this class of asset is limited. However, a programme of retrofitting LV fusing between the transformer bushings and the low voltage board will be developed to mitigate arc flash safety risk, refer to section 9.3.5.

Development

The majority of LV switchboard development is in conjunction with the underground conversion programme and any new urban subdivision that occurs.

6.12 Protection System Assets

Description

Electrical Fault Protection

Electrical Fault protection is one area that has made rapid technological advances in recent years. Historically, electromechanical devices were required to respond to various electrical inputs and then trip a circuit-breaker. This is how the name *relay* evolved. Modern protection is closer to a personal computer than a click/clack relay. The steps between these two extremes were solid state electronic relays, then *intelligent* relays that used the analogue solid-state information, and EA Networks are now at the point where almost all protection is undertaken by *numeric* relays which calculate all the necessary parameters from raw current and voltage inputs.

EA Networks have some of each of these technologies except electromechanical. In some applications, the earliest technology still does a reasonable job. The major benefits of numeric protection devices are the flexibility to alter the logic of the device as well as being able to *talk* to it using a SCADA system or a local computer. Once you are connected to it you can extract any information that it has. This information is vastly detailed. The numeric relay replaces chart recorders, stand-alone panel meters, SCADA transducers, SCADA RTUs, and switches. All of these are built into the one box. Zone substations tend to have a proliferation of protection devices, and this is where the majority are located. Reclosers have the protection built into the supplied equipment and these are also becoming increasingly sophisticated. The modern pole-mounted recloser controller can measure current, voltage, power, direction of power flow and many other useful parameters. EA Networks have approximately 375 numeric relays in service in zone substations at the time of writing.

This number will climb further over the next few years as the 22kV network replaces the 11kV network and more network intelligence is introduced. A full inventory of protection equipment age and condition is still being prepared and will be available in a future plan.

Overvoltage Protection

The area in which EA Networks operate is not particularly prone to lightning which is a blessing for the asset manager. Lightning causes very large voltages on the lines and cables of the electrical network and these tend to *flash-over* to earth at the weakest point. In many cases, this point is the earthed tank of a transformer or circuit-breaker. Once a flash-over has occurred, significant damage can be done to the bushings, insulation, and contacts in the device.

Nothing can truly protect a device from a direct strike by lightning, the energy involved is too great to contain. There is equipment that can protect a device from indirect strikes or switching surges. These are called surge arrestors.

EA Networks apply distribution class surge arrestors to any equipment deemed sufficiently at risk or critical to network security. This has generally involved line-mounted circuit-breakers and sectionalisers, zone substation transformers, and any cable termination.

EA Networks have an additional consideration when applying surge arrestors. The 66 kV network, 22 kV network and the 11 kV network are all earthed using neutral earthing resistors (NERs). During a single-phase to earth fault the *healthy* phases can rise to a voltage 70 % higher than the normal phase to earth voltage. Surge arrestors must be selected taking this into account.

Numeric Protection Relays by Model	
Relay Model	**Quantity**
Schweitzer 2100 MB Hub	2
Schweitzer 2401 GPS Clock	18
Schweitzer 2407 GPS Clock	2
Schweitzer 2440 Numeric RTAC	64
Schweitzer 2414 Numeric RTAC	22
Schweitzer 311C Numeric – Mk0	10
Schweitzer 311C Numeric – Mk1	32
Schweitzer 311L Numeric	2
Schweitzer 351-6 Numeric	4
Schweitzer 351S Numeric	2
Schweitzer 387L Numeric	42
Schweitzer 551C Numeric	1
Schweitzer 587Z Numeric	20
Schweitzer 751A Numeric	81
Schweitzer 3505 Numeric DPAC	1
ABB RACID	2
ABB RED615 Numeric	12
GE Multilin SR345 Numeric	4
GE Multilin URF35 Numeric - H/W rev 5	11
GE Multilin URF35 Numeric - H/W rev 7	20
GE Multilin URT60 Numeric - H/W rev 5	9
GE Multilin URT60 Numeric - H/W rev 7	16
Total	**377**

Condition

Electrical Fault Protection

The electrical fault protection system (protection system) is designed and manufactured to be inherently reliable and low maintenance. This is certainly true of the modern numeric relays that, through self-monitoring, are very low maintenance. The in-built monitoring of these units can detect when a problem has occurred and alert the relevant control system to create an alarm.

Some solid-state relays are now failing as electronic components age. Solid state relays are not usually repaired when they fail, they are replaced with complete spare units or a modern numeric device.

The age of some numeric relays is approaching 20 years old. Component availability as well as economic viability may mean that the repair or refurbishment of aged (>15 years) numeric relays is doubtful. The features and price of numeric relays continue to improve, and it is less likely a numeric relay will be economically repaired if it is more than 10 years old. A replacement would be purchased, and the faulty unit kept for spares or scrapped.

The tests that have been performed on a regular basis reveal any relays in poor condition and they are promptly repaired or replaced. As such, the condition of the modern solid-state relays can generally be reported as good.

The register of devices is incomplete and represents only the protection relays located at zone substations and some RMUs. There are a range of other protection relays associated with reclosers and ring main units that will have additional data captured about them over time.

Over-voltage Protection

The surge arrestor population on the EA Networks network is limited to critical items of plant and cable terminations. The rate of surge arrestor failure is rising on the 22 kV network. Adequately testing these items in or out of service is difficult. The anecdotal evidence would suggest that sectors of the population are still in reasonable condition, but it is likely that a particular 18kV class type is suffering premature failure, probably due to moisture ingress. The previous specification 22 kV arrester was as per the manufacturer’s suggestion for a 22 kV resistance earthed network. The 18kV class surge arrestors are imposing a regular impact on customers and the SAIFI performance of the network. As a result, a replacement programme has been included in the budget concluding in 2028. The failures have had a notable impact on SAIDI and SAIFI. An alternative arrester manufacturer (using a 24kV class device) is now the current supplier. The arrester specification has been increased beyond that normally specified for a 22 kV resistance earthed network.

Surge Arrestor by Operating Voltage	
Arrestor Operating Voltage	Number 3ph
66 kV	83
33 kV	4
22 kV	1 752
11 kV	130
Total 3ph Sets	**1 969**

Standards

Documentation of the standards presently used for testing, inspection and maintenance of protection equipment is still being developed. Purchasing specifications are fully documented and all new protection equipment is audited for compliance.

Maintenance

Although referring to two distinct classes of asset, fault protection and over-voltage protection, this section makes no further reference to overvoltage protection, as the devices in question are low maintenance, low cost and generally very reliable. Additionally, there is little data to provide meaningful analysis of asset condition.

Inspections, Servicing and Testing

The policy in this area is to maintain protection schemes with every 4-8 years, depending on the type of protection (numeric/electronic/mechanical). Electromechanical types are maintained more frequently, while numeric types are tested less frequently.

It should be noted that *maintenance* on protection equipment is essentially *recalibration and testing* rather than the conventional view of maintenance, which would imply replacement of consumable parts. Protection maintenance is mainly required to re-affirm that the protection is calibrated within tolerance and will operate when called upon to do so. Some of this maintenance is as simple as checking relay logs to ensure it has operated correctly on a fault condition in recent times.

There are international trends towards reduced intrusive maintenance. Typically, intervals are being increased to between 5 and 10 years in other utilities comparable to EA Networks. This is particularly so where microprocessor (numerical) protection systems are used, as these protections have in-built self-testing and monitoring routines which reduce the necessity for manually driven maintenance testing. Once the input linearity/accuracy of the device has been proven (this can be done with load current and line voltage), a simple timing test should establish that the internal processes are working correctly. Other sources of information to prove the status of the equipment include event records which show both operation and pick-up on faults, along with the associated currents, voltages, and times.

EA Networks have an advanced relay test set to facilitate maintenance testing. This is being used for commissioning of new protection (developments and enhancements) as well as maintenance.

Fault Repairs

Fault repairs on protection are not generally carried out by EA Networks team members. Replacement of modular components may occur but not discrete internal components. Faulty equipment is returned to the manufacturer for repair or replacement. Thorough examination of the entire scheme is generally done, and a complete test of the scheme advanced from the next planned maintenance.

Surge arrester fault repair is limited to discovery after a fault incident and the replacement within 6-8 weeks. Most arresters have base isolators that disconnect a faulty arrester from earth automatically. Once it is isolated the arrester is live at the base and relies upon a very limited level of insulation to prevent a permanent earth fault. If the arrester is left failed and isolated too long, the base insulation fails and a permanent earth fault occurs, causing auto-reclosing to lockout and an outage. EA Networks makes every effort to avoid this situation arising.

Planned Repairs and Refurbishment

The expenditure planned over the review period is mainly in the following areas:

- replacement of aged lead acid batteries.
- seismic strengthening of protection panels.
- seismic restraints for batteries.

Replacement

Some protection relays will be replaced during the planning period. This is likely to be in conjunction with larger zone substation and subtransmission developments and could be considered in the enhancement category due to the extra functionality that they provide – making some other assets redundant. A significant quantity of other relays will be replaced because of age-related risk of in-service failure.

Some new 22 kV switchboards may be installed in place of existing 11 kV outdoor units. In some cases, this will also see replacement feeder protection installed.

Enhancement

Additional load could require enhanced protection assets in some locations. It is not anticipated that this is likely.

In conjunction with the SCADA expansion programme, it is possible that some protection equipment may be replaced as the most cost-effective way to integrate remote control and data collection into the sites. Other reasons for replacing older equipment would be lack of protective features or reliability of operation.

Development

It is obvious that there are some development projects for the protection system during the planning period. The majority of these projects involve the installation of additional relays in zone substations protecting 66 kV lines, 66 kV transformers or distribution feeders (Section 5.4.3 and Appendix B – Projects and Programmes identifies the location and extent of expenditure).

6.13 Earthing System Assets

Description

Earthing systems form an important part of the electricity network. Under normal circumstances no electricity should flow from a circuit into earth. This allows protective devices to sense when a fault has occurred, such as a tree touching a line or a person touching a toaster that has become live. To provide this protection, the connection to earth of the electrical supply system must be adequate to allow a certain minimum amount of current to flow. For a high voltage network this value is generally 20 amps or more. This corresponds to a value of earth resistance of no greater than 100 ohms (for 11 kV) once all the equipment in the fault loop has been accounted for and a safety margin added.

All equipment that has conductive components that can be touched must be earthed in a safe manner. Any neutral connection must be earthed at the source. This means that all distribution substations need a substantial earth, as do surge arrestors (necessary for correct operation), disconnector handles, recloser operating boxes, cable terminations, and any other item designed to be *screened* or *bonded* to earth.

Much larger earth mats are installed at zone substations, and these must account for voltages that develop on the ground and on equipment within the substation. Additional buried conductors can control these voltages to a safe level and all zone substations have been reviewed to ensure safe conditions exist.

Distribution Earth Count* by Location

Location	Quantity
Distribution Substation	6 683
Disconnector/RMU	769
Recloser/Sectionaliser	33
Surge Arrestor	493
Zone Substation	20
Total	7 998

* The counts shown here are an estimate

At almost all zone substations with 11 kV or 22 kV supply busbars, a device called a neutral earthing resistor (NER) has been installed in the neutral connection of the supply transformer(s). An NER restricts the amount of current that can flow into any type of earth fault. This makes for a safer system, but it can make it more difficult to detect very high resistance faults such as trees brushing the line.

In the future, it is likely that earthing installations will be identified individually within the GIS and asset management system and the items of plant using that earth will then be associated with it. This will enable an accurate inventory of earths to be kept (all earths are known and measured but several devices may share the same earthing system, and not all of these can be associated with it in the GIS or asset management database).

The total number of earths in the EA Networks network is currently obtained by adding together the quantity of equipment known to have earthing systems (excluding zone substations).

Condition

The 2010 Electricity (Safety) Regulations state that all works must have earthing systems that are:

> *designed, installed, operated, and maintained to ensure, as far as practicable,-*
>
> *(a) the effective operation of protection fittings in the event of earth fault currents; and*
>
> *(b) that the voltage of each conductor is restricted to a value consistent with the level of insulation applied; and*
>
> *(c) that step voltages, touch voltages, and transferred voltages are controlled to prevent danger to any person.*

If an earthing system complies with Electrical Code of Practice (ECP) 35 it is deemed as compliant with this clause of the regulations. In EA Networks' situation, because of the very high soil resistivity that is often encountered, a risk-based process must be employed to establish a practical means to comply with the Regulation. The EEA Guide to Power Systems Earthing (August 2009) provides guidance and advice on safe earthing practices for high voltage AC power systems adequate to meet the requirements of electricity safety legislation. EA Networks are using this document as a benchmark for compliance.

The Regulations do require that earthing systems be tested *regularly*, and EA Networks has been addressing this issue in earnest. To meet the requirements, a programme of continuous earth testing is underway and will continue to progressively test the total earth population at no more than ten-yearly intervals. Any distribution substation, disconnector or surge arrestor that is altered, has its earthing retested and improved if it is substandard.

Based on experience, it is expected that during the testing phase, some substandard earthing installations will be identified that are capable of being practically upgraded. A programme of upgrading these earth systems using driven rods and extra copper conductor will follow on directly from the earth testing exercise. The single most important criterion for earth improvement will be – that the resistance of the earth system at any site must provide an earth path of low enough resistance to ensure the HV feeder circuit-breaker operates under all circumstances if a single phase to earth fault occurs at that site. The exercise of earth improvement is not trivial, and it is probable that over time significant resources will be required to attend to this problem.

Large earthing systems such as that found in zone substations are regularly measured to ensure on-going integrity of the conductors and rods. None of the zone substation sites have shown a level of deterioration that requires attention.

Urban distribution substations have the multiple-earthed neutral as a continuous metallic connection from the zone substation out to the earthing point. The result is that urban earthing is never a problem in terms of the value of resistance achieved. Because the earth resistance is low the currents that flow are much higher, and connectors must be checked for integrity whenever the earth is inspected/measured. The use of 20/40Ω 11/22 kV neutral earthing resistors restricts this current to 320 amps which is around load current levels.

EA Networks has an electrical earthing installation at every substation, disconnector, recloser, sectionaliser, and surge arrestor connected to its network. All these earths are required to serve a specific purpose related to personnel and/or equipment safety. The ability of an earth to achieve an acceptably low resistance (to a truly remote earth) is dependent on two major parameters. The first and most important is the earth resistivity[6] of

[6] The resistivity of a material is a measure of how easily current flows through the material when a voltage is applied to it.

the soil, stones, and rocks into which the earth installation must be placed. The second parameter is the physical extent of the installation itself. EA Networks operate in an area where earth resistivity varies considerably. The best locations achieve an average of 300 ohm-metres, which is considered poor in many other regions. The worst locations are almost ten times this at an average of 2 800 ohm-metres. Achieving a desirable low earth resistance value (such as 10 ohms) in these conditions is next to impossible. EA Networks have adopted a pragmatic approach to the problem and concluded that the primary criterion for each installation's earth resistance is that, should the phase wire of any high voltage line contact metalwork connected to that installation, the operation of a high voltage circuit-breaker must occur. Another Canterbury lines company with a similar range of earthing conditions established this principle. The impedance of the earth fault loop has a safety factor of two. The guidelines that have been established and compliance with the Regulations will be used as the criteria to improve the performance of the EA Networks earthing system.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of earthing systems is in place. Construction standards are fully documented. All new earthing systems are audited for compliance.

Maintenance

Inspections, Servicing and Testing

Regular earth testing is performed on all earth installations in the EA Networks network. The typical return period for any one site is 10 years. In conjunction with normal line inspections, the above-ground portion of the earthing system is inspected every 5 years. All the data gathered is saved in the asset management system.

Fault Repairs

A faulty earth typically requires either complete replacement or significant enhancement.

Planned Repairs and Refurbishment

Whenever a substation is altered in any way (this includes a transformer change) the earth installation is retested. If these tests do not meet the established guidelines the site is given priority for earth improvement. A description of the earth improvement programme is shown in the enhancement category.

Earth Testing and Restoration

If, during regular testing or via other means, existing earths on substations and switchgear are discovered to have deteriorated to the point of non-compliance, these are restored to EA Networks’ current standard.

Replacement

There are no proposals to completely replace any earth installation during the planning period.

Enhancement

An historical earth improvement programme has now concluded. It has achieved the goal of lowering distribution system earth impedance to levels that comply with EA Networks standards.

It has been determined (both theoretically and practically) that the only reliable technique to establish a lower earth resistance is to deep drive rods into the ground. Extending the earth horizontally simply extends the hazardous area without necessarily lowering the resistance appreciably. Surge arrestor earth installations are installed to the same guidelines as distribution transformer earths. The only reason a disconnector must be earthed is the continuous metallic path between the disconnector assembly proper and the operating handle. If the operating handle is electrically isolated from the disconnector, the need to provide a substantial earth is removed. It is possible to use a 1 metre fibreglass section in the pipework to isolate the handle from the switch and then bond the handle to an earthed conductive operating pad (which is EA Networks’ standard practice). This ensures that regardless of the condition of the disconnector, the operators do not have any voltage difference between hands and feet.

Development

Whenever a new substation is constructed, an earth is also installed. These earths must meet the established guidelines of tripping a high voltage circuit-breaker for a single-phase fault. An annual allowance has been made for the duration of the planning period to provide for the number of new earths that have been installed in recent years. Zone substation projects incorporate significant earthing systems, but this development is incorporated in the overall zone substation project cost.

6.14 SCADA, Communications and Control Assets

This includes all communications equipment and radio repeater sites as well as vehicle-mounted equipment and the entire Supervisory Control and Data Acquisition (SCADA).

Description

EA Networks have a SCADA system in operation that covers all its modern zone substations and a growing number of remote *pole top* and RMU sites.

A detailed description of the SCADA system will not be given, as such information could be beneficial to someone with a malicious intent. Suffice to say that the necessary information and control will be available to those personnel that require it.

SCADA systems enable fast responses to situations as they arise. The information and control that SCADA provides can shorten restoration times considerably. The historical data that accumulates is also of value to the asset manager as substation asset utilisation is readily apparent. Dynamic rating capabilities can be evaluated at some sites as temperatures are transduced on some zone substation power transformers.

Between 1993 and 2021, EA Networks used a SCADA system developed by QTech Data Systems. This system has now been replaced by an Aspentech **A**dvanced **D**istribution **M**anagement **S**ystem (ADMS) which, at its core, is a SCADA system.

EA Networks has a project underway to enhance its communication with its customers during network outages. This requires the internal systems to be able to gather more accurate and timely information that can be used to inform EA Networks' customers.

The Aspentech system introduces a new SCADA system with state-of-the-art features and greatly enhanced cyber security features. Building on this base are advanced applications such as an Outage Management System which includes predicted fault location and the ability to communicate with customers via regarding planned and unplanned outages posted on a website, with further development planned to enable text message communication. Switch order management has been implemented to enhance control room planning and management of remote controlled and field switching. Additional advanced features include: real time fault and voltage analysis and others.

When fully implemented, it will be possible to create a self-healing network for automated fault response.

As a Lifelines utility, EA Networks treats cyber-security with great importance. The ADMS conforms to NERC security requirements which are federally mandated in the USA.

The new system has been implemented as a joint project between EA Networks and Westpower.

Remote Stations

The concept of an RTU (Remote Terminal Unit) at EA Networks' modern zone substations is largely redundant, in that modern protection relays have sufficient inputs and outputs to control and monitor substation functions and can transduce, calculate, and record virtually any electrical parameter.

The functionality of the protection devices connected to the transformers and feeders is such that they handle virtually all I/O and transducing. An industry standard protocol is used to communicate with the protection devices.

At sites requiring SCADA that do not have advanced numeric protection relays, a small conventional RTU or RTAC (Real Time Automation Controller) is installed to provide the necessary control and data gathering.

Communications System

The EA Networks communications network consists of a mix of several technologies of various ages and age profiles. This equipment provides bearers for operational speech, operational SCADA, and load management information. It also permits engineering access to a range of devices allowing remote detailed interrogation.

Primarily driven by the need for fast acting differential protection on its subtransmission systems, EA Networks has developed an extensive fibre optic network that now links all but two of its zone substations. Of the remaining two, one is a temporary substation (MON33) and the second has been connected to a high bandwidth microwave radio link (MHT). All but one communication link is duplicated with very few common paths. Even the primary radio repeater site is serviced by fibre with a microwave radio backup.

Built on top of the fibre network is a fully routed layer three IP network, providing logical redundancy to all connected zone substations. Currently, speeds of 1Gbps are provided. This can easily be raised to 10Gbps using the existing switching infrastructure should the need arise. The availability of reliable communication paths with low latency and high bandwidth has enabled new features such as VoIP phones and video surveillance to be delivered to connected zone substations. Because EA Networks also provides a public fibre based broadband network, it is possible to use this where it passes remote controllable devices, providing secure, reliable communication to those devices.

As the control centre has moved off-site from the Ashburton substation, for real time control applications the corporate office is connected to the communications hub by diverse, redundant 10Gbps links. The disaster recovery server site for network control is located in Westpower's Greymouth office using functionality of the new Aspentech system, this facility is permanently on-line.

The fibre optic network is a separate business function and as such the asset management of that network is not part of this plan. Only fibre optic cables fully contained within a zone substation site and dedicated to power system functions will be considered in this plan.

The Digital Mobile Radio (DMR) system used for voice communication is 100% digital. Consequently, the system can transport non-voice data transparently. This has been used to supplement the SCADA system by utilising a small DMR data unit as a remote control *mini RTU*. These devices are used where it is difficult to obtain access to the fibre network.

Mobile Speech Network

The DMR mobile speech network is provided via a number of digital radio repeaters used exclusively by the Network and Contracting divisions of EA Networks. All but two of the repeaters are housed on EA Networks sites and is connected by a redundant IP backbone. One repeater is co-located on a Transpower site and connected via microwave radio link.

A further repeater has been installed on a remote mountain site in the Ashburton Gorge (Mt Tripp) and connected back via microwave link. Now that this site is commissioned, EA Networks have virtually 100% coverage of its network by voice radio and low-speed data communications.

Building on the digital infrastructure, EA Networks have implemented additional safety features for its employees, particularly remote workers. These include man down and emergency call features and the ability to use portable radio devices across most of the network.

To further enhance safety operations, EA Networks have enabled remote access to the radio via intelligent device (phone or tablet). This enables whole crews to have access to the two-way radio system from a job site e.g. upon noticing a safety issue, a person in the bucket of an Elevated Work Platform could, via their cell phone, establish a call via the two-way radio network back to the **N**etwork **O**perations **C**entre (NOC) or initiate a system wide emergency call.

The DMR radios have also had another feature added that turns the vehicle into a communications hub, where DMR is just one of the communications links to the vehicle, others being WiFi and cellular data. This will reduce the need for the operator to decide which communications mechanism to use when communicating with the NOC. Typical examples of usage would be:

- if a photo of failed network equipment is to be sent, it will be routed via WiFi or cellular data but not the DMR data channel,
- if written switching instructions are being sent then they will be able to use the DMR data channel to ensure delivery in virtually all places and conditions.

Further enhancements include two-way radio traffic being transmitted via WiFi or cell data when vehicles are operating out of DMR network coverage. This will enhance control and communications when assisting other networks in times of disaster. All the relevant vehicles now have WiFi hotspot functionality supported by cellular back-haul and a fallback to DMR.

The DMR radio system is supplemented by a VoIP phone installed in every connected substation and communications facility.

At most zone substations, a 19m concrete communications tower has been installed and this serves as the platform for all radio communications needs to and from the site.

Condition

SCADA

As part of the implementation of the Aspentech system, the SCADA base stations and underlying computing layer have been replaced with up-to-date equipment. The new SCADA system is comprehensive at the sites covered. Backup systems are in place for data and power supply and are being further enhanced with the move to the new system. Maintenance of the SCADA system should be limited to occasional computer infrastructure refreshes, setting changes of the protection relays, software upgrades of the SCADA application, or other operating system revisions.

Communications

EA Networks has a successful digital DMR system. This system provides GPS location of all DMR-equipped vehicles and handheld radios and has a significant degree of in-field data coverage.

As mentioned previously, the trunked DMR system also provides remote control and indication of pole top and other remote devices.

The building housing the fibre-connected communications facilities at Gawler Downs was replaced in 2009. A backup digital microwave link to the Gawler Downs hill-top repeater site exists. In 2012, communication facilities were constructed to house both the SCADA IP based systems and the public broadband system. In 2024, the aged main wooden communications mast at Gawler Downs was replaced with a much more capable steel mast.

The microwave link to the DMR repeater co-located at a Transpower’s Roundtop site is recent, having been installed in 2018. The microwave link to Mt Hutt substation running off Roundtop is also recent, installed in 2019.

The condition of other communications assets is excellent for the required level of performance.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of SCADA, communication, and control systems are still being developed. Construction standards are fully documented, and all new SCADA, communication, and control equipment are audited for compliance.

Maintenance

Inspections, Servicing and Testing

SCADA

The integrity of the main hardware and software system at the NOC is of the highest importance to the on-going management and safety of the electricity network. EA Networks’ Network Division staff, with assistance from the IT staff, manage the computer system and maintain the operational state of the software and hardware systems. Full 24hr monitoring of SCADA equipment is provided by automated systems. This is a 24-hour per day task, with staff on call to ensure high availability of equipment. The main SCADA computer hardware is non-proprietary with full redundancy and suitable spares are readily available, as are entire workstations should the need arise. The base station operates in a virtual arrangement spread across several hosts, with independent back up processors and a remote system capability housed in Greymouth.

The Network Division maintains most equipment external to the master station and sufficient spares are held to guarantee prompt response and repair times.

Communications

The intra-substation fibre optic cables that EA Networks own are *new* in infrastructure timeframes, and in excellent order. Automated monitoring equipment monitors all communication links and supporting hardware such as UPSs 24 hours a day.

Similarly, the inter-substation fibre optic cables that EA Networks own (in a separate business unit) are *new* and in excellent order. Automated monitoring equipment monitors all communication links and supporting hardware such as UPSs 24 hours a day.

Fault Repairs

In recent times, maintenance technicians have had to respond to relatively few SCADA or communications faults in any particular year.

Planned Repairs and Refurbishment

SCADA

As mentioned earlier, EA Networks continue to enhance and develop a new Aspentech Advanced Distribution Management System, which incorporates, amongst other systems, a new SCADA system.

Communications

The replacement and augmentation project for the fixed communications bearers is complete.

Replacement

SCADA

The process of installing the Aspentech system is largely complete, but configuration of the advanced features continues. The Aspentech SCADA is operating all zone substations and all connected pole-top devices. The old SCADA system will be completely decommissioned once the security access control to zone substations and the third-party access to the Ashburton Zone Substation outer compound has been migrated away from it.

Communications

It is only planned to replace electronic communications equipment during the planning period. This primarily involves periodically replacing the IP switches in zone substations which are at the end of, or nearing the end of, their design life.

Enhancement

SCADA

With the advent of industry-wide performance monitoring, EA Networks is benchmarked against other Electricity Distribution Businesses in terms of system reliability and continuity of supply. Furthermore, consumers are becoming more aware of fault outages, this being partly due to the increase in the number of electronic home appliances and the resulting reliance on a continual supply of electricity. For these reasons, it is becoming increasingly important to cut down on fault restoration times and inform consumers of timely information about causes and restoration times.

One way to do this is by automating remote switches. This greatly reduces the travelling time required for a fault responder during sectionalising of faulted line sections. It also means that fewer staff are required to isolate the fault, reducing the overall cost of fault restoration.

It is proposed that critical main line switches continue to be automated at the rate of five to ten per annum.

This process will be in conjunction with the use of gas switches and rural ring main units which are purchased ready for remote control. Good progress is being made with this programme.

Communications

The recent addition of a digital microwave link from Methven substation to Round Top hill-top repeater site has provided a DMR repeater that can be used up into the Rakaia Gorge. A digital microwave link has also been commissioned between Round Top and Mt Hutt zone substation to provide a high bandwidth digital link into Mt Hutt permitting SCADA, remote engineering access to the substation equipment, and VOIP telephony. The DMR system hardware architecture is now complete. Some DMR feature development will continue.

Development

See section 5.4.10 – Planning Our Network.

6.15 Ripple Injection Plant Assets

Description

EA Networks own two ripple injection plants, with one each at Ashburton 66/11kV Substation (ASH), and Transpower Ashburton Substation (ASB). All plants are solid state and manufactured by Landis & Gyr Ltd (formerly Zellweger Ltd) and use the Decabit code system. The plant at the Ashburton 66/11kV substation is an 11kV injection plant. The 33kV plant at ASB is used to inject ripple onto the 66kV network via a 33/66kV autotransformer. The ASB plant and the ASH plant are centrally controlled from the Aspentech power management system and inject synchronously so they reinforce the signal strength across the network.

Condition

EA Networks sold all its ripple relays to the incumbent retailer (*Trustpower*) on 31 March 1999 along with exclusive use of channels in use at that time. The ripple injection plants were retained for the purpose of load control as well as providing a load switching service to retailers under contract. *Trustpower* have since sold the ripple relays to *The Lines Company*.

Most of the remaining ripple injection plant components appear to be in acceptable order, but at up to 26 years old they have the potential for age-related issues. There have been two injector failures (ASH plant and ASB plant). The ASH failure was resolved with the supplier and a modern replacement injector unit was installed at ASH. The ASB failure was solved by purchasing the *spare* injector held by Landis & Gyr. Both the ASH and ASB plants are now a hybrid of a newer high-capacity injection components (300kVA and 440kVA) and older much lower capacity high voltage coupling components (~60kVA). At ASB, the air cored reactors are cracking, indicating replacement is necessary. At the same time, recent tests have shown that the ASB ripple injection plant signal strength is declining, leading to concerns about the ability to maintain load control over the full network at peak periods. Certainly, there is not n-1 security related to maintaining load control following the loss of one of the ripple control plants, since the output of both plants is limited by the rating of their primary coupling cell.

Because of the solid-state construction of the injection plants, faults are less likely to be a frequent occurrence. If they do occur, the consequences can be very poor service levels to retailers and customers, unconstrained peaks on various parts of the network, high loadings on some network equipment, and the inability to control streetlights. Due to the rating constraints on the primary coupling cells, the Ashburton 220 (ASB)/ Elgin 33kV ripple injection coupling cell will be replaced during 2024/25 to improve signal strength and provide n-1 back up between the two ripple injection plants. The age of some of the solid-state components (> 25 years) is such that spare parts are becoming difficult or even impossible to source. The converter panels are circa 15-18 years old, with an expected end of life at 20 years. The failure of one panel can be covered by a service contract that provides a replacement panel within a few days, to cover the period until a new panel is procured.

Standards

Documentation of the standards presently used for testing, inspection and maintenance of Ripple control systems is still being developed. Construction standards are fully documented, and all new Ripple control systems are audited for compliance.

Maintenance

EA Networks' two in-service ripple injection plants are both the same make (Landis & Gyr), making lifecycle management easier to implement. Although not identical, the plants have some interchangeable components and operate in an identical manner. The Methven33 plant was decommissioned as it did not have the capacity to either inject enough signal or adequately block external signals. The injection plant supplier has stated that they terminate support for any specific generation of equipment 10 years after it has ceased production. Portions of the two remaining plants are now in that position.

Inspections, Servicing and Testing

Monthly checks are carried out as part of regular zone substation visits which include the visual inspections of the

- converters
- coupling transformers
- coupling cells

Advice received from the manufacturer indicates a higher risk of intermittent faults can be expected as the plant age nears 20 years. With this in mind, a service contract is in place with the manufacturer, which includes an annual test on performance plus a full inspection. Tests include injection levels, current balance, optimum tuning, and load sharing with other units.

Summary of Ripple Injection Plant Components				
Site	Infrastructure	Capacity	Install Date	Manufacture Date
Ashburton 66 (ASH)	SFU/Coupling cell	440/60kVA	2007/1985	2007/1985
Ashburton 220 (ASB)	SFU/Coupling cell	200/60kVA	2010/1992	2010/1988

Fault Repairs

The solid-state construction of the injection plants means that faults are very infrequent.

On rare occasions, the high-power output transistors may require replacement, or the logic board may require repair (although this is becoming more difficult on the older units).

Vermin may get into the high voltage coupling cells causing flashover, although this has not occurred on any of EA Networks' plants.

The redundancy built into the injection network is becoming less robust. Failure of the ASH plant could severely impact overall ripple signal propagation - causing loss of load and tariff control. The ASH plant can inject over most of the urban 11kV network during peak loading (keeping many ripple relays operating correctly), but the more distant rural network is likely to be uncontrolled. In the absence of the ASH plant, the ASB plant cannot currently inject sufficient signal to control ripple relays.

Planned Repairs and Refurbishment

Minor repairs are required on the coupling equipment and converters from time to time caused by fault events.

Replacement of the primary coupling cells for both ripple injection plants is planned. The plants are otherwise in acceptable condition. It is expected that the plants should give continued service for some years.

Replacement

As a consequence of component failure, two of the older (1985/88) inverter units were replaced in 2007 and 2010 respectively (both 22 years old). One of these was oversized to suit future use to signal the 66kV network alone. The other was the only available option at the time and is somewhat smaller. EA Networks continues to consider alternative signalling technology as a range of technical and commercial challenges appear. The ASB 66kV GXP Ripple Injection Generator Replacement project will replace the complete converter panel at that site, providing one completely new ripple plant alongside the legacy Ashburton Substation 11kV ripple plant.

Enhancement

The capacity of the existing ripple equipment is limited and provides no room for 66kV network expansion. As the network configuration changes, there will be a need to look at alternative signalling technology, ripple plant control technology, location, and size.

Development

With the conversion of all GXP load to 66kV, the ripple control system has been assessed to ensure it provides adequate security and signal level. The addition of a third 220/66kV transformer supplying EGN from ASB lowered the available signal level.

An option for a new type of load control technology has arisen and is the subject of a pilot trial. However, there are contractual issues related to not being able to interfere with the operation of the incumbent ripple control receiver relays that are likely to preclude an alternative being implemented.

The future need for the ripple control system contains some uncertainty, given the growth in IoT technology and the predicted demand for demand flexibility likely to give rise to flexibility traders utilising their own technologies. The proposed approach of replacing the primary coupling cell of one of the existing ripple control plants and one inverter unit is a prudent asset management approach, minimising expenditure but maintaining functionality. This will give time for the future needs and solutions to load control to become clearer before committing more expenditure.

See section 5.4.11 – Planning Our Network for details.

6.16 Vegetation Management

EA Networks' vegetation policy objective is to provide a secure and safe power supply to all EA Networks' consumers by minimising the impact of trees located near power lines. EA Networks is required to act without delay to remove any immediate safety hazard to persons or property from trees; in some cases, this may be achieved by cutting or trimming any tree to the extent necessary to remove immediate danger or to restore supply. The vegetation policy has been updated in January 2025 to incorporate the new regulations related to the cut-back zone and the clear to the sky provisions.

Power supply maybe isolated to the relevant area, without notice until satisfactory works have been completed. EA Networks will work with affected customers, as far as practicable, to arrange a suitable time. Unless otherwise mutually agreed, 10 working days' notice will be provided for any isolation.

A network-wide tree survey in has been carried out between 2022 and 2024 to produce a complete list of risk ranked tree defects in a geographical dashboard system. Vegetation defects will be prioritised to ensure the vegetation management budget is spent with greatest safety and reliability effect, and with consideration of the weather conditions that will produce high impact outages (e.g. high northeast winds causing tree fall into lines).

6.16.1 Trees Encroaching Cut back or Growth Limit Zones

a. Tree Owner Notification

Should EA Networks become aware of a Hazardous, or Potentially Hazardous tree that encroaches the Notice or Growth Limit Zone of any EA Networks owned power line, contact is to be made with the tree owner. The level of notification e.g. phone call, letter etc. will be determined by the level of risk the hazardous tree presents.

This approach is also applied to customer owned lines.

b. Responsibilities

The Regulations clearly state that it is the tree owner's responsibility to ensure trees are cut to a distance outside of the Cut Back Zone of EA Networks owned lines.

This is not always practicable and at times not able to be done in a timely manner. EA Networks will work with our customers to help facilitate this.

The first cut or trim of a hazardous tree will be undertaken at EA Networks' cost as per the regulations. Ongoing maintenance of hazardous trees is the responsibility of the tree owner.

c. Tree Removal

Tree owners can elect to have EA Networks cut a hazardous tree at ground level, free of charge, to minimize future maintenance.

6.16.2 Potentially Hazardous Trees

Should EA Networks become aware of a potentially hazardous tree, EA Networks will seek trimming or removal, by mutual agreement with the tree owner.

EA Networks will work with the tree owner for the benefit of the network and in some case subsidise costs associated with the removal of a potentially hazardous tree. It is generally the responsibility of the tree owner to clear any resulting debris.

The Regulations do not require tree owners to act regarding potentially hazardous trees, but should the tree owner not agree to tree trimming or removal, they will be made aware that they may be liable for costs associated with damage to lines and/or interruption to supply caused by a potentially hazardous tree.

6.17 Non-Network Solutions

EA Networks' approach to non-network solutions is provided in sections 5.1.9 (Network Development Options/Considerations/Methods), 5.4.12 (Distributed Generation & Storage) and 5.4.14 (Innovation Practices).

SUPPORTING OUR BUSINESS

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7 SUPPORTING OUR BUSINESS

The definition of these *assets* is: *assets related to the provision of electricity lines services but that are not a network asset*. Examples given are land, buildings, furniture, vehicles, tools, plant, machinery, IT systems, asset management systems, software etc. Every effort will be made to identify these assets. The non-network asset quantities are unlikely to be as definitive as the network assets as they are not generally included in the same datasets or maintained in the same way.

7.1 Non-Network Asset Description

<u>Land and Buildings</u>

EA Networks is based at a new (2012) purpose-built facility in the Ashburton Business Estate north of Ashburton. The site covers about 3.6 hectares and is fully self-contained with main office, Contracting office/workshops, and main store/pole yard. The site has diesel fuel facilities, on-site potable water storage, is generator backed-up, has multiple access roads to/from the site, and is designed for heavy traffic egress. The buildings have been designed as Importance Level 4 (*IL4*) facilities which provides assurance that during and after a significant seismic event they will remain fully functional and permit EA Networks to respond to any earthquake damage without having to remediate or shift from its base facilities first.

Other interests in land and buildings include a small number of decommissioned substation sites that have yet to be disposed of or repurposed.

<u>Furnishings</u>

The buildings have been furnished with new equipment (circa 2012-13) in most cases. Desks, storage cabinets, chairs, and tables are almost all in good condition. As needed, additional furniture is purchased.

<u>ICT Hardware Infrastructure</u>

Desktop PCs and monitors are all in serviceable condition. Desktop PCs are replaced on a regular basis (typically 5 years). Laptops are replaced in the 4-5 year range. Server hardware infrastructure is replaced every 5+ years. The LAN wiring and WiFi infrastructure is in fully serviceable condition. Smartphones are typically expected to last 3 years, but this can depend on the user and the role they have (outdoor workers tend to wear out hardware more quickly).

The back-office systems such as telephony and server infrastructure are adequate, although on-going development and replacement will ensure additional performance and functionality will be provided. Extensive use is made of server virtualisation which ensures high levels of flexibility and relative ease of recovery from server hardware failures.

Vehicles

There are a range of vehicles associated with the provision of the electricity line service function. The Contracting vehicles are assets of the Contracting division business function of EA Networks which are excluded from this plan.

The quantities are as follows:

Summary of Vehicles		
Vehicle Type	Quantity	Typical Lifespan (y)
Car/Wagon/SUV	12	5
Utility	7	5
Forklift (Stores)	2*	10-15
Pole Handler (Stores)	1	10-15
Small Truck (Stores)	1	10

***** There is one electric forklift and one diesel forklift.

The vehicle lifespans indicated here are only typical and a range of other factors will be considered when a vehicle surpasses these ages before replacement necessarily occurs.

Tools/Plant/Machinery

The inventory of tools, plant and machinery is reasonably extensive. Included in this area are items such as electrical test equipment, portable power quality recorders, thermographic equipment, etc. The replacement policies aim to match the depreciation of the assets.

Software and IT Systems

EA Networks have a range of software licences ranging from desktop operating systems and general document editing software through to advanced technical analysis software. Corporate systems include financials, stores, asset management, payroll, and other typical back-office systems.

The major corporate systems/applications are:

- Financial/Stores/Payroll - Technology One
- GIS - Hexagon/Intergraph G/Technology
- Asset Management System - Technology One
- Technical Analysis - DigSilent Powerfactory load flow and fault analysis
- Customer Management System - Customised Salesforce Platform (Cloud hosted)
- Data Warehouse - MS SQL Server with management layer
- Electricity Network Billing Engine - Digital Stock - Arc
- Distribution Management System - Aspentech Monarch (SCADA, OMS, DMS, & Others)

Desktop/user licences include:

- Office Applications - Microsoft Office
- GIS Viewer - Custom Software – Quickmap
- Asset Management System & ERP System Client Licences - Technology One

•	GIS Editing Clients	- Hexagon – G/Technology
•	Business Information Clients	- Tableau and others
•	Customer Management Licences	- Salesforce
•	Distribution Management System	- OSI Monarch (SCADA, OMS, DMS, & Others)

7.2 Non-Network Policies

There are a limited range of formal policies relating to non-network assets.

- Vehicle policy sets out that vehicles will be based on age, reliability, and maintenance costs
- Furniture is expected to last a minimum of 5 years with 10 years being a practical end of life for many chairs.
- Desktop PCs have an average replacement cycle of 5 years.
- The IT infrastructure (servers and switches) is generally upgraded as and when required rather than on any set timescale (although warranty periods and software support validity are considered).

7.3 Non-Network Programmes and Projects

There is a background level of expenditure on non-network assets such as vehicles, plant, and IT that is routine and largely constant. Periodically, larger sums will be required for specific development, replacement, or upgrade projects/programmes.

Our focus for the first three years of this AMP is to replace or strengthen core systems, including replacing the GIS platform and considering the replacement of our Enterprise Resource Planning (ERP) system. Once these foundations are in place, we will progress development to include further integration of electricity-specific systems, such as the Advanced Distribution Management System (ADMS).

FINANCIAL SUMMARY

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8 FINANCIAL SUMMARY

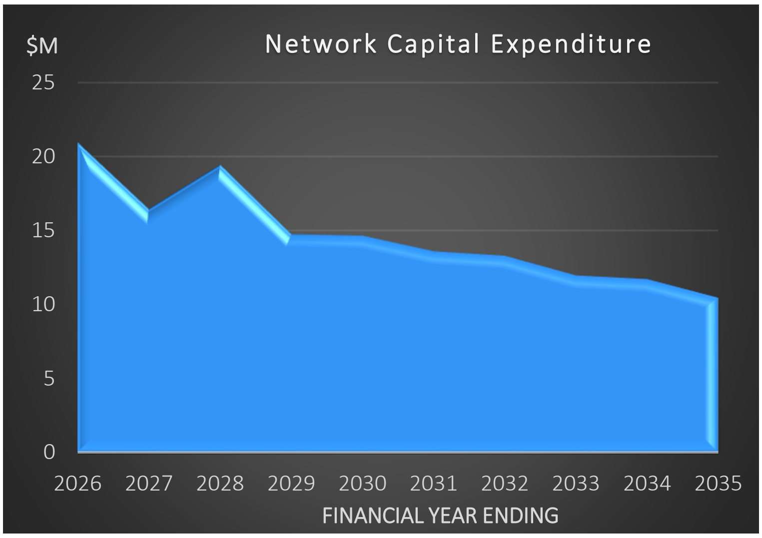
8.1 Capital Expenditure

Costing has been prepared for all projects and programmes identified in this plan. Detailed project costs are shown in Appendix B. Also see the Executive Summary for a capital expenditure by programme breakdown.

Overall Network Capital	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	220	635	1 527	2 018	0	0	0	0	0	0
Zone Substations	1 775	1 000	2 348	938	2 021	416	907	705	514	485
OH Distribution	4 146	4 509	4 652	3 460	2 714	2 832	2 697	2 792	2 861	2 907
UG Distribution	7 549	3 443	4 993	3 104	3 636	5 124	4 678	3 030	2 722	2 064
Dist'n Substations & Transformers	4 704	4 198	3 971	3 682	4 310	3 421	3 138	3 099	3 832	3 191
Distribution Switchgear	760	880	795	629	846	809	840	750	763	775
Other	621	291	270	100	321	183	229	224	217	220
Non-Network	1 189	1 502	901	818	802	806	803	1 363	804	806
TOTAL ($k)	**20 964**	**16 458**	**19 457**	**14 748**	**14 650**	**13 591**	**13 291**	**11 963**	**11 713**	**10 447**

It should be noted that the estimates for the first half of the planning period are based on known drivers and hence are more accurate than those for the second half which are more in the nature of trend analysis due to a large number of unpredictable factors.

The total 10-year capital expenditure is overall $3m, 2% higher than AMP 2024. Net of capital contributions, total 10-year capital expenditure is overall $6.7m, 5% higher. The general trend is for a decreasing expenditure after an initial fluctuating period related to customer driven projects and significant rural overhead to underground conversions. Continuing development causes a significant, but decreasing, amount of expenditure through most of the planning period (2026-35). It must be remembered that there is more uncertainty towards the end of the plan.



Prioritisation and review of capex projects targeted the AMP 2024 expenditure profile, while checking that network needs are met (including public and worker safety, reliability, capacity and meeting customer requirements). Significant movements are related to:

- Expenditure on underground projects closely match AMP 2024 for the first 5 years, then due to the limits of deferment and the need to progress network centres and core network cables, there is a $5.3m increase in capex to compensate for cost escalation.
- The urban underground projects are planned to be completed by 2034, and capex in 2035 (the last year of the new ten-year programme) is at $10.4m. This moderates the underground projects cost-escalation.

- Customer driven/capital contribution capex has been adjusted related to an updated solar farm connection cost (Mt Somers Solar Farm) and an industrial processor capacity increase re-phased and budgeted. The Network Centre and Network Core Cables project phasing has been deferred by 1 year due to switchgear uncertainty and needing to access sites.
- Two major rural overhead to underground (OHUG) projects are planned for FY26, the Lake Heron Feeder ($2.17m, 25km to be completed between October 2025 and March 2026) and the Methven Highway, Shearers Road to Springfield Road section ($1.13m, 7km to be completed between August 2025 and March 2026). The significant difference in cost per kilometre for these two projects is a combination of higher customer connection density and traffic management requirements on the Methven Highway project.

The development programmes that prompt expenditure are: underground conversion (urban and rural), 11-22 kV conversion, utility scale solar connections and industrial expansion, Ashburton 11 kV core network, Tinwald 66/11 kV transformer, and distribution automation as reclosers, gas switches and rural ring main units are progressively automated. By doing this, EA Networks is planning to reduce outage quantities, durations, and switching times, ultimately resulting in improved reliability statistics.

As would be expected, the bulk of the expenditure involves developing EA Networks' major assets – lines and substations. Non-network expenditure has become a significant cost as office-based IT infrastructure and systems to support the business increase in scale and complexity. By 2029, almost all subtransmission line and zone substation development work has been completed, and capital expenditure has dropped significantly. By 2034, the urban underground conversion programme is finishing, as does the 11-22 kV conversion (2031), and the 11 kV core network cabling finishes in 2032.

The *Other* category is the residual items in projects that are difficult to otherwise categorise. It represents a small proportion of the total.

Consumer Connections	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	0	0	296	0	0	0	0	0	0	0
Zone Substations	1 351	0	1 419	0	0	0	0	0	0	0
OH Distribution	528	535	525	538	538	542	543	550	551	560
UG Distribution	1 646	1 213	1 347	1 218	1 219	1 228	1 231	1 246	1 250	1 270
Dist'n Substations & Transformers	1 755	1 510	1 478	1 514	1 515	1 527	1 530	1 550	1 554	1 578
Distribution Switchgear	180	99	97	100	100	101	101	102	102	104
Other	255	0	99	0	0	0	0	0	0	0
Non-Network	9	0	0	0	0	0	0	0	0	0
TOTAL ($k)	**5 724**	**3 358**	**5 259**	**3 370**	**3 371**	**3 397**	**3 406**	**3 448**	**3 457**	**3 512**

Consumer connections are completely demand driven i.e. they occur when the consumer requires a new or enhanced connection rather than in any reliably predictable manner. Statistically, there have been a certain number of new connections and this, along with known development, has been used to project the future requirements. 2026 has a number of urban subdivisions and connection activity which cause a notable increase in forecast expenditure offset by capital contributions.

System Growth	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	97	0	1 109	1 249	0	0	0	0	0	0
Zone Substations	0	351	321	503	1 576	330	384	389	390	396
OH Distribution	177	303	227	196	181	219	17	17	17	18

UG Distribution	37	633	420	716	1 248	1 612	1 206	1 557	1 271	590
Dist'n Substations & Transformers	1 554	2 094	1 640	1 526	2 034	1 031	716	725	727	738
Distribution Switchgear	21	326	119	187	339	301	326	330	330	336
Other	283	195	62	4	224	183	213	216	217	220
Non-Network	0	97	31	2	106	92	107	108	108	110
TOTAL ($k)	**2 170**	**3 999**	**3 930**	**4 382**	**5 708**	**3 768**	**2 969**	**3 341**	**3 061**	**2 408**

System growth assumes the peak demand growth estimated in section 5.2 occurs. If the load growth does not occur or is significantly delayed, then some of this expenditure will drift later in the planning period or not occur at all. The baseline increase in underground distribution is caused by the 11 kV underground cable component of the core network programme to reinforce the urban Ashburton network from 2020 onwards finishing in 2032. Zone substation development causes a large peak in this expenditure which typically corresponds to a significant increase in distribution capacity available from that site (Tinwald in 2028).

Asset Replacement & Renewal	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	0	510	0	769	0	0	0	0	0	0
Zone Substations	223	124	112	85	85	86	86	87	88	89
OH Distribution	2 422	2 406	2 661	1 703	1 534	1 606	1 671	1 753	1 819	1 848
UG Distribution	5 338	1 056	2 687	1 070	1 043	2 207	2 103	117	123	125
Dist'n Substations & Transformers	1 243	508	768	556	674	776	805	736	772	784
Distribution Switchgear	393	247	424	183	249	326	332	235	247	251
Other	0	0	0	0	0	0	0	0	0	0
Non-Network	0	0	0	99	0	19	0	0	0	0
TOTAL ($k)	**9 619**	**4 852**	**6 651**	**4 465**	**3 586**	**5 020**	**4 996**	**2 929**	**3 049**	**3 097**

Asset replacements are at a significant level for the first six years. This can be explained by the amount of development that has occurred and is still planned. All condition-based underground conversion (urban and rural) is included here. The remainder is rural overhead distribution line rebuilding. Once the underground conversion programmes begin to wind back (2033 onwards) the level of replacement activity drops sharply to largely rural overhead distribution line rebuilding activities.

Asset Relocations - Nil

Asset relcoations are relatively rare events in the predminantly rural Mid-Canterbury district. When they do occur they are on-demand at relatively short notice so cannot be reliably predicted. EA Networks have not allowed for any asset relocations.

Reliability, Safety & Environment	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	123	124	122	0	0	0	0	0	0	0
Zone Substations	201	525	497	350	359	0	437	229	36	0

OH Distribution	1 020	1 265	1 240	1 024	461	464	466	471	473	480
UG Distribution	528	541	539	99	126	76	138	110	78	79
Dist'n Substations & Transformers	151	86	84	86	86	87	87	88	780	90
Distribution Switchgear	166	207	155	159	159	82	82	83	83	85
Other	83	96	109	96	97	0	15	8	0	0
Non-Network	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	**2 272**	**2 844**	**2 746**	**1 814**	**1 289**	**710**	**1 225**	**990**	**1 450**	**7**

The reliability, safety and environment category contains a number of the development programmes that EA Networks runs. These include the Ashburton 11 kV core network switching centres, one 11-22 kV conversion project (2026-27), the distribution automation programme, and a number of subtransmission and distribution projects that have generally been triggered by a need to improve reliability and/or safety.

8.2 Maintenance Expenditure

Network related maintenance expenditure is 16% higher than AMP 2024, with an uplift related to maintaining aging assets. Aspects of note are:

- The allocation of FY26 maintenance expenditure between activities has been set using analysis of historical expenditure combined with current labour rates. An additional $0.4m of overhead removals is incorporated in FY26 associated with the major OHUG projects (lake Heron Feeder, Methven Highway, Shearers Road to Springfield Road) mentioned above.
- Over the 10-year period, to reflect aging assets requiring more attention Routine and Corrective Inspection and Testing and Asset Renewal expenditure has been escalated over the 10-year period at 1.5% per annum once works specific asset renewals (e.g. line removals) were excluded. Vegetation management and Interruptions and Emergencies are held at the FY26 expenditure in real terms over the 10-year period.

In future plans, the maintenance programmes will be assessed individually and trended and the impact of both more modern and increased quantities of equipment will be factored into the cash-flows. Currently the maintenance planning costing is relatively short-term and this has been extrapolated forward as the best information currently available.

As information systems and condition data improve it will be used to refine the future maintenance expenditure forecasts.

Overall Maintenance	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	179	179	181	183	185	187	189	190	191	193
Zone Substations	890	813	844	881	916	961	983	1006	1030	1053
OH Distribution	3 349	2 884	2 920	2 903	2 872	2 836	2 861	2 672	3 020	3 048
UG Distribution	193	182	170	175	184	191	194	412	201	205
Dist'n Substations & Transformers	592	717	723	754	799	838	857	877	897	917
Distribution Switchgear	518	579	595	618	637	664	677	691	596	607
Other	69	69	85	76	92	86	90	76	83	84
Non-Network	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	5 791	5 423	5 519	5 590	5 686	5 763	5 852	5 923	6 017	6 107

The EA Networks network is relatively young overall. The significant levels of recent development have replaced much of the subtransmission network and coincidentally the distribution network on the same route. The 11-22 kV conversion programme has *refreshed* much of the distribution network although it has not necessarily extended the life of individual overhead structures. All the 22 kV transformers are in very good condition. Underground conversion continues to remove the oldest urban overhead lines from the asset pool and consequently there is no *maintenance mountain* within the planning period.

Service Interruptions & Emergencies	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	48	48	48	48	48	48	48	48	48	48
Zone Substations	22	22	22	22	22	22	22	22	22	22
OH Distribution	816	816	816	816	816	816	816	816	816	816
UG Distribution	50	50	50	50	50	50	50	50	50	50
Dist'n Substations & Transformers	27	27	27	27	27	27	27	27	27	27
Distribution Switchgear	108	108	108	108	108	108	108	108	108	108
Other	0	0	0	0	0	0	0	0	0	0
Non-Network	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071

The levels of expenditure for faults are forward extrapolations of a typical year. Future plans will continue to refine the impact that intensive development and maintenance have on the fault rate/cost.

Vegetation Management	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	87	87	87	87	87	87	87	87	87	87
Zone Substations	0	0	0	0	0	0	0	0	0	0
OH Distribution	997	997	997	997	997	997	997	997	997	997
UG Distribution	0	0	0	0	0	0	0	0	0	0
Dist'n Substations & Transformers	0	0	0	0	0	0	0	0	0	0
Distribution Switchgear	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
Non-Network	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	1084	1084	1084	1084	1084	1084	1084	1084	1084	1084

Trees are the bane of network operators. The control and management of trees appears to be an on-going and unavoidable cost. It is possible these costs may be changed in the future if vegetation control policies and/or regulations are revised in an attempt to reduce tree-related faults.

The inspection, servicing, testing and fault-reactive expenditure has been kept to the same level through the plan to continue monitoring the condition of older components such as hardwood poles so that future maintenance may be targeted toward life extension of ageing assets. Newer assets are also monitored and tested to ensure they are maintained to an adequate level to preserve capability and guarantee a full expected lifetime of operation.

Routine-Corrective-Maintain-Inspect	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	45	45	46	48	50	53	54	55	57	58
Zone Substations	818	739	769	804	833	876	897	918	940	962
OH Distribution	322	318	331	346	359	377	386	395	513	525
UG Distribution	54	59	45	47	49	51	53	54	55	57
Dist'n Substations & Transformers	320	399	399	418	433	455	466	477	488	499
Distribution Switchgear	286	321	334	349	362	381	390	399	300	307
Other	34	36	51	41	53	46	49	34	39	39
Non-Network	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	1 879	1 917	1 976	2 053	2 139	2 238	2 293	2 332	2 392	2 447

Asset Replacement and Renewal	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Subtransmssion	0	0	0	0	0	0	0	0	0	0
Zone Substations	50	52	53	55	60	63	65	66	68	69
OH Distribution	1 214	753	776	744	506	646	661	463	693	710
UG Distribution	88	73	75	78	85	90	92	94	96	98
Dist'n Substations & Transformers	245	291	298	310	340	356	365	374	382	391
Distribution Switchgear	124	150	153	160	167	175	179	183	188	192
Other	35	33	34	35	39	40	41	42	43	44
Non-Network	0	0	0	0	0	0	0	0	0	0
TOTAL ($k)	1 757	1 352	1 389	1 382	1 197	1 370	1 403	1 223	1 471	1 505

There are relatively low levels of like-for-like component replacements in the EA Networks asset pool. The majority of asset replacement/renewal involves an intentional increase in capacity or functionality to offer additional system capacity, system security or reliability. The two areas of note where some like-for-like replacements occur are overhead distribution lines (e.g. 11 kV or 22 kV refurbishment) and distribution transformers and substations where physical deterioration can cause a component of an asset to be replaced.

Non-Asset Specific	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Business Support	9 081	8 402	8 178	8 178	7 909	7 909	7 909	7 909	7 909	7 909
Operations & Network Support	7 006	6 089	7 278	6 395	6 384	6 397	6 389	7 192	6 457	6 462
TOTAL ($k)	16 087	14 491	15 456	14 573	14 293	14 306	14 298	15 101	14 366	14 371

The 10-year non-network operating expenditure (Business Support and Operations & Network Support) is 13% higher than AMP 2024, related to investment in systems, people and organisational capability.

The non-asset specific expenditure covers the running costs of the business – both technical and back-office. Increased expenditure relates to:

- Investment in strategic initiatives and systems development (e.g. GIS implementation, ERP system replacement, ADMS development).
- Increased people costs related to filling FY25 vacancies, new roles created in the FY25 change proposal to insource roles, and newly budgeted roles related to strategic initiatives. This organisational capacity will assist in responding to connection demand and resourcing to operate, manage, and build the network in line with our strategy of enabling our region.

DELIVERING ON OUR PLAN

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9 DELIVERING ON OUR PLAN

9.1 Progress Against Plan

It has become evident to EA Networks that during times of rapid load growth, significant demands are placed on the company and its resources – both financial and human. This extra pressure means that work is prioritised and even though every best endeavour is made to complete work in the timescale originally proposed, occasionally it is not. This can be for any number of reasons but primarily it is that there were more important things that had to be done and any work that could be deferred was. In recent times, external factors such as resource consents and COVID-19 have caused some delays. If the task involves supplying new load or a safety requirement, it will inevitably be done. Where the task involves improvements to security or reliability it will be done with the next highest priority. Where the task is largely documentary and pre-emptive (e.g. contingency plans), it has been known to slip down the list of priorities. As growth declines, EA Networks will be able to progress the Asset Management Plan to become an increasingly accurate and mature document, with more robust linkages to other systems.

9.1.1 Physical

Physical progress is essentially measured against the items in the financial plan for any given financial year. This can give a slightly distorted view in that a delay of weeks or a few months causes some projects to slip from one financial year to another which, for equipment with life expectancies of 40 to 50 years, is negligible. If replacement works or new project planning is timed that critically (other than for specific new loads) that it cannot wait for a few months, then it has been left too late.

Targets

The basic target for physical progress is to ensure that network performance and customer needs are not sacrificed because of planned work not proceeding on the proposed timescale.

Outcome

Capital projects critical for supplying new load and dealing with immediate security concerns were generally attended to. Some less immediate and more strategic projects have been deferred, a few by only months.

The 2024 Asset Management Plan Update identified many projects that were planned for completion during the 2024 financial year. The following table identifies the completion status of each major project (>$100k) listed in the 2024 Asset Management Plan Update.

2024 Asset Management Plan Project Progress/Forecast as at March 2024

Planned F.Year	Project ID	Description	Status Mar 2024	Commentary
2024	-1007	Non-Network - Routine Info Tech	100%	Normal CapEx spend on IT.
2024		Non-Network – Routine Vehicles	0%	Vehicle replacement purchases in hiatus while vehicle policy is reworked.
2024		Non-Network – GIS Upgrade Investigation	10%	Internal investigation continuing but no external assistance formally engaged yet.
2024		Non-Network - Gawler Downs Comms Pole	56%	Completed during 2024-25 due to other project commitments.
2024		Non-Network - Software - ADMS Upgrade - Control Centre	0%	Upgrade path is not trivial, and a number of issues have prevented progress. Progress indicates that this will be completed in 2025-26.
2024	12050	11kV OH Rebuild - Rangitata Gorge Bluffs	0%	Difficult section that may be resolved with short section of underground cable. Requires negotiation with Timaru District Council. Re-prioritised based on acceptable condition until 2025.

Planned F.Year	Project ID	Description	Status Mar 2024	Commentary
2024	13037	11kV OH Rebuild - Klondyke Tce to Rangitata River Crossing	0%	Re-prioritised based on acceptable condition until 2027.
2024		11kV OH Rebuild - Seafield Rd (Bridge St East to end.)	0%	Re-prioritised based on acceptable condition until 2026
2024	13841	11kV OH Rebuild - Upper Downs Rd.	0%	Delayed until 2026
2024		22kV OH Rebuild - Crows Rd (Dowdings Rd - East to end)	100%	
2024		22kV OH Rebuild - Kyle Rd (McCrorys Rd to Longs Rd)	100%	
2024		2kV OH Rebuild - Lismore Mayfield Rd (Lismore School Rd to Hackthorne Rd)	100%	
2024		22kV OH Rebuild - Maronan Valetta Rd (Maronan Rd to Pooles Rd)	100%	
2024		22kV OH Rebuild - Maronan Valetta Rd (Maronan Rd to Pooles Rd)	100%	
2024		22kV OH Rebuild - Windermere Rd (Surveyors Rd West)	100%	
2024		66kV OH Rebuild - PDS-DOR	100%	
2020	00521	66kV OH New - LSN-LSNT	85%	Resource consent and Council road relocation proposal & consultation has delayed Lauriston end of line. Council road relocation now resolved, will complete in 2026.
2024	11636	SCADA - Distribution Automation Programme	40%	This is an ongoing annual programme, but ADMS has taken priority due to engineering resource constraints.
2021	12778	11kV OH Rebuild - Rangitata Gorge (Rangitata River - Waikari Hills)	100%	Access to a couple of poles difficult. 95% complete in 2022-23.
2021	-1034	22kV OH Rebuild - Winters Rd (Christys Rd - East)	100%	90% complete in 2022-23, required 1 ground mounted transformer to complete U/G section in 2023-24.
2021	12814	UG Conversion - McMurdo St (Hassel St - Wilkins St)	100%	Issues with sequencing of work and 11kV switchgear approval have delayed progress. 90% complete in 2023.
2022	12807	UG Conversion - Cambridge St (Nelson St - Wakanui Rd)	100%	A few house services remain to be converted, and old poles removed. 90% complete in 2023.
2022	13061	UG Conversion - Mackie Street (Elizabeth Ave - Dunford St)	100%	Minor finishing work required. 95% complete in 2023.
2022	13063	UG Conversion - Michael Street (West Side, West Town Belt - Railway Terrace West)	100%	Minor finishing work required. 95% complete in 2023.
2022	13064	UG Conversion - Moore St (William St - Chalmers Ave)	100%	Minor finishing work required. 95% complete in 2023.
2021	-1061	UG Conversion - Methven Hwy (Pole Rd - Methven)	95%	Construction plans issued 2024 after considerable debate due to NZTA funding issues. Completed in April 2024.
2024	-1062	UG Conversion - Methven Hwy (Rooneys - Shearers)	0%	Rescheduled for 2025 after reprioritisation based on pole condition elsewhere on Methven Highway.
2024		UG Conversion - Fergusson Street (Railway Terrace East - Burrowes Rd)	100%	

Planned F.Year	Project ID	Description	Status Mar 2024	Commentary
2024		UG Conversion - Forest Dr. to Pudding Hill Rd (Beyond Spaxton St - open point)	80%	Carried over into 2025 due to resource limitations with customer connection work.
2024		UG Conversion - Harland St (Catherine St - Graham St)	0%	Carried over into 2025 due to resource limitations with customer connection work.
2024		UG Conversion - Hobbs Rd Methven (Beyond South Belt)	100%	
2024		UG Conversion - Racecourse Rd (Charlesworth Dr - Allens Rd)	88%	Carried over into 2025.
2024		UG Conversion - Double Hill Run Rd Stage 1 & 2	50%	Stage 1 completed, Stage 2 under design then carried over into 2025. Delay caused by resource limitations with customer connection work.
2024		UG Conversion - Double Hill Run Rd Stage 3 & 4	0%	Carried over into 2025 due to resource limitations with customer connection work.
2024		UG Conversion - Tancred Street, Rakaia (South Town Belt - Dunford St)	80%	Carried over into 2025 due to resource limitations with customer connection work.
2024		UG Conversion - Upper Hakatere Huts No's 2 to 28	0%	Carry over into 2024 to line up with water network installation.
2024	-1097	ZSS ASB – Elgin Ripple Injection Coupling Cell Upgrade	10%	Delays in procurement due to slow response from one vendor delayed ordering the primary coupling cell until Nov-23. The long-lead time on manufacture resulted in delivery in Oct-24. Commissioning is expected in Mar-25.
2024		ZSS EGN - Replace McWade 66kV Disconnectors	100%	
2024	-1089	22 kV Surge Arrester - Replacement Programme	5%	Initial data gathering to locate faulty type held up first year of this four-year programme. On track in 2025.
2024	-1088	22kV Conversion - Ruapuna	65%	Project in progress and carried over into 2025.
2024		Subdivision - Ashbury Grove, Tinwald Stages 3, 4 & 5	100%	
2024		Subdivision - Camrose Methven Stage 12 & 13	100%	
2024		Subdivision - Camrose Methven Stage 8 & 9	100%	
2024		Subdivision - Carters Rd Stage 1	0%	Waiting on developer to proceed.
2024		Subdivision - Lake Hood Stage 15A	0%	Waiting on developer to proceed.
2024		Subdivision - Lake Hood Stage 15B	0%	Waiting on developer to proceed.
2024		Subdivision - McKain Trevors Rd	100%	
2024		Subdivision - Strowan Fields, Trevors Rd Stages 3 & 4	100%	
2024	12766	New Technology - ICP Load Monitoring & Control	70%	The trial of this technology has pivoted to load control of new load types and LV monitoring, with use cases defined. Implementation has been held back by other engineering priorities.
2024		Vegetation Management	104%	External contractor appointed with focus on scoping and cutting high risk vegetation.

Reasons for Variance

In general, new connections (and work further into the network) that is required to support new connections is given priority over other capital or maintenance except for work required to mitigate safety issues. The 100% completion of subdivision work is an example seen above.

Delays in projected work have many underlying reasons ranging from the need to level human resource demands, to legal proceedings or on occasion access difficulties. The window of opportunity for much of the work on the EA Networks' network is narrow, as irrigation demand removes the summer months from the rural work schedule. This leaves the less settled autumnal, winter, and early spring months as the rural work window. With the advent of dairy herds across the entire EA Networks region, it has further narrowed this window as milking also occurs outside the irrigation season. To further compound this, dairy shed supplies often limit planned outages to between 9am and as early as 3pm. When a significant winter storm occurs, it can take resources away from planned work and create a backlog of project work that must be either completed or deferred until next autumn at the earliest. Thankfully, during 2022-2023 the weather has caused few widespread issues.

The notable slowing in peak load growth has altered the priorities of the forecast work. A seven-year individual project schedule for underground conversion work and a three-year project schedule for 11-22kV conversion is incorporated in the plan. Both these programmes are forecast to conclude during the planning period.

Delays in critical projects can have a cascading effect as others are either directly dependent or will impact negatively on security if they proceed prior to the critical project. In these cases, every effort is made to address the delay as quickly as possible but there are occasions when this is outside the control of EA Networks.

Engineering Resources

During the last few years, EA Networks has employed multiple engineering staff to assist in the workload that a considerable number of projects have placed upon the existing resources. It takes time for new engineers to become familiar with the business and adapt to a workplace. To become productive, the new engineers are mentored by the existing team, and this does take time away from *production* tasks such as design and planning. Internal development pathways from field technicians to the engineering team are effective, filling the gaps that have caused many delays in the past. EA Networks currently have recruitment underway for several additional engineering roles to augment our capacity to deliver work and increase our asset management maturity.

Volume of Externally Driven Work

The volume of work that has been driven by external agencies and organisations can be significant. Subdivision development was at an all-time high in 2023 and 2024. All this work increases demands on engineering and construction teams. Our people do their best to meet these challenges, but there are times when they cannot meet all expectations and the 2023 – 20204 period has been one of those times.

Managing expectations of external organisations is an important aspect of dealing professionally with them. Realistic timeframes need to be given when it is known that the staff involved are already very busy. This has not always been handled well.

Detailed Design Revealing Supply Security Issue

When project budgets are prepared, a draft design is prepared based upon certain assumptions. Once detailed design is undertaken it can reveal issues that were not initially apparent, and these require alternative approached to mitigate. For example, during detailed design for a Rakaia underground conversion project, it became obvious that a supply security situation would have arisen in Rakaia if the draft design were used, and the solution was to advance two projects from future years to fill the security gap. The two projects advanced were within four years of starting and displaced some other projects that could tolerate an additional year's delay without dramatically increasing risk.

Contractor Availability

The availability of contractors and the progress they make compared to that anticipated can both have a significant impact on project progress. There are a limited number of contractors active in the Mid-Canterbury area. There are times when EA Networks is using most of them in some capacity. If other important clients call upon the contractor's services EA Networks' projects can slip.

Planned Outage Availability

The nature of the Default Price-Quality Path for 2020-2025 is such that planned and unplanned SAIDI and SAIFI have been separated. Should some extraordinary faults occur that threaten to cause a breach of the SAIDI and/or SAIFI cap, reducing planned outages will not be able to compensate.

For example, the 2022-23 year had a risk of unplanned SAIFI breach due to numerous outages in high wind events in July and August 2022. Unplanned SAIDI has a lower risk of breach, and all work is continued as planned.

The planned outage SAIDI and SAIFI allowances under the Default Price-Quality Path are significantly higher and more flexible than previously permitted. It is not anticipated that the imposed limits will prevent planned work in any future years. The unplanned limits are more stringent and are likely to be periodically challenged by weather conditions and other natural events.

Plans to Address Variance

To date, the variation in planned work completion dates has not had a material effect on network performance. Essential work is always completed and any work that is targeted for deferral is evaluated for its criticality. If it is seen that a particular project must proceed, external assistance is sought to ensure its completion in the required timeframe.

Load growth has slowed considerably, and this has freed up some resources. The internal contractor still has vacancies for staff and the likelihood of further pressure nationwide for skills will continue with some other lines companies having ambitious programmes to upgrade their networks.

The overhead network continues to age. The requirement of all new connections to the network at 22 kV or below to be by underground cable has placed additional workloads on cable laying resources. As a result of this, EA Networks has increased its field resources including an internal civil crew in this area.

In the last decade, EA Networks invested in additional resources, both human and non-human, to address some of the project management issues that had hindered completion of some jobs. With increasing regulatory, business systems complexity, and consumer expectations staffing levels are again under pressure.

To improve EA Networks' ability to deliver work on time, to the required quality and within budget, a strategic initiative is planned for April – September 2025 to introduce a formalised project management framework and tiered project management processes and reporting for major/complex projects, routine network projects and minor projects, to ensure greater levels of project management are applied to major, high value and complex projects, but routine and minor projects are not over-burdened with management and reporting. Delivery KPIs will be established, and regular monitoring meetings will be held between Network and Contracting to discuss progress on capital and maintenance work.

The separation of planned and unplanned outage reporting in regulatory disclosure and consequently in the cap and collar breach limits means an inadvertent risk of breach in unplanned outages cannot be compensated for by lowering planned outages. This removes any restriction on planned work towards the end of the disclosure year (other than approaching the planned work cap). Because the planned cap is over five years, the amount of planned outage time in any particular year is not fixed and this allows significant flexibility to do more planned work, when necessary, without breaching in that particular year.

9.1.2 Financial

For more than two decades the EA Networks Asset Management Plan has formed the core of future financial planning for the Board and management of EA Networks. Corporate 10-year cash-flows are based on the data contained in the schedules prepared for the annual Asset Management Plan.

The reader is also referred to https://www.eanetworks.co.nz/Disclosures/ for additional detailed information about the financial performance of the company and its assets. The Consolidated Information Disclosure providing the full-year performance for the year ended 31 Narch 2025 will be provided on the above website.

Budget

Each year the AMP is prepared in tandem with the annual budget and the major projects are extracted from the AMP to form the core of the budget. Smaller, previously unscheduled, works are identified in the budget and used to *flesh out* the AMP to include the details of work that comes to light at relatively short notice or is based upon newly gathered information.

This approach to budgeting/AMP preparation tends to cause an influx of small projects into the AMP project schedules that were previously unidentified. These numerous small projects, although not identified, are allowed for in the AMP forecast as *unscheduled* items that are grouped together in an estimate of the total likely cost of such activities (based upon historical statistics).

As budgeting techniques and tools are refined, and more staff resources can be made available for data analysis showing trends and previously hidden statistics, it is possible that some of the unscheduled work will be placed in to scheduled projects and programmes to target specific aspects of network performance.

The following analysis focuses on network expenditure rather than non-network expenditure. The AMP's focus is on managing the assets in the network, so this approach is considered valid. A summary of non-network expenditure is provided but no detailed explanation is provided.

The following financial performance evaluation is of the 2023-24 year using the 2024 August Information Disclosure actuals versus the forecast provided in AMP 2023 Schedules 11a (Capital Expenditure) and 11b (Operating Expenditure).

No forecast is provided for 2024-25 as the final finanical outcome is not available – this will be provided in the 2025 August Information Disclosure.

	Category	2024 Capital Expenses		2024 Operational Expenses		Delta
		Forecast	Actual	Forecast	Actual	
2023-33 AMP Forecast – 2024	Customer Connection	5 268	5 028	-	-	-240
	System Growth	1 751	380	-	-	-1 371
	Reliability, Safety and Environment	1 395	829	-	-	-566
	Asset Replacement & Renewal	7 830	9 793	-	-	1 963
	Asset Relocations	-	9	-	-	9
	Non-Network Assets	917	543	-	-	-374
	Routine & Preventative	-	-	1 051	1 336	285
	Refurbishment & Renewal	-	-	1 328	1 155	-173
	Fault & Emergency	-	-	1 488	742	-746
	Vegetation Management	-	-	831	1 081	250
	TOTAL ($ 000)	**17 161**	**16 582**	**4 698**	**4 314**	**-963**
	Non-Network System Operations & Network Support	-	-	7 826	4 161	-3 665
	Non-Network Business Support	-	-	8 202	6 979	-1 223

The 2023-33 Asset Management Plan contained the financial plan above for the 2024 financial year (actual results are shown alongside):

Outcome

The table above shows the disclosed 2023-24 actual performance compared to the forecast amount in the 2022-23 plan.

The actual values have been extracted from 2023-24 disclosure data.

As can be seen from the chart, the operational (maintenance) expenditure was 92% of that forecast (-$384k). The capital expenditure was 97% of the forecast (-$579k).

Overall, both Capital and Operational expenditure were close to the values predicted.

Reasons for Variance

Explanation of variance more than 10% and others for interest:

Capital Expenditure. Customer Connection (-$240k ~ -5%)

Subdivision activity moderated in 2023-24 but significant connection projects for the Lauriston Solar Farm and the ANZCO capacity upgrade boosted customer connection expenditure in line with budget. The actual investment in consumer connection has historically and continues to be affected by numerous external macro events. While EA Networks incorporate all known factors into its connection AMP forecast, a large amount of data remains hidden from EA. The recent past surge in development of urban subdivisions was unexpected and many developers keep their cards close to their chest. There will always be some variance from forecast to actual as the ebb and flow of the economy governs consumer decisions.

Customer connection activity is currently reducing back to lower levels and is expected to remain nearer average over the next few years.

Capital Expenditure. System Growth (-$1 371k ~ -78%)

Factors that impacted on end of year progress were; delays in 22kV conversion, the PowerPilot programme, and the 66kV tee connection to the Lauriston zone substation due to additional workload from solar farm connections

Capital Expenditure. Reliability, Safety and Environment (-$566k ~ -41%)

The category was well below budget as some work was not completed.

- SCADA related engineering resource was diverted to solar fam connection work.
- Surge arrestor replacement programme say delayed in commencing and underspent for the year due to the need to gather data on surge arrestor locations of the failure-prone type.
- 11 kV Core Network Centres (Urban): protection and SCADA commissioning has been delayed due to engineering priorities on solar farm connections and an industrial site capacity upgrade.
- 22kV Conversion - Methven Hwy Springfield Rd to Methven, Alford Forest to Newtons Cnr: The Springfield Rd to Methven section was completed but the Alford Forest to Newtons Corner section has been deferred to 2025-26.

Capital Expenditure. Asset Renewal and Replacement (+$1 963k ~ +25%)

A number of both overhead and underground projects contributed to the overspend in this category. A lot of the projects were completed, but some of the completed works went over forecast, for various reasons. Some were unanticipated complexities in work execution. There was also unplanned renewal of the network revealed by additional inspection work. Some projects carried over from the previous year by a few months.

Capital Expenditure. Non-network Assets (-$38k ~ -41%)

Expenditure was below forecast with key projects not proceeding and investment in the vehicle fleet being deferred.

Operating Expenditure. (-$384k ~ -8%)

The direct asset operational expenditure was close to forecasts and a lack of inclement weather assisted greatly in achieving this via an underspend on faults. The *Business Support* was underspent on forecasts as was the *Operations & Network Support,* related to vacant positions and system related projects requiring a longer procurement phase before commencing.

Please refer to EA Networks annual regulatory disclosure for further details.

Plans to Address Variance

While distributed load continues to grow in somewhat unpredictable locations and scale, the rescheduling of capital projects and expenditure during the forecast year cannot be precluded. Any capital expenditure is spent completing projects for legitimate reasons. Aside from resource constraints driven by higher priority customer driven work, there are plans to improve project delivery in timeliness and cost within 2025-26 via process development training and reporting.,

The appointment of additional staff for substations and overhead and underground works has helped provide better coordination of works as well as focusing personnel on the critical path for all projects.

Efforts are being made to provide a progressive planning mechanism that will review the planned projects every three months and develop a moving 18-36 month active projects database. The projects at the 18-month horizon are candidates for inclusion in the coming year's works programme. The 36-month horizon projects are more conceptual and will only become realistic proposals once thorough investigation has taken place. The projects in the database will be refined as time goes by to ensure their viability and scope. By the time they come to be designed in detail there should be a large amount of knowledge built up about how the project will be designed, built, commissioned, and operated. All the project knowledge will be held in the database, so any interested personnel can contribute ideas and critique the technical, timing and cost aspects of the proposal.

9.2 Service Level

9.2.1 Actual Levels of Service

Network Performance

EA Networks have historically set high expectations for its network performance. This is driven by the rising dairy industry profile – where even momentary interruptions caused by a circuit breaker reclosing causes significant disruption to a dairy shed's operation. There is also a rising expectation from all customers that the power will *always be on*.

While setting high expectations is a worthy exercise, it can be a difficult target to reach. The current method used to set the individual SAIDI and SAIFI performance targets is to use the regulatory caps. The regulatory caps are set at two standard deviations above a long-term average of these measures and thus reflect the type of performance expected on the network. Other measures use an average of the last six years unplanned performance. Separately, the planned performance is forecast looking at historical baseline work and also the level of planned work proposed in coming years. This technique attempts to provide targets that are achievable at least some of the time. Previous methods of calculating targets gave unrealistically low values that were very rarely achieved.

The targets are now located in amongst the peer companies that have similar styles of networks. For example, the average SAIDI forecast for peer companies for 2025-29 is 149 minutes unplanned and 138 minutes planned (total 287 minutes) while their 2018-2024 average performance is about 410 minutes unplanned (non-normalised) and 539 minutes planned (total 270 normalised minutes). The current target for EA Networks SAIDI is 335 minutes. Previous EA Networks targets have been as low as 149 minutes – 25% below the peer average. EA Networks' SAIFI performance is better than average in comparison with both peer companies and slightly better than average for lines companies generally. The 17 peer group lines companies have a SAIFI forecast of 1.94 unplanned and 0.63 planned and an average 7-year SAIFI performance of about 2.12 unplanned and 0.49 planned.

SAIDI	Total	Unplanned	Planned
2025-26 **Targets**	335.1	87.4	247.7
Actual / EOY 2024-25 **Forecast**	201	57.9	143.1

The internationally recognised CAIDI, SAIDI and SAIFI indices are useful barometers of how a network has performed over a given interval. These indices can be plotted over time to establish any trends. The tables above and below represent EA Networks' performance during 2024-25 (to 1 February – 31 Mar 2025 estimated).

The SAIDI target looks likely to be met. The planned SAIDI is well below target (-42%). Unplanned SAIDI is well below target (-33%).

SAIFI	Total	Unplanned	Planned
2025-26 **Targets**	2.12	1.24	0.88
Actual / EOY 2024-25 **Forecast**	1.29	0.78	0.51

The overall SAIFI performance looks to be meeting target by about -39%. Unplanned interruptions look likely to be -37% of the target.

It should be noted that, in the interests of safety, EA Networks has strict criteria for relivening rural circuits after a fault event. It is possible that irrigators can become entangled in HV lines. There are significant line lengths in and around farmyards. Car vs pole events are not uncommon. For these reasons, in almost all cases EA Networks' standard requires a full line patrol (including on-property lines) after the occurrence of an earth fault. This significantly increases fault restoration times, however, public safety, in EA Networks' opinion, requires this.

Interruptions	Total	Unplanned	Planned
2025-26 **Targets**	500	230	270
Actual / EOY 2024-25 **Forecast**	555	224	331

The total interruptions index is only useful to compare to previous network performance as intercompany performance is skewed by the length of network each company operate. From 2018 to 2024, the total interruptions have averaged 534 per annum (273 unplanned and 261 planned). 2024-25 performance is close to target for unplanned but well over target for planned. The number of planned outages is increasing as preventative works increase and regulatory changes make planned work that is cancelled unplanned.

The faults per 100 km (by voltage) parameter is the most useful index to the asset manager.

The performance of the network at subtransmission voltages is encouraging despite exceeding the target values. The voltages which require improvement are the 11 kV and 22 kV networks. For 2023-24 the overall rate of faults per 100 km seems to be about 109% of the target value although still appreciably better than the industry and peer average.

The table shows the voltage at which the network faults are occurring and the chart in section 3.5.1 illustrates the trend of these faults.

Faults/100 km	Total	11 kV-22 kV	33 kV-66 kV
2025-28 Targets	10	11.5	3
2023-24 Performance	10.94	12.34	2.81
2018-24 Average Performance	11.12	12.47	3.39
2018-24 All Industry Average	16.93	18.47	4.76
2018-24 Peer Average	16.81	18.20	5.14

- These values are calculated using combined *Circuit Lengths* and combined *Number of Faults* from disclosure data 10(v) for 2018-24.
- Overall average is 16.93 faults per 100 km (17 348 faults and 102 437 km of circuit length) (calculated using combined averages for 2018-24).

EA Networks has revised its vegetation management and line inspection procedures to better predict and prevent future network failures.

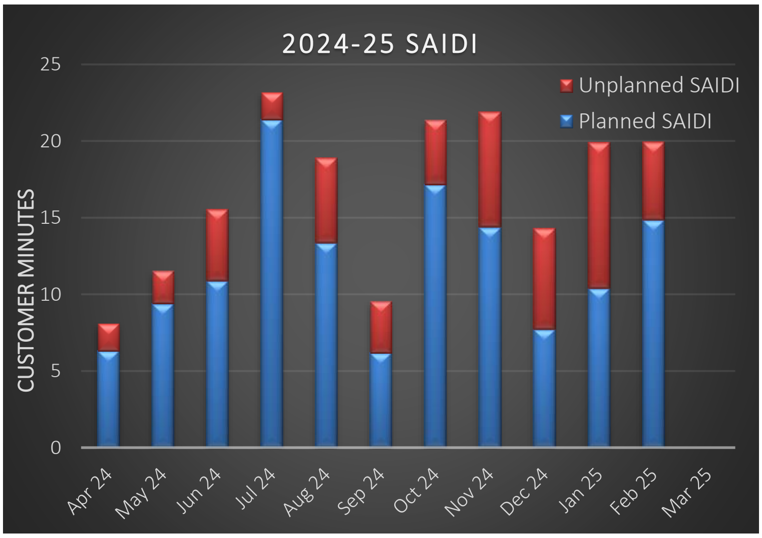
Discussion

A considerable quantity of 22 kV conversion is undertaken each year. Every effort is made to minimise interruptions by employing additional contractors to complete as much work as possible in every planned interruption. As mentioned previously, the influx of dairy farming severely impacts on the available number of shutdowns and the duration of each shutdown has an effect. The option of live-line techniques for 22 kV conversion projects is prohibitively expensive and slow.

The contribution of planned work to lost customer minutes is significant and this can only be reduced by doing less construction work or more live-line work. The suspension of live-line work in mid-2016 caused the planned SAIDI and SAIFI to rise considerably. There is now a new live-line work protocol in place to assess each job to ensure it is appropriate to use live-line as a benefit/risk trade-off. Planned outages have reduced from the highs of 2017-18 but will not return to pre-2016 levels as the tasks approved for live line work are now more restrictive. The chart below illustrates the spread of planned work and unplanned faults over the 2024-25 year.

Over recent years, EA Networks has invested heavily in remote controllable devices in the field. This involves installation of modern reclosers, gas switches and, in situations where 3 or 4 lines meet, ground mounted ring main units. At the same time, almost all zone substations have been linked with fibre optic cable. The advent of the fibre optic cable is allowing differential line protection to be fitted to virtually all sub-transmission circuits. Along the fibre route, RMUs, reclosers, and gas switches are being connected to the communications infrastructure. This will facilitate quicker fault location identification and restoration on sections not directly affected by the fault. Outside the fibre route, remote-controlled devices will be connected via a radio network. Mid-Canterbury's flat terrain makes reliable radio communication difficult (hence the deployment of a fibre network for protection purposes) however EA Networks have a device available that creates a low bandwidth data network using EA Networks radio voice network core infrastructure (DMR).

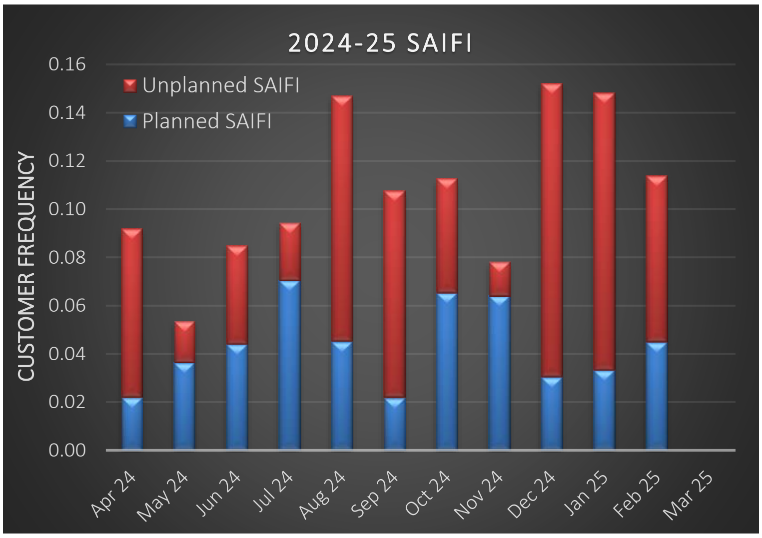
Installation of remote controllable devices has generally occurred when other works are happening. As a result, it takes some time to get sufficient concentration of these devices in any one area to make a noticeable difference to overall performance. There is now a concerted effort to roll out remote control to as many devices as is practical to achieve noticeable improvements in SAIDI.



Several years ago, EA Networks introduced a policy requiring all new connections to the network at 22 kV or below had to be via underground cable. The policy was to reduce the large number of faults that occurred on private property but resulted in a network outage. Since implementing this policy, EA Networks have had very few incidents on property involving underground cable, much less than would have been expected from an overhead service. In addition, safety has been improved through less chance of strikes by irrigators, grain augers, etc.

22 kV conversion work (and to a much lesser extent 66 kV conversion work) will continue to influence the indices for several more years. If unexpected increases in load occur, networks at both voltages may need to be extended and the best cost/reliability trade-off occurs by having relatively few, reasonably long, but very productive planned interruptions.

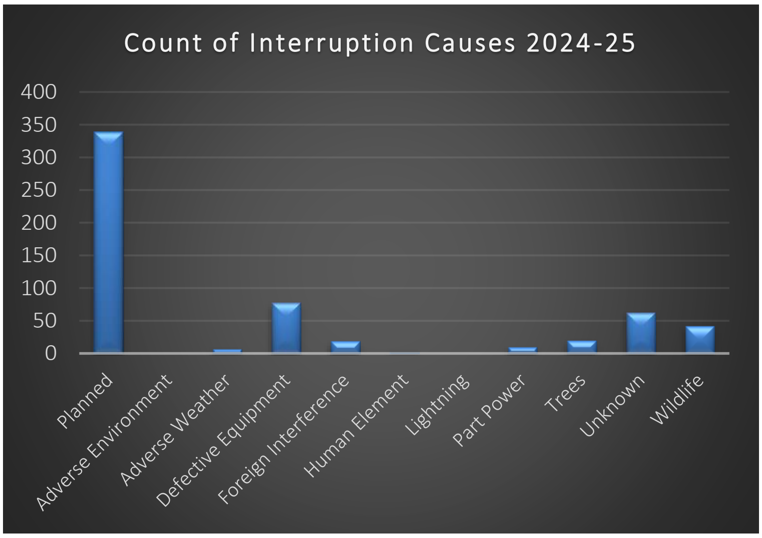
EA Networks initial 22 kV conversions were driven directly by the inability of the existing 11 kV network to maintain acceptable voltages under increasing loads. On a voltage-constrained network, doubling the voltage allows four times the load to be delivered within regulatory voltage tolerances. This is achieved for a modest increase in cost and with little change to operating and construction procedures. As the 22 kV network has expanded, it has introduced several areas where network security has been compromised owing to the need to supply additional load. This 22 kV expansion creates open points between 11 kV and 22 kV lines that were previously interconnected, which enabled back-feeding during both planned and unplanned outages. EA Networks are now in a catch-up situation where there is a drive to convert additional sections of network to restore the previous security levels. This expenditure is a legacy of responding to rapidly increasing loadings and



will prevent future deterioration in reliability performance rather than necessarily improving future performance.

The rates of faults per 100 km of distribution lines is now at a level that is competitive in the industry. While most measures are above the target values, the targets do not appear unobtainable and were revised for 2022 and beyond. The subtransmission fault rate is better than the target in 2025-28, most faults are caused by trees outside the control of the tree regulations. Car versus pole incidents also continue to occur.

A variation in 11 kV vs 22 kV performance has been observed (not shown in tables or diagrams) and can be partly explained by the location of 22 kV and 11 kV across the district. Looking at the diagram showing the location of the 11 kV and 22 kV distribution lines in Section 5.4.4, it is apparent that events can affect one voltage more than the other as a consequence of their geographic location. When strong wind, lightning or other environmental events occur the network impact is not always uniform. For example, strong winds are channelled or dispersed by geographic features and if the voltage of the network in near proximity is 22 kV, then the faults are attributed to the 22 kV network even though an 11 kV network would also have failed had it been similarly exposed.



The contributions of the various categories of fault cause have shown that although planned faults are the highest individual category in terms of total quantity and duration, it is the next two highest categories of unplanned fault that are worthy of examination. Wildlife and defective equipment suggest that there are components in the network that are deficient. Of note are the high levels of 22 kV surge arrester failures which have not yet been definitively explained but are expected to be caused by moisture ingress into the surge arrestor. A change of supplier and specification has occurred, and a four-year programme to replace the fault-prone type is underway. Accurate categorisation of faults is important. The need to separate cause and effect is critical. For example, a transformer that fails during a lightning storm is not *defective equipment* – that is the result of it being struck by lightning.

During June 2015, Mid-Canterbury was subjected to a reasonable snowstorm. Generally, the network held up well; better than it has in the past, and power was restored more quickly than would previously have been expected. There were however many faults that originated on property that affected the network. Typically, these are earth faults where the network protection is faster or more sensitive than the fuse supplying the customer. Investigation revealed a large quantity of old, poor condition conductor on property, much of it #8 galvanised steel (fencing wire). A programme to encourage line owners with poor condition lines, especially #8 galvanised steel has begun with a view to getting these lines bought up to standard.

Unplanned CAIDI (restoration time) is an interesting parameter that indicates the average time it takes from the fault occurring to the power being restored. In recent time this value has been in the range 65-75 minutes. This compares favourably with not only EA Networks peers (75-115 minutes) but also the whole industry (75-100 minutes). EA Networks' practice exceeds the requirements of the EEA publication *NETWORK FAULT MANAGEMENT – Guide to Manual Closing and Hazard Management (2022)*. EA Networks have examined this document closely and decided, in balance, the new guide provides the minimum acceptable approach to post-lockout circuit breaker closing. By meeting this document's requirements, there will be penalty in SAIDI and CAIDI. EA Networks are not able to comment on other companies' practices, but anecdotal observations would suggest that not all companies are quite as rigorous in their application of what EA Networks considers to be industry best practice (patrolling of lines following a recloser lockout). The other factor influencing SAIDI heavily was live-line working (or lack thereof). This has now resumed, and it is anticipated planned SAIDI will stabilise but will not return to pre-2016 levels.

Faults per 100 km is better than average for all lines. Faults per 100 km was trending lower for 11-22 kV lines. It is still below the median for all companies. The targets have been set at ambitious levels, which are only occasionally met, but reducing faults intrinsically improves most other reliability measures.

Service Levels

This is the area of performance measurement that directly affects the quality of service that consumers experience. Section 3 of this plan, *Our Customers,* addresses most aspects of performance and performance improvement as it relates to service levels.

Targets

The service level targets have been detailed in section 3.5.

Outcome

See section 3.5.1.

Reasons for Variance

There are a range of reasons whereby performance may not be as per target. The significant ones are:

- Adherence to *Patrol after auto-reclose lockout* philosophy. This can delay restoration considerably but ensures a much lower risk of livening onto vehicle or other situation where it could place the public at risk.
- The level of planned outages.
- A low number of lightning, weather, and perennial *unknown* faults have contributed to the observed network performance.

There are the other perennial reasons such as defective equipment, trees, and wildlife that always cause issues, but they tend to be lower frequency and sporadic. For the current year they are significant.

Plans to Address Variance

Addressing service level performance issues is an on-going process. There is no magic answer to solve all the issues at once. EA Networks are concentrating on solving the obvious issues as they become apparent.

The resumption of live-line working has measurably reduced the planned SAIDI and SAIFI. This was possible as the distribution industry have converged on an agreed protocol for justifying the use of live-line techniques for approved jobs.

The replacement of faulty equipment prior to failure is a simple action to increase performance if the imminently faulty equipment can be reliably detected. More effort with diagnostic equipment such as infrared and acoustic cameras is being made, and this will continue for the foreseeable future. The high failure rate of a particular type of 22 kV surge arrester is imposing a not inconsiderable SAIFI impact on customers. The failures are suspected to be due to moisture ingress, so a proactive replacement programme is underway for the coming three years to phase out this fault-prone type.

More research is being done on the causes of faults. Distribution areas each have their own character whether it be trees, wildlife, mechanical interference, vehicle crashes etc.

The policy to encourage on-property underground distribution will, over time, lower the frequency and impact of on-property faults which are commonly cleared by a network circuit-breaker. The operation of a circuit-breaker affects large feeder segments or entire feeders instead of just the consumer causing the fault. A fault in an underground cable is rare and when it does happen will commonly be caused by mechanical interference which is generally reported by the person excavating allowing faster isolation and restoration of supply.

All customers with poor condition lines, especially #8 galvanised steel, are being contacted with a view to getting these lines bought up to standard.

There are no plans to change the line patrol after auto-reclose lockout policy which meets the EEA guide on manual reclosing after lockout.

The level of planned work is a fact of life. While new load appears, it will require servicing. Live line techniques are not suitable for the scale of work required for large line rebuilds.

Advances in SCADA operation and distribution automation will reduce the time taken to restore consumers after a fault. This will greatly assist in reducing SAIDI and CAIDI. EA Networks have completed the implementation of the core functions of an Advanced Distribution Management System. Further development/configuration of advanced ADMS features will continue.

It is apparent that relatively few faults can have a dramatic effect on EA Networks performance. For a smaller company (<20 000 ICPs) the relatively rare event of a typical urban feeder tripping once can have a dramatic effect on system SAIDI as the affected ICP count is a significant proportion of the total. Compare this with a large urban company (100 000+ ICPs) where a single urban feeder tripping is unlikely to impact on system SAIDI by a detectable amount. The only way to address this is by reducing the proportion of ICPs per protective zone so that a single fault affects fewer than say 2-3% of the total ICP count (in EA Networks case this would be 400-500 ICPs). For a large utility this could be 2 000 to 3 000 ICPs. EA Networks are planning to proceed down this path with more urban circuit breakers and reduce feeders to fewer than 250 ICPs on each. In rural situations, the customer count is rarely high enough to affect SAIFI on a single fault, but SAIDI can be adversely affected when faults take a long time to diagnose and repair. The installation of many rural RMUs with SCADA, fault detection, and interrupting capability will begin to address some of these issues as well.

9.2.2 Overall Reliability

The overall reliability for the 2024-25 year has shown a consistent fault-related performance. At time of writing, the forecast normalised SAIDI and SAIFI are comfortably below the default price path normalised caps and EA Networks' own targets. The weather has been reasonably benign over the last 11 months and has helped reliability immensely. Only one event has been normalised for unplanned SAIFI and none for unplanned SAIDI. The planned outage SAIDI and SAIFI forecast are above the average levels, and this is mostly attributed to increasingly stringent requirements when working near live equipment (more outages) and a general increase in preventative maintenance (such as surge arrester replacement). Planned SAIDI And SAIFI are capped over five years, not annually. The forecast suggests end-of-year total SAIDI being 201 (367 target) and total SAIFI 1.29 (2.26 target).

To illustrate the principle of the of the last paragraph of the previous section, in January 2021, a fallen tree (outside the control of the Tree Regulations) caused a brief (10 min) outage to approximately 25% of the customers EA Networks supply (Northtown Substation) causing the unplanned non-normalised SAIFI to increase by 0.25. This is a significant proportion of the forecast total for the year (0.94). Further work is being done to ensure similar incidents do not occur in future, but it does show the potential volatility of SAIFI in particular.

The EA Networks tree control policy will be administered with rigour. The tree control policy is based upon the Electricity (Hazards from Trees) Regulations 2003 but has additional opportunities for the tree owner to allow EA Networks tree control standards to apply. If the tree owner chooses to allow EA Networks to apply their own tree proximity and trim standards (more rigorous than those in the *Tree Regulations*) then there is the possibility of significantly reduced cost of tree control to the tree owner. Together, it is hoped that these measures will reduce the impact of any future weather events and thereby prevent any future breach of the price-quality path thresholds. The notable number of tree faults that occurred can be attributed to trees outside the regulations (fall-zone trees). Refer to section 6.16 Vegetation Management for details.

EA Networks' HV distribution network (particularly 22 kV) has not performed to the faults/100km target. The performance of this voltage (22 kV) does occasionally approach the target. The target has been very ambitious when compared to the industry average. It is probable that the EA Networks target was unachievable in all but the most environmentally benign of years. The underlying planned interruption rate was reducing as development work tailed off. 22 kV conversion work continues to have some planned outage impact and potentially several of the coming years will feel the impact of 66 kV or 22 kV line construction/rebuild projects.

When planned outage frequency begins to drop, the system interruption duration will drop with it. As the 66 kV subtransmission network is largely developed, many of the high impact faults seen historically have been reduced as circuit redundancy eliminates outages. As always, tree control is an ongoing problem that specific regulations and EA Networks own tree control policy now covers. It appears that assertive tree control will continue to reduce fault frequency to some degree. Of more concern than fault frequency are duration measures such as restoration time. Full line patrolling after an auto-reclose lockout is something that EA Networks always undertakes. It is unknown whether this is the norm for all other similar companies. This has a significant impact on restoration time if no cause is found and the line is successfully restored, but it is industry best practice to do this.

A marked boost to performance is expected with additional SCADA control over remote switchgear. This will provide significant information and faster responses to interruptions, reducing the duration aspects of faults but probably not the frequency (although intensive monitoring of protection relay reclosures and pickups may allow proactive preventative maintenance actions).

The planned interruption rate is completely under EA Networks' control, and it forms a large portion of the frequency and duration indices. Other than the impact of new live line working protocols, it is unlikely that these will fall dramatically until the major line construction and voltage conversion projects are complete.

In summary, the overall performance of the network shows it is relatively fault resistant when compared with similar companies, but fault response needs to continually improve.

9.3 Service Improvement Initiatives

Having identified the level of performance that EA Networks are achieving and the level of performance and standards that stakeholders, consumers and EA Networks wish to achieve, this section details proposals that, where necessary, will drive improvements to the services EA Networks delivers to consumers. The solutions relate to different voltage levels and components within the EA Networks network. See section 6.1 for a chart showing the different voltage levels and the interconnections between them.

As EA Networks move from a period of extremely high growth to one of modest growth, the maintenance regime at EA Networks will become much more focused on preventing failures rather than reacting to them or maintaining equipment at set time-based intervals. EA Networks look at any new diagnostic tests that become available and assess their usefulness for preventative maintenance. When it can be shown that the tests can reliably predict the condition of equipment and any incipient fault, it is used in a targeted fashion on the equipment that is most critical for security or other performance criteria such as safety.

All the initiatives that have been identified for implementation are subject to economic analysis to ensure EA Networks are offering value for the increase in performance. The value can sometimes be difficult to quantify and if a business case cannot be made, the costs, pros and cons will all be presented to the Board to consider. The Board provide the sometimes-intangible strategic influence of consumers/shareholders wishes on the proposal.

9.3.1 Transpower Network

Transpower has identified that it has a need to increase the capacity of the national transmission network supplying the Upper South Island to maintain the level of security required of a national grid. Proposals have included a new 400kV line that takes electricity from the hydro schemes in the south of the South Island to the greater Christchurch area. Other, interim, less expensive steps such as the establishing new 220kV switching stations in the Orari area are the preferred option. All these approaches will offer increased security to Transpower's Ashburton substation (Ashburton220) thereby improving both the security and quality of supply to EA Networks' consumers. Transpower have previously altered Ashburton220 to interconnect both circuits of the Twizel-Bromley/Twizel-Islington double circuit 220kV line (previously only one of the circuits was deviated into Ashburton220). As well as assisting in relieving Transpower's grid constraints, this project has increased the security of Ashburton220's 220kV bus from *n-1* to at least *n-2* in relation to 220kV circuits.

The addition of a third 220/66kV transformer (T9) permitted a reconfiguration of the Elgin 66kV bus which connects to Ashburton220. Protection system alterations have also been implemented that improve the performance of the EA Networks subtransmission network protection and allows more reliable and selective detection of faults. This assists in reducing the extent of future outages when particular types of fault occur.

The third 220/66kV transformer has provided a level of firm capacity that exceeds the present 66kV peak load. There are no projects planned to further increase the 66kV capacity at Ashburton220. In future beyond the horizon of this plan, should load begin to exceed the 220/66kV transformation capacity level deemed suitable for supply from Ashburton220, larger transformers could be added to increase security alongside further EA Networks 66kV network capacity to convey the electricity into the network.

9.3.2 Subtransmission System

At least one part of the subtransmission network carries electricity to every consumer supplied by EA Networks. A consequence of this is that loss of any part of the subtransmission network is felt far more widely than the loss of an equivalent portion of the distribution voltage networks. Compensating for this is the level of redundancy that has been built into the subtransmission network.

There are a range of initiatives that have been undertaken to improve the service levels obtained from the subtransmission network:

- 66kV line design has been externally reviewed to ensure reliable conductor displacements under both normal and extreme conditions.
- Vegetation patrols and hardware inspections are more frequent on subtransmission circuits due to the critical function they perform.
- Vibrations dampers have been (retro)fitted to subtransmission circuits – this lowers vibration related faults on the subtransmission network and ensures the line endures for its full design life.
- Older lines have been inspected with a corona camera and have had subsequent inspections using ultrasonic equipment that detects cracked or faulty insulators as well as defective insulation on most equipment.
- Infra-red cameras that detect thermal discrepancies are used on an annual basis to examine important lines for overloaded or potentially faulty joints and connections.
- High performance protection equipment has been installed on all 66kV subtransmission circuits resulting in lower fault clearance times, increasing safety, and decreasing the duration of voltage depressions.

9.3.3 Zone Substations

A failure in a zone substation can be particularly difficult to deal with. A combination of sensible overall design and modern asset specification can reduce the risk of failure considerably and therefore increase the level of service it provides. Specific initiatives undertaken in zone substations include:

- Very careful monitoring of critical equipment using partial discharge tests, infra-red cameras, ultrasonic equipment, and sophisticated oil analysis to provide details of internal transformer condition.
- Selection of equipment for new substations that is more immune to factors that have been the cause of historical failures.
- Configuration of new substations that makes them more tolerant of equipment failure – supply is not completely lost during or after a critical equipment failure.
- 66kV bus zone protection that reduces fault clearance times to a few cycles, dramatically reducing fault damage (although not preventing the fault) and localising the outage to the faulted equipment only.

There are many other changes that have been implemented as a consequence of the major zone substation construction programme of the last 10 years. Suffice to say that they all assist in providing a higher level of service from the zone substation to the consumer.

It is noticeable that there are increasing numbers of devices being connected to the network that are creating harmonic distortion of the supply. EA Networks have engaged in a more proactive stance on this and have installed real-time monitoring equipment at most zone substations.

9.3.4 22kV and 11kV Distribution System

The high voltage (HV) distribution network (22 and 11kV) has the most geographically widespread lines in the entire EA Networks network. HV distribution also forms the highest percentage of total lines and switchgear. Consequently, it features in most faults affecting consumers.

Underground

The underground HV distribution network is generally meeting expected performance. Some condition monitoring is done on cables although it has not proven to be particularly good value because the low fault frequency requires monitoring a large proportion of the network to provide a proactive response. Generally, the few faults that do occur in the underground HV network are caused by either external influences such as mechanical excavators (this is only preventable by extensive education) or faulty joints and terminations which are always being re-evaluated based upon performance.

Future developments are planned to include a new core 11 kV cable network programme for Ashburton township [12469] & [12470]. This will increase overall capacity and decrease the average number of ICPs per feeder to lower levels. This will mean a lower impact for any given cable fault since fewer consumers will be affected. The same network will also allow much more substantial and faster load transfer between Ashburton and Northtown substations during both planned and unplanned outages. This should make planned outages of urban Ashburton ICPs very rare and unplanned outages very short.

Overhead

The overhead HV distribution network is much more prone to external influences and the majority of overhead line faults affecting consumers occur on the overhead HV distribution network. There are a number of improvement initiatives that have already been undertaken:

- Urban underground conversion programme – progressive conversion of the urban overhead HV distribution lines to underground cable causes dramatic reductions in fault frequency. Because this combines with high customer density in urban areas, the resulting benefit to reliability statistics is considerable.
- Rural underground conversion where it is deemed to be prudent and sufficiently advantageous. This is particularly the case on high volume state highways where the incidence of vehicle versus pole incidents is high.
- Thermal imaging analysis of major distribution feeders to detect faulty connections or overloaded components.
- An on-going tree control programme informed by risk assessments to target activity onto the highest impact trees. This is now backed up by additional measures for tree owners who wish to take advantage of them.
- Replacement of parallel groove connectors and line taps with higher reliability wedge connectors, and renewal of line splices when completing renewal works on a feeder section.
- Repositioning displaced line reclosers to increase network segregation.
- The routine use of more reliable and remote controllable gas switches instead of air-break switches.
- The installation of rural ring-main units to increase switching reliability and safety while providing the opportunity for ring-main unit circuit-breaker fault clearance, single-shot auto-reclose, as well as remote control.
- Vibration dampers are being fitted to underbuilt HV distribution on long spans to decrease vibration damage.
- Additional surge arrestors have been fitted at locations where existing equipment provides the relatively high cost of an earthing system (e.g. SF_6 load-break switches).
- Universal application of possum guards to poles with high voltage attached to them.
- 11 kV glass tube fuses are progressively being replaced with expulsion drop-out types.
- Additional interconnections between feeders to provide alternative supplies.
- 11 kV to 22 kV conversion increases capacity significantly and permits back-feeding which lowers both planned outages and unplanned outage length.
- Neutral earthing resistors reduce the thermal stress on wires and connectors during earth faults as well as dramatically reducing the fault voltage depression seen by consumers.

- More rigorous actions in relation to non-compliant privately owned HV lines.
- Elimination of unfused overhead extensions onto private property.
- Thermal infrared camera inspection of lines and accessories to detect abnormal heating.
- The requirement that all new network connections (both LV and HV) shall be via underground cable and encouragement to have all on-property reticulation underground.
- Investigation of ICP monitoring to detect real-time back-feed voltages, no power situations, and upstream line down faults.

There is still the need to further improve the performance of the overhead HV distribution network and there are three main possibilities for achieving this.

(1) Reduce Fault Frequency (SAIFI reduction)

This is possibly the most difficult of the three methods to increase performance. There will always be people driving cars that crash into poles, irrigators that either push wires together or directly hit the wires, birds that perch on insulators, etc. Fault immunity can be increased by these initiatives that EA Networks are initiating or contemplating:

- Use of covered conductor in specific areas prone to conductor contact by trees or machinery (not being actively pursued).
- Use of insulator shrouds and conductor insulation in areas prone to wildlife interference (being used for specific equipment).
- Use of pole-mounted fully enclosed load-break switchgear in place of air-insulated disconnectors – reducing the frequency of equipment malfunction.
- Increased monitoring and inspection of on-property service lines to help ensure lines that are presently privately owned and are on private property do not cause preventable outages on the EA Networks network.
- Review of recent severe weather events has identified certain types of conductor, poles and fittings that feature in a high proportion of faults (these assets are targeted for replacement as the opportunity arises).
- Even stricter enforcement of tree control to prevent (a) earth faults caused by trees touching the line, (b) bark and branches blowing onto the line, and (c) trees falling and mechanically damaging the line. This has been implemented.
- Completion of a network-wide tree survey, producing risk ranked tree defects that can be prioritised to ensure the vegetation management budget is spent with greatest reliability effect.
- Careful consideration of asset location to avoid vehicle contact.
- Underground conversion of overhead assets where there is a compelling safety or reliability case when assisted by roading authorities.

(2) Reduce Extent of Fault Impact (CAIDI/SAIDI reduction)

Another possible performance improvement is to reduce the number of consumers affected by a fault. This can be either fewer consumers with the power off, or fewer consumers seeing the consequences of the fault. Several initiatives are under consideration or have been implemented:

- Application of neutral earthing resistors in an urban cable network to reduce the thermal stress on wires and connectors during earth faults as well as dramatically reducing the fault voltage depression seen by consumers (widespread implementation).
- Increase the total number of HV distribution feeders thereby reducing the number of consumers served by each feeder (planned for urban Ashburton).
- Continue to install additional line reclosers increasing the network segmentation (rural circuit breaker RMUs are displacing/supplementing reclosers).

- Implement a degree of distribution automation that would rearrange the network, automatically restoring supply to some consumers within 60 seconds (possible via the advanced distribution management system).

(3) Reduce Duration of Fault Impact (CAIDI reduction)

If the fault is inevitable (some are) and the number of consumers affected cannot be economically reduced, the last option is to restore supply to as many consumers as possible, as quickly as possible. This is one area where modern technology can have a considerable impact. The initiatives under action or consideration are:

- More remote control of line reclosers, disconnectors, gas switches and ring-main units (actively being implemented).
- Increase the sophistication of protection systems to limit the duration of fault voltage depressions (actively implemented at 66kV, less so at distribution level).
- Permanently install distributed power quality monitoring equipment at consumers' properties to report not only fault information but also other power quality statistics (some aspects of this have arisen through the fibre optic network which also supplies on/off information via the consumer connected modem and there is potential for every connection to have a remote signalling voltage/load transducer if an alternative load control system is adopted).
- Equip field staff with devices that assist in locating faults and provide real-time operational information to allow fully informed decisions (project completed).
- Possible use of a large (200-300kVA) generator and step-up transformer to provide an alternative supply during all types of interruption (still being considered).
- Investigate self-healing networks using the ADMS.

Switchgear

The majority of switchgear has proven to be trouble-free provided the manufacturer's recommended maintenance is performed. There are however some particular items of plant that are sub-standard and the only remedy short of major modification is to replace the item. Things that have been done to improve performance or are proposed to be done include:

- Replace switchgear where there is a known risk to safety and/or equipment integrity.
- A substantial population of resin/air insulated 12kV Eaton Holec Magnefix units have been used as switches for connection of distribution transformers, without high voltage fusing within the RMU. The current design relies on the transformer in-tank fuse that has been found not to provide fast clearance of faults on the transformer low voltage switchboard. To manage arc flash safety risk, a programme to implement a new design solution (retrofit high voltage elbow fuses to transformer bushings) will be implemented from 2026-27.
- Use of equipment with better cable termination integrity (screened elbows), lowering the burden on jointers to use materials that are prone to environmental influences.
- Regular inspection of ground-mounted switchgear using partial discharge detection equipment.
- Use of equipment that is designed to be fundamentally safer, more durable, and more reliable.
- Increased use of remote control to minimise exposure of personnel to switching equipment.
- Fault indicators are being applied in more locations to reduce restoration times by locating the fault.
- Adopting the routine and extensive use of fully enclosed SF_6 gas load-break switches which are both more reliable, more capable (400amp load breaking) and safer than open contact style switches for both new and many existing sites.

Transformers

Distribution transformers have proven to be a very reliable asset category. Failures are typically caused by wildlife, lightning, or overloading, with equipment failure coming much further down the list. Since distribution transformers are very reliable, little additional effort can be justified in further increasing performance. The main initiative that has been implemented is a universal system spare 1 000kVA distribution transformer. This unit is self-contained with HV and LV cables and can operate at either 22kV or 11kV. It has been put to good use on a number of occasions already during transformer faults that would have been difficult to deal with otherwise. A significant number of smaller transformers are kept as spares for replacing faulted units.

Although not particularly increasing the reliability of the transformer, EA Networks has adopted the use of in-tank high voltage fuses for all new transformers intended for ground mounting (this typically encompasses all transformers larger than 100kVA and *mini/microsub* style units used when the choice is made to mount smaller units on the ground. These fuses are intended solely as fault protection for the transformer internals and equipment directly connected to the low voltage bushings. By putting these fuses in the transformer now it prepares them for inclusion in any future underground reticulation network that may not allow for costly ring main units or HV fuses at each transformer site. It also overcomes the problem of adequately protecting a large and small transformer (such as occurs on many farms) on the same piece of underground cable. Previously, the fusing for a large and a small transformer was done collectively at the start of the underground cable, and this was not entirely satisfactory.

One of the intentions of the policy of ground-mounting any new transformer above 100kVA is to promote a more reliable mounting arrangement for each transformer. During extreme events such as snowstorms, windstorms, and major earthquakes, a ground-mounted transformer is much more secure than the equivalent pole-mounted unit. Things that have been done to improve performance or are proposed to be done include:

- Distribution transformer sites with greater than 1000 litres of oil (some 1 MVA and all 1.5 MVA types) will be collated and communicated to Ashburton District Council in 2025-26 for evaluation related to oil bunding requirements. Refer to section 3.9 for details.

9.3.5 LV Distribution System

The low voltage (LV) distribution network (400 volts) is typically quite reliable and any faults that occur affect relatively few consumers (security standards dictate no more than 25 initially and no more than 15 during the repair). There have been several improvement initiatives that have provided worthwhile increases in performance:

- Conversion of overhead LV lines to underground cable has provided significantly increased reliability, capacity, and quality (better voltage regulation and fewer fault voltage depressions).
- Replacement of old open contact LV fuses and links with modern high-capacity switchgear has improved the reliability, configurability, and safety of: kiosk substations, roadside switching boxes, and consumer service fuses.
- Related to managing the arc flash safety risk on the low voltage side of distribution transformers, a combination of barrier mitigations, operating restrictions and improved PPE operator protection is applied to manage inspection, switching and working on low voltage switchgear, with particular attention to the JW3 type. A programme of retrofitting LV fusing between the transformer bushings and the low voltage board will be developed for 2026-27 onwards for installations where this is currently not installed, prioritised by risk.
- When overhead lines are installed or replaced in rural areas, PVC covered LV wires are now universally used and prevent problems with wires clashing and reduce safety concerns.

9.3.6 SCADA, Communications and Control

The remote-control system (SCADA) functionality at EA Networks has been evolving for some time. The new SCADA/ADMS system is now able to provide a significant improvement in network performance with the widespread ability to control switchgear and other power system devices as well as retrieve information that assists in diagnosing both faults and power quality issues.

The new SCADA system is fully functional and expanding. The opportunity exists to have the SCADA system extend into automation of some network activities. This will permit faster restoration and allow staff to concentrate on repair of the fault rather than switching of the network.

Having stated in older plans that the ripple control system had proven to have high availability, the electronic portion of one of these plants failed during 2005 and then another failed during 2011. Certain electronic components are no longer available and in some cases the service contractor cannot repair failed equipment. Unfortunately, this was the case with both plants that failed. A decision was made to repair one of the failed plants using parts of a smaller standby plant. The 2005 failed equipment has been replaced with an item sized to suit future application at 66 kV. This returned the injection plant count to two and will ensure no on-going loss of load control for a fault in one plant under most loading conditions.

The issue of high harmonic distortion and the potential for the required mitigation measures to degrade the signal of the ripple system appears not be a significant issue.

A project in 2023/24 to 2024/25 to replace the primary coupling cell of the Elgin ripple plant will extend the life of the system while restoring n-1 security. Further investment in a replacement Ripple Injection Generator at Elgin will increase resilience of the system, as described in sections 5.4.11 and 6.15.

9.3.7 Protection Systems

Any electrical protection component is by design a high reliability item. The configuration of individual components of protective equipment can have a considerable influence on the performance of the protection system in total. Protection maloperation is rare, but it does happen. Depending on the back-up component available, it can lead to a more widespread outage and more damage.

Protection relays (*relay* is a term for the control box that senses faults and switches the circuit-breaker off) are becoming much more sophisticated than they have been. Most modern protection relays are based on microprocessor technology which permits not only advanced decision making, but also direct digital communication with other devices such as PCs and of course SCADA systems.

EA Networks have utilised many of these modern protection relays, and they have proven valuable in providing all manner of loading information as well as post-fault analysis. There is a lot of scope in the application of advanced protection relays for improved network performance. This is not only in the way the relay controls the circuit-breakers but also the information they provide to staff for future engineering decisions.

Live line work is now a routine part of network construction and maintenance techniques. Modern protection relays have the capability of being programmed to disable automatic reclosing either locally or remotely (via SCADA) and, if so desired, change the protection settings for live-line working so that a trip operation is extremely fast compared to normal operation. This does not lower the risk of an incident occurring, but it can make the consequences much less.

The main initiative will be to keep abreast of developments in the protection field so that maximum benefit can be obtained from worthwhile technology.

Some of the early electronic relays are now beginning to show sign of age-related degradation. The oldest relays are being progressively replaced either as issues become apparent during testing or simply based on the age of the unit, its criticality, the spares held, and its repairability. Fortunately, the conversion of the subtransmission network to 66 kV has made the vast majority of very aged protection relays redundant. Some of the early 66 kV line relays have been scheduled for replacement as they approach 20 years of age.

9.4 Asset Management Maturity Evaluation

A re-evaluation of asset management processes and systems at EA Networks against the Asset Management Maturity Assessment Tool has been completed. Based on work completed since the last evaluation in 2023, improvements have been seen in areas including the training and competency matrix, safety and contractor management, risk management and resilience planning. The 2025 assessment will provide a basis for determining priorities for future improvement.

Appendix G contains the EA Networks disclosed AMMAT response.

9.5 Gap Analysis

The service level performance gap analysis has been partly addressed in section 9.3 with a range of initiatives targeting systemic baseline performance characteristics.

EA Networks have not been able to complete a comprehensive AMMAT gap analysis. Rather than present an insubstantial commentary on the range of issues requiring attention, it has been decided to leave this section without comprehensive analytical content. Suffice to say that there are a range of AMMAT topics that will require attention and as internal resources permit, they will be developed, documented, and addressed. Some of the latent issues that have existed for some time are documented in section 9.6 below.

Areas that have arisen out of the 2025 AMMAT evaluation, and will be considered and prioritised are as follows:

- Asset Management Policy update, including alignment with EA Networks strategy, approval by Board and SLT, communication to teams.
- AMP Communications Plan and circulation of the AMP Exec Summary to stakeholders (including Shareholders Committee, Ashburton District Council, Environment Canterbury, industrial customers, major developers, irrigation groups, National Emergency Management Agency, relevant Lifelines organisations).
- Further maturation in understanding resources required to deliver the plan, particularly in maintenance activities - actual versus scheduled and resources required to complete the planned programmes.
- Implement Resilience Action Plan actions for 2025-26, 2026-27.
- Implement project delivery framework and project management processes for tiered project size and complexity.
- Establish KPIs on delivery (capex/maintenance) for regular discussed with Contracting and Finance, provided to general organisation circa quarterly to increase awareness of project and programme delivery progress.
- Competency definition and development of competency matrix for Network Asset Management responsibilities beyond legal compliance and safety.
- Communicate AMP projects for next two financial years to Contracting teams as well as managers.
- A prioritised and resourced plan regarding how AM systems and processes will be documented, e.g. Digital systems roadmap, ADMS roadmap, GIS development, identification and prioritisation of what processes and documentation will be updated. Use publicly available CPP developed asset management documentation as a model.

Future plans will contain a more rigorous AMMAT discussion and analysis of gaps that exist and the areas that EA Networks consider worthy of on-going attention – offering value for money.

As discussed in section 3.6.10, an evaluation of the indicative target consumer per electrical asset targets is planned for 2025-26 to explore any current gap that exists between the target and actual number of consumers per electrical asset at a sub-transmission and distribution voltage level (i.e., LV excluded at this time). The analysis will approximate the view on any gap following implementation of the 10-year plan of projects and programmes, and an estimate of the investment required to close that gap. Significant contributors to closing the gap within the current plan are the Ashburton urban network centres and network cables projects, and rural switch installations. The outcomes of the analysis will inform the value of further investment, or the tailoring of the targets to a more appropriate level.

9.6 Asset Management Improvement Initiatives

There are a raft of processes and systems that need significant improvement to become equivalent to the level of excellence that are considered industry's best practice. To attempt to improve all these elements in the short-term would be folly. There are some key processes and systems that need immediate attention, while others represent a high benefit/cost ratio and should be advanced on simple economic grounds.

The following items represent elements of EA Networks' Asset Management that have been targeted in previous plans as essential for improvement during the short term (3-5 years).

SCADA – Control and Data Gathering

The SCADA system is now fully functional at all zone substation sites. Distribution system sites continue to be connected as communications paths become available. The DMR system is boosting the numbers of distribution

SCADA sites dramatically, with the addition of a small radio/RTU device that can be used wherever voice coverage is available.

A big part of the successful SCADA implementation was obtaining reliable data communication to all zone substations. A separate fibre-optic communications infrastructure was developed as a commercial enterprise and all 66kV zone substations are connected plus other field equipment in close proximity are being progressively connected. This platform provides a very secure and reliable network.

Now fully operational at all controllable sites, the SCADA system provides: full remote control (a means to reduce restoration times), remote fault diagnosis, gathering of equipment loading in real time, gathering of condition-related data in real time, gathering of power quality data in real time, and temporal trending of a range of power system parameters. All this data supports effective asset management.

Further development of the Advanced Distribution Management System (ADMS) will initially focus on the following features:

- Outage Management System functionality to improve locating faults, automatically notifying customers and calculating reliability statistics for planned and unplanned outages.
- Distribution Management System functions like Switch Order Management that will provide structured digital collation of switching sequences with enhanced error and safety checking.
- Distribution power flow analysis for improved understanding of network voltages and currents in locations without SCADA telemetering, and for "what-if" analysis of network back-feeds prior to switching.

Risk Management

The appointment of additional resource has permitted good progress in the risk assessment process. There are now a number of contingency plans to assist staff in the event of a risk affecting particular items of equipment or classes of equipment. After consideration, some risks may be treated by engineering responses to reduce exposure to the risk instead of attempting to reduce its consequences after the event through contingency planning.

The target of EA Networks' risk management is to follow through on high-risk items already identified and create documentation to manage the outcome of that risk. This work is progressing well, and additional analysis will continue. More contingency plans will be created as the need is identified.

Spatial Information and Network Modelling

The spatial data storage application EA Networks use is called Hexagon G/Technology (formerly Intergraph G/Technology). The same application maintains the electrical model of the network which facilitates intelligent tracing of faults and analysis of the network. This model also nightly updates the Aspentech ADMS system for its electrical connectivity and mapping features. G/Technology also captures and models the EA Networks fibre-optic network. The as-built data provided by field staff is now captured quickly and available to all users the next day.

The Hexagon G/Technology system itself suffers from limitations, including expensive licencing that restricts its wider use in the organisation, the inability to produce detailed enough construction drawings that requires duplicate AutoCAD and GIS drawings to be produced, and complex administration of data. A project to replace the G/Technology GIS with a new ESRI ArcGIS has commenced, with data to be converted into the EPRI Utility Network Common Information Model to enhance the ability to integrate the network data with other enterprise applications via minimal integration effort and technology debt by the use of this open data model. The new ESRI ArcGIS will have improved licencing, allowing access to the GIS throughout the organisation, including on field tablets to enable productivity and safety benefits. Ongoing enhancement of the Esri ArcGIS system is planned following scheduled completion of the data migration and go-live in March 2026.

Levels of Service

Having set in place a number of security standards that are intended to target improvements in the levels of service, additional effort is required to determine the degree of compliance with these standards. All new projects are designed to offer the prospect of improved compliance with the standards but may require some redesign to achieve 100% conformity.

The ability to efficiently analyse compliance with the security standards has been hindered by the lack of integrated data. The Advanced Distribution Management System (ADMS) and other inter-system integrations currently underway will enable this work to be undertaken and monitored.

The ADMS will also allow the development of more granular service measurements. There is already a measure under consideration that represents the components of SAIDI, and this will allow the different stages of a fault or a collection of faults to be examined to determine the effectiveness of various types of intervention. This will be detailed in a future plan once more work has been done to prove its worth/validity.

The target for this aspect of asset management is to identify the non-compliant sections of the EA Networks network and rank them according to priority. With the ADMS operational, permitting a degree of network analysis, progress should be made during 2025-26.

Asset Management Maturity

Items raised in section 9.5 above will be collated, along with other prioritised initiatives, into an Asset Management Improvement Plan (AMIP) to plan, prioritise, resource and implement asset management disciplines, systems, processes and organisational capability to deliver EA Networks' strategy and ensure prudent and optimised asset management. The AMIP will be developed during FY2026 and confirmed by March 2027.

9.7 Capability to Deliver

People

Our ability to deliver the Asset Management Plan and its success relies on our people having the capability and capacity. We must maintain a strong employer value proposition (EVP) that allows us to attract and retain people. Our focus is on developing employer value proposition including:

- Ensuring fair and competitive remuneration that aligns with industry standards.
- Enhance employee satisfaction, productivity, and retention through comprehensive benefits.
- Foster a culture of wellbeing, supporting both physical and mental health.
- Promoting our values and driving consistency in behaviours.
- Strengthen EA Networks reputation as an employer of choice.

Safety

We are committed to ensuring the safety of its customers, employees, contractors, and the public. We provide a safe and healthy workplace for our people and contractors that enables us all to function and deliver great outcomes, in the provision of a safe and reliable network for our community. Our strategy is to deliver on our vision and values through:

- Leadership and Culture - We will support leaders in their approach to a positive safety culture, behaviours, attitudes, and work processes.
- Hazard and Critical Risk Management - Our focus is on understanding our critical risks, implementing all required risk controls, and ensuring all of our workers are equipped with enough knowledge, systems and processes and the right mindset to work safety in the business.
- Suitable Systems and Assurance - We will take a consistent approach to safety across our business, which means our safety systems and documentation need to be simple, fit for purpose, user friendly and accessible to everyone.

Asset Management Planning and Delivery

This plan has been published annually for more than 20 years and has been instrumental in guiding the development and lifecycle management of the EA Networks electricity assets. Overall, the strategies outlined around the year 2000 (66kV subtransmission and 22kV rural distribution) have succeeded or are steadily progressing the network towards the desired level of performance. Delivery of annual projects and programmes is improving as budgeting, phasing, resource planning and project management disciplines continue to improve. Further focus on those areas is planned in the coming several years.

Analysis of network customer needs in an evolving industry will require more sophisticated forecasting and network analysis systems to meet the challenges of renewable generation, decarbonisation of process heat and transport and evolving land use and irrigation methods. Analysis of investment and project commercial viability All these drivers will shape the network development and renewal plans.

Forecasting of asset maintenance and renewal expenditure and resource requirements with assets at different stages of the lifecycle will require enhancement of ERP/EAM systems.

Business systems and process improvement is planned with the intent to improve functionality, make data and information more widely available within the organisation and increase the efficiency of operations.

Strategic initiatives have been put in place to implement over a 2-year, 2 to 4-year and 5 to 10-year horizon to ensure EA Networks has the capability to deliver on its strategic objectives and this Asset Management Plan.

APPENDICES

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10 APPENDICES

10.1 Appendix A – Definitions

The Electricity Distribution Information Disclosure Determination 2012 contains an extensive range of definitions covering a range of activities, assets, and associated terms. In future plans it is intended to make every effort to synchronise the terms in use in the plan (and here in the definitions) with those used by the Disclosure Determination. Unfortunately, there has been insufficient time available to change the structure of this plan to reflect the Disclosure Determination preferred terms.

EA Networks do have philosophical issues with some of the Disclosure Determination asset definitions, seemingly having more to do with financial asset definition than physical populations of like assets which are managed in common using the same methodology.

Maintenance Activity Definitions

Inspection, Service and Testing

Routine

This is expenditure on patrols, inspections, servicing, and testing of assets on a routine basis. Typically, these activities are conducted at periodic intervals defined for each asset or type of asset. This work does not involve any repairs other than some minor component replacements during servicing.

Special Inspection, Service and Testing

Expenditure on patrols, inspections, servicing, and testing which are based on a specific need, as opposed to being time based as with periodic inspections and servicing.

Faults

Repairs undertaken during fault conditions to restore supply. This does not include the eventual repair of a faulted asset, where it is taken out of service while repairing the fault; only the expenditure required restoring supply is included.

Planned repairs and refurbishment

Repairs to, and refurbishment of, an asset which may involve component replacement but not the complete replacement of the asset. This includes corrective repairs of defects identified within a year, *special* repairs (e.g. based on an identified type failure or type weakness) and planned refurbishments that may involve a significant proportion of component replacement. However, to identify refurbishments as distinct from general repairs would require identification of all specific refurbishment projects over the planning period and this has not proved feasible for this plan.

Planned replacement

Replacement of an existing asset with a modern equivalent asset providing similar capacity or other aspect of service provided. Note that the asset need not be identical in capacity etc but should be materially similar.

Maintenance contingency

An explicit planning contingency, where it is not feasible to identify all minor work, or where it is expected that work will arise, but its classification cannot be easily predicted. All contingencies are specifically identified, and no implicit contingencies are included in the detailed expenditure projections for other activity classifications.

This contingency is converted into one of the above activity classifications once committed. Therefore, *Maintenance Contingency* is not a real activity for reporting purposes.

Enhancement and Development Activity Definitions

Enhancement

This is the replacement of an existing asset with a modern equivalent asset, which is materially improved on the original asset, or modifications to an existing asset, which have this effect. Specifically, this will include improvements to the existing asset configuration, which are undertaken with the purpose of:

- Further improving the inherent safety of the system (e.g. installing smoke/heat detectors and entry alarms in substations)
- Improving the level of consumer service (e.g. increasing capacity by replacing a transformer with a larger unit, or adding an extra circuit to it to increase security)
- Improving economic efficiency or investing to improve the asset by reducing operating or maintenance costs (e.g. fitting vibration dampers to specific lines to reduce the rate of component deterioration)
- Improving environmental risk management (e.g. fitting oil containment facilities at substations)
- Improvement to corporate profile (e.g. landscaping station grounds, although this is also fully justifiable based on reduced grounds maintenance)

Note that each aspect of improvement is related to a specific asset management performance driver.

Development

This is work which involves installation of new assets in sites or configurations where none previously existed. This may also include substantial upgrade work (e.g. re-building a substation at a higher voltage) in which the original configuration is significantly altered or extended.

Development contingency

An explicit planning contingency, where it is not feasible to identify all minor work, or where it is expected that work will arise, but its classification cannot be easily predicted. No implicit contingencies are included in the detailed enhancement and development expenditure projections. For the same reasons as those discussed under *Maintenance Contingency*, this activity is not included in financial reports.

Other Activity Definitions

Operating

Any disconnection of consumers' services for any reason except non-payment of electricity accounts. This includes activities such as house painting, transportation of high loads and low voltage switching. It also includes operation of the high voltage network where this is not directly associated with maintenance or enhancement work.

Trees

This activity covers all tree cutting and trimming to maintain safe working clearances from power lines and any costs incurred during negotiations with consumers regarding tree trimming.

Planning Period Definitions

Plan(ning) Period

In this plan the term is used to describe the interval that the plan is attempting to predict with a tolerable degree of certainty. Beyond the end of this interval there are too many unknown factors that will influence contemporary engineering decisions to allow reasoned assessment. The solutions that are proposed in this plan will have lifetimes considerably exceeding the planning period but may not provide the specified level of service beyond the planning horizon without enhancement.

During periods of high load growth, such as historically experienced by EA Networks, the accuracy (and therefore risk) of looking too far ahead can be unacceptably poor. EA Networks have chosen to keep the load forecasting horizon coincident with the end of the planning period for the moment. Projects that are initiated during the planning period are designed with future expansion capability in mind to provide options for accommodating unknown future load/security requirements.

Plan(ning) Horizon

The end of the planning period.

Asset Type Definitions

High Voltage Lines and Cables (Subtransmission and Distribution)

Includes all power distribution and subtransmission lines with a rated voltage of 11 kV or higher. Within the plan, lines may be further disaggregated into major components, being:

- Poles
- Conductors and accessories
- Insulators and hardware
- Down and aerial guys
- Underground cables
- Terminations
- Joints
- Ducting
- Land or easements

Low Voltage Lines and Cables

Includes all low voltage lines with a rated voltage of 400 V or lower up to the consumer's service fuse. As for high voltage lines, lines may be further disaggregated into major components, being:

- Poles
- Conductors and accessories
- Insulators and hardware
- Underground cables
- Distribution, link, or pillar boxes
- Terminations
- Joints
- Ducting
- Land or easements

Service Lines (High Voltage and Low Voltage)

Includes all service lines on road reserve from the consumer's service fuse to the point at which it crosses the consumer's boundary. This includes:

- Lines and cables
- Fuse arms
- Service fuses
- Service lines on road reserve

Zone Substations

This includes substation facilities such as land and buildings and the power transformers within them that are connected to the subtransmission network. Individual items of equipment such as disconnectors, circuit-breakers and bus-work are covered in other asset type definitions, which are generic for the whole network. For example, no distinction is made between a disconnector in a substation and one on a distribution line.

- Power transformers
- Foundations
- Oil interception equipment
- Land or easements
- Buildings and fencing
- Other ancillary station equipment such as batteries, chargers, NERs, etc

Distribution Substations

All distribution and regulator substation equipment including:

- Kiosk covers
- Foundations
- Connection cables LV and HV
- Land or easements
- Accessories – heaters, instruments, CTs, etc

High voltage and low voltage switchgear located in distribution substations are covered in separate asset definitions.

Distribution Transformers

All distribution transformers from 5 kVA to 1500 kVA 11 kV and 22 kV primary voltage, including regulators or autotransformers up to 10 000 kVA:

- Ground-mounted transformers
- Pole-mounted transformers
- 11 kV or 22 kV Regulators, 22/11 kV Transformers, and 22/11 kV Autotransformers

High Voltage Switchgear

All high voltage switchgear, busbars, and other items of equipment, both on lines and within substations, including:

- Circuit-breakers
- Reclosers
- Sectionalisers
- Disconnectors
- Ring-main units
- Expulsion drop-out fuses
- Structures and bus-work
- Instrument transformers
- HV Capacitors

Low Voltage Switchgear

All low voltage switchgear and busbars installed in distribution substations, distribution boxes, link boxes, or pillar boxes, including:

- Load-break switches
- Fuse Switches
- Fuses
- Support frames
- Busbars
- LV Capacitors

Protection Systems

There are two main protective systems applied to the electrical network. These are:

a) the systems that detect when a piece of electrical equipment has become faulty or has been damaged making it unsafe or at risk of further damage.

The electrical fault protection system is comprised of many components that include:

- Electronic relays (solid state and numeric).
- Metering/Datalogging devices.
- Interconnecting cables.
- Panels for mounting.
- Control switches and control devices.

b) the systems that prevent excessive voltages from damaging network equipment.

The over-voltage protection that is applied to protect the EA Networks network is limited to the following components:

- Metal Oxide Varistor (MOV) surge arrestors
- Spark-gap devices mounted on some transformers

Earthing Systems

All earthing systems connected to EA Networks equipment. The componentry required to construct earthing systems is relatively simple and includes:

- Driven earth rods from 10 mm diameter to 40 mm diameter, copper, and steel.
- Buried copper conductor
- Insulated copper conductor
- Crimped, welded, and clamped joints

SCADA, Communications and Control

Includes SCADA Master Station(s) and Remote Terminal Units at individual sites. Communication equipment comprises specific communications sites, associated equipment and facilities and radio communications equipment installed in vehicles, at substations and other bases. Radio aerial support structures are included in this category.

Ripple Control

Ripple Injection Plants installed at Zone Substations or Grid Exit Points. This definition also includes the load control software included in the SCADA Master Station. The physical injection plant consists of solid-state components. These complex plants comprise capacitors, inductors, transformers, generators, and controllers.

Performance Indicator Definitions

There are a range of parameters that can be derived from raw reliability statistics to indicate the level of performance of a particular network or portion of network. In order to reliably compare these *performance indicators* between networks, the specific method of calculation needs to be defined. The majority of these parameters are as defined in the *Electricity Information Disclosure Determination 2012,* but they are reproduced here for completeness.

Consumer Service Indicators

Interruption: in relation to the supply of electricity lines services to a consumer by means of a prescribed voltage electric line, means the cessation of supply of electricity lines services to that consumer for a period of 1 minute or longer, other than by reason of disconnection of that consumer-

(a) for breach of the contract under which the electricity lines services are provided;

(b) as a result of a request from the consumer; or

(c) as a result of a request from the consumer's electricity retailer; or for the purpose of isolating an unsafe installation.

Planned Interruption: means any interruption in respect of which not less than 24 hours' notice was given, either to the public or to all electricity consumers affected by the interruption.

Unplanned Interruption: means any interruption that is not a planned interruption.

Interruption Duration: means the time from the cessation of supply of electricity until the supply of electricity is restored.

Interruption Duration Factor: in relation to an interruption, means the sum obtained by calculating, for each electricity consumer that is affected by that interruption, the duration (in minutes) of that interruption and adding together the results of each calculation.

SAIDI: means the average forced sustained interruption duration per connection point served per year, measured in minutes. Connection point numbers are to be the average for the disclosure year

SAIFI: means the average forced sustained interruption frequency per connection point served per year, measured in frequency per year. Connection point numbers are to be the average for the disclosure year

CAIDI: Is the value obtained by dividing SAIDI by SAIFI. It represents the average duration of outage experienced by those connection points that have had an outage in that year.

Consumer:	a person that consumes or acquires electricity lines services to which electricity is conveyed by means of works owned, provided, maintained and/or operated by EA Networks.
Network Connection Point:	means a point where a supply of electricity may flow between EA Networks' electric lines and the electrical installation of a consumer or consumers.
Urban:	means a zone or geographic area that is predominantly used for relatively high-density housing and business use.
Rural:	means a zone or geographic area that is predominantly used for farming, forestry, or recreation and cannot be construed as a city or township but is accessible by more than one major arterial road.
Remote:	means a zone or geographic area that is distant from the general location of the rural population. Typically served by only one minor road and subject to disruption of vehicular access during adverse weather.
Prescribed Voltage Electric Line:	means an electric line that is capable of conveying electricity at a voltage equal to or greater than 3.3 kilovolts.

Asset Performance Indicators

Fault:	means a physical condition that causes a device, component, or network element to fail to perform in the required manner.
Faults per 100km:	means the number of faults per 100 circuit kilometres of prescribed voltage electric line (can be broken down into per nominal line voltages).
System Length:	means the total circuit length (in kilometres) of the electric lines that form part of the EA Networks system.
System:	means all works owned, provided, maintained, or operated by EA Networks that are used or intended to be used for the conveyance or supply of electricity.

10.2 Appendix B – Asset Management Plan Cash-flow Schedule

This appendix contains the network capital cash-flow schedule which includes all capital items from the electricity network portion of the current EA Networks 2025-26 budget, the capital projects and programmes and baseline unscheduled capital expenditure currently identified as being necessary in the financial years 2026-35.

For legibility it is recommended that the following two pages are printed at A3.

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CAPITAL CASHFLOW ($ 000)												
Parent	Child	Name	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
11172		~Consumer Connection - Other (inc Large Subdivisions)	520	528	517	530	530	534	536	542	544	552
11136		~Consumer Connection - Rural Alteration Capacity	387	392	385	394	394	397	398	403	404	411
11136		~Consumer Connection - Rural Alteration Safety	491	498	488	500	500	504	506	512	513	521
11136		~Consumer Connection - Rural LV	362	367	360	368	369	371	372	377	378	384
11136		~Consumer Connection - Rural Transformer	696	706	692	709	709	715	716	725	727	739
11058		~Consumer Connection - Urban Alteration Capacity	24	25	24	25	25	25	25	25	25	26
11058		~Consumer Connection - Urban LV	151	154	150	154	154	155	156	158	158	161
11058		~Consumer Connection - Urban Transformer	46	46	46	47	47	47	47	48	48	49
-1006		~DTX - System Growth (inc 22kV Conversion)	1 402	1 302	1 276	1 308	1 308	347	132	134	134	136
-1005		~DTX - Renewal & Replacement	31	31	30	31	31	31	31	32	32	32
-1004		~DTX - Reliability, Safety & Environment	12	12	12	12	12	13	13	13	13	13
-1174		~DTX - Consumer Connection (Rural Capacity)	83	84	80	82	82	83	83	84	84	86
-1174		~DTX - Consumer Connection (Rural LV)	66	67	66	67	67	68	68	69	69	70
-1174		~DTX - Consumer Connection (Rural Safety)	92	82	80	82	82	83	83	84	84	86
-1174		~DTX - Consumer Connection (Rural TX)	367	372	365	374	374	377	378	382	383	389
-1175		~DTX - Consumer Connection (Urban TX)	37	37	36	37	37	38	38	38	38	39
-1007		~Non-Network - Routine Info Tech	977	557	232	546	475	475	475	475	475	475
11550		~Non-Network - Routine Building Work	48	808	95	95	95	95	95	95	95	95
-1009		~Non-Network - Routine Vehicles				66	66	66	66	66	66	66
-1008		~Non-Network - Routine Plant	10	10	10	10	10	10	10	10	10	10
-1007		~Non-Network - Routine Info Tech	86	30			50	50	50	50	50	50
11059		~Unscheduled System Growth	67	68	66	68	68	68	69	69	70	71
11078		~Unscheduled Quality of Supply	60	61	60	61	62	62	62	63	63	64
11079		~Unscheduled Other Reliability, Safety and Environment	63	64	63	64	64	65	65	66	66	67
11704		~Unscheduled Asset Replacement and Renewal	537	544	1 280	1 421	1 968	2 093	2 208	2 348	2 466	2 506
		SUBTOTAL ANNUAL PROGRAMMES	6 615	6 846	6 413	7 053	7 581	6 772	6 682	6 868	6 997	7 098
		11kV OH Rebuild - Company Rd. (Seafield Rd to Ashford Ave)	253									
		11kV OH Rebuild - Quarry Rd.	38									
13802	13802	11kV OH Rebuild - Seafield Rd (Bridge St East to end.)	437									
	13841	11kV OH Rebuild - Upper Downs Rd.	147									
	0	22 kV OH - Resolve Potential Ferroresonance Issues.	76	77	75	77	77					
-1203	0	22 kV OH - Switchgear Upgrade	87	88	86	88	88	89	89	90	91	92
13802	13802	22/11kV OH - Pole Replacements - Scheduled	103	104	102	105	105	106	106	107	107	109
13802	13802	22/11kV/LV OH - Pole Replacements - Unscheduled	53	54	53	54	54	54	54	55	55	56
13802	13802	22kV Conversion - Montalto / Rangitata	321									
13802	13802	22kV Conversion - Mvn Hwy Spngfld Rd to Mvn, AForest to Nwtns Cnr	67									
		22kV OH New - Quarry Rd.	196									
13802	13802	22kV OH Rebuild - Bruces Rd	34									
		22kV OH Rebuild - Dicksons Rd.	53									
		22kV OH Rebuild - Hardys Rd.	45									
		22kV OH Rebuild - Highbank School Rd	118									
		22kV OH Rebuild - Jaines Rd (Hackthorne Rd East)	129									
		22kV OH Rebuild - Kyle Rd.	118									
		22kV OH Rebuild - Longs Rd.	133									
13802	13802	22kV OH Rebuild - Muckles Rd	64									
		22kV OH Rebuild - Normanby & Sheehans Rds	64									
13802	13802	22kV OH Rebuild - Rushford Rd.	113									
		22kV OH Rebuild - SOPL Rebuild Programme	461	585	573	470	252	254	255	258	259	263
		22kV OH Rebuild - Swamp Rd. - Section 1 (Maronan Rd to Scales Rd)	194									
		22kV OH Rebuild - Transformer Pole Replacements	968	1 228	1 203	986	424	427	428	433	434	441
		22kV OH Rebuild - Unnamed Rd Ealing	20									
		22kV OH Rebuild - Unnamed Rd off River Rd	50									
		22kV OH Rebuild - Wards Rd.	67									
13802	13802	22kV OH Reconductor - Unscheduled	40	40	40	41	41	41	41	41	42	42
13570		22kV Surge Arrester - Replacement Programme	418	424	416							
13048	13048	66kV OH Dampers Installation.	123	124	122							
13048	13048	66kV OH New - LSN-LSNT	97									
	0	Consumer Connection - MSO Solar Farm - 15.3MW	1 930									
	0	Consumer Connection - MSSF Solar Farm - 0.999MW	244									
	0	Consumer Connection - TFSF Solar Farm - 4.4MW	77									
700		Consumer Connection - ANZCO Security of Supply & Capacity Upgrade	151									
13048	13048	DSS - Earthing Upgrades	53	54	53	54	54	55	55	56	56	57
-1189		DSS Rebuild - Tancred St 77 Substation	215									
12747	12747	DSS Replacement - Reclosers End of Life	72	73	72							
12766	12766	New Technology - LV Network Monitoring	283									
-1202	0	Non-Network - Cable Rating Software	23									
		Non-Network - Hardware - Industrial Acoustic Imaging Camera	36									
12087	11636	SCADA - Distribution Automation Programme	83	84	83	85	85					
		Transpower Crossings - Improve Clearances	59									
12747	12747	UG Conversion - Carters Tce (SH1 - Grove St)	565									
		ANNUAL TOTAL	20 964	16 642	19 457	14 748	14 650	13 591	13 291	11 963	11 713	10 447

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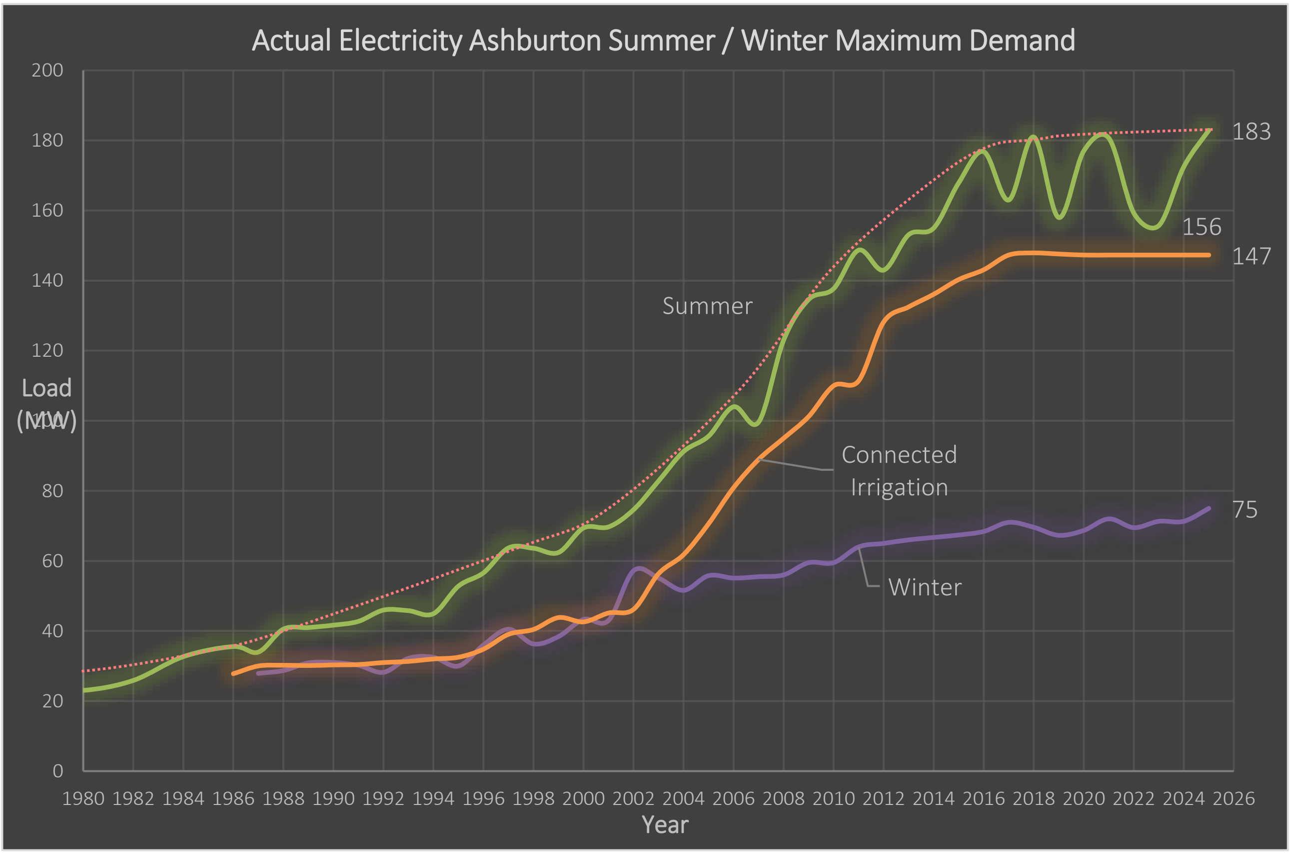
Parent	Child	Name	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
		UG Conversion - Lake Heron Line	2 188									
12747	12747	UG Conversion - Longbeach Rd.	186									
13736	13736	UG Conversion - Lower Hakatere Huts Stage 3B	335									
-1121		UG Conversion - Methven Hwy (Shearers Rd to Springfield Rd)	1 100									
13736	13736	UG Conversion - Oxford St (Beach Rd - Wellington St)	636									
13736	13736	UG Conversion - South Town Belt East (Bridge St - Burrowes Rd)	602									
12755		ZSS - Protection - Replace 20 year Old Numeric Relays	190	85	83	85	85	86	86	87	88	89
13736	13736	ZSS - Substation Security Access Control Replacement Programme	33	39	28							
13736	13736	ZSS - Synchrophasors	41									
-1148		ZSS ASH - Ripple Injection Generator Replacement	160									
-1148		ZSS EGN - Ripple Injection Generator Replacement		66								
12469		11kV Core Network Cables		108	106	503	644	1 115	634	978	691	
12470		11kV Core Network Centres		397	573	385	423		514	269	728	
13736	13736	11kV OH Rebuild - Klondyke Tce to Rangitata River Crossing		158								
12050	12050	11kV OH Rebuild - Rangitata Gorge Bluffs		166								
-1133		22kV Conversion - Anama		333								
		22kV Conversion - Quarry Rd		240								
		22kV OH Rebuild - Ashburton Staveley Rd		208								
		22kV OH Rebuild - Blacks Rd.		71								
		22kV OH Rebuild - Chertsey Kyle Rd.		208								
		22kV OH Rebuild - Christys Rd.		43								
-1092		22kV OH Rebuild - Copley Rd (Chertsey Kyle Rd East to end.)		139								
-1116		22kV OH Rebuild - Mayfield Klondyke Rd (RDR)		72								
		22kV OH Rebuild - Swamp Rd. - Section 3 (Winslow Rd to Hendersons		101								
		22kV OH Rebuild - Trevors Rd.		70								
		22kV OH Rebuild - Wakanui School Rd.		27								
	0	33 kV OH Rebuild - MTV-MHT Line		762		765						
700		Decarbonisation & Smart Technology Programme		1 949	617	38	2 112	1 833	2 134	2 160	2 166	2 201
-1190		DSS Rebuild - Wills St 161 Substation		282								
12050	12050	UG Conversion - Melcombe St (Anne St - Lagmhor Rd)		356								
13982	13982	UG Conversion - Rakaia Huts		816								
-1126		ZSS MSM - Mt Somers to Montalto 22 kV Feeder Protection		164								
-1139		22kV Conversion - Highbank			422							
-1116		22kV OH Rebuild - Anama School Rd & Blairs Rd (Hekeao Rd to Lower			320							
-1116		22kV OH Rebuild - Anama School Rd (ARG Rd to Hekeao Rd)			262							
		22kV OH Rebuild - Emersons Rd			118							
		22kV OH Rebuild - Longbeach Rd. (Grahams Rd to Lower Beach Rd)			222							
-1116		22kV OH Rebuild - Lower Downs Rd & Mayfield Klondyke Rd			353							
		22kV OH Rebuild - Rangitata Hwy - Section 1 (Frisbys Rd to Giddings Rd			99							
		22kV OH Rebuild - Rangitata Hwy - Section 2 (Giddings Rd to Ealing Rd			106							
		22kV OH Rebuild - Swamp Rd. - Section 2 (Scales Rd to Winslow Rd)			81							
700	0	66 kV OH New - EGN-FTN			1 233	1 263						
	0	Consumer Connection - SSF Solar Farm 30MW			1 971							
700		Non-Network - ADMS Basic DERMS			533							
-1136		UG Conversion - Farm Rd (Middle Rd - Racecourse Rd)			718							
-1157		UG Conversion - Graham Street (Thomson St - McMurdo)			209							
-1187		UG Conversion - Line Rd Methven (200m LV)			105							
-1152		UG Conversion - Rolleston Street (Tancred St - Burrowes Rd)			718							
-1153		UG Conversion - South Town Belt - West (West Town Belt - SH1)			718							
13768	13768	UG Conversion - Wilkin St (McMurdo St - Millibrook Pl)			361							
700	0	ZSS EGN - New EGN-FTN 66 kV Line Bay			210							
-1150		22kV Conversion - Waimarama/Mt Hutt / Lower Rakaia Gorge				357	329					
500		Non-Network - Corporate UPS Battery Replacement				99		19				
	0	UG Conversion - Mt Hutt Station Road (Holmes Rd to Back Track)				570						
-1138		UG Conversion - Racecourse Rd (Creek Rd - Allens Rd)				713						
-1162		UG Conversion - Shearman St				112						
700	0	ZSS FTN - New EGN-FTN 66 kV Line Bay				450						
700	0	ZSS FTN - Rearrange for 22 kV loading				396						
13370	13370	UG Conversion - Allens Road (Harrison St-Alford Forest Rd)					723					
-1158		UG Conversion - Thomson St (Carter Tce - Wilkin St)					327					
-1149		ZSS TIN - New 66/11kV Transformer					1 246					
-1154		22kV Conversion - Ashburton Gorge						404				
-1160		UG Conversion - Agnes St (McMurdo St - Grove St)						460				
-1161		UG Conversion - Catherine St (McMurdo St - Grove St)						403				
-1158		UG Conversion - Thomson St (Wilkin St - Graham St)						1 474				
-1138		UG Conversion - Racecourse Rd (Allens Rd to Farm Rd)							721			
-1158		UG Conversion - Thomson St (Grahams St - Hassel St)							1 493			
700		Non-Network - ADMS Advanced DERMS								559		
		ANNUAL TOTAL	20 964	16 642	19 457	14 748	14 650	13 591	13 291	11 963	11 713	10 447

10.3 *Appendix C – Forecast Load Growth*

Future load estimation is as much art as it is science. There are two main techniques one can use to try and predict future load. The first approach is to look at historical trends and extrapolate these into the future (referred to in this plan as projection). The second approach is to model the loads and estimate the impact of various factors such as the economy, commodity prices, resource availability, legislative changes, weather, etc on the future loads placed on the network (referred to in this plan as estimation). During periods of high load growth, the projection technique appeared to offer a reasonable fit. Now that constraints have come on water for irrigation, the historical information that projection relies upon is no longer valid for load growth prediction. EA Networks have now moved to use the estimation technique which offers more granularity, albeit with less hard data to justify it. The long-term demand graph shown below indicates the correlation between connected irrigation growth and summer peak demand growth. In the last five years there has been zero net increase of connected irrigation.

The estimation approach is more time consuming and detailed, but it does offer the advantage of estimating zone substation maximum demands individually. The model EA Networks has chosen takes each substation and derives a series of base load curves for the current year from about 4-5 years of historical data sourced from zone substation power quality meters. A real power and reactive power curve is created for an average and maximum day of each month. The average is the average load for each half hour of the day of that month for every year of the historical sample. Maximum curves are also derived that take the maximum for each half hour of the days/month/years. This gives a series of 24 loading curves for each zone substation that can be used to forecast loading at different locations on the network at different times of the day and year. Generation curves are created in a similar fashion. The curves are created as per unit values with the absolute maximum value as one (1.0). This allows curve scaling with a single maximum demand number stored in a separate table rather than embedding actual loads into the curve. The previously separately forecast irrigation load is now part of the base curves, and the static nature of irrigation load growth means it is no longer a load forecast variable. It may be separately modelled again in future if an increase or decrease in irrigation load can be foreseen. Additional forecast curves are created for known future loads such as large generators, rooftop solar at a zone substation level, and EV charging at a zone substation level. The base load curve and the future load/generation curves are combined to offer an estimation of the future load at zone substation level, individual subtransmission line level



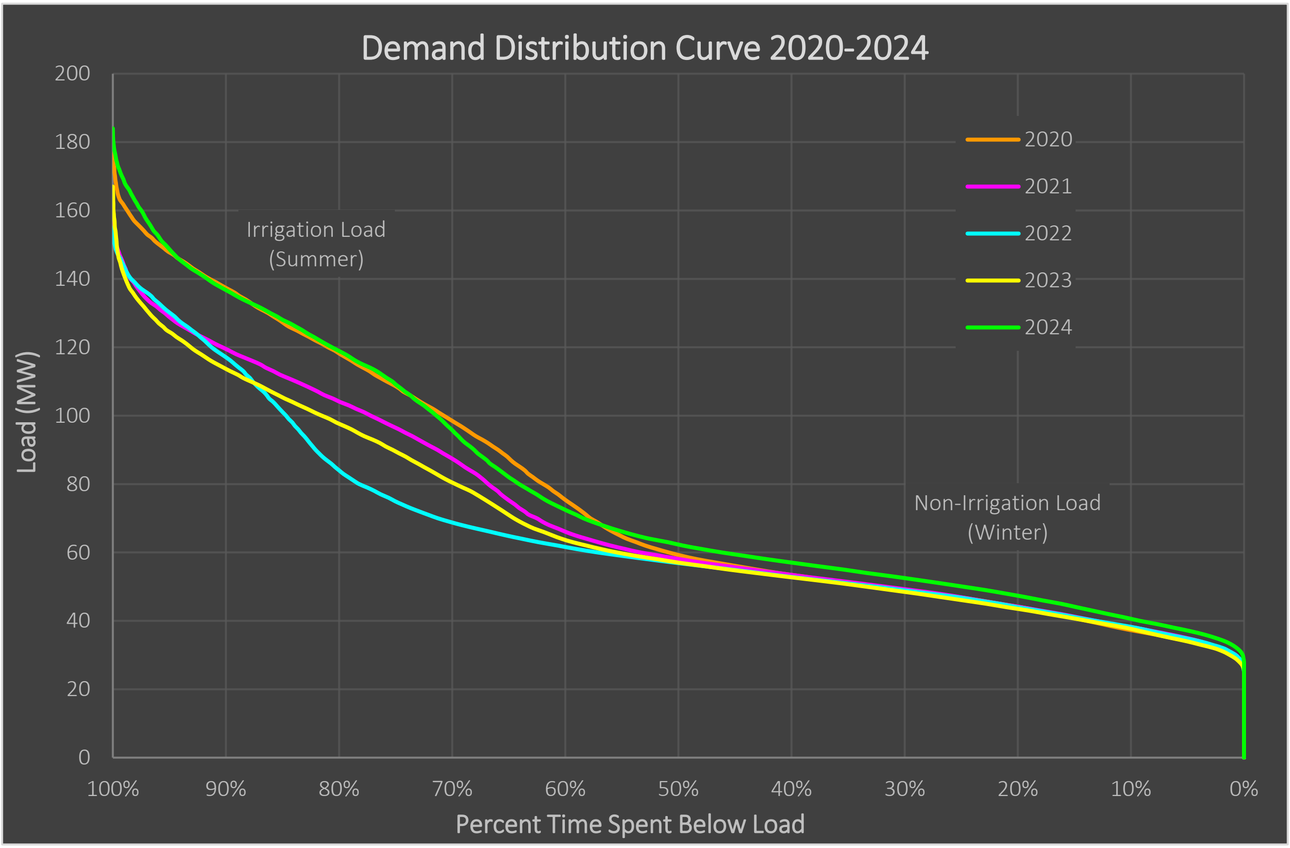
and, ultimately, Transpower GXP maximum demand. Base load growth at each substation is estimated from a trend in load during non-irrigation periods. These trends require somewhat subjective assessments but attempt to represent a likely increase in many small loads. The chart *Actual and Estimated EA Networks Summer/Winter Maximum Demands* (see section 5.2.4) and the table *Zone Substation Load Predictions* (see below) show the results of this modelling. This curve-based estimation technique is new, and EA Networks will develop and mature the technique over the next few years. The values it provides will be used as a realistic/minimum growth curve for the 2025-35 plan.

Zone Substation Load Predictions					
Substation	2025 Load (MVA)	2030 Load (MVA)	2035 Load (MVA)	Summer/ Winter Peak	Firm n-1, sw, n *
Ashburton (66/11kV)	21	16.4	17	W	22_{n-1}, 30_{sw}
Carew (66/22kV)	16	16.4	16.7	S	15_{n-1}, 20_{sw}
Coldstream (66/22kV)	12	12.3	12.5	S	n, 10_{sw}
Dorie (66/22kV)	11	11.2	11.4	S	n, 10_{sw}
Eiffelton (66/22kV)	13	13.3	13.5	S	n, 10_{sw}
Elgin (66/22kV)	4	4.1	4.2	S	n, 7_{sw}
Fairton11 (66/11kV)	4	4.4	4.8	All	n, 10_{sw}
Fairton22 (66/22kV)	9	9.2	10	S	n, 15_{sw}
Hackthorne (66/22kV)	15	15.3	15.6	S	n, 10_{sw}
Lagmhor (66/22kV)	11	11.2	11.4	S	n, 10_{sw}
Lauriston (66/22kV)	16	16.3	16.6	S	20_{n-1}, 25_{sw}
Methven11 (66/11kV)	5	5.1	5.2	W	n, 8_{sw}
Methven22 (66/22kV)	4	4.1	4.2	S	n, 8_{sw}
Methven33 (22/33kV)	3	3.1	3.1	W	n
Montalto (33/11kV)	3	-	-	S	n, 1_{sw}
Mt Hutt (33/11kV)	3	3.1	3.1	W	n, 1_{sw}
Mt Somers22 (66/22kV)	6	6.1	6.2	S	n, 8_{sw}
Mt Somers33 (22/33kV)	3	-	-	S	n
Northtown (66/11kV)	14	15.3	16	W	22_{n-1}, 30_{sw}
Overdale (66/22kV)	13	13.3	13.6	S	n, 10_{sw}
Pendarves (66/22kV)	17	17.3	17.6	S	22_{n-1}, 25_{sw}
Seafield (66/11kV)	8	9	11	All	n, 5_{sw}
Tinwald (66/11kV)	-	6	7	W	n, 10_{sw} (2030+)
Wakanui (66/22kV)	8	8.1	8.2	S	n, 10_{sw}

***** Firm capacity is defined by the remaining capacity on loss of the largest asset. **n-1** capacity is the capacity with no loss of supply, **sw** capacity is the capacity after switching with short loss of supply, and **n** represents capacity with loss of supply.

It should be noted that the firm capacity referred to in the table above is the present firm capacity (steady state and switched) and this will change with development in the network (both subtransmission and distribution development). Some of the firm capacity constraints are addressed by network development projects during the plan period.

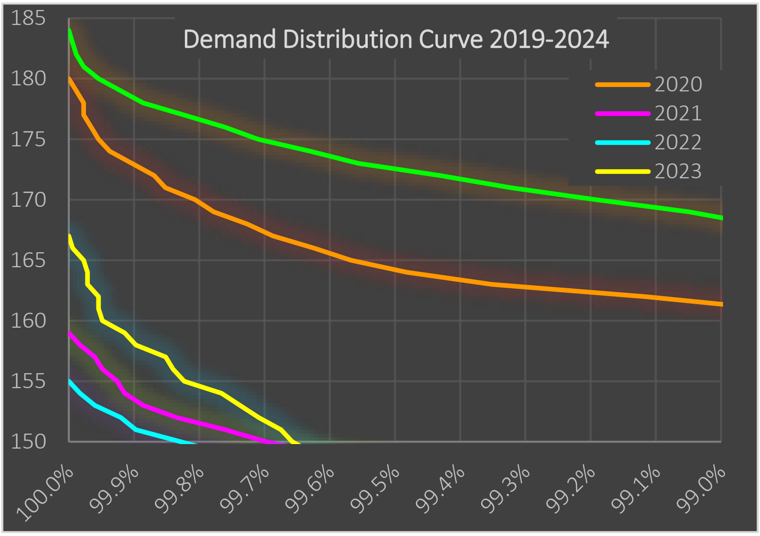
The load forecasts assume a dry year (low diversity) and a cold winter, as that is the demand the network must cope with and when the irrigation capacity is most needed. The risk of irrigation load falling because of surface irrigation scheme piping has resulted in a change of approach for load estimation. Dry year estimates are used as the realistic load estimate for subtransmission planning. Future individual zone substation loads are assessed using non-diverse load estimates.



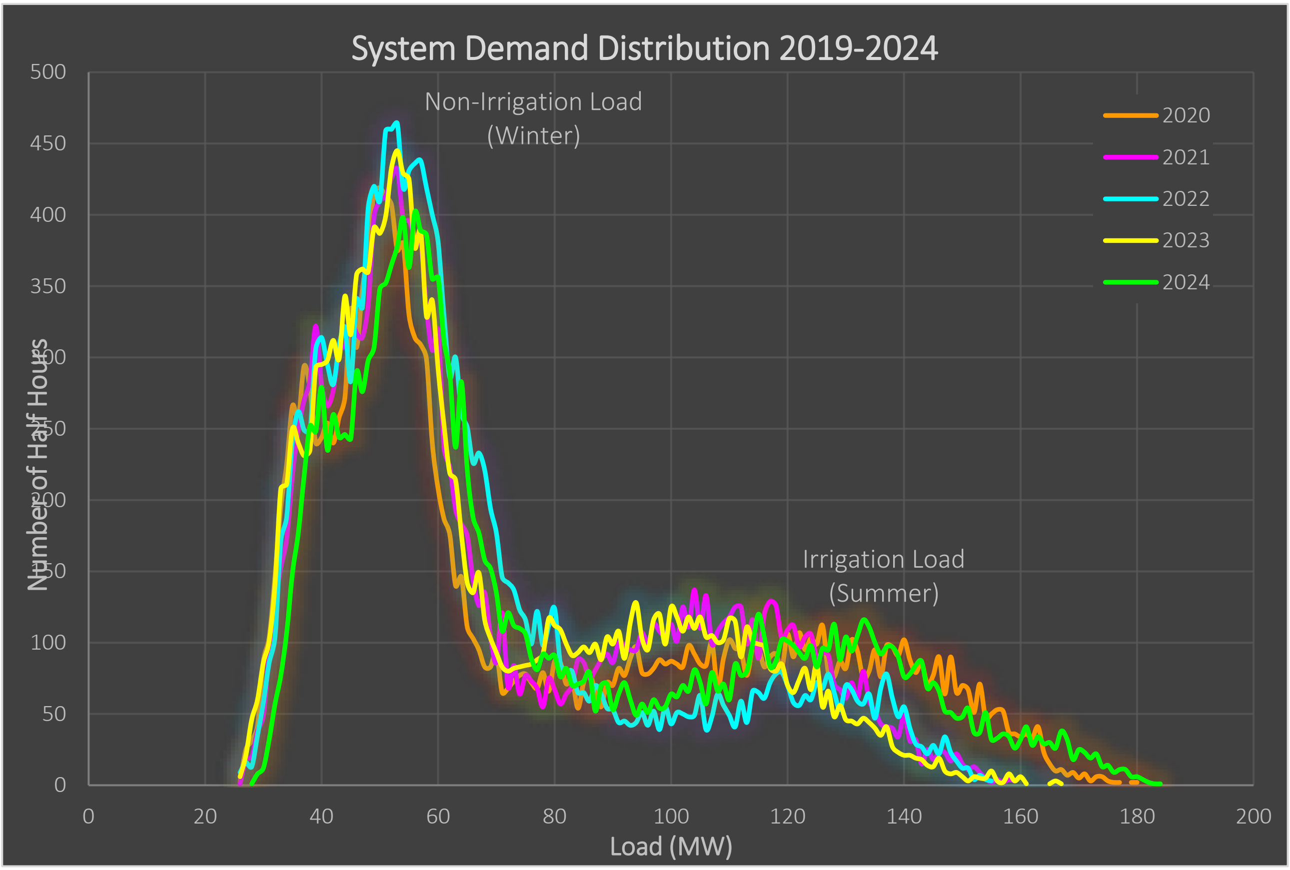
Hours Spent Above Load	2019	2020	2021	2022	2023	2024
≥110 MW	889	2 178	1 478	1 107	1 127	2 200
≥160 MW	75	129	-	-	8	237
≥170 MW	9	19	-	-	-	83
≥180 MW	-	1	-	-	-	7

The two charts shown above and below represent demand duration data for the 2020, 2021, 2022, 2023, and 2024 calendar years. The charts show the seasonal sensitivity of the system demand as well as the demand duration sensitivity of rain during summer. A marked transition occurs from summer high demand to base winter demand (where Highbank generation of 20-26 MW is running but is not visible here). The demand below 70 MW is considered winter demand, or summer base demand. The third (frequency

distribution) chart has two distinct *humps* that show the winter demand (25-65 MW) and summer demand (70-184 MW). A considerable amount of productive *growing* time is spent beyond 150 MW and the irrigation consumers causing this peak have indicated they are prepared to pay for the assets (both EA Networks and Transpower) necessary to avoid load control of the absolute peak demand.



The summer of 2024 started with irrigation beginning in October, but significant rain caused lower levels of load during October and November. Early to mid-December was peak irrigation, and a new all-time maximum demand occurred during this period. The actual summer peak demand (183 MW) was very similar to that previously predicted for a dry year and was not unexpected during a dry December. 2021, 2022, and 2023 were all wet summers that suppressed peak demand. 2020 and 2024 were summers with distinct dry periods that drove higher peak demands (less irrigation diversity). Both diagrams show the impact dry conditions have on irrigation demand duration and peak. In the past six years a total of 111 hours has been spent above 170 MW and only eight hours above 180 MW.



EA Networks have reached a point in time where some of the underlying assumptions about summer load growth have changed. The total amount of water that can be abstracted from underground aquifers in much of Mid-Canterbury has reached the limit stipulated by ECAN. This limit forces other sources of water to be sought. These other sources are typically obtained from storage regimes and water conservation from existing river abstraction schemes. The piping of existing open race schemes can have a twofold effect:

1) The losses from open race systems are eliminated and that water is now available to the scheme as *new* water.

2) The pipe system is gravity pressurised for most of its length, and this allows existing electrical surface pumps to be relinquished or saved only for a dry year. It also can permit some small hydro generation options.

Some of the farms that have *new* surface water available are existing deep well irrigators with a water abstraction consent and a large electrical pump. This deep well water consent is to some degree portable in that the water is no longer taken from the aquifer so another farmer can apply for the consent to take water from the same aquifer. Initially, it is likely that the original consent holder will retain the consent and deep well pump to guarantee reliability of water supply during drought conditions (river-based schemes may be restricted). If the piped gravity scheme proves to be reliable, the electrical demand from the deep well pump may shift to a less traditional irrigation area that is less well serviced for this type of demand by EA Networks. Overall, the demand for water from all sources will remain high. It is very unlikely the total electrical pumping demand will fall considerably in the medium term. The growth rate in irrigation demand will be minimal at best.

The other environmental issue that constrains rural intensification is that of nutrient run-off. ECAN have released a decision on a variation to the Regional Water Plan that:

- precludes almost all additional water abstraction south of the Ashburton River,
- places strict limits on groundwater nitrate levels, and
- places strict limits on the quantity of nitrogen run-off from farming operations.

In 2020, the Government released a *National Environmental Standard (Regulations:2020)* as part of the *Essential Freshwater* package that further constrained the nitrogen discharge limits into water. The consequences of this standard have been significant for the Ashburton region. A report was released that concluded dairy farming profitability would decline by 83% and farm expenditure would decline by -$139.9M. It is unknown what the actual impact has been, but it will obviously flow through to other sectors. It is not clear how any consequent land-use changes will impact irrigation usage. The Government has now indicated it intended to begin work on a replacement for the National Policy Statement for Freshwater Management (NPS-FM) in 2024. The result of this amendment may have an impact on load forecasting once it become clear what it contains.

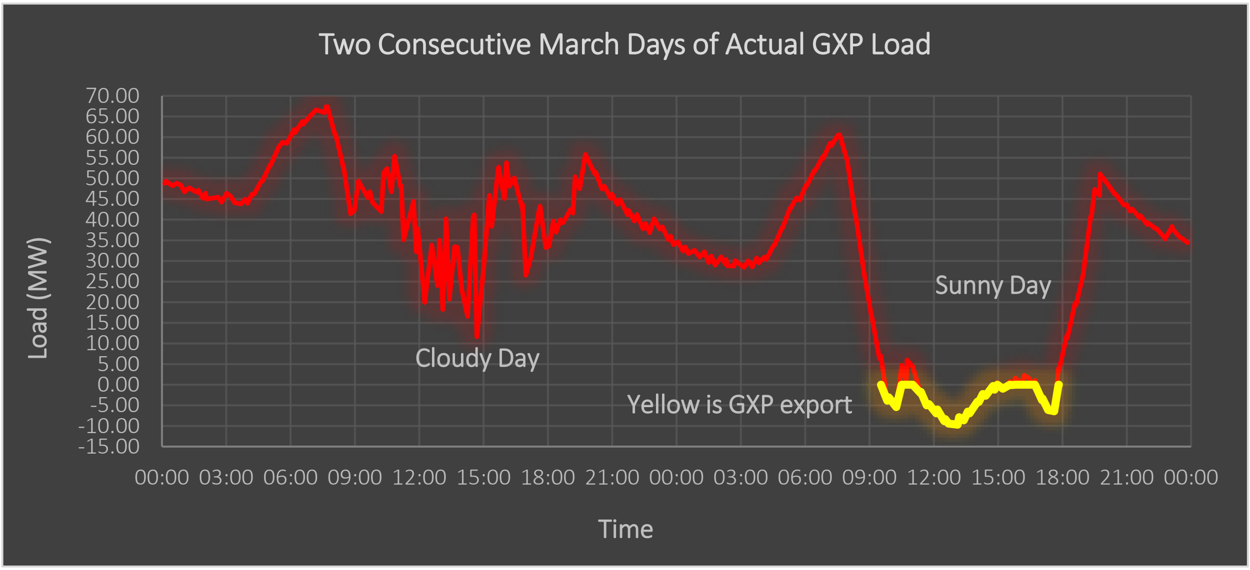
These additional 2020 restrictions resulted in EA Networks capping the irrigation load growth potential in all areas of the Ashburton District. The area north of the Ashburton River may have some capability for additional irrigation development but it is likely to be delivered via a gravity pressurised scheme and not electric pumping.

EA Networks are planning on the basis that all available deep well consents will be used, and some existing surface electrical pumps will be substituted by gravity pressurised pipe schemes. The level of generation provided by piped schemes has been low (of the order of a few MW at best) and will not materially affect the GXP load. It may however affect particular zone substation loads and delay the need for transformer upgrades and similar demand-driven asset intensive solutions.

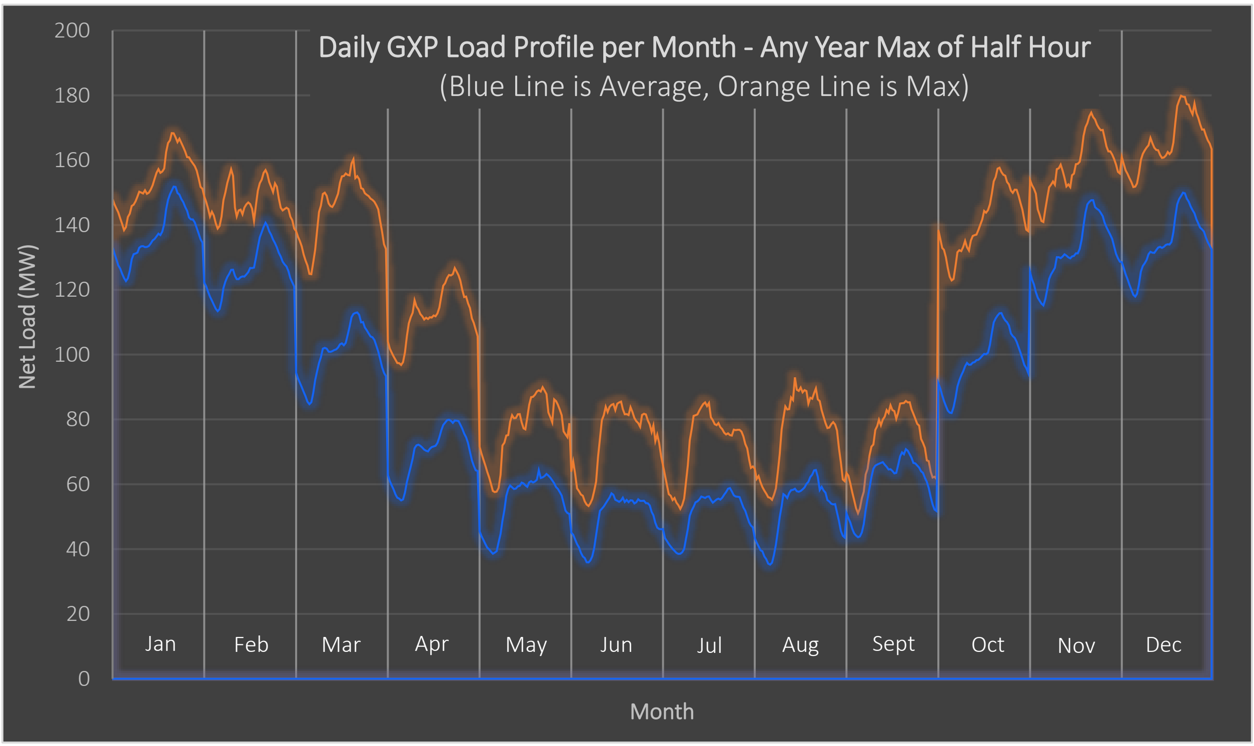
There is a remote possibility that some additional pumping at Highbank may be developed. Prior to the *Essential Freshwater* package being released, there had been discussions around making more water available for irrigation by adding up to 3 MW of additional pumps at the existing or another site. At this stage, the additional pumps appear to be unlikely in the next 5 years.

The prospect of electric vehicle (EV) charging causing significant impacts on the distribution network are real and will occur at some future time. At the moment, the penetration of EVs is low but over the next ten years it will grow. The critical factor for the impact of EVs is the timing of the charging cycle. The cost of energy will initially remain least expensive in the off-peak periods which will encourage charging from 11:00 pm to 6:00 am. Provided the bulk of controlled charging takes place during this period the impact on peak demand should be low, although at some future time there is the potential for midnight peaks to occur. The impact of EV charging has now been factored into the GXP demand. Once EV uptake increases, it will become more apparent how owners choose to operate the charging facilities both at home and elsewhere. The study that DETA undertook examining future EV charging forecasts has been incorporated into the loading estimates in this study. Up until 2035 the forecast impact at zone substation/GXP level is minor. Beyond 2035 the forecast shows more impact especially if charging is not effectively scheduled/controlled to avoid adding to existing peaks or creating new ones.

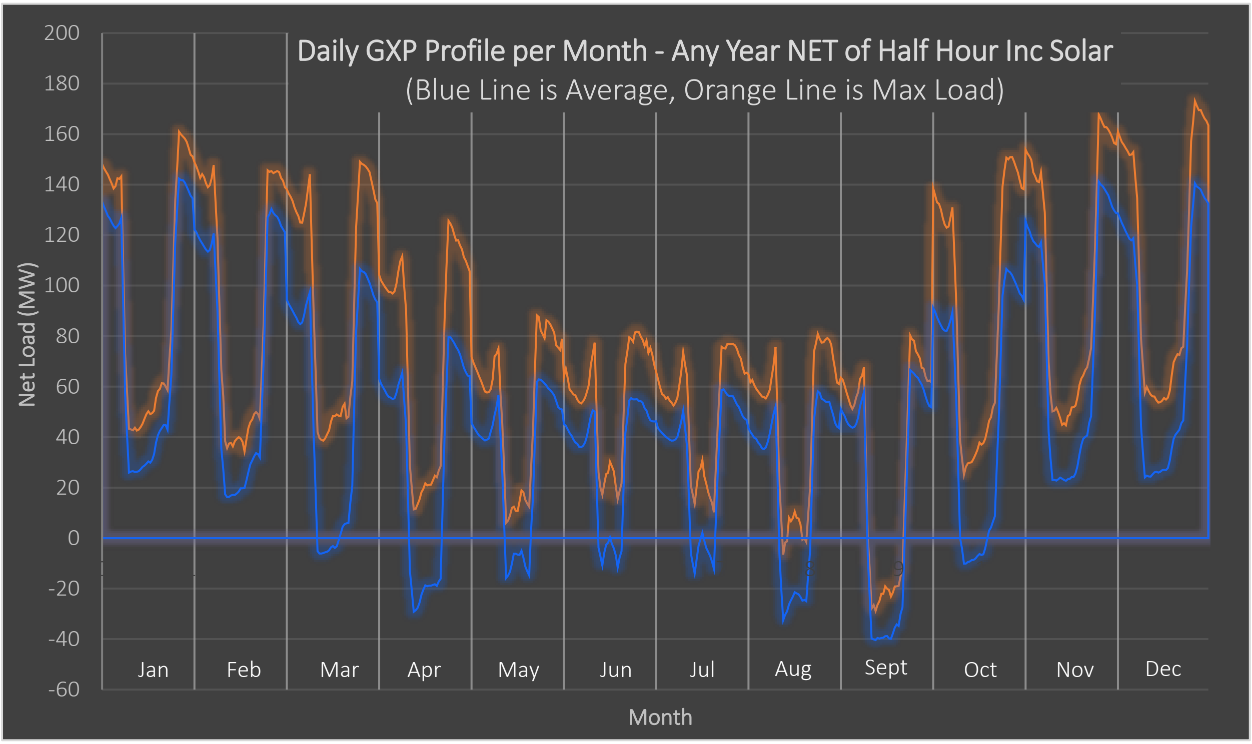
Solar photovoltaic electricity generation is becoming reasonably common (EA Networks have approximately 670 Solar PV installations). The combined total output is 61.9MW (which includes utility scale solar). Excluding individual solar over 500kW, the total is 7.4MW (much of which will be consumed on the load side of the meter). The average size <500 kW of these installations is about 11 kW each. The impact of Solar PV is now clearly seen in the peak demand of the Transpower grid exit point, some zone substations, as well as at distribution substation level.



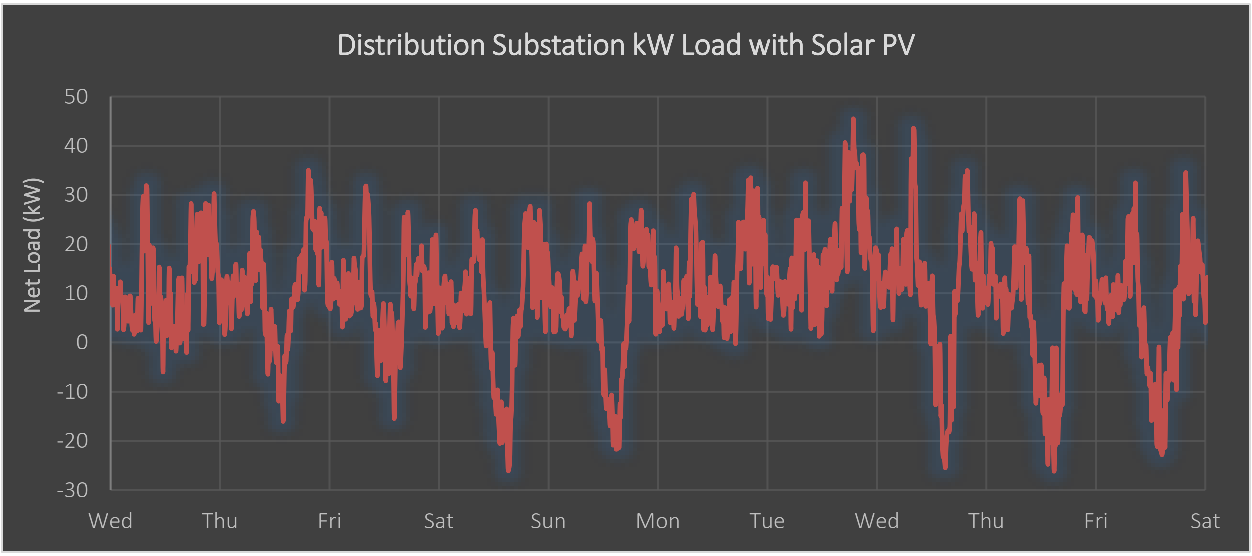
The impact of Solar PV generation has been factored into the 10-year GXP demand. Solar (on a sunny day) does reduce mid-late afternoon December peaks at the GXP, which is when EA Networks' GXP maximum demand traditionally occurs. This shifts the new GXP peak to later in the evening. The two solar farms that have been commissioned in late 2024 are supplying notable amounts of energy and at times of low load are capable of supplying all EA Networks' load in the middle of a sunny day much as shown in the chart below. Significant applications have been received for further utility scale solar farm connections, totalling circa 56MW. If all applications are commissioned, total distributed generation would be approximately 137MW (solar and hydro). In general, while connection assets would have to be constructed, so far there does not seem to be the need for significant extra network capacity to accommodate this new generation. Solar generation at this scale has already influenced the network peak load at the GXP to some degree, but due to the fluctuation of solar, will not provide firm capacity offset. The 24h nature of irrigation load means that the impact of solar on system peak is a small fraction of the total solar capacity. The summer peaks will probably shift to later in the evening on sunny days and be about 10 MW lower than previous. Generation output will require voltage control and monitoring, and generation run-back schemes will be required due to constraints that may arise during subtransmission contingencies.



The graphs above and below illustrate the potential (and now observed) impact solar generation would have on the GXP daily load profile for each month of the year. The first graph is the average daily load per month over the period 2011-2021. The second graph shows the impact of 109MW of solar (the current rating under



application or connected). On average, the GXP would export for some of an average day for eight of the twelve months. Even with 107 MW of solar, the GXP maximum demand is still on average 142 MW, and in very dry years it would have peaked at 173MW, only 8 MW lower than without the solar (irrigation is 24/7).



The potential for coal or gas process heat to be converted to electrical demand is a possibility. Some research has been done about the scale of process heat locally. It is possible up to 20 MW of electrical demand may eventuate from existing boilers being converted. EA Networks engaged Deta Consultants to interview known fossil fuel consent holders and determine their plans and the suitability for conversion to electrical heating. There are still no firm proposals in place, but it is looking likely that some conversion will occur. To that end, about 1 MW of new load has been incorporated as additional planned demand. Some of the possible new load (above the 1MW included in load estimates) can be supplied using existing assets, but it may require additional assets to maintain the current levels of security. Te Whatu Ora's Ashburton Hospital has converted to groundwater heat pumps (~800 kW total) to displace coal fired boilers. This may also have a minor impact on summer demand as the system can also be used for cooling.

With the possibility of land use changes caused by the Essential Freshwater package and ultimately climate change, it is possible additional agricultural process loads could be attracted to Mid-Canterbury. Industries such as vegetable processing could become more common than those that exist currently. A small allowance has been made in the process heat conversion additional load for a known vegetable processing plant that is likely to use electrical heating for most process heat. There could be other, as yet unknown, vegetable processing participants that find Mid-Canterbury an attractive option for establishing new plants. As the impacts of nutrient discharge regulations and climate change become apparent, future plans will document the likely impact on the electricity demand.

10.4 Appendix D – Disclosure Cross-References

To assist people reading this plan in relation to the Electricity Information Disclosure Requirements, a cross-reference list of mandatory items is shown here. This allows the reader to find all items listed in *Attachment A* of the *Electricity Information Disclosure Determination 2012* without searching the entire plan.

3. The AMP must include the following-

3.1 A summary	Exec. Summary
Background and Objectives	
3.2 Details of the background and objectives of the EDB's asset management and planning processes	s1
3.3 A purpose statement which-	
3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices.	s1.3, s1.5
3.3.2 states the corporate mission or vision as it relates to asset management	s1.4, s1.7
3.3.3 identifies the documented plans produced by the annual business planning process	s1.6
3.3.4 how do the different documented plans relate to one another, particularly asset management	s1.6
3.3.5 the interaction of the objectives of the AMP and other corporate goals, business processes, and plans	s1.6, s1.7
3.4 Details of the AMP planning period	s1.5
3.5 The date that it was approved by the directors	I.F.C.
3.6 A description of stakeholder interests identifying important stakeholders and indicates -	s1.2
3.6.1 how the interests of stakeholders are identified	s1.2
3.6.2 what these interests are	s1.2
3.6.3 how these interests are accommodated in asset management practices	s1.2, s1.4
3.6.4 how conflicting interests are managed	s3.2
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	
3.7.1 governance	s1.3, s1.6
3.7.2 executive	s1.3
3.7.3 field operations	s1.9
3.8 All significant assumptions	s1.10
3.8.1 quantified where possible	s1.10
3.8.2 clearly identified in an understandable manner to interested persons, including	s1.10

3.8.3 a description of changes proposed where the information is not based on the EDB's existing business	s1.10.3
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information	s1.10
3.8.5 the price inflator assumptions used to prepare nominal New Zealand dollar costs	s1.10.6
3.9 Factors that may lead to a material difference (disclosed vs future actual)	s1.10, s9.1
3.10 An overview of asset management strategy and delivery	s1.7
3.11 An overview of systems and information management data	s1.8, 6.2.5
3.12 Any limitations in the asset management data and any data improvement initiatives	s1.8
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance	s6.2.5, s6
3.13.2 planning and implementing network development projects	s5.1.6 – s5.1.8
3.13.3 measuring network performance.	s9
3.14 An overview of asset management documentation, controls, and review processes	Not Available
3.15 An overview of communication and participation processes	Not Available
3.16 AMP must present all financial values in constant price NZD except where specified otherwise;	Compliant
3.17 The AMP must be structured and presented to support the purposes of AMP disclosure (clause 2.6.2)	Compliant
Assets covered	
4. The AMP must provide details of the assets covered, including-	
4.1 a high-level description of the service areas covered, including-	
4.1.1 the region(s) covered	s4.1
4.1.2 identification of large consumers that have a significant impact on the network	s4.1
4.1.3 description of the load characteristics for different parts of the network	s4.1
4.1.4 peak demand and total energy delivered in the previous year	s4.1, s1.1
4.2 a description of the network configuration, including-	s4.2
4.2.1 GXPs and any DG greater than 1 MW inc. firm supply capacity and current peak load;	s4.2.1
4.2.2 subtransmission system off each GXP, and security/capacity of zone substations.	s4.2.2, s4.2.3
4.2.3 a description of the distribution system, including the extent to which it is underground;	s4.2.4, s6.4.2

4.2.4 a brief description of the network's distribution substation arrangements;	s4.2.4.2
4.2.5 a description of the low voltage network including the extent to which it is underground; and	s4.2.4.3, s6.5.2
4.2.6 assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	s4.2.5
4.2.7 a quantification of the contribution each non-network solution makes towards solving a network risk or constraint, and the extent to which those non-network solutions are provided by a related party, or third party.	s5.1.9
4.3 sub-networks as per subclause 4.2.	Not Applicable
Network assets by category	
4.4 The AMP must describe the network assets by providing the following information for each asset category-	
4.4.1 voltage levels;	s6.3 – s6.15
4.4.2 description and quantity of assets;	s6.3 – s6.15
4.4.3 age profiles; and	s6.3 – s6.15
4.4.4 condition of the assets	s6.3 – s6.15
4.5 The asset categories discussed in subclause 4.4 above should include at least the following-	
4.5.1 Sub transmission	s6.3
4.5.2 Zone substations	s6.7
4.5.3 Distribution and LV lines	s6.4.1, s6.5.1
4.5.4 Distribution and LV cables	s6.4.2, s6.5.2
4.5.5 Distribution substations and transformers	s6.8, s6.9
4.5.6 Distribution switchgear	s6.10, s6.11
4.5.7 Other system fixed assets	s6.12, s6.13, s6.14, s6.15
4.5.8 Other assets;	s7.1
4.5.9 Assets owned by the EDB but installed at bulk electricity supply points owned by others;	s6.15
4.5.10 Reliability and security mobile substations and generators; and	Not Applicable
4.5.11 Other generation plant owned by the EDB.	Not Applicable
Service Levels	
5. A set of performance indicators.	s3.5
6. Performance indicators SAIDI and SAIFI values for the next 5 disclosure years.	s3.5.1, s3.5.3
7. Performance indicators for which targets have been defined in clause 5 above should also include-	

7.1 Consumer oriented indicators that preferably differentiate between different consumer types;	s3.5
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency.	s3.5
8. Basis on which the target level for each performance indicator was determined.	s3.2, s3.4
9. Targets should be compared to historic values where available to provide context and scale to the reader.	s3.5.1
10. Forecast expenditure materially affecting performance vs target – expected change.	s3.5.3
Network Development Planning	
11. AMPs must provide a detailed description of network development plans, including-	
11.1 A description of the planning criteria and assumptions for network development;	s5.1, s5.2
11.2 Planning criteria for network developments should be described logically and succinctly;	Compliant
11.3 Strategies or processes promoting cost efficiency;	s5 By Asset Category
11.4 The use of standardised designs may lead to improved cost efficiencies.	s5.1.4
11.4.1 the categories of assets and designs that are standardised;	s5.1.4
11.4.2 the approach used to identify standard designs.	s5.1.4
11.5 Energy efficiency strategies or processes.	s5.3
11.6 Equipment capacity for different types of assets or different parts of the network.	s5 By Asset Category
11.7 Prioritising network development projects.	s5.1.11
11.8 Demand forecasts – basis, constraint locations;	s5.2, Appendix C
11.8.1 load forecasting methodology and factors;	s5.2, Appendix C
11.8.2 forecasts to zone substation. Uncertain but substantial load accounted in forecasts;	s5.2, Appendix C
11.8.3 network or equipment constraints; and	s5 By Asset Category
11.8.4 Non-network, DG, and demand management impact on the load forecasts.	s5.2, s5.4.12 Appendix C,
11.9 Significant network level development options identified satisfying target levels of service, including-	s5.3
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	s5.3
11.9.2 alternative options for projects planned within five years and any non-network solutions;	s5 By Project and s5.1.9
11.9.3 planned innovations that improve efficiencies, utilisation, asset lives, and defer investment.	Various locations

11.10 Network development programme inc. DG and non-network with expenditure. Must include-	s5.3, s5.4, Appendix B
11.10.1 detailed description of projects underway or planned to start within the next 12 months;	s5.4 by Project
11.10.2 summary description of programmes/projects for the following four years; and	s5.4 by Project
11.10.3 overview of the big projects being considered for the remainder of the AMP planning period.	s5.4 by Project
11.11 EDB's policies on distributed generation.	s5.4.12
11.12 A description of the EDB's policies on non-network solutions, including-	s5.1.8
11.12.1 economically feasible and practical alternatives to conventional network augmentation; and	s5.1.8
11.12.2 the potential for non-network solutions to address network problems or constraints.	s5.1.8, s5.2.3, s5.4.1, s5.4.3 by Project
11.12.3 how information on current and forecast load and injection constraints is shared with non-network solution providers (inc. LV).	s5.1.10
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12. The AMP must provide a detailed description of the lifecycle asset management processes, including-	
12.1 The key drivers for maintenance planning and assumptions;	s6.2
12.2 Routine and corrective maintenance and inspection policies/programmes/ actions per asset category, must include-	s6
12.2.1 approach to inspecting/maintaining each asset category – inspection types/tests/monitoring/intervals;	s6.3 – s6.15
12.2.2 systemic problems identified per asset types and proposed actions to address these problems; and	s6.3 – s6.15
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	s8.2
12.3 Asset replacement and renewal policies/programmes/actions per asset category, inc. expenditure. Must include-	s6
12.3.1 processes used to decide when and whether an asset is replaced or refurbished;	s6.2, s6.3 – s6.15
12.3.2 a description of innovations made that have deferred asset replacement;	s6.2, s6.3 – s6.15
12.3.3 a description of the projects currently underway or planned for the next 12 months;	s6.3 – s6.15
12.3.4 a summary of the projects planned for the following four years (where known); and	s6.3 – s6.15

12.3.5 an overview of other work being considered for the remainder of the AMP planning period.	s6.3 – s6.15
12.4 Asset categories in subclauses 12.2 and 12.3 should include at least the categories in subclause 4.5 above.	Compliant
12.5 Identification of the approach used for developing capital expenditure projections for lifecycle asset management.	
12.5.1 the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	6.2.5
12.5.2 the rationale for using the approach for each asset category.	6.3 - 6.10, 6.15
12.6 Identification of vegetation management related maintenance.	6.16
12.7 The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management.	6.17
Non-Network Development, Maintenance and Renewal	
13. Description of material non-network development, maintenance, and renewal plans, including-	s7
13.1 a description of non-network assets;	s7.1
13.2 development, maintenance, and renewal policies that cover them;	s7.2
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	s7.3, Appendix E
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	s7.3, Appendix E
Risk Management	
14. AMPs must provide details of risk policies, assessment, and mitigation, including-	s2
14.1 Methods, details, and conclusions of risk analysis;	s2.2 – s2.5
14.2 Strategies to identify areas vulnerable to high impact low probability events;	s2.8
14.3 A description of the policies to mitigate or manage the risks of events identified in subclause 14.2;	s2.6
14.4 Details of emergency response and contingency plans.	s2.8
Evaluation of performance	
15. AMPs must provide details of performance measurement, evaluation, and improvement, including-	
15.1 A review of progress against plan, both physical and financial;	s9.1
15.2 An evaluation and comparison of actual service level performance against targeted performance;	s9.2
15.3 AMMAT evaluation and comparison vs objectives of the EDB's asset management and planning processes.	s9.4
15.4 Gap analysis from AMMAT and performance. Planned initiatives to address the situation.	s9.3, s9.4, s9.5, s9.6

Capability to deliver	
16. AMPs must describe the processes used by the EDB to ensure that-	
16.1 The AMP is realistic, and the objectives set out in the plan can be achieved;	s9.7
16.2 Organisation structure and processes for authorisation/business capabilities to support AMP implementation.	s9.7
Requirements to provide qualitative information in narrative form	
17. AMPs must include qualitative information in narrative form	
Notice of planned and unplanned interruptions **17.1** a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions	s3.3, s3.5.2
Voltage quality **17.2** a description of the EDB's practices for:	s3.7
17.2.1 monitoring voltage	
17.2.1 (a) the EDB's practices for monitoring voltage quality on its low voltage network	s3.7.4
17.2.1 (b) work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010	s3.7.4
17.2.1 (c) how the EDB responds to and reports on voltage quality issues	s3.7.4
17.2.1 (d) how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network	s3.7.4
17.2.1 (e) any plans for improvements to any of the practices outlined at clauses (a) - (d) above	s3.7.4
17.2.2 monitoring load and injection constraints	
17.2.2 (a) any challenges, and progress, towards gathering data to inform of current or forecast LV constraints	s5.1.10
17.2.2 (b) any analysis and modelling undertaken or planned with data obtained using (a)	s5.1.10
Customer service practices **17.3** a description of the EDB's customer service practices	s3.3
17.3.1 the EDB's customer engagement protocols and customer service measures	s3.3
17.3.2 the EDB's approach to planning and managing customer complaint resolution	s3.3
Practices for connecting new consumers and altering existing connections **17.4** a description of the EDB's practices for connecting consumers	s5.1.7
17.4.1 the EDB's approach to planning and management of connecting new consumers, overcoming commonly encountered issues, and alterations to existing connections (offtake and injection connections)	s5.1.7

17.4.2 how the EDB is seeking to minimise the cost to consumers of new or altered connections	s5.1.7
17.4.3 the EDB's approach to planning and managing communication with consumers about new or altered connections	s5.1.7
17.4.4 commonly encountered delays and potential timeframes for different connections	s5.1.7
17.4.5 approach to sharing constraint information with potential new consumers (inc. LV)	s5.1.10
New connections likely to have a significant impact on network operations or asset management priorities 17.5 A description of the following:	s.5.2.3
17.5.1 how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network inc. scale, impact, timing, uncertainty, and other factors such as location	s.5.2.3
17.5.2 how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity	s.5.2.3
Innovation practices 17.6 a description of the following:	s.5.4.14
17.6.1 any innovation practices the EDB has planned or undertaken since the last AMP	s.5.4.14
17.6.2 the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers	s.5.4.14
17.6.3 how the EDB measures success and makes decisions regarding any innovation practices	s.5.4.14
17.6.4 how the EDB's decision-making and innovation practices depend on the work of other companies	s.5.4.14
17.6.5 the types of information the EDB uses to inform or enable any innovation practices	s.5.4.14
17.7 For the purpose of disclosing the information required under clauses 17.6.1-17.6.5 above, an EDB is not required to include commercially sensitive or confidential information	Acknowledged

Please note that this list is does not include explicit references to every passage in the plan that has some relevance to each mandatory item. For readability, EA Networks have chosen to discuss different aspects of some mandatory items in discrete places – where they are relevant. Complete understanding of the plan's concepts and direction requires digestion of the plan as a whole.

10.5 Appendix E – Disclosure Schedules

This appendix contains the schedules that are required to be disclosed to the Commerce Commission and the plan must "*Include, in the AMP or AMP update as applicable, the information contained in each of the reports*". To ensure all the information contained in the schedules is in the plan, they have been included here. They are also disclosed in the original formats on the EA Networks website.

Schedule	Description
11a	Report on Forecast Capital Expenditure
11b	Report on Forecast Operational Expenditure
12a	Report on Asset Condition
12b	Report on Forecast Capacity
12c	Report on Forecast Demand
12d	Report on Forecast Interruptions and Duration
13	Report on Asset Management Maturity
14a	Mandatory Explanatory Notes on Forecast Information
17	Certification of Year-beginning Disclosures

Notes on the schedules:

11a	• The 12 month forecast values for the current year have been derived by escalating the 10 months of available YTD values by a factor of 1.2.
	• The pages are laid out for A3 portrait printing. The text is small at this scale.
12a	• The data in this schedule represents the best assessment of EA Networks' understanding of the requirements, unique asset categorisation, and known condition. The "*% of asset to be replaced in next 5 years*" is a formulaic assessment based on known age with some manual interpretation. Replacement forecasts will be refined over time to reflect actual condition if it is obtained.
12b	• There is a significant increase in switched transfer capacity in +5yrs at many sites, however there is no clear way of showing this in the schedule.
	• Feeder open points can change, and this may lead to variations in quoted "*Current Peak Load*" values in different parts of the plan for the same site.
13	• The AMMAT report has been presented in a compact manner. If readers wish to see the full template with associated commentary and scoring notes, please go to: https://comcom.govt.nz/__data/assets/excel_doc/0023/363371/Electricity-Distribution-Information-Disclosure-Requirements-Templates-Schedules-11a-13-consolidated-27-November-2024.xlsx to download the "*EDB ID Determination AMP Templates*" in Excel format. Warning: the default print layout of Schedule 13 requires 16 pages of A3 with very small text.

	Company Name	**Electricity Ashburton Ltd**
	AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY	2031 FY	2032 FY	2033 FY	2034 FY	2035 FY
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	8 600	5 724	3 429	5 477	3 579	3 653	3 755	3 839	3 965	4 055	4 202
11		System growth	434	2 170	4 083	4 093	4 655	6 184	4 164	3 347	3 842	3 590	2 880
12		Asset replacement and renewal	5 868	9 619	4 954	6 927	4 743	3 885	5 548	5 632	3 367	3 575	3 705
13		Asset relocations	-	-	-	-	-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	910	1 042	1 440	1 397	659	714	82	663	397	942	92
16		Legislative and regulatory	-	59	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	1 064	1 171	1 464	1 463	1 267	683	702	718	741	758	786
18		**Total reliability, safety and environment**	1 974	2 272	2 904	2 860	1 927	1 397	784	1 381	1 138	1 700	878
19		**Expenditure on network assets**	16 875	19 784	15 370	19 357	14 905	15 119	14 252	14 198	12 312	12 920	11 665
20		**Expenditure on non-network assets**	809	1 180	1 435	906	762	754	769	785	1 443	816	833
21		**Expenditure on assets**	17 684	20 964	16 804	20 263	15 666	15 873	15 021	14 983	13 755	13 737	12 498
22													
23	*plus*	Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less*	Value of capital contributions	3 318	2 782	480	2 328	480	480	480	480	480	480	480
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	14 367	18 182	16 324	17 935	15 186	15 393	14 541	14 503	13 275	13 257	12 018
28													
29		Assets commissioned	14 367	18 182	16 324	17 935	15 186	15 393	14 541	14 503	13 275	13 257	12 018
32			**$000 (in constant prices)**										
33		Consumer connection	8 600	5 724	3 358	5 259	3 370	3 371	3 397	3 406	3 448	3 457	3 512
34		System growth	434	2 170	3 999	3 930	4 382	5 708	3 768	2 969	3 341	3 061	2 408
35		Asset replacement and renewal	5 868	9 619	4 852	6 651	4 465	3 586	5 020	4 996	2 929	3 049	3 097
36		Asset relocations	-	-	-	-	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	910	1 042	1 411	1 341	621	659	75	588	345	803	77
39		Legislative and regulatory	-	59	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	1 064	1 171	1 434	1 405	1 193	630	635	637	645	646	657
41		**Total reliability, safety and environment**	1 974	2 272	2 844	2 746	1 814	1 289	710	1 225	990	1 450	734
42		**Expenditure on network assets**	16 875	19 784	15 053	18 587	14 031	13 954	12 895	12 595	10 708	11 017	9 751
43		Expenditure on non-network assets	809	1 180	1 405	870	717	696	696	696	1 255	696	696
44		**Expenditure on assets**	17 684	20 964	16 458	19 457	14 748	14 650	13 591	13 291	11 963	11 713	10 447
45													
46		**Subcomponents of expenditure on assets (where known)**											
48		Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
49		Overhead to underground conversion	4 350	5 955	1 172	2 828	1 395	1 050	2 336	2 214	-	-	-
50		Research and development	-	-	-	-	-	-	-	-	-	-	-
52													

		2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY	2031 FY	2032 FY	2033 FY	2034 FY	2035 FY
54												
55	**Difference between nominal and constant price forecasts**	**$000**										
56	Consumer connection	-	-	71	218	210	281	357	433	517	597	689
57	System growth	-	-	84	163	273	477	396	378	501	529	473
58	Asset replacement and renewal	-	-	102	275	278	299	528	636	439	527	608
59	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
60	Reliability, safety and environment:											
61	Quality of supply	-	-	30	56	39	55	8	75	52	139	15
62	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
63	Other reliability, safety and environment	-	-	30	58	74	53	67	81	97	112	129
64	**Total reliability, safety and environment**	-	-	60	114	113	108	75	156	148	251	144
65	**Expenditure on network assets**	-	-	316	770	873	1 165	1 356	1 603	1 604	1 904	1 914
66	Expenditure on non-network assets	-	-	30	36	45	58	73	89	188	120	137
67	**Expenditure on assets**	-	-	346	806	918	1 223	1 429	1 692	1 792	2 024	2 050

68

69 **Commentary on options and considerations made in the assessment of forecast expenditure**

70 *EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15*

71

74 11a(ii): Consumer Connection

		2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY
75	*Consumer types defined by EDB**	**$000 (in constant prices)**					
76	Urban LV	410	151	154	150	154	154
	Urban Transformer	312	82	84	82	84	84
	Urban Alteration for Safety (No new ICP created)	-	-	-	-	-	-
	Urban Capacity Alteration (No new ICP created)	117	24	25	24	25	25
	Rural LV	144	428	434	425	436	436
77	Rural Transformer	1 604	1 063	1 078	1 056	1 082	1 083
78	Rural Alteration for Safety (No new ICP created)	603	583	580	568	582	583
79	Rural Capacity Alteration (No new ICP created)	467	470	477	465	476	476
80	Other (including large subdivisions)	4 943	2 922	528	2 488	530	530
81	**include additional rows if needed*						
82	**Consumer connection expenditure**	8 600	5 724	3 358	5 259	3 370	3 371
83	*less* Capital contributions funding consumer connection	3 318	2 757	480	2 328	480	480
84	**Consumer connection less capital contributions**	5 282	2 967	2 878	2 931	2 890	2 891

85 11a(iii): System Growth

		2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY
86	Subtransmission	-	97	-	1 109	1 249	-
87	Zone substations	44	-	351	321	503	1 576
88	Distribution and LV lines	98	177	303	227	196	181
89	Distribution and LV cables	-	37	633	420	716	1 248
90	Distribution substations and transformers	30	1 554	2 094	1 640	1 526	2 034
91	Distribution switchgear	197	21	326	119	187	339
92	Other network assets	65	283	292	93	6	329
93	**System growth expenditure**	434	2 170	3 999	3 930	4 382	5 708
94	*less* Capital contributions funding system growth	-	-	-	-	-	-
95	**System growth less capital contributions**	434	2 170	3 999	3 930	4 382	5 708
96							

			2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY

11a(iv): Asset Replacement and Renewal

$000 (in constant prices)

			2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY
100		Subtransmission	-	-	510	-	769	-
101		Zone substations	-	223	124	112	85	85
102		Distribution and LV lines	1 802	2 422	2 406	2 661	1 703	1 534
103		Distribution and LV cables	266	5 338	1 056	2 687	1 070	1 043
104		Distribution substations and transformers	2 030	1 243	508	768	556	674
105		Distribution switchgear	1 496	393	247	424	183	249
106		Other network assets	274	-	-	-	99	-
107		**Asset replacement and renewal expenditure**	5 868	9 619	4 852	6 651	4 465	3 586
108	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
109		**Asset replacement and renewal less capital contributions**	5 868	9 619	4 852	6 651	4 465	3 586
110								

11a(v): Asset Relocations

$000 (in constant prices)

		*Project or programme**	2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY
115		N/A	-	-	-	-	-	-
116		N/A	-	-	-	-	-	-
117		N/A	-	-	-	-	-	-
118		N/A	-	-	-	-	-	-
119		N/A	-	-	-	-	-	-
120		**include additional rows if needed*						
121		All other project or programmes - asset relocations	-	-	-	-	-	-
122		**Asset relocations expenditure**	-	-	-	-	-	-
123	*less*	Capital contributions funding asset relocations	-	-	-	-	-	-
124		**Asset relocations less capital contributions**	-	-	-	-	-	-
125								

11a(vi): Quality of Supply

$000 (in constant prices)

		*Project or programme**	2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY
130		22 kV OH - Resolve Potential Ferroresonance Issues.	-	76	77	75	77	77
		22kV Conversion - Mvn Hwy. Springfld Rd to Mvn, AF Rd to N Cnr	525	67	-	-	-	-
		22kV Surge Arrester - Replacement Programme	-	418	424	416	-	-
		66kV OH Dampers Installation.	-	123	124	122	-	-
131		SCADA - Distribution Automation Programme	-	83	84	83	85	85
132		ZSS EGN - Ripple Injection Generator Replacement	344	160	66	-	-	-
133		11kV Core Network Centres	-	-	397	573	385	423
134		ZSS MSM - Mt Somers to Montalto 22 kV Feeder Protection	-	-	164	-	-	-
135		**include additional rows if needed*						
136		All other projects or programmes - quality of supply	41	114	74	72	74	74
137		**Quality of supply expenditure**	910	1 042	1 411	1 341	621	659
138	*less*	Capital contributions funding quality of supply	-	-	-	-	-	-
139		**Quality of supply less capital contributions**	910	1 042	1 411	1 341	621	659
140								

Row		2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY
143	**11a(vii): Legislative and Regulatory**						
144	*Project or programme**	**$000 (in constant prices)**					
145	N/A	-	-	-	-	-	-
146	N/A	-	-	-	-	-	-
147	N/A	-	-	-	-	-	-
148	N/A	-	-	-	-	-	-
149	N/A	-	-	-	-	-	-
150	**include additional rows if needed*						
151	All other projects or programmes - legislative and regulatory	-	59	-	-	-	-
152	**Legislative and regulatory expenditure**	-	59	-	-	-	-
153	*less* Capital contributions funding legislative and regulatory	-	25	-	-	-	-
154	**Legislative and regulatory less capital contributions**	-	34	-	-	-	-
155							
157	**11a(viii): Other Reliability, Safety and Environment**						
158	*Project or programme**	**$000 (in constant prices)**					
159	22 kV OH - Switchgear Upgrade	-	87	88	86	88	88
160	22kV OH Rebuild - Transformer Pole Replacements	-	968	1 228	1 203	986	424
161	DSS - Earthing Upgrades	-	53	54	53	54	54
162	22kV Conversion - Methven Hwy Springfield	592	-	-	-	-	-
163	UG New - Moorhouse Rd Fill In	263	-	-	-	-	-
164	**include additional rows if needed*						
165	All other projects or programmes - other reliability, safety and environment	208	63	64	63	64	64
166	**Other reliability, safety and environment expenditure**	1 064	1 171	1 434	1 405	1 193	630
167	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
168	**Other reliability, safety and environment less capital contributions**	1 064	1 171	1 434	1 405	1 193	630
169							
172	**11a(ix): Non-Network Assets**						
173	**Routine expenditure**						
174	*Project or programme**	**$000 (in constant prices)**					
175	Routine Information Technology	90	1 063	587	232	546	525
176	Routine Building Work	-	48	808	95	95	95
177	Routine Vehicles	491	-	-	-	66	66
178	N/A	-	-	-	-	-	-
179	N/A	-	-	-	-	-	-
180	**include additional rows if needed*						
181	All other projects or programmes - routine expenditure	57	10	10	10	10	10
182	**Routine expenditure**	638	1 121	1 405	337	717	696
183	**Atypical expenditure**						
184	*Project or programme**						
185	Cable Rating Software	-	23	-	-	-	-
186	Industrial Acoustic Imaging Camera	36	36	-	-	-	-
187	ADMS Basic DERMS	-	-	-	533	-	-
188	Bunker Fire Suppression	53	-	-	-	-	-
189	Gawler Downs Comm's Pole	82	-	-	-	-	-
190	**include additional rows if needed*						
191	All other projects or programmes - atypical expenditure	-	-	-	-	-	-
192	**Atypical expenditure**	171	59	-	533	-	-
193							
194	**Expenditure on non-network assets**	809	1 180	1 405	870	717	696

Company Name: **Electricity Ashburton Ltd**

AMP Planning Period: **1 April 2025 – 31 March 2035**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

sch ref			2025 FY	2026 FY	2027 FY	2028 FY	2029 FY	2030 FY	2031 FY	2032 FY	2033 FY	2034 FY	2035 FY
8													
9	**Operational Expenditure Forecast**		**$000 (in nominal dollars)**										
10	Service interruptions and emergencies		1 117	1 071	1 093	1 115	1 138	1 160	1 184	1 207	1 231	1 256	1 281
11	Vegetation management		1 100	1 084	1 107	1 129	1 151	1 175	1 198	1 222	1 246	1 271	1 297
12	Routine and corrective maintenance and inspection		2 770	1 879	1 957	2 058	2 181	2 318	2 473	2 585	2 681	2 805	2 927
13	Asset replacement and renewal		946	1 757	1 380	1 446	1 468	1 508	1 514	1 582	1 652	1 725	1 800
14	**Network Opex**		5 933	5 791	5 537	5 748	5 938	6 160	6 369	6 596	6 811	7 057	7 306
15	System operations and network support		4 840	6 694	7 508	6 024	6 144	6 354	6 481	6 610	6 628	6 760	7 015
16	Business support		7 716	11 245	10 564	11 047	11 240	11 488	11 670	11 904	12 142	12 384	12 632
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
18	**Non-network opex**		12 556	17 939	18 073	17 070	17 384	17 842	18 151	18 514	18 769	19 145	19 647
19	**Operational expenditure**		18 489	23 730	23 610	22 818	23 322	24 002	24 520	25 110	25 580	26 202	26 953
21													
22			**$000 (in constant prices)**										
23	Service interruptions and emergencies		1 117	1 071	1 071	1 071	1 071	1 071	1 071	1 071	1 071	1 071	1 071
24	Vegetation management		1 100	1 084	1 084	1 084	1 084	1 084	1 084	1 084	1 084	1 084	1 084
25	Routine and corrective maintenance and inspection		2 770	1 879	1 917	1 976	2 053	2 139	2 238	2 293	2 332	2 392	2 447
26	Asset replacement and renewal		946	1 757	1 352	1 389	1 382	1 391	1 370	1 403	1 437	1 471	1 505
27	**Network Opex**		5 933	5 791	5 423	5 519	5 590	5 686	5 763	5 852	5 923	6 017	6 107
28	System operations and network support		4 840	6 694	7 354	5 784	5 784	5 864	5 864	5 864	5 764	5 764	5 864
29	Business support		7 716	11 245	10 347	10 607	10 581	10 603	10 560	10 560	10 560	10 560	10 560
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
31	**Non-network opex**		12 556	17 939	17 701	16 391	16 365	16 467	16 424	16 424	16 324	16 324	16 424
32	**Operational expenditure**		18 489	23 730	23 124	21 911	21 955	22 153	22 187	22 275	22 247	22 341	22 531
33	**Subcomponents of operational expenditure (where known)**												
35													
36	losses		-	-	-	-	-	-	-	-	-	-	-
37	Direct billing*		-	-	-	-	-	-	-	-	-	-	-
38	Research and Development		-	-	-	-	-	-	-	-	-	-	-
39	Insurance		537	565	582	599	617	636	655	675	695	716	737
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*												
44													
45	**Difference between nominal and real forecasts**		**$000**										
46	Service interruptions and emergencies		-	-	22	44	67	89	113	136	160	185	210
47	Vegetation management		-	-	23	45	67	91	114	138	162	187	213
48	Routine and corrective maintenance and inspection		-	-	40	82	128	179	235	292	349	413	480
49	Asset replacement and renewal		-	-	28	58	86	116	144	179	215	254	295
50	**Network Opex**		-	-	114	229	348	475	606	745	887	1 040	1 199
51	System operations and network support		-	-	154	240	360	490	617	746	864	996	1 151
52	Business support		-	-	217	439	659	885	1 110	1 344	1 582	1 825	2 072
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
54	**Non-network opex**		-	-	372	679	1 019	1 375	1 727	2 090	2 445	2 821	3 223
55	**Operational expenditure**		-	-	486	908	1 367	1 850	2 333	2 835	3 333	3 861	4 422
56													
57	**Commentary on options and considerations made in the assessment of forecast expenditure**												
58	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*												

Company Name	**Electricity Ashburton Ltd**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref

7 **Asset condition at start of planning period (percentage of units by grade)**

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.04%	0.72%	81.04%	18.20%	-	3	0.01%
11	All	Overhead Line	Wood poles	No.	0.83%	1.05%	12.96%	43.01%	42.15%	-	3	1.09%
12	All	Overhead Line	Other pole types	No.	-	-	16.67%	33.33%	50.00%	-	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	0.35%	4.14%	62.24%	33.27%	-	3	0.09%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	2.25%	53.78%	43.97%	-	3	-
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.	-	4.35%	-	21.74%	73.91%	-	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	22.22%	77.78%	-	-	-	3	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	0.78%	25.78%	42.97%	30.47%	-	3	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	46.58%	26.03%	27.40%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	1.09%	8.70%	47.28%	42.93%	-	3	0.27%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-
35												

36 **Asset condition at start of planning period (percentage of units by grade)**

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	2.94%	5.88%	11.76%	44.12%	35.29%	-	4	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.09%	2.75%	18.72%	48.54%	28.91%	-	3	1.78%
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	0.01%	0.01%	3.24%	23.20%	73.55%	-	3	0.01%
44	HV	Distribution Cable	Distribution UG PILC	km	5.74%	-	89.33%	4.94%	-	-	1	1.43%
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.	-	-	14.29%	75.00%	10.71%	-	3	-
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.	-	1.04%	4.65%	47.84%	46.47%	-	2	0.26%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	6.93%	7.99%	15.10%	32.15%	37.83%	-	3	1.73%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.49%	5.46%	22.57%	35.60%	35.88%	-	3	0.49%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.35%	6.87%	15.40%	24.32%	53.06%	-	3	0.35%
53	HV	Distribution Transformer	Voltage regulators	No.	-	7.69%	7.69%	53.85%	30.77%	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	4.39%	2.64%	12.48%	24.96%	55.54%	-	3	5.05%
55	LV	LV Line	LV OH Conductor	km	6.66%	6.34%	14.02%	63.49%	9.49%	-	2	8.24%
56	LV	LV Cable	LV UG Cable	km	0.02%	1.25%	11.57%	32.02%	55.15%	-	3	0.33%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.20%	1.69%	10.74%	34.63%	52.74%	-	2	1.89%
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	7.15%	35.19%	57.66%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	1.03%	5.14%	93.84%	-	3	2.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	10.00%	90.00%	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	70.00%	30.00%	-	-	-	3	70.00%
63	All	Load Control	Relays	No.	-	-	-	-	-	100.00%	1	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the netw

sch ref

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

sch ref	*Existing Zone Substations*	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)
8														
9	Ashburton (66/11kV)	21	Winter	20	N-1	Security	-	Winter	3.6	N-1	Winter	3.0	3.0	N-1
10	Carew (66/22kV)	16	Summer	15	N-1	Security	-	Summer	-	N-1	Summer	-	-	N-1
11	Coldstream (66/22kV)	12	Summer	10	N-1 switched	Security	-	Summer	-	N-1 switched	Summer	-	-	N-1 switched
12	Dorie (66/22kV)	11	Summer	10	N-1 switched	Security	-	Summer	-	N-1 switched	Summer	-	-	N-1 switched
13	Eiffelton (66/22kV)	13	Summer	10	N-1 switched	Security	-	Summer	-	N-1 switched	Summer	-	-	N-1 switched
14	Elgin (66/22kV)	4	Summer	7	N-1 switched	No constraint	3.0	Summer	3.0	N-1 switched	Summer	3.0	3.0	N-1 switched
15	Fairton11 (66/11kV)	4	Winter	10	N-1 switched	No constraint	6.0	Winter	5.5	N-1 switched	Winter	5.0	5.0	N-1 switched
16	Fairton22 (66/22kV)	9	Summer	10	N-1 switched	No constraint	1.1	Summer	1.1	N-1 switched	Summer	1.0	1.0	N-1 switched
17	Hackthorne (66/22kV)	15	Summer	10	N-1 switched	Security	-	Summer	-	N-1 switched	Summer	-	-	N-1 switched
18	Highbank (66kV)	8	Summer	32	N	No constraint	-	Summer	-	N	Summer	-	-	N
19	Lagmhor (66/22kV)	11	Summer	10	N-1 switched	Security	-	Summer	-	N-1 switched	Summer	-	-	N-1 switched
20	Lauriston (66/22kV)	16	Summer	20	N-1	No constraint	4.0	Summer	3.0	N-1	Summer	3.0	3.0	N-1
	Methven11 (66/11kV)	5	Winter	8	N-1 switched	No constraint	2.7	Winter	2.7	N-1 switched	Winter	1.6	1.6	N-1 switched
	Methven22 (66/22kV)	4	Summer	8	N-1 switched	No constraint	4.0	Summer	4.0	N-1 switched	Summer	4.0	4.0	N-1 switched
	Methven33 (22/33kV)	3	Winter	5	N	Security	2.0	Winter	2.0	N	Winter	2.0	2.0	N
	Montalto (33/11kV)	3	Summer	1	N-1 switched	Capacity	-	[Select one]	-	[Select one]	[Select one]	-	-	[Select one]
21	Mt Hutt (33/11kV)	3	Winter	1	N-1 switched	Security	-	Winter	-	N-1 switched	Winter	1.0	1.0	N-1 switched
22	Mt Somers22 (66/22kV)	6	Summer	8	N-1 switched	No constraint	2.0	Summer	2.0	N-1 switched	Summer	1.6	1.6	N-1 switched
	Mt Somers33 (22/33kV)	3	Summer	5	N	Security	-	[Select one]	-	[Select one]	[Select one]	-	-	[Select one]
23	Northtown (66/11kV)	14	Winter	20	N-1	No constraint	6.0	Winter	4.0	N-1	Winter	1.0	1.0	N-1
24	Overdale (66/22kV)	13	Summer	10	N-1 switched	No constraint	-	Summer	-	N-1 switched	Summer	-	-	N-1 switched
25	Pendarves (66/22kV)	17	Summer	20	N-1	No constraint	3.0	Summer	3.0	N-1	Summer	3.0	3.0	N-1
26	Seafield (66/11kV)	8	Autumn	5	N-1 switched	No constraint	-	Autumn	-	N-1 switched	Autumn	-	-	N-1 switched
27	Tinwald (66/11kV)	-	[Select one]	-	[Select one]	[Select one]	-	Winter	3.0	N-1 switched	Winter	2.7	2.7	N-1 switched
28	Wakanui (66/22kV)	8	Summer	10	N-1 switched	No constraint	2.0	Summer	2.0	N-1 switched	Summer	2.0	2.0	N-1 switched

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

Company Name	**Electricity Ashburton Ltd**
AMP Planning Period	**1 April 2025 – 31 March 2035**

ork in its normal steady state configuration.

Existing Zone Substations	**Forecast constraint type**	**Year of any forecast constraint**	**Constraint primary cause**	**Constraint solution type**	**Constraint solution progress**	**Temporary constraint solution remaining lifespan**	**Explanation**
Ashburton (66/11kV)	Security	4	Zone substation transformer	Divert load to alternative substation	Planning stage	> 3 years	Urban. Ashburton (2 x 20MVA) is close to Northtown (2 x 20MVA). Significant switched capacity exists, adding to the 20MVA N-1 transformer capacity.
Carew (66/22kV)	Security	1	Zone substation transformer	Not required	No active planning	> 3 years	Rural. 1 x 15MVA and 1 x 20MVA plus switched capacity. Serves as system spare of each size/type.
Coldstream (66/22kV)	Security	1	Distribution back-up circuit capacity	Not required	No active planning	> 3 years	Rural. 1 x 15MVA. 72h spare transformer install while managing load.
Dorie (66/22kV)	Security	1	Distribution back-up circuit capacity	Not required	No active planning	> 3 years	Rural. 1 x 15MVA. 72h spare transformer install while managing load.
Eiffelton (66/22kV)	Security	1	Distribution back-up circuit capacity	Not required	No active planning	> 3 years	Rural. 1 x 20MVA. 72h spare transformer install while managing load.
Elgin (66/22kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Rural. 1 x 20MVA.
Fairton11 (66/11kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Industrial. 1 x 20MVA with 10MVA 22/11kV tie.
Fairton22 (66/22kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Industrial. 1 x 20MVA with 10MVA 22/11kV tie.
Hackthorne (66/22kV)	Security	1	Distribution back-up circuit capacity	Not required	No active planning	> 3 years	Rural. 1 x 20MVA. 72h spare transformer install while managing load.
Highbank (66kV)	Security	1	Other	[Select one]	[Select one]	[Select one]	Generation in winter and load in summer. **Manawa-owned 66 kV connection**.
Lagmhor (66/22kV)	Security	1	Distribution back-up circuit capacity	Not required	No active planning	> 3 years	Rural. 1 x 15MVA. 72h spare transformer install while managing load.
Lauriston (66/22kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Rural. 1 x 20MVA and 1 x 35MVA. 47.2MW solar farm connected.
Methven11 (66/11kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Urban. 1 x 15MVA with 10MVA 22/11 kV tie.
Methven22 (66/22kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Rural. 1 x 25MVA with 10MVA 22/11 kV tie.
Methven33 (22/33kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Rural. 1 x 5MVA 22/33 kV. Steps up from Methven22 and supplies Mt Hutt. In 2030, 11 kV to 22 kV conversion offers more switched distribution capacity.
Montalto (33/11kV)	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	Rural. 1 x 2.5MVA. Supplied via Mt Somers33. To be removed in 2027 after 22 kV conversion of surrounding 11kV network.
Mt Hutt (33/11kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Rural. 1 x 10MVA. Supplied via Methven33. After 2030, 11 kV to 22 kV conversion provides more switched capacity.
Mt Somers22 (66/22kV)	No constraint	None	Not applicable	Not applicable	Not applicable	> 3 years	Rural. 1 x 15MVA. 72h spare transformer install while managing load.
Mt Somers33 (22/33kV)	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	[Select one]	Rural. 1 x 5MVA 22/33 kV. Steps up from Mt Somers22 and supplies Montalto. To be removed in 2027 after 22 kV conversion of surrounding 11kV network.
Northtown (66/11kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Ashburton (2 x 20MVA) is close to Northtown (2 x 20MVA) and significant switched capacity exists, adding to the 20MVA N-1 transformer capacity.
Overdale (66/22kV)	Security	1	Distribution back-up circuit capacity	Not applicable	No active planning	> 3 years	Urban/Rural. 1 x 20MVA. 72h spare transformer install while managing load.
Pendarves (66/22kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Rural. 2 x 10/20MVA. 1 x 20MVA serves as a system spare.
Seafield (66/11kV)	Security	1	Distribution back-up circuit capacity	Not applicable	Not applicable	Not applicable	Industrial. 1 x 15MVA with 22/11kV 5MVA back-up. Security by agreement with solitary customer.
Tinwald (66/11kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Urban. No transformer in 2025. Suppied from Ashburton. In 2030, 1 x 20MVA unit to be installed to relieve Ashburton.
Wakanui (66/22kV)	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	Rural. 1 x 15MVA.

Company Name	**Electricity Ashburton Ltd**
AMP Planning Period	**1 April 2025 – 31 March 2035**

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

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

sch ref

7 12c(i): Consumer Connections

sch ref							
8	*Number of ICPs connected during year by consumer type*			**Number of connections**			
9		*2025 FY*	*2026 FY*	*2027 FY*	*2028 FY*	*2029 FY*	*2030 FY*
11	*Consumer types defined by EDB**						
12	Urban LV	134	130	120	110	100	100
	Urban Transformer	2	5	3	3	3	3
	Urban Alteration for Safety (No new ICP created)	-	-	-	-	-	-
	Urban Capacity Alteration (No new ICP created)	1	5	5	5	5	5
	Rural LV	46	50	50	45	45	45
13	Rural Transformer	31	40	35	35	35	35
14	Rural Alteration for Safety (No new ICP created)	29	25	25	20	20	20
15	Rural Capacity Alteration (No new ICP created)	12	15	15	15	15	15
16	Other	166	120	120	110	110	100
17	**Connections total**	421	390	373	343	333	323
18	**include additional rows if needed*						
21							
22	**Distributed generation**	*2025 FY*	*2026 FY*	*2027 FY*	*2028 FY*	*2029 FY*	*2030 FY*
23	Number of connections made in year	140	150	160	170	170	170
24	Capacity of distributed generation installed in year (MVA)	64	23	35	3	3	3

25 12c(ii): System Demand

sch ref								
27		**Maximum coincident system demand (MW)**						
28		GXP demand	159	150	150	151	152	152
29	*plus*	Distributed generation output at HV and above	24	35	36	36	36	36
30		**Maximum coincident system demand**	183	185	186	187	188	188
31	*less*	Net transfers to (from) other EDBs at HV and above	0	0	0	0	0	0
32		**Demand on system for supply to consumers' connection points**	183	185	186	187	188	188
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	494	388	391	285	306	309
35	*less*	Electricity exports to GXPs	-	3	13	33	53	55
36	*plus*	Electricity supplied from distributed generation	128	240	250	380	383	386
37	*less*	Net electricity supplied to (from) other EDBs	0	0	0	0	0	0
38		**Electricity entering system for supply to ICPs**	622	625	628	632	636	640
39	*less*	Total energy delivered to ICPs	587	590	593	597	601	605
40		**Losses**	35	35	35	35	35	35
41								
42		**Load factor**	39%	39%	39%	39%	39%	39%
43		**Loss ratio**	5.6%	5.6%	5.5%	5.5%	5.5%	5.4%

Company Name	**Electricity Ashburton Ltd**
AMP Planning Period	**1 April 2025 – 31 March 2035**
Network / Sub-network Name	**Electricity Ashburton 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		*2025 FY*	*2026 FY*	*2027 FY*	*2028 FY*	*2029 FY*	*2030 FY*
8							
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	143.1	247.7	247.7	247.7	247.7	247.7
12	Class C (unplanned interruptions on the network)	57.9	87.4	87.4	87.4	87.4	87.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.51	0.88	0.88	0.88	0.88	0.88
15	Class C (unplanned interruptions on the network)	0.78	1.24	1.24	1.24	1.24	1.24

Company Name	Electricity Ashburton Ltd
AMP Planning Period	1 April 2025 – 31 March 2035
Asset Management Standard Applied	No Formal Standard Applied

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	1	The organisation has AM policy in place but requires revision in line with the new EA Networks strategy and statement of corporate intent and it is not well communicated to stakeholders or employees.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	EAN's asset management strategies are in line with its asset management policies and both are in line with organisational strategies and policies. EA Networks' organistional strategy is to enable our region through a safe, reliable and resilient network, delivery of electricity to enable economic growth, be a relevant and customer centric organisation, sustainable operation both financially and environmentally and ensuring out people are kept safe, retained and developed with meaningful careers. Health and safety meetings are regularly held and minutes are circulated to all staff. There is also a regular auditing and interviewing process to identify and resolve any health and safety issues. Biannually, there is a representative survey of customers which provides an input into the asset management strategies of the company. Stakeholders are comprehensively covered in the asset management plan and comapny strategy and policies. Robust discussion is held at senior management level to ensure the asset management strategies are consistent with other company policies and strategies. The Public Safety Management System is closely linked to AM strategy and policies related to safe operation of the network in public. Refer to AMP sections 1.4, 1.7, 3.2, 3.3, 3.4, 3.5, 3.6, 3.7, 3.8, 3.9.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	Age based asset maintenanace and renewal is carried out. Equipment is replaced or there is contingency plan put in place for end of life equipment. To carry this out efficiently age profiles are analysed and conditions of assets are monitored regularly. GIS and Technology One (maintenance management system) are frequently used to maintain an up-to-date knowledge of the assets installation date, categories etc. The organisation understands the importance to improve its strategy and processes to improve current practices. Refer AMP section 6.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	EAN's AMP has a 10 year outlook to maintain and develop assets. Major projects, system upgrades and activities are identified, developed and implemented to optimise the network. There is currently work being carried to clearly allocate resource and costs to these tasks. Feedback is taken from customer surveys, outage data and public safety inspections to modify the plan as appropriate. Refer to AMP section 6.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	Asset management plans are communicated to all the key stakeholders and those parties involved in implementing the plan. High level presentations are made to all staff in company wide meetings. The AMP is published on EA networks website for reference by stakeholders.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2.5	AMP responsibilities are accurately defined to appropriate roles in the organisation and documented within the AMP. This is well documented in sections 1.2 and 1.9 of the AMP.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.	Between, (1) Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation. AND (2) Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	The sections of asset management plan are delegated to relevant teams to action and create a works programme for field services or are passed onto field services to create a work programme. Additional field or design resources may be contracted in where internal resources are insufficient. Where the plan cannot be fully implemented in the proposed time frame the priorities are reassessed on a risk-based approach. Competitive sourcing and procurement is used to ensure cost effective implementation of the plan.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2.5	As a lifeline utility EA Networks delegated staff have completed CIMS training in line with our documented emergency preparedness plans and CDEM alignment with ADC, NEMA and Canterbury Lifelines is in place. Resilience to emergency events have been built in through appropriate seismic specification for our depot building, back up generator and fuel supply and disaster recovery facilities for our SCADA ADMS system. There are good operational guidelines for emergency scenarios and more ADMS modules (OMS and SOM) assist in emergency situations. Outage communications are improved using a website for unplanned outages. In addition, we have a Mutual Aid agreement with other South Island lines companies to assist each other in major events. There are arrangements in place with contracted resource to assist us in emergency situations. A Resilience Action Plan for FY25-27 is improving performance in this area. is Refer to AMP section 2.8.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.	Between, (1) Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete. AND (2) Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	The GM - Network has overall responsibility to undertake these functions. Appropriate structures, authorities and responsibilities are in place. Current structure is more reliant on matrix management for the best possible outcome. Other structures are also mentioned in AMP Sections 1.2, 1.6 and responsibilities in Section 1.9.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Resources are allocated based on the needs of the organisation, including finances, materials, equipment and people resources. An assessment of resource hours to complete the annual AMP projects and programmes is compared to field resources and external contracting capability is monitored. In the current market there is shortage of people hence there are recruitment plans in place to hire and upskill staff. Currently the organisation is working towards improving work plans and delivering them efficiently. This means improving project management practices, allocating resources and planning work ahead. An asset management improvement action plan is currently being progressed, involving a mix of internal and external resources.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2	There are resources in place to carry out the planned works and asset management requirements are communicated to the relevant teams. Progress on delivery of the AMP programme is regularly reported to the Board. Progress with project delivery is regularly reviewed with asset management and field delivery teams. Asset maintenance requirements are documented and managed using Technology One to ensure delivery of programmes.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	Most projects are carried out by our field services team. There are control systems in place for outsourcing activities that include contract management processes for external contractors, suppliers or designers. Further developments in process and control system are required to get consistent desirable outcome. Most of our civil works is subject to competitive tendering. Construction manuals are used to record technical specifications. We have a representative who monitors contracted work to ensure quality and scope is achieved. A focus on safety and quality auditing of contractors has been implemented.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	Training plans are identified on an individual basis, but with reference to competency requirements recorded in position descriptions and the Common Competency Framework. Monitoring of staff's validity of competency and training records is carried out to ensure ongoing compliance. Regular meetings are held with staff to discuss training and personal development opportunities. Staff and various departments are encouraged to come up with their own training, awareness and competence requirements. We have an ongoing commitment to developing competencies and work procedures directly relating to job positions and job tasks. Future AMP work programme includes estimate of labour hours required, and the future work profile is assessed related to the workforce required for delivery. A Network team capability development plan has been developed related to asset management capability development and succession planning.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2.5	There is a competency register (based on the common competency framework) to capture competency levels of all staff and appropriate contractors. It is kept up to date, but it is aimed more at operational competencies. Refer Q 48. Competencies for other staff are recorded in position descriptions and planning for training is carried out using a development plan review. A consistent and single competency register has been developed for all team members and records for training an assessments for achieving competency are being maintained.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.	Between, (1) The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied. AND (2) Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	Competency register exists as mentioned above but, to date, review and assessment has concentrated on operational and network teams related to safety. Where appropriate, the company will send staff to conferences, forums, training, workshops etc to increase awareness and knowledge of asset management activities, as well as collaborating with other EDBs to share knowledge and understand asset management practices. Refer Q 48.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	Major work programmes, target service levels and any other major works is communicated to Board for approval and then published in the AMP. Regular staff meetings are held where AMP projects are discussed. Asset management plans and policies are published on internet and intranet. Feedback of asset related information from maintenance, inspections, identified defects and As Built information are provided to update asset information and to inform asset renewal and replacement programmes. Network and Contracting teams liaise over the 10 year programme capital projects and annual major ZSS maintenance programme. Provide annual work programme of capital underground projects to external civil contractors for resource planning.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	1.5	The organisation has several repositories of asset management information - financial system, asset management system, GIS etc. There is not much documentation in place for asset management systems (TechOne) and their interaction with GIS or people. Further work is required to document our asset management processes to ensure consistent good practice and clear communication, as significant gaps exist.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.	Between, (1) The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system. AND (2) The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	1.5	Technology One is used for storing asset information. At the time of purchasing the information system considerable effort was put into determining what information is required. Information is regularly captured to support the AMP processes. For example, the assets database captures asset information relating to assets such as CBs, and transformers. GIS captures location, types and other technical information relating to many other assets within the network.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.	Between, (1) The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this. AND (2) The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	1	There are dedicated resources to keep the systems up to date. Tech One and GIS is currently used for storing and analysing asset information. Tech one also contains the financial and maintenance data. Further controls will need to be in place to improve data quality and consistency. Further improvements are needed related to asset condition/health data.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	1.5	The systems are currently to make sure that they could be integrate with other systems and the information is shared freely in between different systems. Scoping of new GIS system has been completed and upgrade of the system is underway to replace the legacy system and meet new organisation needs. Ongoing development of the ADMS is focused on ensuring the network operation is ready for future DER/technology disruption that will require a more flexible and automated network. A data management maturity assessment was completed and a number of cases for improvement were identified. A digital roadmap is under development to manage the upgrade of organisational systems including ERP/EAM in the next two years.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.	Between, (1) The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs. AND (2) The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2.5	Risk management framework and process is documented in the AMP. The organisational critical risks include high level risks related to network performance and emergency response. The Network asset specific risk register has been updated with a comprehensive approach accross asset classes include asset specific risks and environment and stakeholder aspects. Refer to AMP section 2.2, 2.5 and 2.8.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.	Between, (1) The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration. AND (2) Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2.5	All major risks are covered under AMP section 2. This covers asset, technology, environment and network based risks and the organisation's response to those risks, including both human and equipment resources, and the training and competency of staff. Outcomes of safety incidents contribute to actions that will address inadequacies in systems, processes resources and team training and competency. The updated competency and training register allows this to be managed.Further work is needed on documenting risk assessments into action plans.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.	Between, (1) The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies. AND (2) Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2.5	The organisation aims to meet all legal and regulatory requirements in regards to AMP. Our Public Management Safety System ensures that our asset management practices produce a safe and reliable network. Audits are carried out to ensure systems are compliant. Responsible people are encouraged to participate in industry events to keep up to date knowledge of the legal and compliance requirements. ComplyWith is being used as a system to test compliance with the company and identify and close out actions where non-compliances exist. A regulatory compliance meeting is held regularly to track progress on meeting requirements. Refer to AMP section 1.7.6.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives	Between, (1) The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed. AND (2) Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	The organisation has good practice and framework around the procurement/acquisitions and creation of assets in accordance with life cycle plans for each major asset class. The process for this work is only documented at a high level and there could be some inconsistencies due to a lack of procedural detail. An improved Safety in Design process has been developed and improved commissioning planning processes have been introduced. Refer to AMP sections 5.1.3, 5.1.4 and 6.2.5.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	1.5	Maintenance history of major network assets is recorded and there is service maintenance management system in place. Inspections and some maintenance is carried out on age/time basis, with other maintenance carried out based on condition. The improvement plans for this are captured in Section 1.8 and refer to AMP section 6 for Asset Lifecycle Management.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.	Between, (1) The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them. AND (2) The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	1.5	There are plans to more widely implement condition monitoring of assets. At present regular inspection and maintenance of assets is carried out, with condition based information gathered for some assets like poles and earthing and Magnefix RMUs via accoustic monitoring during inspections and before and after maintenance. Further system and process development is required to effectively implement condition monitoring across all major assets.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).	Between, (1) The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives. AND (2) The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	2.5	Regular inspections, feedback from reliability reports, and other measures such as survey and real time SCADA information are collected and analysed as required. Investigation into failures is extensive and feeds back into our asset management processes. Responsibilites within the Emergency Preparedness Standards is well defined and review of major emergency events is completed to ensure lessons are incorporated into future practice. Safety investigations are completed whenever required (incidents and continuous improvement opportunities both produce actions) and the responsibilities and process is well documented. Close out of actions is reported to the Board.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.	Between, (1) The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities. AND (2) The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	1.5	The organisation does not formally audit the asset management process but has recently involved external parties for the audit of its asset management system which has come out with few recommendations. Although H&S, Financial audits are carried out on regular basis. Important aspects of the asset management system are audited annually through the Public Safety Management System audit.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.	Between, (1) The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s). AND (2) The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information	Score Description
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2	The organisation proactively monitors and records the key contributors to poor performance, related to drivers and causes of poor reliability, asset failures and risk assessments. It further investigates the contributors to poor performance and prepares improvement programs to improve performance. Equipment or public safety incidents are evaluated and fed back into the asset management process. PSMS Audit corrective actions are tracked and closed out. There is budget allocation in the AMP for corrective and preventive action work (refer to Schedule 11b).		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	The company has commitment to continual improvement and a continuous improvement process is in place. Where continual improvement processes have implications for asset management there are discussion resulting in agreed actions that, if appropriate, are included in future iteration of the AMP.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2.5	The company is committed to continual improvement and have recently seek advice from the industry experts to improve and explore new ideas. It is working towards implementation of new AM practices in near future and move to a more condition based asset management approach. Monitoring of industry best practice through EEA guides and attending EEA conferences ensures that technical staff remain current and find ways to improve our approach. Strategic initiatives have been defined for the next 2 years based on industry good practice to improve project and programme delivery (capital and maintenance), systems updates (GIS and ADMS), network analysis, load forecasting and the ablity to connect load and generation effectively and improve organisational emergency resilience. Collaboration with other EDBs through the Future Network Forum, SI Network Operations Group and on network desgin standards assists in evaluating new approaches.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.	Between, (1) The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them. AND (2) The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

   This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

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

2. 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.

The difference is 0.0% for the 2025-26 year. Costs have been prepared using 2025-26 values for labour, plant and materials. Years after 2025-26 have been escalated by the "Half Year Economic and Fiscal Update 2024" CPI Forecast by the New Zealand Government Treasury published in December 2024. When the forecast ends, the final year CPI value has been used until the period end. (https://www.treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2024)

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

3. 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.

The difference is 0.0% for the 2025-26 year. Costs have been prepared using 2025-26 values for labour, plant and materials. Years after 2025-26 have been escalated by the "Half Year Economic and Fiscal Update 2024" CPI Forecast by the New Zealand Government Treasury published in December 2024. When the forecast ends, the final year CPI value has been used until the period end. (https://www.treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2024)

Financial Year (ending March)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Treasury CPI Forecast (%)	2.1	2	2	2.0	2.0	2.0	2.0	2.0	2.0	N/A
Cumulative CPI Price Inflator	1.0000	1.0210	1.0414	1.0622	1.0835	1.1052	1.1273	1.1498	1.1728	1.1963

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, **Andrew David Barlass** and **Paul Jason Munro**, being directors of **Electricity Ashburton Limited** certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of **Electricity Ashburton Limited** prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

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

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with **Electricity Ashburton Limited's** corporate vision and strategy and are documented in retained records.

Andrew David Barlass	Paul Jason Munro
28 March 2025	28 March 2025


EA networks