Asset Management Plan 2026

Counties Energy

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Message from the CEO

Tēnā koutou

The world around us is changing fast, but our promise remains the same: Always on and future ready, to power thriving communities today and tomorrow.

As a 100% consumer-owned electricity distributor, Counties Energy exists to serve the people of South Auckland and Northern Waikato, from our smallest communities through to our largest industries. That means every decision we make, every dollar we invest, is guided by a commitment to creating long-term community value for customers.

Reliability, safety, and resilience are non-negotiable, and we combine those foundations with forward-thinking strategies that are preparing our network and communities for the future.

The Counties Energy region is growing rapidly. Thousands of new homes and businesses are coming online, electrification is accelerating, and extreme weather events are becoming ever more frequent. These changes bring both challenges and opportunities and must be balanced across security, reliability, accessibility, affordability and the imperative to decarbonise.

We are responding with a clear plan. We are:

- **Investing prudently in scalable, standardised infrastructure and in programmes across vegetation and asset maintenance to improve reliability and affordability.**
- Embedding resilience into every part of our network to better withstand storms and recover more quickly in the event of outages.
- Building intelligence through digital innovation, leveraging smart data, automation, and advanced analytics to make faster, better decisions.
- Enabling greater energy choice by accommodating more distributed energy resources such as solar, batteries, and Electric Vehicles (EVs), and by trialling services that help customers manage their cost.
- Optimising our investment approach and evaluating non-network alternatives, deferring expenditure where possible, and focusing on whole-of-life value for communities.

We remain a DNO at our foundation, and we are now maturing our DSO capabilities that will enable active management of distributed energy resources and customer participation.

Our transition from a traditional Distribution Network Operator (DNO) to a modern and innovative Distribution System Operator (DSO) is well underway. In essence this means moving from passively managing a simple, one-way power flow delivering electricity to your home or business, to orchestrating a complex, two-way, digital network with many small, dispersed energy sources (solar, batteries, EVs; requiring active management, data exchange, and market facilitation) to balance supply and demand dynamically for a smarter, more decarbonised system.

This essential shift will build our capabilities in data, automation, energy orchestration, and unlock new ways for more people to participate in the energy system, supported by technologies such as Artificial Intelligence (AI), machine learning, and digital twin modelling.

These capabilities, combined with strengthened alignment to ISO 55001 asset management standards, ensure our plans are technically robust and strategically positioned to deliver long-term resilience, value for money and greater sustainability.

In terms of customer trust, we're aiming ever higher, through simpler communications, faster restoration, and easier connections, so customers feel supported at every touchpoint. We are immensely proud of the progress we've made, reflected in recent customer satisfaction scores, where 95% of respondents rated our power supply as safe and 92% rated it reliable.

But we know there is a lot more to do. This 2026 AMP sets out how over the next decade we will continue to invest in improving reliability, strengthening resilience, and delivering smarter, more flexible energy services while keeping costs to the community fair.

Our purpose is clear: to power thriving communities. This AMP is our roadmap to do just that, by balancing today's needs with tomorrow's possibilities.

I invite you to read it, share your feedback, and join us on this journey to a brighter, more sustainable, more resilient energy future.

Ngā mihi nui,

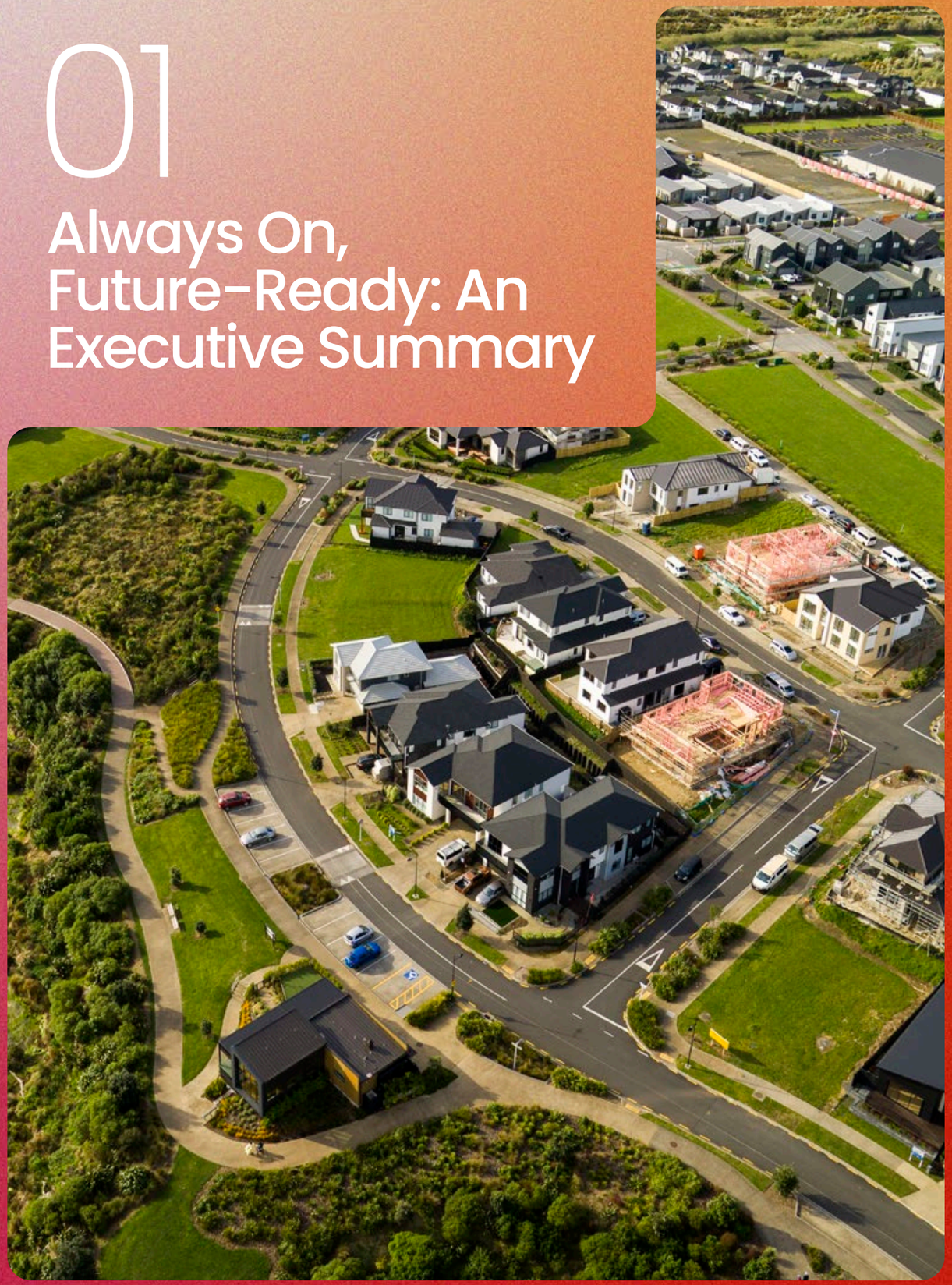
Judy Nicholl
Chief Executive Officer, Counties Energy

Liability statement

This asset management plan (AMP) has been prepared and publicly disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012. Some of the information and statements contained in this AMP are comprised of, or are based on, assumptions, estimates, forecasts, predictions, and projections made by Counties Energy. In addition, some of the information and statements are based on actions that Counties Energy intends to take in the future. Circumstances may change, assumptions and estimates may prove to be wrong, events may not occur as forecasted, predicted or projected, and Counties Energy may at a later date decide to take different actions to those it currently intends to take. Except for any statutory liability for which Counties Energy cannot be excluded, Counties Energy will not be liable, whether in contract, to part (including negligence), equity or otherwise, to compensate or indemnify any person for any loss, injury or damage arising directly or indirectly from any person using or relying on any content of this AMP. When considering the content of this AMP, persons should take appropriate expert advice in relation to their own circumstances and must rely solely on their own judgement and expert advice obtained.

01

Always On, Future-Ready: An Executive Summary



1.1 Introducing our Asset Management Plan

This document presents the Counties Energy Asset Management Plan (AMP) for the 10-year period from 1 April, 2026 to 31 March, 2036.

It sets out our assessment of the operating and economic environment of the electricity sector and how we will invest in and operate our network to ensure safe, reliable and affordable power delivery to over 50,000 connections across southern Auckland and northern Waikato.

It outlines how our network and associated assets will grow and adapt to meet rising demand and new challenges, such as the increasing impact of climate change and the shift toward a low-carbon economy, while preparing the network for greater electrification, more distributed energy resources (DERs), and more data-driven operations over the next decade.

It discusses how we think about the future needs of our region, the risks to mitigate, the need to strengthen network resilience, how best to use the rapidly emerging new technologies, and how we will invest over the next 10 years to best deliver on our promise to customers.

1.1 Introducing our Asset Management Plan

1.1.1 Purpose and Status of our AMP

This AMP is the primary expression of Counties Energy's asset management practices. It translates our strategies, expectations, and regulatory requirements into specific objectives, programmes and investment priorities. It also serves as a key planning and disclosure document under the Electricity Distribution Information Disclosure Determination.
Its purpose is to:

- articulate the long-term direction for our network and assets;
- describe the systems and processes that support prudent, risk-based decision-making;
- demonstrate how we balance reliability, resilience, affordability, safety, sustainability, and customer experience; and
- ensure transparency for our stakeholders, regulators, and communities.

1.1.2 Objectives of our Asset Management and Planning

Our asset management and planning processes aim to:

- Deliver safe, reliable and resilient electricity distribution services;
- Optimise whole-of-life value from our assets;
- Ensure investment is prudent, efficient, and aligned with customer expectations;
- Plan for rapid growth, electrification, new technologies, and climate change impacts.

1.1 Introducing our Asset Management Plan (continued)

1.1.3 Relationship Between Other Critical Business Documents and the AMP

The AMP serves as both a strategic and operational guide for managing Counties Energy's electricity distribution assets. It translates our corporate vision and values into actionable asset management objectives and aligns and inter-relates with other critical business documents, including:

- Corporate Strategy;
- Statement of Corporate Intent;
- Annual Budget; and
- Network Capital Investment Programme.

Counties Energy's Corporate Strategy sets the long-term direction and outcomes sought for the business and the communities we serve. The Statement of Corporate Intent translates this strategy into formal commitments and performance expectations. The Asset Management Plan gives effect to these strategic commitments by defining how network assets will be planned, managed, maintained and developed to deliver the required service outcomes.

The Annual Budget and Network Capital Investment Programme are informed by, and derived from, the AMP, ensuring that planned operating and capital expenditure reflects asset condition, risk, performance requirements and customer priorities. Together, these documents form an integrated planning framework that links strategic intent to asset management actions and delivery.

1.1.4 Interaction with Corporate Goals and Business Planning Processes

The objectives of this Asset Management Plan are also closely integrated with Counties Energy's broader corporate goals and business planning processes. The AMP supports the delivery of corporate objectives by translating customer, safety, reliability, resilience, sustainability, and financial performance goals into practical asset management strategies and investment decisions. Through the annual business planning and budgeting process, AMP objectives are reviewed alongside corporate priorities to ensure that asset management outcomes remain aligned with organisational goals and available resources.

Where trade-offs are required, these are assessed within the context of the AMP to balance short-term operational requirements with long-term network performance, customer outcomes, and inter-generational value. This interaction ensures that asset management decisions consistently support the wider strategic direction of the business.

1.2 Our Strategy for Delivering on Our Commitments

> We exist for our customers and communities. Our commitment to you is simple: keeping the lights on today, and for the future. This means doing the basics exceptionally well and preparing early and appropriately for what's next. Our strategy is underpinned by our purpose, which is to "power thriving communities", which we will achieve through our vision of "unlocking the full energy potential of our region, to secure a sustainable and prosperous future of generations to come."

1.2.1 Our Strategic Framework

We have a clear strategic framework to balance our focus and levels of innovation across a 10-year period. Our strategic objectives cover core business, emerging opportunities and transformational possibilities.

For Counties Energy, our three objectives are described below:

1. Delivering a robust and reliable electricity service every day.
2. Unlocking new energy services and experiences.
3. Reimagining a new energy future through our role as a DSO.

In the near-term, between 2026 and 2028, our strategic focus is on three key areas: electricity distribution, our energy services portfolio, and energy innovation.

1.2 Our Strategy for Delivering on Our Commitments
(continued)

1.2.2 Our Changing Operating Environment

Our operating environment is rapidly changing across several fronts, including population growth, climate change impacts, customer expectations, cost-of-living, technological change, and our regulatory settings. These macro-forces must all be addressed through our strategy, our planning and our approach to asset management.

a) Rapid Demand Growth: Counties Energy operates in one of New Zealand's fastest-growing regions. Many new large developments, combined with the electrification of transport and decentralised generation, are rapidly reshaping the demand for energy. We are well positioned to support residential and industrial growth across the region and to accommodate the integration of more DERs, including household and business solar and batteries, and electric vehicles and EV chargers.

b) Climate Change Imperatives: At the same time, climate change is driving ever more frequent severe weather in New Zealand, so we must further strengthen the resilience of our assets and invest in predictive maintenance, rapid power restoration and customer communications for when storms inevitably hit.

c) Providing Customers with More Control and Choice: Customer expectations in today's digital and 24/7 era have also changed. Increasingly, customers want information when, where and how they prefer to access it. Customers want more control and choice over the services and information they receive, as well as better and faster communications if outages do occur.

d) Keeping Services as Affordable as Possible: As a consumer-owned electricity distributor, we must also aim to keep energy services as affordable as possible, through the way we invest and operate. This perpetual need is even more acute during economic downturns.

e) Making the Most of Technological Advancement: Technological advancements are also rapidly changing the sector, with AI and smart use of data giving incumbents and potential market disruptors alike the chance to improve existing services, drive efficiencies, increase asset resilience and develop new tools and services for customers.

f) Ongoing Regulatory Change: Lastly, Counties Energy, like all participants in the electricity sector, operates in a tightly controlled regulatory environment, one which is constantly evolving as regulators seek to stay ahead of emerging trends and provide the best possible outcomes for competition and consumers, as well as ensure the continuity of power supply to New Zealanders is protected.

1.3 Who We Are and Who We Serve

1.3.1 Our Organisation, Customers and Stakeholders

Counties Energy operates in one of New Zealand's fastest-growing electricity distribution regions, stretching coast to coast between southern Papakura and Mercer, and West of the Waikato River from Mercer to Waikaretu. We serve over 50,000 residential and business customers with innovative energy solutions and build enduring relationships with all of our stakeholders, including iwi, government, industry, and community organisations.

Figure 1.1
Counties Energy stakeholders and their interests

1.3.2 Who We Are

We are a 100% consumer-owned Electricity Distribution business (EDB) exempt from Commerce Commission price-quality regulation, with the Counties Energy Trust acting on behalf of consumers. This ownership structure provides strategic advantages in pursuing long-term value creation for customers and communities. Information about the Trust can be obtained from countiesenergytrust.org.nz.

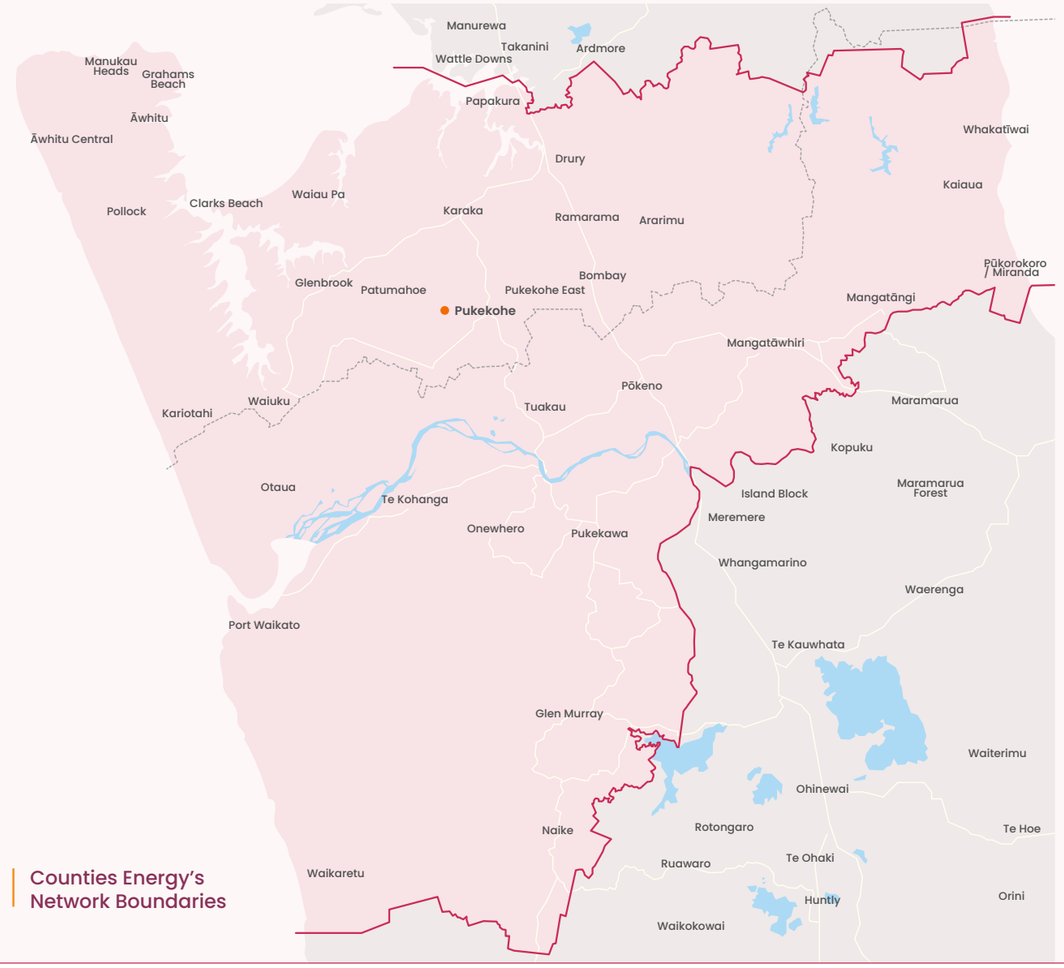
We have evolved from our 1924 inception as Franklin Electric Power Board to Counties Power, to our current identity as Counties Energy, and positioning ourselves as a smart, customer-centric energy orchestrator. This evolution reflects our strategic transformation from a traditional lines business to an energy and technology business focused on smart solutions and customer-first energy ecosystems.

At the heart of this transformation is a strong commitment to asset management, ensuring the electricity network is reliable, resilient, and ready for future demands while placing community needs at the centre of our decision-making.

Park Green, Karaka

Our assets at a glance:

- Service area spans coast-to-coast between southern Papakura and Mercer, and west of the Waikato River from Mercer to Waikaretu.
- Two Transpower grid exit points (GXPs): Bombay (110 kV) and Glenbrook (33 kV).
- 8 zone substations and 1 switching station; 57 HV feeders at 22 kV/11 kV.
- ~50,000 customer connections supplied from ~4,300 distribution substations.
- Mix of overhead and underground assets with targeted urban undergrounding.
- Dedicated communications networks (radio, fibre) supporting safe operations.



Counties Energy's Network Boundaries

1.4 How We Plan Ahead

Our wider planning and investment approach is based on 10 key focus areas, supported by a clear asset management system, framework and policy, and a sophisticated, data-driven forecasting process for network and non-network expenditure.

1. Our Promise and Purpose: We will focus on keeping the lights on today and in the future. This promise is anchored in Counties Energy's consumer ownership and our commitment to powering thriving communities.

2. Reliability and Resilience: We will add capacity where demand growth is strongest, strengthen network and asset resilience where it matters most, improve System Average Interruption Duration Index (SAIDI)/ System Average Interruption Frequency Index (SAIFI), address root causes like vegetation and overhead defects, automate restoration, and harden the resilience of our network assets for the likelihood of more frequent severe weather. Resilience is an increased focus, given the rise of extreme weather events. Counties Energy invests in network redundancy, automation, and real-time monitoring systems to enhance the adaptability and robustness of its network. The integration of DERs and energy storage further strengthens network resilience, establishing the foundations for a self-healing distribution system that remains customer-centric and reliable.

3. Customer Experience and Transparency: We will put more control and choice in the hands of customers. This includes proactive outage and planned-work communications, voltage quality monitoring, streamlined connections, visible Utilities Disputes pathways, and more communications on our performance against the targets we set. We remain "customer obsessed" through collaboration with industry players, stakeholders, and regulators to put more power in the hands of customers through automation and personalised energy solutions.

4. DER Readiness and LV Visibility: We are increasing our focus on enabling greater distributed energy resource and Low Voltage (LV) readiness, including publishing hosting capacity, building LV analytics, integrating more solar, batteries, and EVs, and trialling more flexibility services.

5. Asset Intelligence and Asset Management System (AMS) Maturity: We are strengthening our AMS toward greater ISO 55001 alignment, using health/criticality indices and other leading indicators to prioritise renewals and reliability investments. Central to this maturity journey is building a robust asset intelligence capability that transforms raw asset data into actionable insights. By integrating data from multiple sources — including condition monitoring, operational performance, maintenance history, and external factors — we are creating a comprehensive intelligence layer that enables evidence-based decision-making. This data-driven approach allows us to move beyond reactive management toward predictive and strategic asset stewardship, ensuring our investments deliver optimal value and network reliability for our customers.

6. Affordability and Prudence: To improve and maintain affordability, we will use advanced modelling to sequence and optimise our capital expenditure and operating expenditure, renew aging assets in the most cost effective and efficient way, ensure standardised and scalable designs, evaluate non-network alternatives, defer growth projects where possible, and link all investments to long-term community value, while maintaining high reliability standards and accommodating rapid load growth. The asset management strategy prioritises standardised and scalable infrastructure solutions, ensuring that investments meet current demands but also enable flexibility for integrating emerging technologies.

1.4 How We Plan Ahead (continued)

7. Community-Owned and Region-Committed: We leverage our consumer ownership for long-term planning and deepen our iwi and community partnerships as we strive to build and maintain social licence through greater transparency.

8. Regulatory Context and Readiness: We ensure full regulatory compliance traceability with clause mapping, schedules, and Directors' Certificate, while also preparing for the ongoing evolution of regulatory settings and changes.

9. People, Safety and Delivery Excellence: We continue to embed and prioritise a safety-first culture, aim to align with ISO 45001 by 2029, and structure our works-delivery life cycle to ensure operational excellence.

10. Future-Ready Scenarios and Innovation Pipeline: We are getting ready for the future through investing in digital tools, technology and data to operate smarter and faster, through scenario planning for demand, EVs, solar and batteries, by piloting and trialling innovations ahead of deployment at scale, and by developing our people's skills and capabilities. Our digitalisation strategy encompasses artificial intelligence, machine learning, and AI-enabled analytics to transform raw data into actionable intelligence. This will help us deliver predictive insights, optimise network performance, and enhance customer experience.

1.5 How We Manage Our Assets

Counties Energy has a clear Asset Management Policy (AMP), Asset Management Framework, Asset Management Principles, and an Asset Management System (AMS) which is increasingly aligned with ISO 55001:2024, widely recognised globally as the best practice standard.

Our approach to asset management is based on four clear principles that guide every decision we make, from daily maintenance to long-term investments. By following these principles that are embedded into the AMP, Counties Energy will continue to deliver safe, reliable, and affordable electricity, now and into the future.

1. Reliability and Resilience: We will continually enhance reliability through targeted programmes: feeder automation, structural strengthening, vegetation management, improved protection and control systems, and faster restoration following storms. Risks and associated mitigation plans will continue to be regularly assessed across safety, operations, finance, regulations, and the environment. We will continue to improve our preparedness for emergencies by updating crisis plans, maintaining spare parts, and collaborating with local emergency groups and other utilities.

2. Community Engagement and Communications: As a consumer-owned electricity distributor, we keep service simple, proactive and transparent, improving outage communications, voltage quality, and connection journeys. We work closely with customers, local iwi, regulators and community groups to understand what matters most to them, and we use that feedback to inform investment choices and operational decisions. Customer satisfaction is measured regularly as we strive for continual improvement.

Counties Energy working on the Oyster Capital site in Drury

1.5 How We Manage Our Assets (continued)

3. Value for Money: We will optimise and sequence our investments, evaluate non-network alternatives, and focus on long-term whole-of-life value, linking forecasts to price-quality settings and community expectations. We are building greater LV visibility and hosting capacity visibility, integrating distributed energy resources (including solar, batteries, and EVs), and trialling flexible demand solutions so we can enable customer choice and defer non-essential spend. We will continue to strengthen our Asset Management System (AMS), further aligning with ISO 55001:2024, and using health/criticality models and analytics to prioritise our investments.

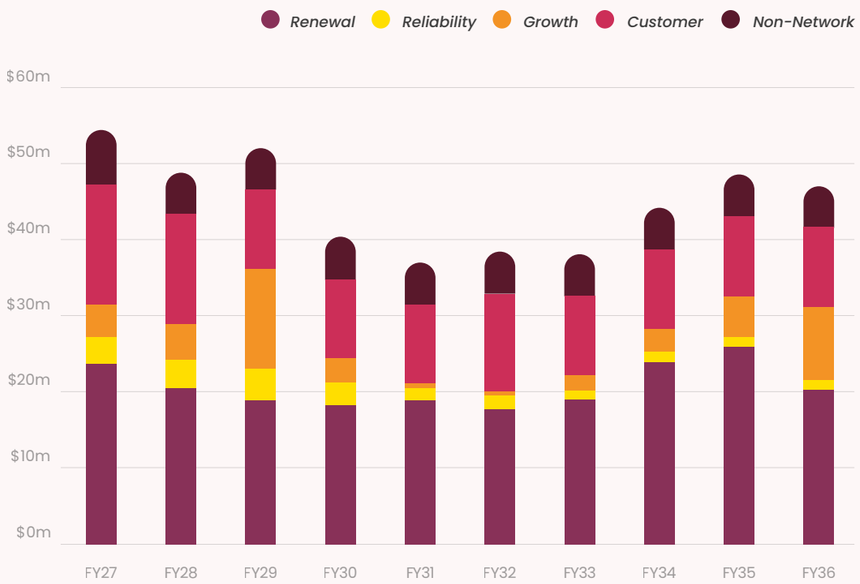
4. Intelligent and Innovative Asset Management: Every asset is managed throughout its life cycle, from power poles to transformers, from installation and proactive maintenance (using drones and sensors) to timely replacement or upgrades. We use advanced network modelling and scenario planning to make smart investment decisions, focusing on reliability and sustainability. Asset inspections are conducted on a regular basis, and pre-emptive upgrades made to equipment and network design. We continue to modernise our systems for better remote monitoring and control and use data-driven risk assessment tools to prioritise maintenance and upgrades.

Fault detection technology, proactive inspections, and smart meter data aims to ensure there are fewer and shorter power interruptions. We use advanced analytics, artificial intelligence, and machine learning to transform raw data into actionable insights, enabling predictive maintenance, faster problem-solving, and improved customer service. Looking ahead, Counties Energy continues to embrace new technologies such as autonomous drones, AI/ML (Machine Learning)-based asset image recognition to identify potential problems, to further enhance asset management and to deliver a smarter, more flexible energy network. Counties Energy has a clear Asset Management Policy (AMP), Asset Management Framework, Asset Management Principles, and an Asset Management System (AMS) which is increasingly aligned with ISO 55001:2024, widely recognised globally as the best practice standard.

1.6 The Key Numbers In The AMP

We plan to spend $447 million in capital expenditure over the next ten years, up 0.5% from $445 million in last years plan. Total operational expenditure is planned at $328 million, up 2.9% from $318 million in last years plan.

Figure 1.2 Ten-Year Total CAPEX Forecast Constant Price



Forecasted Network Expenditure (FY27 to FY36)

Over the next decade, we will invest $391 million in our network to renew critical assets, enable growth, and connect new customers. More than half of this investment is dedicated to asset replacement and renewal, with over a quarter supporting new connections. Expenditure reflects the delivery of major programmes, peaking at $47 million in FY27 before moderating to below $35 million per annum from FY30 to FY33.

Forecasted Non-Network Expenditure (FY27 to FY36)

We are committing $56 million over the next decade to non-network capital investment, enabling our digital transformation while modernising and sustaining our property, plant, and vehicle fleet to support the vision and values laid out in this plan.

Major Projects Planned (FY27 to FY36)

In addition to our core distribution workload, we are delivering a substantial programme of critical substation and enabling infrastructure upgrades. This includes major substation rebuilds and replacements across the network, investment in a new Quarry Road Substation, completion of our automation transformation, and the rebuild of our Glasgow Road data centre – strengthening resilience, capacity, and operational capability for the future.

Unless stated otherwise, all financial values presented in this Asset Management Plan are expressed in constant price New Zealand dollars.

Forecasted Network Operational Expenditure (FY27 to FY36)

We are forecasting $104 million of network operational expenditure over the next decade to safely operate, maintain, and support the performance of the electricity network. This investment underpins day-to-day network reliability through planned, corrective and reactive maintenance, vegetation management and fault response, ensuring we continue to deliver safe, reliable outcomes for customers while supporting the service levels and strategic objectives outlined in this plan.

Forecast Non-Network Operational Expenditure (FY27 to FY36)

We are forecasting $224 million of non-network operational expenditure over the next decade to support the effective operation of the business and enable the delivery of network outcomes. This expenditure covers corporate services, information and digital services, property and fleet operations, health and safety, and regulatory and customer support functions. These activities provide the organisational capability, systems, and governance required to operate the network safely, efficiently, and in line with the objectives and service commitments set out in this plan.

How We Will Measure and Demonstrate the Success of this AMP

Our performance will be tracked and reported through:

- Customer satisfaction and engagement scores;
- Reliability metrics (SAIDI, SAIFI, CEMI*, CELID*);
- Utilisation and cost-efficiency indicators; and
- Business operations metrics (health and safety).

*CEMI = Customers Experiencing Multiple Interruptions, CELID = Customers Experiencing Long Interruption Durations

1.7 Have Your Say

We welcome and value feedback from customers, stakeholders, iwi, and community partners. Contact us at info@countiesenergy.co.nz.

1.8 The AMP Section Summary

This Asset Management Plan has been divided into nine sections.

Executive Summary

The executive summary summarises the key areas of focus of Counties Energy's 2026 AMP, in the context of the current economic and regulatory environment.

Chapter 2: Our Strategy for Delivering on Our Commitment

In this chapter, we describe in more detail how our AMP approach aligns with our corporate vision and strategy.

Chapter 3: Our Organisation, Customers and Stakeholders

This chapter outlines our customer strategy and key customer priorities, with customer engagement as a key metric. We also detail stakeholder engagement with diverse groups including local council, community groups, iwi, and industry bodies.

Chapter 4: Managing Our Assets

We provide an overview of our approach to managing our network and assets. The chapter covers network performance, risk management and mitigation, and resilience planning, as well as strategies to mitigate climate change, cybersecurity, asset failure, and other key risks.

Chapter 5: Our Network

This chapter provides an in-depth overview of our network and asset base. It outlines asset age, condition, performance trends and key risks, and explains how structured maintenance, renewals, inspections and data-driven asset health modelling ensure a safe, reliable and resilient network.

The Manukau Heads Lighthouse

1.8 The AMP Section Summary (continued)

Chapter 6: Our Planning and Investment Approach

Here we outline the methodology for forecasting demand and peak load, together with strategies to ensure sufficient capacity to meet future needs. Both the capital and operational expenditure programmes are detailed, as are investment drivers and priorities.

Chapter 7: Our Plan

This chapter sets out Counties Energy's 10-year network development plan, outlining where growth is expected across the Eastern and Western regions and the infrastructure required to meet demand. It details planned zone substation upgrades, feeder reinforcements, renewals and undergrounding, addressing emerging constraints to maintain safety, reliability and long-term network resilience.

Chapter 8: Getting Future Ready - Assets, People and Technology

This chapter outlines how Counties Energy is thinking about and preparing for the future needs of the region, including how we think about future assets, future skills and the technology advancements that will unlock value. This chapter also details our non-network solutions and innovation, primarily in the digital, DSO, and flexibility space.

Chapter 9: Our Performance and Delivery

This chapter discusses our capability to deliver our plan, and also reviews our performance and delivery of the plan set out in previous AMPs.

Appendices

This chapter provides a glossary of terms, the information disclosure schedules and Directors' Certification.

Approval Date

This AMP was reviewed and approved by the Counties Energy Board of Directors on 25 March 2026.

02

Our Strategy for Delivering on Our Commitment

2.1 About This Chapter

Our strategy is designed to address the challenges and opportunities posed by the expected growth on our network, rising costs, supply constraints, and the increasing electrification of society. It incorporates our purpose, values and vision, the different time horizons we plan for, the near-term strategic focus areas, and the changing operating environment and macro trends. It also outlines the key business assumptions that underpin our strategic thinking and AMP.

2.2 Our Purpose, Vision and Strategy

2.2.1 Our Purpose and Vision

Our purpose is to “power thriving communities”, which we will achieve through our vision of “unlocking the full energy potential of our region to secure a sustainable and prosperous future for generations to come.”

2.2.2 Our Strategic Framework

We use a strategic framework to balance our focus and levels of innovation across a 10-year period.

For Counties Energy, our three strategic objectives are described below:

1. **Delivering a robust and reliable electricity service every day;**
2. **Unlocking new energy services and experiences; and**
3. **Reimagining a new energy future through our role as a DSO.**

2.2.3 Strategic Focus Areas

For this AMP, our focus is on the following strategic objectives for 2026-2028:

2.2.3.1. Electricity Distribution

We recognise every dollar invested in the network ultimately impacts our customers in the end. Our planning process focuses on achieving the right balance between reliability, resilience, affordability, and service quality.

We are committed to improving network performance to a level that meets DPP-compliant levels while enabling future growth and optimising cost-to-serve, ensuring our infrastructure foundation supports today’s operations and tomorrow’s expansion plans. Simultaneously, we are placing customer experience at the centre of our business, focusing relentlessly on providing a quality service that differentiates us from other electricity distribution companies.

To support these customer-facing improvements, we are transforming our business operations through digital technologies and processes, creating a high-performing, future-fit organisation that can adapt and scale efficiently. Underpinning all these efforts is our commitment to attracting, securing, and retaining critical skills while fostering a safe, high-performance culture that empowers our people to deliver results and drive innovation.

2.2.3 Strategic Focus Areas (continued)

2.2.3.2. Energy Services Portfolio

We are enabling a diversified renewable generation and storage portfolio encompassing wind, solar, and battery technologies to create new sustainable revenue streams that align with market decarbonisation trends. Additionally, as a Metering Equipment Provider (MEP) on our network, we have access to granular consumption data that supports initiatives such as delivering five-minute interval data across our electricity network. The granular data enables Counties Energy to proactively detect issues like undervoltage events and improve outage response. The five-minute data will also enable better asset optimisation, preventative maintenance, smarter investment decisions, and facilitate integration of distributed energy resources to meet future energy demands. This strategic area also sees the development of new services, such as enabling a Hot Water Demand Flex service for retailers using the existing smart meters, community batteries as flexible infrastructure "solutions", and undertaking a trial of a Community Energy Sharing scheme to address energy hardship.

2.2.3.3. Energy Innovation

We are developing foundational DSO capabilities while proactively preparing for future market roles and functions, ensuring we are positioned to lead in the evolving energy distribution landscape. This foundation enables us to develop the required organisational structures and capabilities needed to identify, prioritise and incubate the development of new DSO services that meet emerging customer needs. Supporting this transformation is our commitment to building strategic local and international partnerships with key industry thought leaders while fostering a culture that encourages experimentation, learning, and rapid adaptation to market changes, ensuring we remain at the forefront of DSO evolution.

The company is working alongside Unison and The Lines Company to share foundational DSO capabilities, expertise and resources to address emerging market needs and accelerate innovation. These local partnerships also enable Counties Energy to develop and learn capabilities in the areas of ISO 55 000 Asset Management and Energy Hardship. Additionally, Counties Energy is building strategic partnerships with international organisations such as South Australian Power Networks and Plexigrid, fostering a culture of experimentation and rapid adaptation to global energy trends. These collaborative efforts are designed to support the development of new services, enhance operational agility, and ensure Counties Energy remains at the forefront of technological and market advancements in the energy distribution sector.

Barber Road Substation

2.3 How Strategic Imperatives Inform This AMP

Counties Energy's strategic vision encompasses the development of next-generation network architecture that seamlessly integrates traditional distribution infrastructure with advanced digital platforms and renewable energy systems.

We recognise the ongoing change from a Distribution Network Operator (DNO) to a Distribution System Operator (DSO) is an essential transformation to drive performance and resilience on the network, while generating new value that unlocks more energy potential and affordability for communities.

This transformation is driven by the fundamental shift in how energy is sourced, consumed, and managed across the electricity system. As Counties Energy transitions to becoming "energy orchestrators" our investment and asset management approach will respond to the following key strategic and macro imperatives:

2.3.1 Market Dynamics

Rapid population growth and more renewable and decentralised generation on the network, alongside potential competition from emerging market participants (such as DER aggregators, embedded networks) and regular regulatory changes in the New Zealand energy system, is collectively putting pressure on traditional demand patterns, timing uncertainties and affordability challenges.

AMP Response:

- **Prioritise optimising network utilisation through a more innovative approach to planning and augmentation.**
- **Develop our capability to harness potential increase of DERs to supplement traditional firm planning, using tools like community batteries and flexibility services.**
- **Include utilisation Key Performance Indicators (KPIs) and cost-efficiency metrics in performance dashboards.**

2.3.2 Infrastructure Modernisation Imperative

Strategic investments are needed for decarbonisation and electrification, and new ways of connecting to the network, which must be balanced against affordability and regulatory efficiency targets ($/kW, $/kWh).

AMP Response:

- **Sequence capital expenditure using standardised, scalable designs to defer large builds where possible.**
- **Embed whole-of-life cost analysis and optimisation metrics in planning templates.**
- **Strengthen resilience through 4Rs (Reduction, Readiness, Response, Recovery) and climate risk strategies.**

2.3.3 Regulatory Proactivity Imperative

Ongoing regulatory reforms (connection pricing, flexibility services) require proactive engagement and scenario modelling to effectively manage the cost-to-serve our customers.

AMP Response:

- **Establish a regulatory engagement roadmap under our Planning and Investment Approach.**
- **Model demand-side flexibility scenarios and integrate outputs into our investment prioritisation.**
- **Include assessment against our disclosure requirements and compliance assurance in AMP appendices.**

2.3.4 Community-Centric Advantage

Consumer ownership provides a strategic advantage by enabling a long-term focus on shareholder value, alongside a clear obligation to maintain our social license through visible community benefits, energy hardship support, and iwi partnerships.

AMP Response:

- **Enhance customer choice through the provision of capacity maps and self-service capabilities.**
- **Expand customer engagement programmes (discussion panels, Outage Hub enhancements, proactive communications).**
- **Introduce hardship mitigation initiatives and energy literacy campaigns.**
- **Embed iwi engagement principles and partnership projects in delivery plans.**

2.3.5 Digital & Technology Transformation Opportunity

Digitalisation, cybersecurity, and advanced analytics are rapidly improving and are critical enablers for efficiency and new service models.

AMP Response:

- **Accelerate LV visibility and Distributed Energy Resource Management System (DERMS) deployment for smarter network operations.**
- **Strengthen cybersecurity and data privacy compliance under data, visibility and analytics.**
- **Invest further in predictive analytics, digital twins, and automation for asset health and flexibility orchestration.**

2.3 How strategic imperatives inform this AMP (continued)

2.3.6 Energy Transition Leadership

Counties Energy is pioneering the transition from a traditional Distribution Network Operator (DNO) to a modern Distribution System Operators (DSO) and enabling renewable generation and storage at scale.

AMP Response:

- Develop foundational DSO capabilities and flexibility service catalogue.
- Progress community battery pilots, energy sharing trials, and renewable energy zones to become business as usual (BAU).
- Build strategic partnerships with other electricity distribution businesses (EDBs) and industry innovation partners to drive best-practice collaboration and efficiencies.

2.4 Our Values and Ways of Working

Our values are the foundation of everything we do; they guide our decisions, shape our priorities, and define how we deliver for our customers and communities.

Safety, reliability, customer obsession, respect, innovation and guardianship are not just values, they are commitments that underpin our long-term strategy. By embedding these values into every aspect of planning and operations, we ensure that our network investments reflect both technical excellence and social responsibility.

For customers, this means confidence in a service that is dependable, affordable, and future-focused. For our business, it means aligning innovation and efficiency with trust and transparency, creating outcomes that benefit all our stakeholders today and tomorrow.

Figure 2.1
Counties Energy values

Safety First	The safety of our people, our communities and our customers comes first, and we never underestimate the power of energy or how we need to work to stay safe.
Customer Obsessed	From the smallest gestures to major fixes, we aim to surprise, delight and serve our customers above and beyond expectations, giving them an unforgettable experience every time.
Always On	Reliability is important as it builds confidence and trust within our community. We are proactive through adapting and changing our skills and service opportunities for today and the future.
Genuine Respect	At our best with everyone, always. We create a safe environment by showing empathy and respect towards others, whether they are customers or colleagues.
Fearless Innovators	Having the grit and courage to take on big challenges. Solving big problems and challenging the status quo with bold and progressive ideas.
Trusted Guardians	Kaitiaki of our resources and our environment. We protect and preserve our environment by minimising our impact. We're taking care of today so that future generations can thrive.

2.5 Our Changing Operating Environment

Counties Energy operates in a dynamic environment shaped by rapid regional growth, climate change, technological transformation, and evolving regulation. This presents both challenges and opportunities. This section outlines in more detail the key influence factors that are impacting the network and our planning.

2.5.1 Population Growth*

The Drury-Opāheke Structure Plan forecasts approximately 22,000 new homes and 60,000 new residents over 30 years according to plans for Auckland and Waikato. The scale of this development is significant as Drury could rival Napier in terms of size over the next 30 years.

In the Pukekohe-Paerata area, plans allow for a further 12,500 dwellings and an estimated 33,800 new residents in the next 30 years. The Paerata Rise development alone represents a substantial portion of the growth, with approximately 4,500 new build homes planned within the Paerata Rise township, to be completed by 2035.

The combined impact of these two growth areas represents over 34,500 new dwellings over the next 30 years, creating substantial additional demand for electricity. This aligns with Auckland Council's broader planning for 200,000 more Aucklanders expected by 2034.

For Counties Energy, this represents both a major opportunity and challenge, requiring significant network expansion, new substations, and enhanced capacity to serve these rapidly developing communities.

2.5.2 Climate Change and Extreme Weather Vulnerabilities

Climate change presents a material and growing risk to Counties Energy's network reliability, resilience, safety, and affordability. Over the next decade, our network will face increasing exposure to the impacts of climate change and extreme weather events. More frequent and intense storms are expected to cause physical damage to network assets such as overhead lines, poles, and transformers, and elevate the risk of outages and restoration delays. Coastal inundation, linked to sea-level rise, presents a growing threat for assets located in low-lying areas across our network.

In addition, the South Auckland and Northern Waikato regions are projected to experience an increasing number of hot days, more frequent droughts, and higher average temperatures. These changes will alter vegetation growth rates and may shift traditional energy consumption patterns, such as greater summer cooling demand and flatter seasonal load profiles.

**Sources:*

Auckland Council, Drury-Opāheke Structure Plan 2019.

Auckland Council, Pukekohe-Paerata Structure Plan 2019.

Paerata Rise, Master Plan.

Auckland Council, Plans to transform Drury and Pukekohe adopted.

Auckland Council (reported), Development Contributions Policy 2025.

2.5 Our Changing Operating Environment (continued)

The potential impacts on our network are significant. Increased attention on network resilience and adaptation is essential, ensuring that outages from severe weather events are minimised, and that restoration and recovery can occur rapidly and safely when events do occur. While climate change presents clear risks, it also creates opportunities for Counties Energy to play a leading role in enabling a low-carbon, climate-resilient future for its community. The transition to a decarbonised economy will accelerate electrification, drive infrastructure investment, and reinforce the strategic importance of local electricity networks.

Over the next decade, we anticipate a period of major transformation as the industry positions itself to meet this dual challenge: hardening the network to withstand more extreme weather, while delivering increased energy volumes to power New Zealand's low-emission future. Both require significant planning, capability development, and sustained investment.

Counties Energy has already initiated a range of measures to prepare for and mitigate the physical and transitional risks associated with climate change.

These include:

- **Partnering with ClimSystems to model the potential impacts of climate change across multiple emissions and weather scenarios.**
- **Enhancing vegetation management programmes to reduce the risk of weather-related outages.**
- **Embedding resilience into asset management and maintenance projects, including upgrading and improving redundancy across key assets and critical network elements where viable and justified to do so.**

2.5.3 Technological Advancements

The electricity sector is undergoing rapid digitalisation with smart meters, advanced distribution management systems, and real-time monitoring technologies becoming standard requirements, enabling better management of Distributed Energy Resources (DERs). Counties Energy owns and has utilised smart meter mesh network capability over the last decade for Low Voltage (LV) fault restoration processes. This capability has been the foundation for improving the customer experience on the Outage Hub.

We are also investing in IoT (Internet of Things) sensors, automated switching equipment, and predictive analytics capabilities to maintain service levels and operational efficiency. Other new, smart technologies utilised include the use of drones for efficient and targeted fault identification and LiDAR technology to create accurate 3D maps and models of utility infrastructure and the surrounding environment, including vegetation.

LV analytics has enabled us to collect and evaluate data from smart meters and LV monitoring devices — including sensors deployed at substations and transformers — to provide operational visibility into a segment of the network that has traditionally lacked visibility. To optimise grid operations amid bi-directional power flows, Counties Energy is developing DSO and Distributed Energy Resources Management Systems (DERMS) platforms to manage DERs, including rooftop solar, battery storage, and electric vehicles. This includes assessing the impacts and opportunities associated with electric vehicle uptake and broader electrification trends across our network.

With South Auckland's growing population increasing their uptake of DERs, the combined use of these new technologies gives us visibility and the capability to manage and optimise an increasingly smart electrical network. However, increased digitalisation brings heightened cybersecurity risks and data management responsibilities. Counties Energy continues to implement robust cybersecurity frameworks, to ensure customer data privacy, and to maintain our system reliability while enabling digital service offerings and automated network operations.

2.5.4 Regulatory Changes

The New Zealand electricity sector is undergoing significant regulatory reform through coordinated initiatives by the Electricity Authority (EA), the Ministry of Business, Innovation and Employment (MBIE) and the Ministry for the Environment (MfE). These changes are designed to enhance market competition, accelerate electrification adoption, facilitate integration of DERs into the national grid and recognise electricity networks' essential role in national policy statements and environmental standards.

Electricity Authority Regulatory Measures

The EA has implemented comprehensive reforms to address market inefficiencies and barriers to renewable energy adoption. New standardised connection protocols have been established with defined timeframes for network applications aimed at streamlining the customer experience across all EDBs. The authority is also working to improve regulatory settings for distribution networks to encourage more innovation, investment, and coordination to support the growth of DERs.

The EA has introduced regulatory reforms that directly affect how distribution networks manage connections, pricing signals, and customer participation in the energy system. These changes are aimed at improving consistency, transparency, and efficiency across EDBs, while supporting increased uptake of DERs.

New standardised connection requirements establish clearer processes, information expectations, and indicative timeframes for network connections. For EDBs, this places greater emphasis on timely engagement, predictable application assessment, and improved customer communication throughout the connection journey. The reforms are intended to reduce delays and variability in connection outcomes and improve customer confidence in the distribution system.

The EA is also strengthening distribution pricing and regulatory settings to better reflect the value and impacts of distributed generation. This includes clearer signals around peak demand and export value, which in turn influences network planning, investment decisions, and operational coordination with retailers and customers.

More broadly, the EA is encouraging distribution networks to adopt more flexible, innovative approaches to manage growing levels of DERs. These settings are designed to support efficient network investment, improve system resilience, and enable customers to actively participate in the electricity system while managing cost and capacity impacts on the distribution network.

2.5 Our Changing Operating Environment (continued)

MBIE Policy Initiatives

MBIE has gazetted permitted voltage ranges for optimising rooftop solar integration while reducing implementation costs for consumers and businesses. Updates to the Hazards from Trees Regulations now provides greater operational powers to infrastructure owners to manage risks from trees to improve reliability of power supply.

Resource Management Reforms

Broad changes to the national direction under the existing Resource Management Act[1] were proposed in 2025. Changes are proposed across housing, freshwater and infrastructure with the intention of enabling infrastructure and energy projects to support the growing electrification and transition to a highly renewable energy system.

Of particular benefit to the distribution sector is the extension of the National Policy Statement for Electricity Networks and the National Environmental Standards for Electricity Network Activities to include electricity distribution. Recognising electricity distribution networks in national direction is a vital and long-overdue step. It better reflects the essential role that distribution plays in enabling electrification, supporting the transition to a low-emissions economy, and delivering resilient, reliable energy to communities across Aotearoa, New Zealand.

The government is proposing to replace the Resource Management Act 1991 with two new pieces of legislation: the Natural Environment Act and the Planning Act, expected to be passed around mid-2026. This regulatory reform will create a more favourable environment for electricity network development through three key improvements: expanded permitted activity rules, designated grid corridors within spatial planning frameworks, and regulations that better accommodate emerging technologies like EV charging infrastructure.

Other Sector Developments

The Commerce Commission's Energy Competition Task Force is simultaneously evaluating market structure enhancements to intensify competition and expand consumer participation opportunities within the electricity market. These coordinated regulatory initiatives will update the energy sector's infrastructure and market mechanisms for increased competition, reduced barriers to entry and better choices and value for customers and businesses.

The Streamlining Connections group has delivered standardised customer connection processes, and introduced tools such as a glossary of terms and FAQs, and has commenced improvements for transparency of connections through online resources. Counties Energy has supported this initiative by contributing to the development and implementation of these changes. We have also proactively adopted these practices locally, aligning with sector-wide templates and enhancing our digital and process capabilities to enable faster, more efficient customer connections.

1. Refer Resource Management Act 1991, legislation.govt.nz

2.6 The Key Business Assumptions Underpinning the AMP

This AMP is underpinned by a set of strategic business assumptions for Counties Energy that also guide our investment planning, risk management, and service delivery. These assumptions are reviewed annually and updated to reflect emerging trends, stakeholder feedback, and regulatory developments.

2.6.1 Business Structure and Operating Practices

This AMP incorporates assumptions that reflect changes and developments beyond Counties Energy's historic operating practices. These assumptions recognise an evolving operating environment and a deliberate shift in strategic direction as a response, rather than a simple continuation of past practices. Key assumptions include:

- **Increased electrification and integration of distributed energy resources (DER):** Higher uptake of electric vehicles, increased levels of distributed generation, battery storage, and greater use of demand-side flexibility compared with historic levels.
- **Greater digitalisation and system intelligence:** Expanded use of advanced analytics, automation, improved low-voltage network visibility, and enhanced digital asset management capabilities.
- **Evolving asset management maturity:** Continued improvements in asset data quality, risk and resilience modelling, and stronger alignment with ISO 55001 asset management principles.

These assumptions are intended to reflect anticipated changes in how the business operates to meet future network, customer and regulatory needs.

No major structural changes to the asset base are assumed over the AMP period, including changes arising from mergers, changes in ownership, or materially different stakeholder requirement.

2.6.2 Risk Management

Our assumptions about management of risk are largely discussed in section 4.11. Although we have planned for processes and resources to ensure business continuity in the event of a major event or equipment failure, we have not included the actual financial consequences of a forecast or hypothetical major event in our AMP forecasts.

2.6 The Key Business Assumptions Underpinning the AMP (continued)

2.6.3 Service Level Targets

We have based our service level targets on customers' views about the quality of service they expect. Extensive consultation over many years tells us that customers want network reliability, resilience and low prices. To meet this expectation, we look for the right balance between costs for customers and network investment. For a summary of our customer engagement and their views, see Chapter 3. Future changes to regulation are unlikely to reduce our targeted service levels and are likely to continue the pressure to ensure cost-effective delivery of network services.

2.6.4 Lifecycle Management of Our Assets

We have assumed no significant purchase or sale of network assets from Transpower or other EDBs or notable removals of asset from the asset base other than those discussed in later sections of this plan. The planned maintenance and replacement of our assets is largely condition and risk based. This assumes prudent risk management practices associated with good industry practice to achieve the outcomes in line with our targeted service levels.

2.6.5 Data Will Matter More Than Ever

Our asset management decisions are increasingly data-driven. We assume continued improvements in data quality, system integration, and analytics capability to support predictive maintenance and real-time network optimisation.

2.6 The Key Business Assumptions Underpinning the AMP (continued)

2.6.6 Potential Differences Between Our Forecast and Actual Outcomes

The forecasts and assumptions set out in this AMP are prospective in nature and are subject to a range of uncertainties. Actual outcomes may differ materially from the information presented due to factors that were not anticipated, or could not be reliably quantified, at the time this AMP was prepared.

Factors that may result in material differences between forecast and actual outcomes include, but are not limited to:

- **Changes in regulatory, legislative, or compliance requirements,** including amendments to information disclosure, quality standards, or industry codes, which may affect investment priorities, asset specifications, or delivery approaches.
- **Variations in customer demand, growth, and connection timing,** including changes in demand profiles, load growth, or network resilience, and reliability requirements arising from national policy settings, economic conditions, or technological change.
- **Unanticipated customer or generation connections,** including the connection of large consumers or generators not included in the forecast, which may require additional or accelerated network investment.
- **Unplanned asset failures and major events,** such as significant equipment failure, natural disasters, extreme weather events, or cybersecurity incidents, which may require material response and recovery expenditure and may result in deferral or reprioritisation of planned works.
- **Differences in the uptake of new technologies,** including distributed energy resources and demand-side solutions, relative to forecast assumptions.
- **Changes in input costs and funding conditions,** including supply chain disruptions, exchange rate movements, inflation, interest rates, or the cost and availability of borrowing, which may affect project affordability, scope, timing, or delivery (refer section 2.6.8).
- **Material increases or volatility in fuel and energy prices** resulting from global geopolitical tensions, will have a material impact on the inputs and assumptions used to develop this AMP. Whilst this AMP is developed using the available information at the time, the expenditure profiles will be continually assessed and addressed throughout the AMP period.
- **Changes in project scope, prioritisation, or sequencing,** arising from updated asset condition information, revised risk assessments, or operational constraints identified during the AMP period.
- Other risks and uncertainties discussed elsewhere in this AMP.

Counties Energy monitors these uncertainties and risks through ongoing asset performance monitoring, demand forecasting, risk management, and annual business planning processes. Forecasts and assumptions will be reviewed and updated as appropriate in future AMP disclosures to reflect the most current information available.

2.6 The Key Business Assumptions Underpinning the AMP (continued)

2.6.7 Sources of Uncertainty and Potential Impacts

There is inherent uncertainty in prospective information due to factors outside Counties Energy's direct control. Key sources of uncertainty include:

- **Demand uncertainty:** Variability in population growth, development timing, electrification uptake and customer behaviour.
- **Technology evolution:** Rate of adoption, cost and performance of emerging technologies, including DER, EV charging solutions and flexibility platforms.
- **Climate and extreme weather:** Frequency and severity of weather events exceeding historic patterns, impacting asset condition, resilience investment and restoration costs.
- **Regulatory and policy change:** Changes to regulatory frameworks, planning rules, environmental requirements or information disclosure obligations.
- **Market and supply chain conditions:** Changes in material costs, labour availability, contractor capacity and global supply chain constraints.

These uncertainties may affect the timing, scale and cost of our network investments and service outcomes.

2.6.8 Price Inflation Assumptions

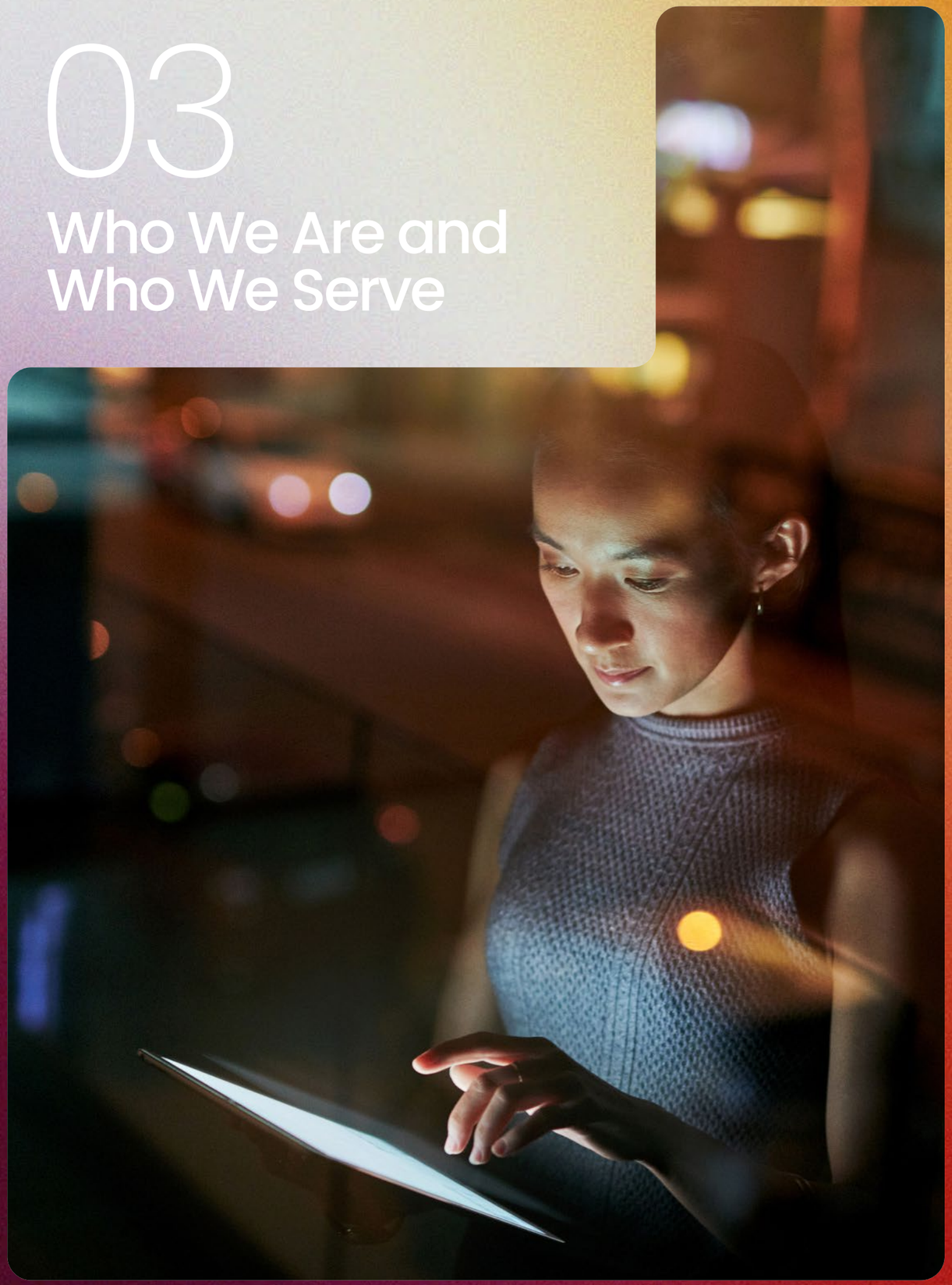
Financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure (Schedule 11a) and Report on Forecast Operational Expenditure (Schedule 11b) has been prepared using price inflation assumptions consistent with our approved financial planning assumptions at the time of AMP development.

These assumptions reflect expected movements in labour costs, materials, contractor rates and general inflation. Actual inflation outcomes may differ from those assumed, which could result in variations between our forecast and actual expenditure.

Drury South Crossing

03

Who We Are and Who We Serve



3.1 About This Chapter

As a community-owned EDB, Counties Energy is committed to investing in customer and community engagement to understand their changing needs and wants, and to better plan for a future that offers a value for money, reliable service and that supports accelerated electrification. This section covers how we organise ourselves to manage our assets, our performance metrics, how we engage with our customers and stakeholders, and the various channels we use to do so.

3.2 Our Corporate and Organisation Structure

Counties Energy operates under the governance of the Counties Energy Consumer Trust, which appoints the Board of Directors to provide strategic oversight and ensure ongoing alignment with stakeholder interests. The Chief Executive leads the organisation and is accountable for delivering corporate objectives and regulatory compliance.

Figure 3.1
Governance structure of Counties Energy

3.3 Asset Management Roles and Responsibilities

We maintain organisational roles, accountabilities and responsibilities for asset management activities to achieve Counties Energy's strategic framework and objectives of delivering a robust and reliable electricity service every day, unlocking new energy markets and experiences, and reimagining a new energy future through our role as a DSO. These roles and responsibilities are outlined below.

3.3.1 Board of Directors

Counties Energy's Board of Directors (the Board) is appointed by the Counties Energy Consumer Trust and is responsible for guiding the company and ensuring it operates effectively. The Board meets eight times each year to review updates from our Leadership Team, covering progress against strategic goals, compliance with legislation, risk management, and overall organisational performance.

In relation to asset management, the Board's key duties include:

- Providing overall governance and direction of the company, including approving the change TBC for asset management.
- Monitoring commercial performance, reviewing business plans, policies and budgets, and ensuring these support sound decisions around acquiring, managing and retiring assets.
- Reviewing and endorsing the 10-year Asset Management Plan (AMP) before the beginning of each financial year.
- Carrying out an annual review and approval of major company policies, including those governing asset management and expenditure.
- Formally signing off AMP certification.
- Approval of key asset-related expenditure when expenditure is forecast to exceed $2 million.

Asset management outcomes are reported to the Board on a regular basis. For example, network performance metrics are reported monthly, the status of our high value and critical projects are reported monthly, and risk reports are reported through the risk and audit committee.

3.3 Asset Management Roles and Responsibilities
(continued)

3.3.2 Chief Executive

Our Chief Executive is accountable for putting the Board's strategic direction into action and managing the company's day-to-day operations. Responsibilities related to asset management include:

- Executing the asset management strategy approved by the Board.
- Ensuring the organisation has the people, tools, and systems required to effectively operate and maintain its asset base.
- Keeping the Board informed on progress against the strategic plan, including regular updates on asset-related performance.

3.3.3 Leadership Team

Our Leadership Team oversees various business areas and execution plans. Their asset management responsibilities include:

- Managing budgets for their departments, including the assets they oversee, and doing so within their approved delegation levels.
- Evaluating and progressing asset-related investment proposals through our review and approval process, ensuring they are assessed by the appropriate technical groups before they reach senior decision makers.
- Securing final approval for asset related expenditure, which may require sign-off from the Chief Executive or the Board.

There are two executive leadership roles most relevant to the AMP:

Our **Chief Network & Digital Officer** (CNDO) provides strategic leadership for Counties Energy's network and digital transformation functions. This role ensures asset management objectives are fully integrated with technology strategy, enabling a resilient, efficient and future-ready energy network. The CNDO is also accountable for aligning network development and digital initiatives within our asset management system. This includes driving innovation, operational reliability, and customer-centric solutions through advanced technology and data-driven decision-making.

Our **Chief Customer & Operations Officer** (CCOO) provides executive leadership for the delivery of safe, reliable and customer-focused network services. This role ensures that operational activities and customer strategies are fully aligned with Counties Energy's asset management objectives. The CCOO is also accountable for translating strategic asset management plans into operational execution, ensuring that service delivery meets performance, safety and regulatory requirements while enhancing customer experience.

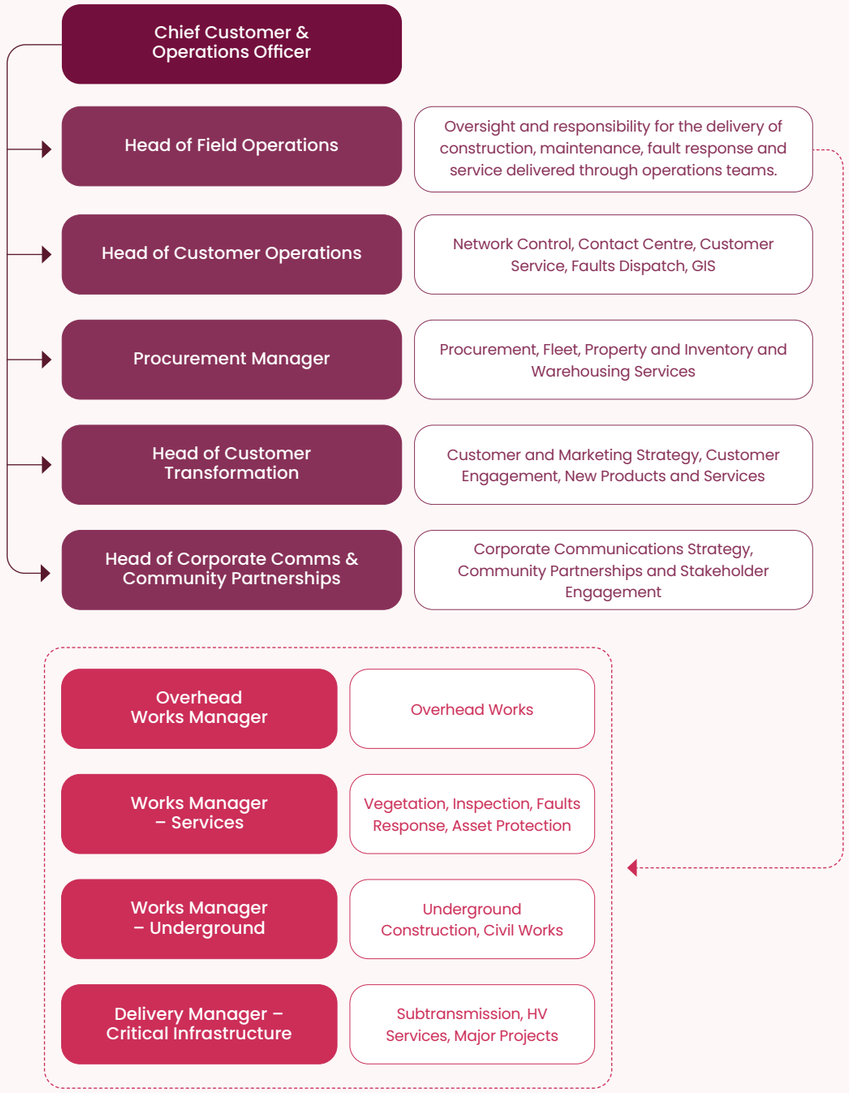
Their respective teams comprise the following key roles and responsibilities across our Network and Field Operations practices:

3.3 Asset Management Roles and Responsibilities
(continued)

Figure 3.2
Network and Digital management structure

3.3 Asset Management Roles and Responsibilities
(continued)

Figure 3.3
Customer and Operations structure

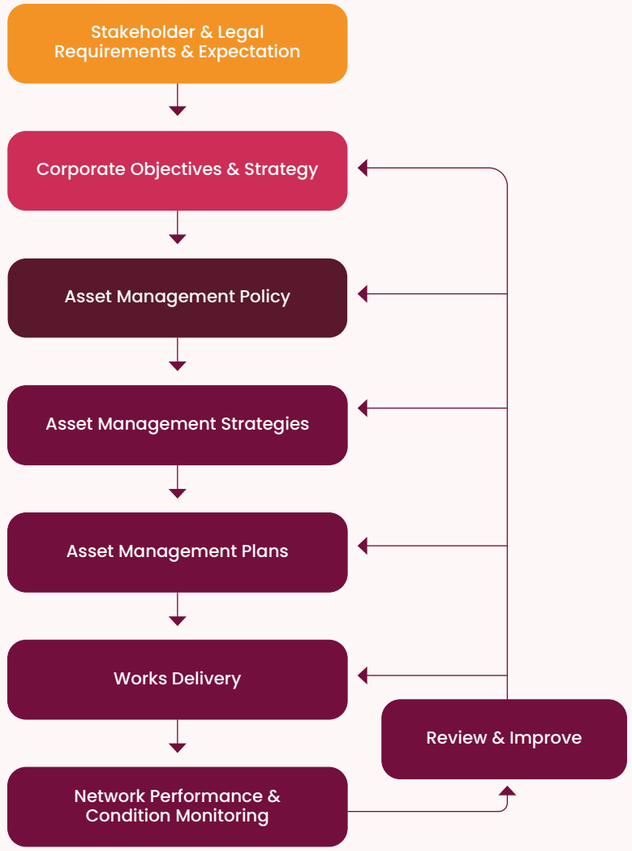


3.3 Asset Management Roles and Responsibilities
(continued)

Asset management and planning activities

Counties Energy's asset management and planning activities, including field operations are undertaken by in-house multidisciplinary teams, responsible for the development and ongoing delivery of this Asset Management Plan. Our organisation is structured to provide clear accountability across asset strategy, network planning, engineering standards, lifecycle management, and performance monitoring. Asset management and planning functions work closely with operational, delivery, and commercial teams to ensure investment decisions are informed by asset condition, risk, performance, and forecast demand. Governance is supported through defined decision-making forums and escalation pathways, providing executive oversight of asset management outcomes and ensuring that planning assumptions, priorities, and trade-offs are transparent, consistent, and evidence based.

Figure 3.4
Asset management system structure



3.4 Who Our Stakeholders Are

Counties Energy recognises the vital role of its diverse stakeholders and their varying interests in shaping the company's strategic direction. In developing the Counties Energy Corporate Strategy and Asset Management Plan, we have carefully considered the needs, perspectives, and expectations of a broad range of stakeholders.

With multiple distinct stakeholder groups, we acknowledge priorities vary widely. Through a comprehensive 2025 materiality assessment involving interviews, surveys, and executive insights, we identified five critical stakeholder priorities: asset management and network reliability, health and safety, financial stability, customer service, and energy affordability.

By maintaining strong stakeholder relationships, we reinforce our commitment to openness, transparency, and trust, ensuring stakeholders have confidence in our ability to deliver sustainable and reliable energy outcomes for the region's future.

Counties Energy employs a range of targeted communication and engagement tactics to ensure stakeholders are informed, consulted and involved in a timely and meaningful way. These include fact sheets, website and social media updates, direct letters and emails, presentations, community events, and both in-person and online meetings. Engagement also extends to long-term partnerships, sponsorships and the establishment of consultative groups that meet regularly to provide feedback and insights.

By proactively anticipating stakeholder concerns and fostering open dialogue, we build strong, enduring relationships that support today's operations and tomorrow's initiatives. This proactive, collaborative approach reflects best practice in stakeholder engagement, helping us maintain trust, manage expectations, and strengthen our connection with the communities we serve.

3.4 Who Our Stakeholders Are (continued)

Figure 3.5
Counties Energy stakeholders and their interests

3.5 Customer Engagement Framework

Our purpose as an EDB is to power thriving communities, now and in the future. The five key aspects of our customer engagement framework are outlined next.

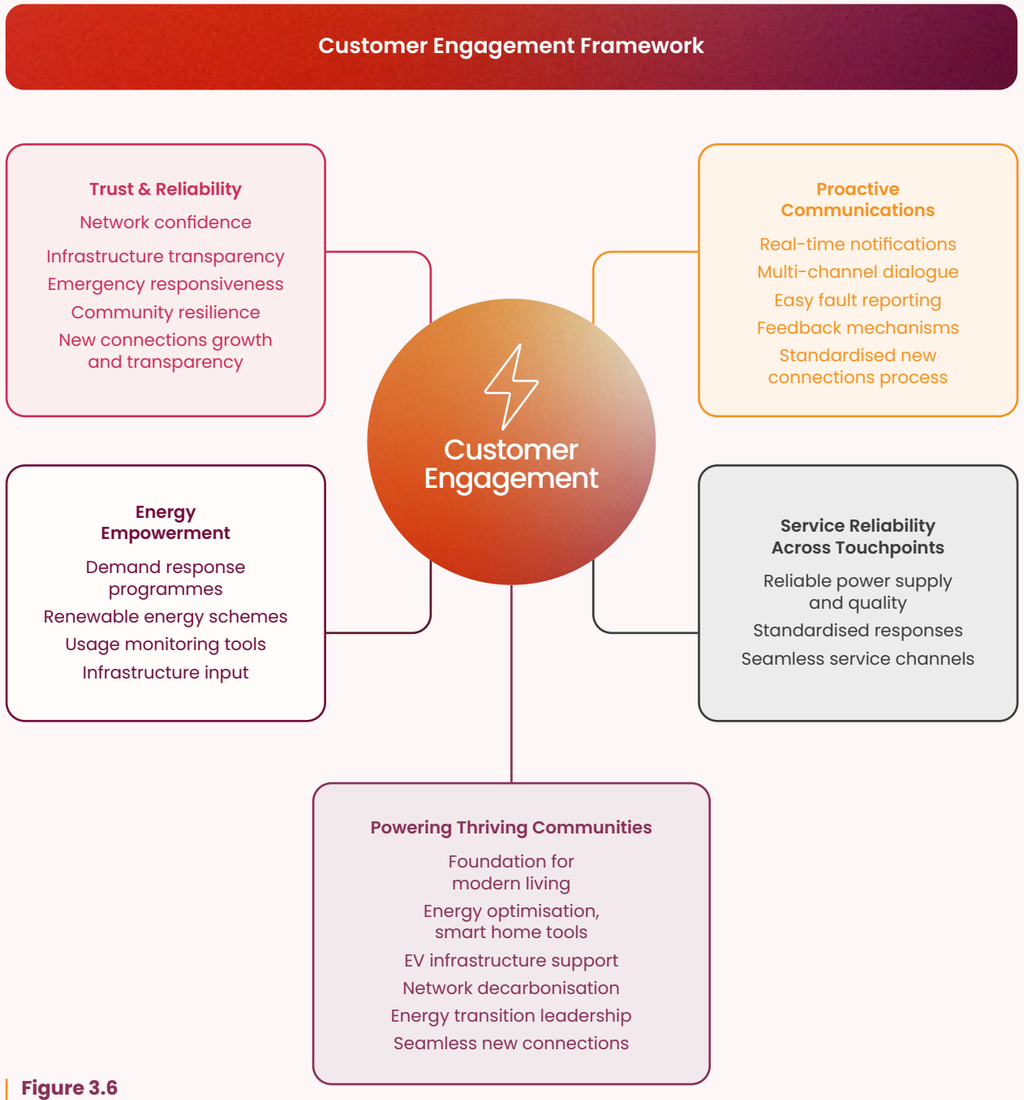


Figure 3.6 Customer engagement framework

3.5 Customer Engagement Framework (continued)

3.5.1 Trust and Reliability

Counties Energy is an essential partner in our customers' daily lives rather than simply a background utility, creating peace of mind through consistent performance and community-focused service delivery. We build trust through demonstrating network reliability, transparent communication about maintenance, and genuine care during outages and emergencies.

3.5.2 Proactive Information Exchange

Two-way communication with customers is established through real-time, multi-channel dialogue with customers. This includes proactive outage notifications, restoration updates, and planned maintenance schedules delivered via email and changes via SMS and the Outage Hub. Of equal importance is providing customers with easy fault reporting mechanisms and service issues, while regularly sharing energy efficiency insights and tips. Section 3.9.2 provides more detail on how the Outage Hub delivers these functions.

3.5.3 Energy Empowerment

As part of our plan to power thriving communities, we actively engage customers as partners in network management and the energy transition through pilots such as the Karaka Harbourside Demand Flexibility Pilot. This includes demand response programmes during peak periods and energy efficiency initiatives. Customers will be offered tools to monitor and optimise consumption, with their insights and experience shaping how we manage network performance in the future.

3.5.4 Service Reliability Across All Touchpoints

A consistent experience for our customers means delivering a reliable power supply, coupled with seamless customer service across digital and traditional channels. This requires standardised response times and consistent information, including during extreme weather periods (more on these KPIs in sections 3.9.1 and 4.8.6). Every customer interaction — whether via phone, website, Outage Hub, social channels, or in-person reflects the same service standards and commitment.

3.5.5 Powering Thriving Communities

As the demand for electricity grows, Counties Energy's role is extending beyond simply supplying electricity to positioning the network as the platform that enables modern residential and commercial life. This includes providing customers with tools and insights to optimise energy use and reduce costs, supporting electric vehicle adoption through infrastructure development, and enabling smart home technologies. Our aim is to deliver intergenerational value through smart energy orchestration and technologies to address affordability, while facilitating decarbonisation and the broader energy transition.

3.6 Meeting Rising Customer Expectations

As a lifeline utility, we understand the importance of customers being able to contact us, either during an outage, planned works, or in organising services, and we take pride in being always accessible and responding to enquiries promptly.

These conversations empower us to act on customers' immediate needs while uncovering trends, concerns, and opportunities to elevate our service continuously.

We know that customer expectations of an essential service changed radically post Cyclone Dovi. Through deep-dive qualitative research, customers told us they were less tolerant of less-than-ideal experiences and service levels. To date, three significant customer insights have shaped the way in which we manage customer experience and customer engagement, primarily in our role of keeping the lights on:

3.6.1 Customers Expect Services Where, When, and How They Want Them

Our services are also accessible via our website, Outage Hub and social media channels. We've expanded digital channels to provide real-time information and self-service options. Our mobile app and website offer outage maps, restoration timelines, and easy ways to report issues. Where relevant, we also send SMS notifications for time sensitive updates.

3.6.2 Outages Are Make-or-Break Moments for Customer Trust

Counties Energy operates a 24/7 customer service function handling approximately 3,000 calls each month. All customer interactions are captured in Salesforce, our Customer Relationship Management (CRM) system. We've enabled customers to help themselves without having to wait over the phone. When an unplanned outage occurs, subscribed customers receive updates through the new and improved Outage Hub by choosing either text or email. The Outage Hub provides real-time information and automated notifications for unplanned outages, leveraging smart meter data covering 95% of the network to enable proactive fault identification. Our frontline teams are also trained to prioritise clear, helpful communication during these critical interactions.

3.6.3 Minimise Disruption by Keeping Customers Informed Before, During, and After Restoration

We know from research that, although customers accept that outages happen from time to time, they value information to help them plan around these events. So, we've invested in proactive outage alerts and automated restoration notifications. Customers are informed as soon as we know about an outage and kept updated during repairs through the Outage Hub push notifications (if subscribed) and via social media where appropriate.

3.6.4 Customer Strategy Overview

Our customer strategy delivers a holistic, end-to-end experience across all touchpoints, from initial contact through to ongoing support. We manage service requests, inquiries, issue resolution, and information access while integrating customer feedback to drive continuous improvement. This comprehensive approach ensures seamless, efficient interactions for residential, commercial, and industrial customers, building trust and satisfaction across all segments.

Digital Engagement and Support Capabilities

Counties Energy continues to enhance digital engagement and self-service for all customer segments with robust data privacy and security. We have 24/7 support capabilities for outages and incidents, leveraging data insights to proactively address customer needs. Continuous improvement of customer-facing processes focuses on integrating feedback into redesigned workflows and upgraded business systems to streamline interactions and improve accessibility.

Salesforce CRM

Salesforce provides a single view of the customer, capturing all interactions, and service requests. It enables targeted communications and supports proactive engagement through digital channels.

Additional enhancements made to Salesforce aim to deliver superior customer experience. All interactions are recorded against a case or an account, with multiple contacts possible for each. This delivers a unified view of all customer-related activities, interactions, service requests, and connection history, enabling efficient enquiry handling with accurate and timely responses.

We are currently progressing with a self-service function, allowing customers to initiate service requests online, track progress and receive real-time updates. A deep-dive review of internal workflows has been completed to streamline operations, eliminate friction, and enable self-service in the future..

3.7 Delivering For Our Customers

3.7.1 Balancing Stakeholder Requirements

At Counties Energy, we recognise the wide range of stakeholders we work with and the differing — and sometimes conflicting — requirements that can arise. Our approach is to seek consensus through open dialogue, transparent reasoning, and a genuine focus on "win-win" outcomes. We remain flexible and empathetic in exploring alternative solutions, valuing long-term, positive relationships. While we aim to resolve issues early through engagement and design, safety remains our non-negotiable priority and takes precedence over all other considerations. Balancing differing requirements is managed in the following order:

- Safety and hazard mitigation;
- Regulatory and legal requirements;
- Contractual requirements;
- Customer price or quality; and
- Investment requirements.

3.7.2 Growth in Connections

Counties Energy manages over 620 customer connection projects annually, adding approximately 1,000 new connections per year to a network that now supports over 50,000 Installation Control Points (ICPs). The Customer Network Design team applies a structured connection approach with defined stages, timeframes, and automated notifications to guide customers through the connection journey. From initial request and design, right through to ICP energisation, projects are managed and customers informed. We expect this steady growth in demand for connections to continue, driven by regional development and electrification.

3.7.3 Customer Satisfaction Measures

Annual customer surveys measure satisfaction across overall service (current: 81%, target: >80%), new connections (81%, target: >80%), and unplanned outages (89%, target: >85%). Communication takes place across multiple channels including a biannual customer panel, media engagement, community events, an annual newsletter reaching 30,000 households, and targeted safety campaigns covering tree trimming, farm safety, and excavation awareness.

3.7 Delivering For Our Customers (continued)

3.7.4 Network Reliability

We measure network reliability through key performance indicators covering both planned and unplanned outages: SAIDI (duration), SAIFI (frequency), CEMI (customers experiencing multiple interruptions), and CELID (customers experiencing long durations). Forward targets and the overall reliability strategy align with the Commerce Commission's DPP4 methodology despite our exemption as a community-owned EDB.

3.7.5 Health and Safety

Performance is monitored through monthly internal audits (typically 98%+ compliance) and audits which align with external ISO 45001 requirements. A targeted safety programme launched in early 2026 focused on addressing critical risks such as vehicle impacts, uncontrolled energy release, and asset failure.

3.8 Resolving Customer Complaints

At Counties Energy, we pride ourselves on delivering exceptional customer service. A key part of this commitment is ensuring even when customers are dissatisfied, we respond with respect, transparency, and urgency. Every interaction is an opportunity to strengthen trust and improve our performance.

We view complaints not as setbacks, but as valuable feedback that helps us identify opportunities to enhance service quality and operational efficiency. All complaints are logged in our CRM system and the Customer Services Team is well trained in complaint management. If an issue cannot be resolved immediately, we follow a clear escalation process to explore every possible avenue for resolution.

Customers are regularly informed through multiple channels about their right to escalate a complaint for independent review by Utilities Disputes Ltd (UDL). Should a complaint reach UDL, we engage openly and constructively, with the primary objective of reaching a resolution.

Complaints escalated to UDL give us an opportunity to test and refine our processes, including our complaints management process. Outcomes often lead to improvements in business procedures, ensuring that we are continually raising the level of service for our customers.

3.9 Providing Outage Communications

As a designated Lifeline Utility under civil defence legislation, our focus is on reducing the impact of a major event through preparation, clear communication, robust safety measures, and restoring power as quickly as possible to support essential community and business functions.

Our network crosses three council areas, and we participate in both Auckland and Waikato emergency planning groups. We're also exploring the possibility of community resilience hubs - safe spaces with backup power and charging facilities during major disruptions - with two pilot sites planned for the coming years based on community feedback.

For outages, we leverage our core systems and highly automated processes to keep customers informed every step of the way. When an outage is planned or occurs, our technology ensures:

Advance Notice: Customers receive timely alerts for planned outages so they can plan for periods when power is isolated to deliver maintenance or renewal works. For more information, please refer to the "planned outages" section that follows.

Real-Time Updates: Any changes to restoration times or outage details are communicated immediately across multiple channels, refer to "unplanned outages" in section 3.9.2.

Customer Confidence: By providing clear, proactive information, we minimise disruption and reinforce trust in our service. Our approach combines automation with customer-centric thinking, ensuring communication is fast, accurate, and accessible.

3.9.1 Planned Outages

All outage planning, notifications, and related customer interactions are tracked and managed through Salesforce. Email is the preferred contact method for most customers, and it serves as our primary communication channel. Where requested, we also provide notifications via conventional mail. If neither we nor the electricity retailer have an email address for the connected party, we contact the customer by alternative means during the planning process to confirm the most suitable communication channel.

For customers subscribed to email notifications, our aim is to send notification of planned outages 10 days prior, with a reminder notification sent one day prior to the planned outage. Email is also used to advise customers of any changes, including confirmation of alternative dates, cancellations, and ad-hoc updates before and during planned outages.

Additionally, our Outage Hub provides up to date information on all advertised planned outages and reflects real-time changes made within Salesforce. Recognising the greater impact of outages on medically dependent customers, schools, and major energy consumers, we include an additional pre-engagement step during the planning stage before formal notification is issued. At times, due to the customer group impacted or the complexity of a project, additional engagement steps may be employed.

We also provide retailers with daily updates via the Electricity Information Exchange Protocol (EIEP5). Some retailers may choose to inform their customers of planned outages, in addition to the communication already provided by Counties Energy.

3.9.2 Unplanned Outages (Faults)

As the primary Metering Equipment Provider (MEP) in our network area, we have visibility and monitoring of over 95% of smart meters. This allows real-time data analytics to seamlessly integrate into our in-house outage management system, INDI (Infrastructure and Network Data Interface).

Access to real-time meter data delivers significant operational benefits that enhance customer experience. For example, outage events are automatically generated and made visible to all Outage Hub users, allowing us to identify and respond to issues before customers report them, while also reducing call volumes and freeing phone lines for high-priority calls. Additionally, the real-time meter ping function enables us to confirm network connection status, preventing unnecessary call-out costs. During storm response, this capability provides a clearer picture of which meters remain offline, improving efficiency and speed in restoring service.

Our Outage Hub displays real-time outage information and response details, with users able to subscribe to notifications for any unplanned outage affecting their property. Customers can report outages or other power supply issues through the app or via our 24/7 Customer Services team.

Figure 3.7
The Counties Energy Outage Hub app

In 2022, survey data showed 27% of customers wanted better outage updates and in 2024, 31% of customers reported that the Outage Hub took too long to load information.

As a result, a cross-functional team was set up to redesign the Outage Hub to improve the customer experience in the following ways, based on customer feedback and insights:

- **Faster subscription to notifications to stay informed.**
- **Ability to sign up to updates for multiple locations.**
- **Guided journey for reporting an outage.**
- **Refreshed User Interface (UI), for a seamless experience.**
- **Increase functionality, scalability, and performance.**
- **Additional outage information for greater visibility.**
- **Customers can subscribe to outages and/or future updates from notifications received.**

Our goal was to improve the experience during high-impact weather and outage events, ensuring the app is faster, easier to use, and ready when customers need it most.

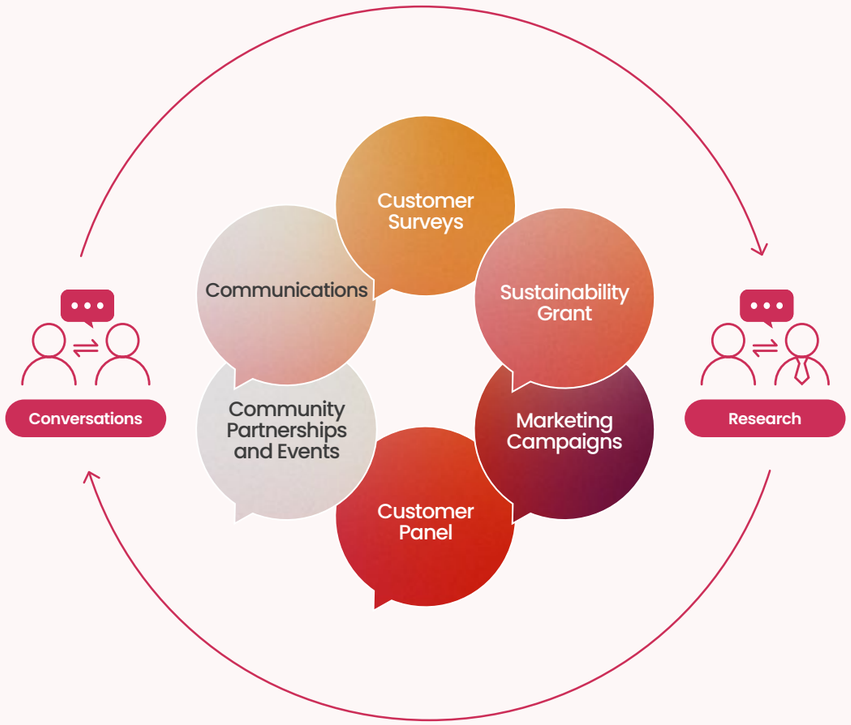
As part of this project, we redesigned our approach to collecting information from customers, focusing on gaining an accurate understanding of the issues they are experiencing and determining whether the condition may be linked to a public safety incident.

By improving the reliability of our data collection, we can better prioritise events and reduce customer impact. Regardless of whether an outage is reported through the Outage Hub or by phone, it is handled with the same outage management process.

3.10 The Customer Channels We Have

This section delves into what customer engagement channels we use, how we use them to keep a finger on the customer pulse, together with performance ratings, and results against internal targets as well as Commerce Commission benchmarks.

Figure 3.8
Customer engagement channels



3.10.1 Customer Panels

Our customer panel consists of representatives from local community groups as well as from the Franklin Local Board. Rural communities and social support groups are also included so that diverse perspectives are heard. Panel meetings also provide an opportunity for participants to raise issues and ask questions important to them, while enabling Counties Energy to share initiatives with a key group of stakeholders. In essence, the panel acts as a biannual town hall meeting, providing valuable two-way insights into what's important to the community.

3.10 The Customer Channels We Have (continued)

3.10.2 Media, Community Partnerships and Events

Counties Energy communicates key messages to our community through a range of channels designed to inform, engage and build trust. Our communications approach includes proactive media engagement, community partnerships, event participation and targeted advertising.

Media Engagement: We share important updates and initiatives through media releases, briefings and interviews with local, regional, national and industry media outlets. These activities ensure transparent communication around large-scale outage events, safety, innovations and energy-related issues that affect our customers and community.

Community Partnerships and Energy Wellness: Through strategic partnerships, we collaborate with community organisations to promote safety, energy resilience, and energy hardship awareness within their communities of interest. These partnerships enable us to reach diverse audiences and deliver important messages that support wellbeing and safety across our region.

Community Events: We proudly support and participate in a variety of community events, including Counties Energy Christmas on the Green, Counties Energy Christmas Lights, Trains at Night, and School Holidays in the square. These events provide valuable opportunities for face-to-face engagement with our community, allowing us to share key safety messages, promote energy wellness programmes, provide outage and service updates, and highlight initiatives such as the Annual Discount. Through our involvement, we support much-loved local events that bring our community together and reinforce our ongoing commitment to the people we serve.

Advertising and Campaigns: We advertise regularly on social media and in publications, including the *West Franklin Breeze*, *Franklin Times*, and *Valley Voice*, ensuring important messages about safety, outages, and community updates are accessible to everyone in the region. We also utilise our Nelson Street billboard in Pukekohe to promote key campaigns and initiatives.

Our advertising campaigns focus on encouraging safe behaviours that help maintain network reliability and public safety. Key topics include:

- Tree trimming and safe planting distances near power lines and electrical equipment;
- Farm safety practices around power infrastructure;
- DIY and excavation safety, including "Check Before You Dig" and "Look Up For Lines"; and
- General safety messaging such as "Down Means Danger" messaging.

Counties Energy also participates in national and industry-led safety initiatives, such as Safe Digging Month, and delivers targeted communications to our rural communities covering high-load transport, irrigation safety and safe digging practices.

3.10 The Customer Channels We Have (continued)

3.10.2 Media, Community Partnerships and Events (continued)

Community Communications and Updates: Our publication, Network News, is delivered annually to every household in our network area. This printed newsletter provides updates on the annual discount, service improvements, infrastructure investments, innovation and community support initiatives. In November 2024, we introduced the Power Essentials Handbook, a practical four-page guide accompanying Network News. This resource helps customers prepare for outages, stay safe, and understand what to do during extended outages. It includes tips for medically dependent customers and guidance on building household resilience. Both publications are distributed in print to around 30,000 households and emailed to approximately 40,000 customers. Additionally, email newsletters are issued following major storm events to provide timely updates on network impacts, restoration progress, safety reminders, and post-event preparedness tips. Tree trimming responsibilities and vegetation management remain a key focus in all communications, reinforcing the shared responsibility for maintaining a safe and reliable electricity network.

Students and teachers from Pukekohe Christian School with representatives from The Warehouse Group, Mai Lighthouse and Counties Energy, supporting the Winter Warmer Pack initiative for local whānau.

3.11 Stakeholder Materiality and Feedback

In 2025, we undertook a comprehensive stakeholder engagement process and a full materiality assessment to better understand the environmental, social, governance and economic factors that matter most to the people we serve. This included in-depth interviews, an online survey, and insights from our own executive team. Together, these conversations provided a clear picture of what our stakeholders expect from Counties Energy today and into the future.

What we heard was encouraging: there is strong alignment between stakeholder expectations and our current business priorities. People see Counties Energy as a critical infrastructure provider whose core responsibilities, asset management, reliability, safety and strong governance must remain front and centre. At the same time, stakeholders challenged us to keep evolving, stay ahead of change, and communicate more openly.

3.11.1 Key Themes for Stakeholders

Across all groups, several key themes emerged, which are consistent with our strategic principles and focus areas:

Reliability and resilience are paramount: Customers, partners and regulators all reinforced that they expect a network that performs consistently, even as severe weather events become more frequent. Building resilience into every part of our system is essential for maintaining trust.

Growth must be future focused: Stakeholders want confidence that we're planning ahead for significant regional growth, ensuring the integration of new technologies is seamless and enabling for regional decarbonisation.

Affordability matters: Stakeholders recognise the need for ongoing investment, but they want transparency around cost drivers and assurance that we're balancing investment with long-term affordability, particularly for vulnerable customers.

We must deepen genuine partnerships: Stakeholders, especially iwi, community organisations and suppliers, want Counties Energy to be visible, collaborative and engaged. They expect honest dialogue and strong relationships to underpin how we work.

Environmental and social responsibilities must be part of our approach: Reducing emissions, protecting the environment, developing our workforce and supporting strong communities are seen as essential elements of a modern, responsible network provider.

3.11.2 Where Stakeholders See the Greatest Opportunity for Us to Improve

While the feedback affirmed many of the things we're already prioritising, stakeholders also identified several areas where we can strengthen our performance or increase transparency:

Energy affordability: A critical concern. Stakeholders emphasised the need for fair pricing, clarity about how charges are set, and support for vulnerable households.

Partnerships and collaboration: People want deeper, more proactive engagement with iwi, community groups, industry partners and suppliers.

Asset management and network reliability: Although a core strength, stakeholders still see room to enhance resilience, planning and preventative maintenance.

Climate change resilience: Long-term planning for more severe weather impacts is essential to maintain reliability and protect communities.

Energy education: There is an opportunity to make it easier for customers to understand outages, pricing, electrification trends and how the electricity system works.

3.11.3 How We Will Use This Information

These insights will continue to shape how we set priorities, make decisions and evolve our strategy. The materiality assessment gives us a robust foundation to:

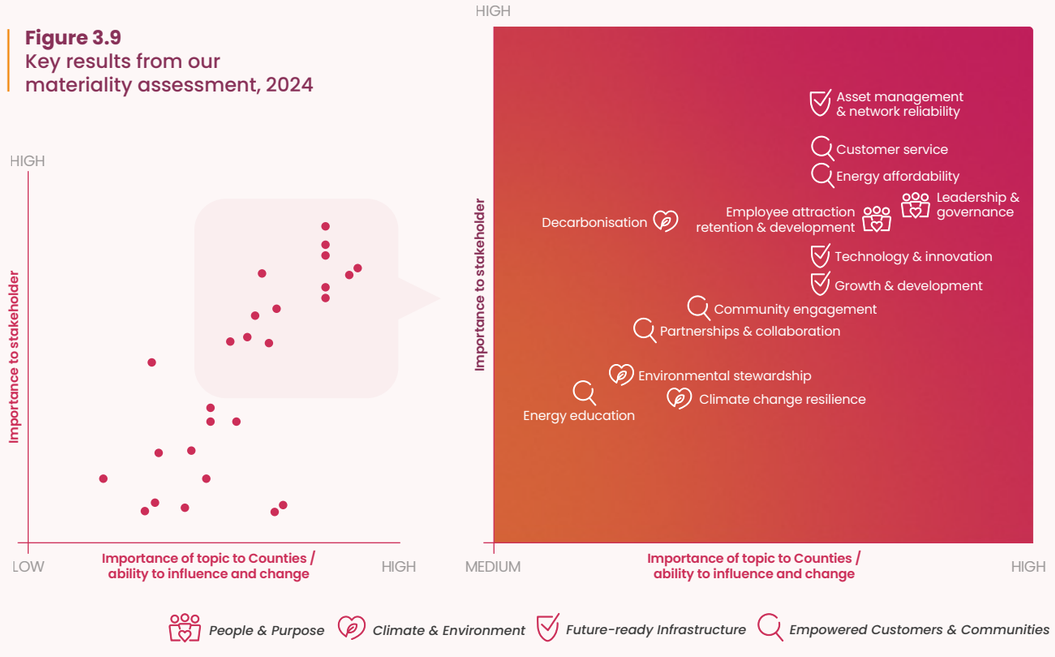
- Focus our investments where they matter most to our communities.
- Prioritise long-term network resilience and future growth.
- Be clearer about the link between affordability and infrastructure investment.
- Strengthen relationships with iwi, partners and communities through meaningful engagement.
- Integrate environmental and social considerations into our planning and operations.
- Improve communication, transparency and energy literacy for our customers.
- Tree trimming and safe planting distances near power lines and electrical equipment

Most importantly, this stakeholder feedback ensures our strategy remains grounded in what our customers and communities value. It brings their voices directly into how we plan, invest and deliver a smarter, more resilient and more sustainable energy future for our region.

3.11 Stakeholder Materiality & Feedback (continued)

2023 Grant recipient Trees for Survival – helped by Mangatawhiri School pupils

Figure 3.9
Key results from our materiality assessment, 2024



3.12 Iwi Engagement

Counties Energy is committed to fostering mutually beneficial partnerships with iwi and local Māori communities. We work on a wide range of projects which may require some form of iwi engagement. In some cases, this may be through statutory obligations which require us to engage. In other cases, engagement is around shared projects and partnerships.

In all cases, the connection and engagement is grounded in whakawhanaungatanga, which is to grow respectful relationships.

Counties Energy supports engagement using the following principles:

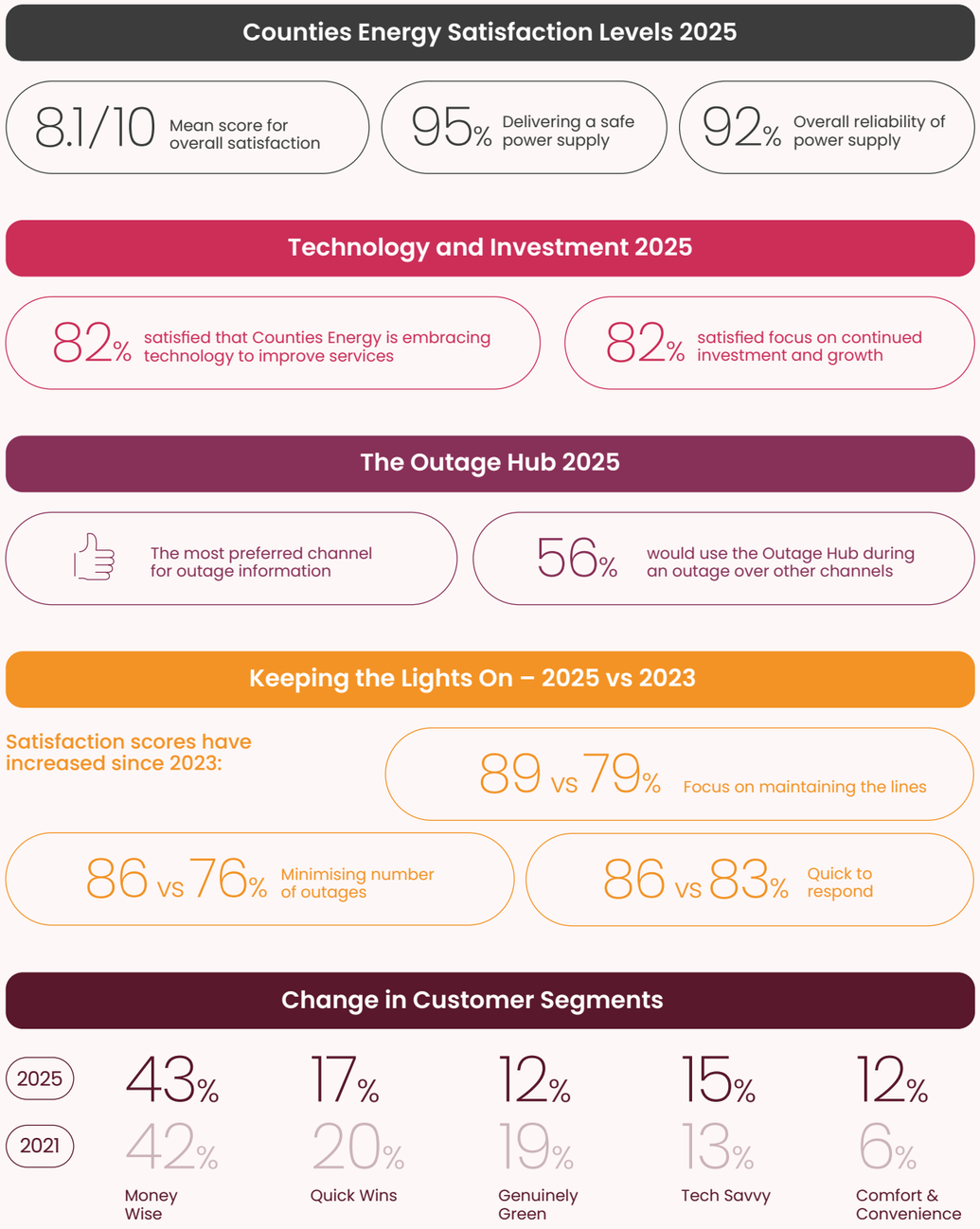
- Kanohi ki te kanohi face-to-face where possible;
- Learn, understand and show respect for customs and protocols;
- Mana ki te mana – chief to chief; and
- As early as possible.

3.13 Improving Customer Satisfaction

To understand how customers feel about the services we provide and how we provide them, we carry out customer surveys annually. The "Services" survey asks customers to rate us on how well we keep the lights on. The "Brand & Communications" survey asks how Counties Energy is doing overall as a company, including our customer communications.

3.13 Improving Customer Satisfaction (continued)

Figure 3.10 Key results from our customer research



3.13 Improving Customer Satisfaction (continued)

The last section in the previous figure refers to the segmentation tracking of Counties Energy's customers. Customer research carried out initially in 2021 identified five key segments based on their attitude towards power usage and sustainability. While most segments haven't changed in terms of size, there has been a shift between the "Genuinely Green" segment and the "Comfort and Convenience" seekers.

As per their namesake, the Genuinely Green care deeply about the environment and feel a growing sense of responsibility to make a difference. They actively look for ways to reduce their impact and have made sustainability a core part of how they live, doing what they can.

The Comfort & Convenience Seekers value comfort and ease above all else when it comes to energy use. They use electricity without restriction to maintain their desired lifestyle and quality of life. While environmentally aware, they don't believe their individual consumption makes a meaningful difference, so cost savings and environmental impact take a back seat to immediate comfort and convenience in their decision-making.

3.14 Practices for Connecting New Consumers and Altering Existing Connections

This section explains how Counties Energy enables safe, transparent, and future-ready connections and alterations for new and existing consumers. It outlines our approach to managing customer-initiated works in a way that supports regional growth, evolving customer expectations, and the shift to a more electrified, data-driven, and distributed energy future.

Our connection practices are designed to:

- **Support affordable, predictable, and timely delivery for customers.**
- **Embed customer-centric communication at every stage of the journey.**
- **Protect network integrity, safety, and resilience as demand and distributed generation grow.**
- **Enable our transition from a Distribution Network Operator (DNO) to a Distribution System Operator (DSO) by supporting two-way energy flows, emerging technologies, and smarter network management.**

3.14.1 Our Approach to Planning, Managing New and Altered Connections

Counties Energy manages connections through a structured process that balances customer needs, safety requirements, regulatory expectations, and long-term network performance. Our approach aligns with our strategic commitments to reliability, resilience, affordability, and customer transparency.

New Connections (Offtake and Injection)

New residential, commercial, industrial, subdivision and distributed generation (DG) connections follow a consistent process designed to ensure safe integration, predictable outcomes, and clear expectations.

Our planning and management approach includes:

- **Early validation of applications and customer provided documentation.**
- **Data-driven load modelling and network capacity assessments.**
- **Site investigations required to confirm technical feasibility.**
- **Standardised underground and overhead design practices that support efficiency and reduced cost to serve.**
- **Clear, transparent quotations and connection agreements.**
- **Coordinated delivery through construction, metering, inspection, testing, and livening.**
- **Completion of compliance verification, as-built capture, and asset data updates.**

3.14 Practices for Connecting New Consumers and Altering Existing Connections (continued)

3.14.1 Our Approach to Planning, Managing New and Altered Connections (continued)

Alterations to Existing Connections

Alterations such as upgrades, relocations, undergrounding, or DG amendments follow the same structured approach as new connections, with additional focus on:

- Assessing existing asset capacity, configuration, and safety.
- Updating metering and protection settings to reflect new load or generation.
- Outage coordination and safe access to private property.
- Timely updates to geospatial and asset management systems.

Common Issues and Mitigation

Common challenges include incomplete customer documentation, third-party consenting delays, easement and access constraints, long lead times for material procurement, and sequencing of civil works.

We mitigate these through:

- Pre-application guidance and digital resources.
- Clear checklists and templates.
- Early capacity identification and design standardisation.
- Coordinated scheduling across internal teams and external contractors.
- Increased use of standardised design and stock standard materials.

3.14.2 Indicative Planning and Delivery Timeframes

Providing customers with predictable, transparent timeframes is critical to supporting growth, affordability, and development certainty. These indicative timeframes reflect typical conditions assuming site readiness, timely third-party inputs, and standard design requirements. Actual durations may vary based on consenting, access, procurement, and construction sequencing These indicative timeframes exclude the customer payment period and the three-month quote validity period.

3.14 Practices for Connecting New Consumers and Altering Existing Connections (continued)

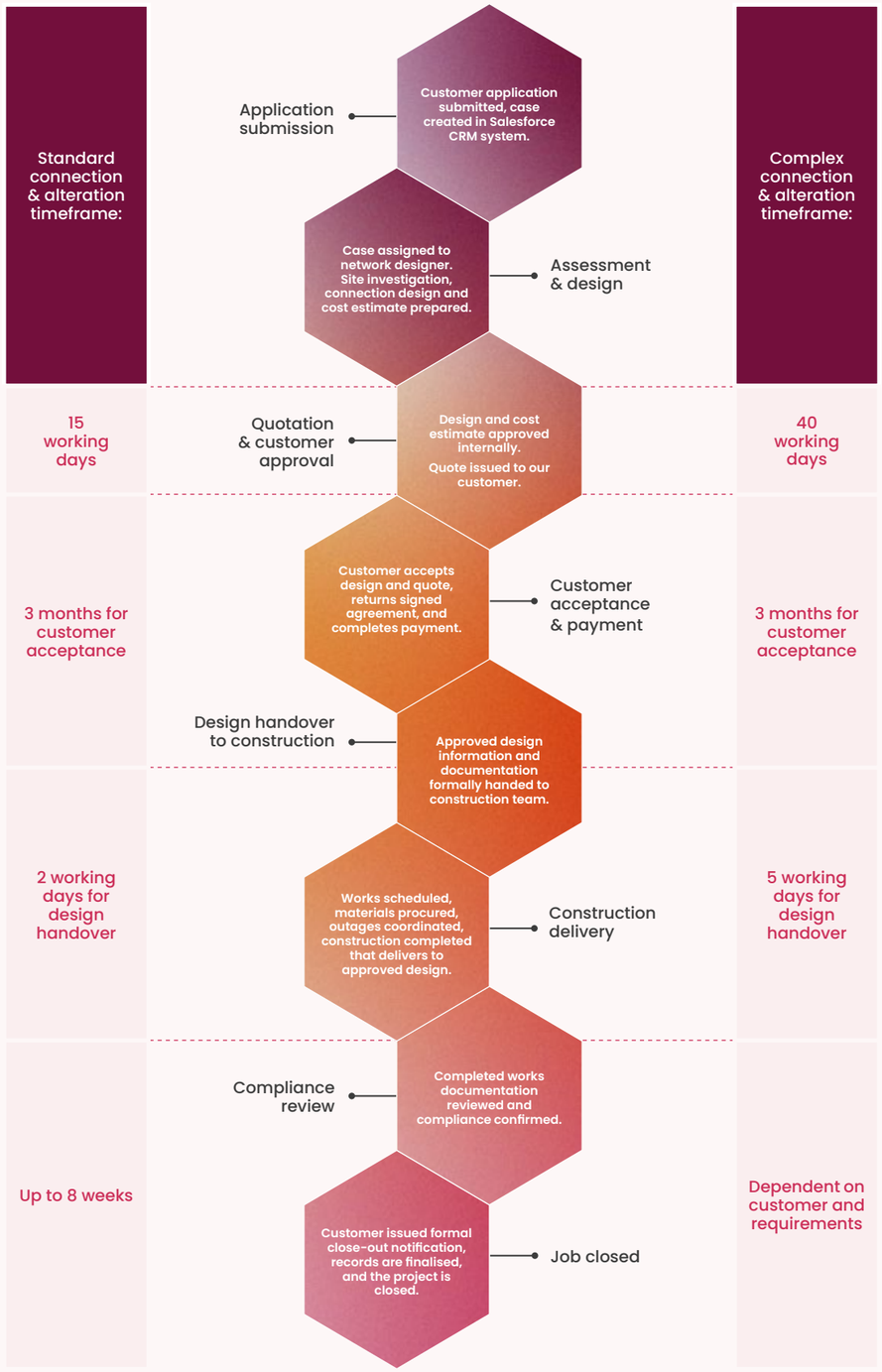
Connection type	Scope summary	Typical duration (weeks)	Key dependencies	Common delay risks
Standard residential offtake	Existing pillar, minimal civil works	6-8 generally, can be completed in 1-3 if minimal work required	Site readiness, meter availability	Missing documentation, council inspections
Complex residential / small commercial	New pillar/cable route, traffic management, minor reinforcement	6-8	Consents, civil works	Subcontractor availability, access constraints
Large commercial / industrial	Studies; design; reinforcement; long lead plant	16-52 depending on customer needs and complexity	Procurement, outage windows	Capacity upgrades; easements. customer requirements, long lead items
DG ≤10 kW Single Phase / ≤30 kW Three Phase	Protection check; design; compliance	1-2	Protection settings, metering	Rework of protection settings
DG >30 kW to >1 MW	Detailed studies, export assessments, and protection	6-52 dependent on complexity	Feeder capacity, plant procurement	Reverse power or hosting constraints
Alterations (relocation/upgrades/ underground)	Additional assessment and outages	6-8 dependant on complexity	Property access, outage coordination	Property access delays

Table 3.1 Connection delivery overview

The system workflow to manage the standard or complex connection or alteration jobs is as shown next.

Aerial view of rural Patumahoe

Figure 3.11 System workflow for standard and complex connections and alterations



3.14 Practices for Connecting New Consumers and Altering Existing Connections (continued)

These timeframes help customers plan development activity with greater certainty and reflect our commitment to transparent, future ready service delivery.

3.14.3 Understanding and Communicating Timeframes and Potential Delays

Delivery of all types of connection jobs may be affected by several external factors. Common delay drivers include:

- Incomplete or missing customer documentation;
- Consenting, inspection, or council approval delays;
- Easements and property access constraints;
- Long-lead or specialist equipment procurement;
- Developer civil sequencing; and
- Capacity-driven reinforcement requirements.

Our indicative timeframe table satisfies regulatory disclosure requirements by providing customers with clear visibility of typical durations. We continue to improve accuracy through enhanced data, digital lodgement, and integrated scheduling.

3.14.4 Minimising Cost to Consumers

Our connection processes are designed to keep costs fair, transparent, and aligned with long-term community value. We do this by:

- Applying standardised designs that reduce engineering effort and unnecessary variability.
- Maintaining efficient procurement, ensuring most materials remain within standard stock.
- Using digital lodgement, automation, and workflow tools to reduce manual processing time.
- Integrating scheduling to reduce unnecessary truck rolls and improve delivery efficiency.
- Providing clear, transparent quotations with defined assumptions.
- Considering non-network solutions where these can defer reinforcement or reduce long-term costs.

These practices support affordability while enabling growth and meeting customer expectations for timely and predictable service.

3.14 Practices for Connecting New Consumers and Altering Existing Connections (continued)

3.14.5 Communication with Consumers

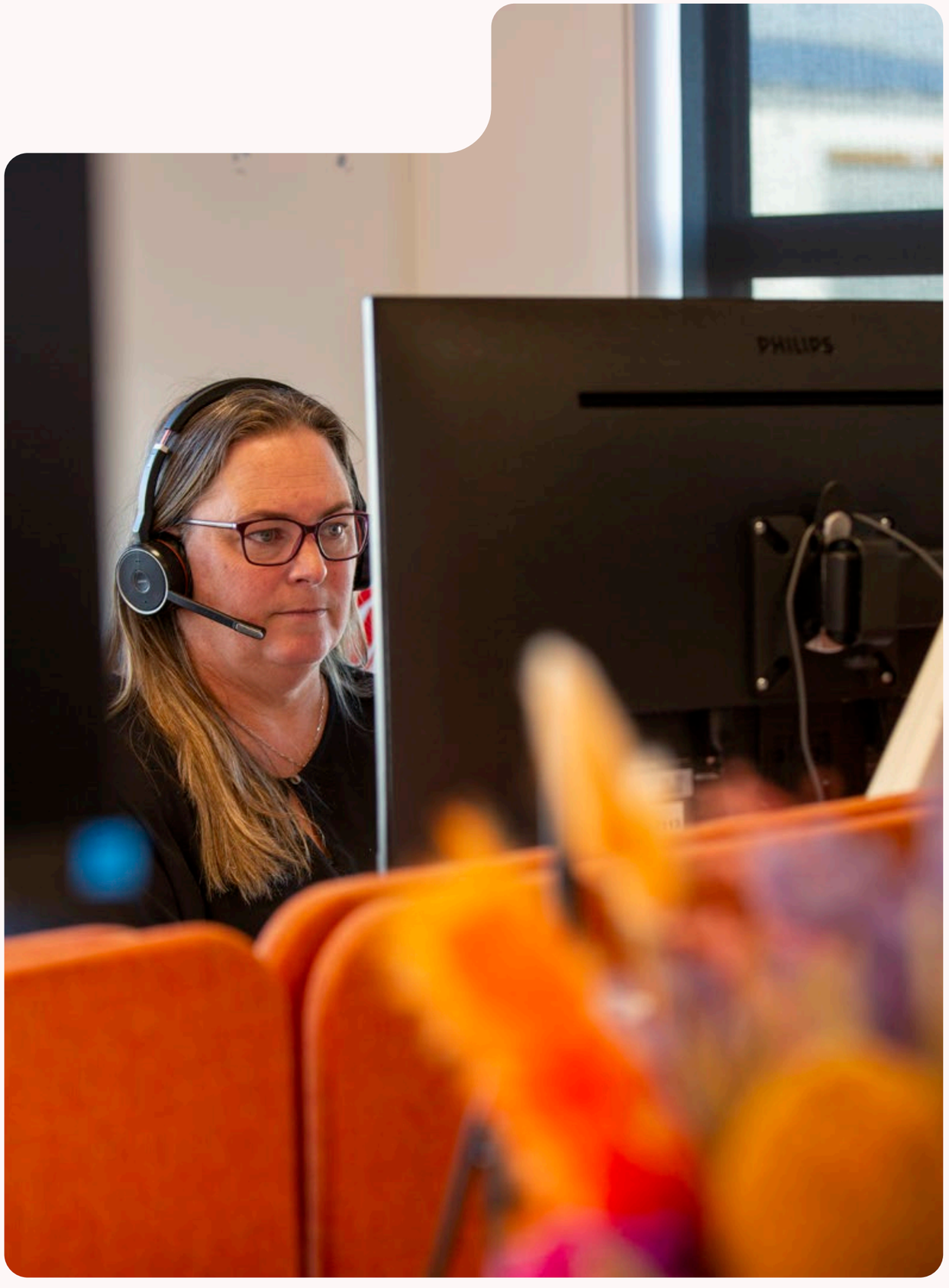
Clear, proactive communication is fundamental to a positive connection experience. Counties Energy provides:

- Automated notifications at key workflow stages.
- Multichannel updates via email, SMS, and phone.
- Proactive communication when delays or issues are anticipated.
- A dedicated Network Designer as a single point of contact.
- A self-service digital platform for application lodgement and document upload.
- Service levels including acknowledgement within two business days and fortnightly design updates.
- Defined escalation pathways: Network Designer > Network Design Team Lead > Head of Customer Works.

These practices reflect our wider customer promise: simple, transparent, and predictable service at every touchpoint. We continue to improve accuracy through enhanced data, digital lodgement, and integrated scheduling.

Historically, we have had very few constraints on the network, and these constraints have been communicated with customers when needed as part of customer initiated projects.

In 2026, we plan to improve how we communicate constraint information to our customers by publishing the available load and injection capacity at a distribution feeder and transformer level online. We plan to add low voltage at a future date, subject to data quality initiatives currently underway.



04

Managing our Assets

4.1 About This Chapter

With the new ways customers use electricity, combined with the significant macro industry trends underway, Counties Energy is committed to ensuring our asset management practices enable communities and stakeholders to access electricity in the way that best meets their needs, now and into the future. To achieve this, we are strengthening our alignment to ISO 55001:2024, focused on decision-making and value, actions to address risks and opportunities, data and information, lifecycle planning, and predictive action.

Our infrastructure upgrades are delivering measurable improvements in network performance when compared to recent years. We've completed the modernisation of our radio communications systems - the technology that lets us monitor and control the electricity network remotely, replacing outdated equipment with more capable and secure systems. We're also making smarter maintenance decisions by using asset health data and risk assessment tools to prioritise where we invest, rather than simply replacing assets based on age. New urban developments now use underground cables which cost more to install but provide enhanced reliability with less ongoing maintenance.

Looking at the trends over the last few years, power interruptions are becoming less frequent, and we are more proactive at preventing the faults that disrupt power supply. This comes from better fault detection technology installed between 2023 and 2025, stricter patrol procedures when circuits trip, and investigating early warning signs before they result in outages.

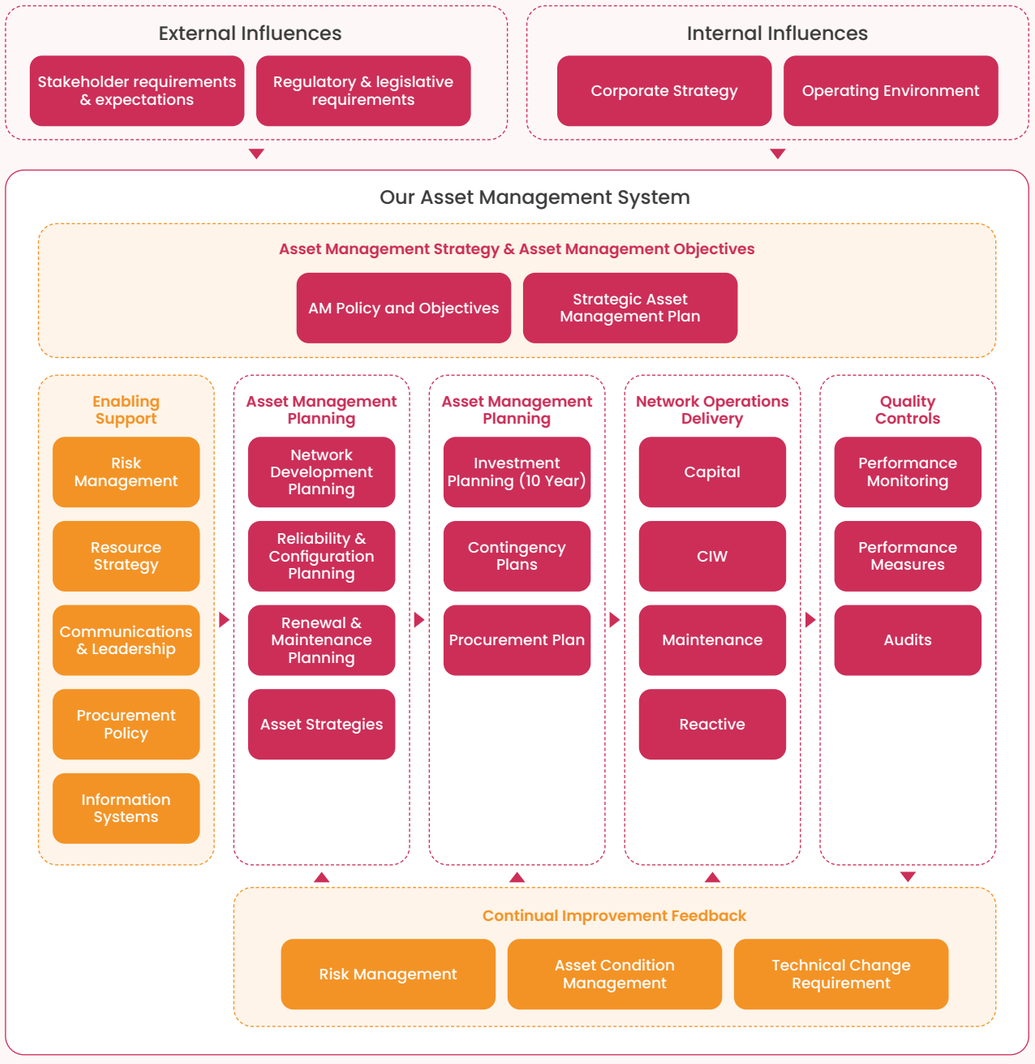
We are also progressively upgrading pole designs to reduce outages caused by bird strikes as we replace aging structures. We will keep lifting our asset performance by focusing on event causes (vegetation, wildlife, connectors, crossarms), customer impact per event, and faster restoration.

An independent assessment in late 2025 using the industry's updated resilience maturity tool showed we've made significant progress since 2018. Some of our emergency response capabilities are near industry best practice, with some aspects such as using smart meter data for faster storm recovery rated as leading best practice. The review also identified areas for improvement: better policies for maintaining critical spare parts, more robust backup generator arrangements, updated crisis management plans that align with national standards, formal mutual aid agreements with other EDBs, and clearer strategies for upgrading infrastructure after major events. These improvements will help ensure we can keep the lights on even when facing increasingly severe weather and other disruptions.

4.2 Our Asset Management Framework

Counties Energy's Asset Management framework is informed by the principles of ISO 55001, a globally recognised standard for asset management. The framework provides a structured approach to managing assets across their life cycle, with the objective of optimising whole-of-life value, supporting network performance and reliability, and enabling effective utilisation of the distribution network. Through this framework, asset management practices reflect our commitment to delivering safe, reliable, and cost-effective electricity services to our community – now and into the future.

Figure 4.1 Asset management framework



4.3 Our Asset Management System (AMS)

To support both the current and future needs of our customers and the network, Counties Energy established an Asset Management System (AMS) that is based on, and progressively aligned with, ISO 55001 principles. This provides the framework for ensuring our decisions, our actions and our value is measured against both qualitative and quantitative targets and align with strategic objectives while delivering safe, reliable, and cost-effective services.

The AMS is in essence the backbone of Counties Energy's asset lifecycle planning and operational execution. It unites our business to deliver to our asset management objectives, ensuring that all asset management activities:

- Align with corporate strategy and objectives;
- Comply with regulatory, legislative, and internal governance requirements;
- Support safety, sustainability, and customer-focused outcomes; and
- Enable continual improvement and risk-informed decision-making.

Our AMS is not static, it is a dynamic system that evolves through continuous improvement, responding to changes in regulatory requirements, customer expectations, technology advancements, and risk profiles. This adaptability ensures asset management practices remain relevant, effective, and aligned with strategic objectives over time.

Operating within a structured review cycle, the AMS integrates feedback from audits, performance monitoring, and stakeholder engagement and our 2025 external AMMAT (Asset Management Assessment Tool) review. This iterative approach strengthens governance and embeds a culture of improvement, ensuring the system delivers sustained value across the asset life cycle. In short, the AMS unites our business to deliver our asset management objectives.

4.4 Asset Management Documentation, Controls and Review Processes

Counties Energy operates a structured suite of asset management documentation, supported by defined controls and regular review processes, to ensure our asset management activities are aligned with corporate objectives, regulatory obligations and good industry practice.

Asset Management Documentation

The Asset Management Plan (AMP) sits within a broader asset management framework and is supported by a hierarchy of documents that together define policy, strategy, processes and delivery standards. Key documentation includes:

- Asset Management Policy, which sets out the principles and commitments guiding asset management across the organisation.
- Asset Management Framework, which supports consistent and informed asset management decision-making through defined governance arrangements and accountabilities.
- Asset Management Strategy, which outlines asset-class specific approaches to lifecycle management, risk, reliability, resilience and investment, recognising that the level of development varies across asset classes and is being progressively strengthened.
- This Asset Management Plan, which consolidates strategic, technical and financial information into a single, publicly disclosed document covering a 10-year planning horizon.
- Supporting plans, standards and procedures, including network development strategies, maintenance and inspection programmes, design standards, operating procedures and works delivery frameworks.

Together, these documents provide a structured basis for asset lifecycle decision-making and support the progressive strengthening of our asset management practices over the AMP period.

Asset Management Controls

Counties Energy employs a comprehensive set of asset management controls to ensure that asset-related activities are planned, delivered, approved, and monitored in a disciplined, transparent, and accountable manner.

- Governance and accountability controls provide clear linkages between Board oversight, executive leadership, and operational delivery. The Leadership Team reports regularly to the Board on all relevant asset management governance matters, including safety and environmental performance, reliability outcomes and analysis, operational issues, risk management, and customer experience. This ensures the Board maintains effective oversight of asset stewardship while management remains accountable for execution.
- Financial and investment controls ensure alignment between the Asset Management Plan (AMP), annual budgets, and capital investment approval processes. While the AMP informs the Board of the expected levels of operational and capital expenditure over the 10-year planning horizon, no expenditure is directly approved through the AMP itself. Instead, annual budgets and individual business cases are prepared for consideration and approval. The Board approves annual operational and capital budgets and delegates expenditure approval authority to the Chief Executive through a delegated authority framework that is reviewed annually.

- All network capital projects are required to have appropriate business justification and delegated financial approval. Significant initiatives are subject to a more detailed business case and options analysis process, and are approved by the leadership team prior to investment. Major capital projects are submitted to the Board for overall approval, with all major projects over $5.0 million reported to the Board on a monthly basis and, where appropriate, subject to post-implementation review to confirm that objectives and targets have been achieved. Any project variations resulting in material cost increases or time delays are managed within approved delegated authority limits and reported to the Board as required.
- Risk management controls are integrated with Counties Energy's enterprise risk management framework, ensuring asset-related risks are systematically identified, assessed, and treated. Risk considerations are embedded within planning, investment decision-making, and performance reporting processes.
- Data and system controls are supported by asset registers, condition and performance data, and defined data governance arrangements. These controls enable informed decision-making, transparency, and traceability across the asset lifecycle.
- Performance monitoring controls use defined service levels, reliability metrics, and condition indicators to track outcomes against asset management objectives and to support continuous improvement.

Together, these controls are designed to manage risk, maintain regulatory compliance, and support consistent, well-governed asset management outcomes across the organisation.

Review and Continuous Improvement Processes

Asset management documentation and controls are subject to regular review to ensure they remain fit for purpose and reflect changes in the operating environment. Key review processes include:

- Annual AMP review and update, as part of the business planning cycle, incorporating updated data, forecasts, risk assessments and investment priorities.
- Periodic policy and framework reviews, to confirm alignment with corporate objectives, organisational changes and regulatory expectations.
- Performance and condition reviews, using reliability metrics, asset health indicators and incident analysis to inform improvements.
- Internal assurance activities and, where appropriate, targeted external reviews, audits or benchmarking.
- Post-implementation reviews, applied to significant projects, events or incidents.

Through these review processes, Counties Energy maintains a focus on continuous improvement and progressively strengthens our asset management capability.

4.5 Our Asset Management Policy

Our Asset Management Policy reflects Counties Energy's long-term commitment to optimising the whole-of-life value, performance, and utilisation of our distribution assets. This policy underpins our ability to deliver safe, reliable, and cost-effective electricity services, while meeting the evolving needs of our customers and communities. It is reviewed every three years, ensuring it continues to reflect and deliver our strategic objectives.

4.5.1 Asset Management Policy Principles

- We prioritise safety to protect workers, contractors, and the public.
- Asset decisions align with purpose, business strategy, risk, and management approach.
- We meet customer expectations, engage stakeholders, and support community and environment.
- We deliver value through risk-based, lifecycle cost decisions and optimisation.
- We optimise performance using data, condition strategies, and proactive maintenance.
- We demand high-quality data to support informed asset decisions.
- We follow standards, innovate, and exceed asset and customer expectations.
- We pursue sustainability with technologies reducing impact and improving resilience.
- Our people drive excellence through recruitment, retention, and development.
- We comply with regulations and uphold governance, standards, and policies.

Our commitment to asset management

We are committed to optimising whole-of-life value, performance and utilisation of our distribution assets to deliver safe, reliable and cost-effective electricity services that meet the evolving needs of our customer – today and for the future.

This commitment drives our transformation towards data-driven decision-making, equipped to support a low-carbon, decentralised energy future through innovation, sustainability and operational excellence.

4.6 Our Asset Management Objectives (AMO)

Our Asset Management Objectives (AMO) are developed to provide measurable actions that deliver our strategic goals and align with our Asset Management Policy principles.

4.6.1 Safety and Compliance

We prioritise the health, safety, and regulatory integrity of our asset operations to protect people, infrastructure, and the environment. All asset-related activities are required to meet or exceed established health and safety standards. Safety risk assessments are embedded into every asset lifecycle decision and project. Compliance with all relevant laws, regulations, and internal governance policies is maintained across every aspect of asset management.

4.6.2 Strategic Alignment

Asset management is aligned with corporate strategy and risk frameworks to deliver long-term value and resilience. We align asset investment plans with corporate strategy and long-term business goals. The enterprise risk management framework guides all asset decisions to ensure consistent, risk-based prioritisation. An ISO 55001 compliant Asset Management System is embedded and supports other relevant standards. Ongoing assessment of asset risks and opportunities enables optimisation of lifecycle costs and value maximisation.

4.6.3 People and Capability

We invest in our people and partnerships to build a capable, well-resourced asset management workforce. A skilled and competent team is supported through ongoing training and professional development. Sufficient internal and external resourcing is secured to enable effective delivery of asset management plans and projects.

4.6.4 Customer and Community Focus

We deliver reliable network performance and engage meaningfully with customers and communities to reflect their values and expectations. Network performance is managed to meet or exceed agreed customer service levels. Stakeholders are actively involved in asset planning and decision-making to ensure community priorities are understood and reflected. Climate resilience and sustainability principles are embedded into our asset planning, design, and lifecycle management to support long-term network performance and community wellbeing.

4.6 Our Asset Management Objectives (AMO) (continued)

4.6.5 Innovation and Data-Driven Asset Optimisation

We embrace digital innovation and data intelligence to optimise asset performance, utilisation, and decision-making. Emerging technologies such as digital twins, AI, and advanced analytics are evaluated and adopted to enhance asset insights and operational outcomes. Strategies for dynamic asset capacity calculation are developed to support dynamic operating envelopes and maximise network utilisation. Asset utilisation is continuously monitored and optimised to improve efficiency and reliability. Time-based planning is integrated with lifecycle strategies to reduce costs, extend asset life, and enable timely, data-driven decisions.

An Enterprise Asset Management (EAM) system has been established as the central source of our asset information, supported by high-quality asset and connectivity data. Robust systems and processes uphold data integrity and enable predictive analytics while network losses are measured, and reduction opportunities identified.

Overhead team working in Te Toro

4.7 Our Asset Management Maturity

Counties Energy is progressively aligning our asset management practices with the ISO 55001 series of asset management standards. While a fully mature, ISO aligned asset management system is not yet in place, we have established a structured and prioritised improvement programme to develop, refine and embed the required documentation, governance arrangements, controls and assurance processes over time.

This programme is informed by internal reviews, independent maturity assessments and recognised industry good practice, and is supported by specialist external advisers, including Covaris, to provide independent insight and assurance that developments are appropriately framed, robust and proportionate. Improvement initiatives are prioritised based on risk, materiality and organisational readiness, and are progressively embedded into business as usual activities through governance oversight, training and regular review.

Counties Energy undertook our most recent Asset Management Maturity Assessment Tool (AMMAT) review late 2025, during the current disclosure period, to provide a transparent and structured assessment of the maturity of its asset management practices and to inform ongoing improvement planning. The review was conducted using the Commerce Commission's AMMAT, extended to reflect ISO 55001 principles, to provide an objective view of our current capability across policy, strategy, planning, lifecycle management, information, governance and assurance.

Covaris, an independent external adviser, was engaged to undertake this AMMAT assessment and provide objective challenge and guidance. Covaris is a specialist asset engineering consultancy and is accredited by the Institute of Asset Management (UK) as an Endured Asset Management Assessor. The lead assessor, Dr Robin Platfoot, is qualified as FIEAust, FISEAM, and WPiAM CAMA, and provides ISO 9001 endorsed consulting services in physical asset management.

Dr Platfoot's assessment was conducted in accordance with the Commerce Commission AMMAT, extended using the Global Forum on Maintenance and Asset Management (GFMAM) framework and the Competency Specification for an ISO 55001 Asset Management System Auditor/Assessor.

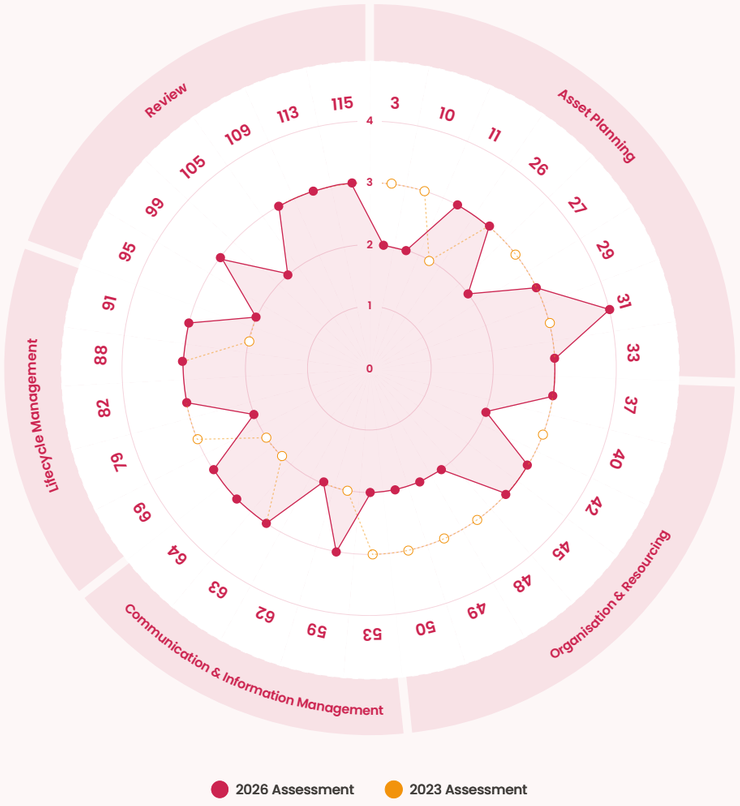
The assessment was evidence based and drew on multiple sources, including documented asset management policies, strategies and plans, asset information systems, work and fault management data, and structured engagement with personnel across our organisation. This approach ensured maturity scores were supported by verifiable evidence of both documented requirements and their consistent application in practice.

4.7 Our Asset Management Maturity (continued)

In some AMMAT dimensions, maturity scores reduced by one level compared with previous assessments. These reductions reflect tighter alignment with Commerce Commission guidance and ISO 55001 expectations, where documented requirements or formal assurance processes were not yet consistently demonstrated across the organisation, notwithstanding established practices or clear improvement intent. The revised scores are considered to provide a more accurate representation of current maturity and better support targeted, risk-based improvement planning.

The outcomes of the AMMAT review are used to inform a targeted asset management improvement programme. Recommended improvement actions are prioritised based on risk, value and organisational readiness, and aligned with the broader programme of progressive alignment with the ISO 55001 series of standards. Improvements are embedded through governance oversight, updates to documentation and processes, capability development, and integration into business as usual activities, supporting a controlled and sustainable uplift in our asset management maturity over time.

Figure 4.2
2026 AMMAT completed by external reviewer, Covaris.



4.7 Our Asset Management Maturity (continued)

The results of the Asset Management Maturity Assessment disclosed in Schedule 13c in the appendix, have been evaluated against our asset management and planning objectives set out in this Asset Management Plan.

The assessment indicates that our current asset management practices support core objectives relating to safety, regulatory compliance, operational reliability and prudent lifecycle decision-making. These areas reflect established processes, governance arrangements and operational controls that are consistently applied across the network.

The assessment also identified that further maturity is required to fully support objectives relating to risk-optimised investment planning, consistent asset-class strategy development, improved asset information quality, and the use of information to support decision-making across all levels of the organisation. These gaps are most evident in areas where processes, systems and documentation are still being standardised or strengthened.

In response to these findings, we are establishing a staged asset management improvement programme that focuses on:

- Strengthening leadership, governance and clarity of asset management expectations.
- Improving asset planning and investment decision-making, including better integration of risk, performance and lifecycle cost considerations.
- Enhancing lifecycle management practices, including condition assessment, maintenance planning and renewal optimisation.
- Progressively improving asset information systems, data quality and reporting to better support decision-making.

These improvement initiatives are aligned with ISO 55001 asset management principles and are being implemented progressively over the AMP period. Together, they are intended to strengthen alignment between our asset management maturity and our long-term objectives of resilience, affordability, customer outcomes and sustainable network development.

4.8 A Strategic Approach to Asset Management

In this AMP, we outline our commitment to the continuous improvement of our systems, our people, our processes, and our asset management practices to establish a robust foundation for the next 10 years and beyond.

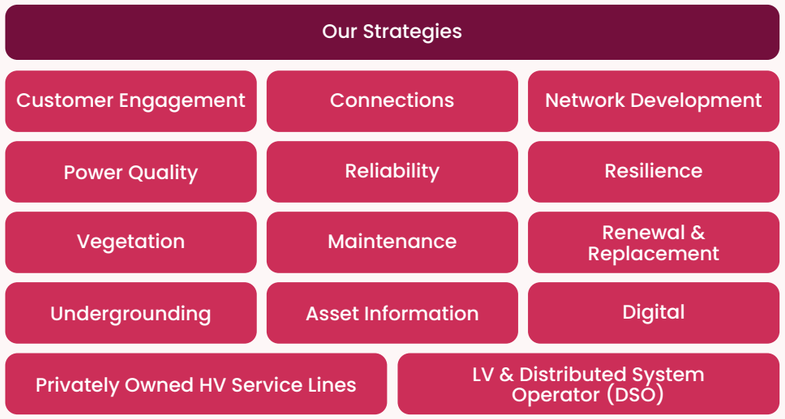
We employ a number of interconnected strategies across reliability, resilience, maintenance, renewals, connections, and digital transformation, supported by progressively integrated systems and a disciplined works delivery life cycle.

At Counties Energy, asset management extends beyond a purely technical function and plays an increasingly strategic role in supporting the delivery of safe, reliable and resilient electricity services across our region.

Our asset management strategies set out the principles and planned actions that guide how we plan, operate and invest in the network across the asset life cycle. These strategies continue to be strengthened through a structured programme of improvement informed by independent AMMAT assessments, supporting progressive alignment with the ISO 55001 series of standards and increasingly future-ready outcomes for our customers and communities.

Each strategy addresses a critical aspect of asset performance, from reliability and resilience through to maintenance, renewals and future network development, ensuring that decisions appropriately balance cost, risk and performance across the asset life cycle. Together, these strategies form the foundation of this AMP. An overview of each strategy is outlined below.

Figure 4.3 Strategic landscape overview



4.8 A Strategic Approach to Asset Management (continued)

4.8.1 Customer Engagement Strategy

Our asset management approach is shaped by the voices of our customers and communities. Through structured engagement – surveys, forums, and targeted consultations – we capture insights that directly inform service levels, reliability targets, and future network development. By embedding customer feedback into the AMP, we demonstrate our commitment to delivering value, transparency, and outcomes that reflect stakeholder priorities (refer to section 3.4).

4.8.2 Connections Strategy

The connections strategy supports growing demand for connections by ensuring efficient delivery while maintaining network capacity and integrity. Founded in customer excellence, it includes technical assessments and planning coordination to avoid strain on existing infrastructure and to align with long-term development goals (refer to 3.14).

4.8.3 Network Development Strategy

As demand on the network increases, we must ensure it continues to meet consumers' capacity, security, and reliability requirements. We have established network security and planning criteria and assessed the performance of the network against these criteria under a reasonable demand growth forecast. This assessment identifies emerging network constraints and the indicative timing of investment required to address them.

Our network development strategy is focused on selecting options that are economically efficient and consistent with prudent network management. In doing so, we seek to avoid over-investment, premature investment, and an undue risk of asset stranding. Where growth-related investment is required, we aim to maximise renewal benefits by coordinating upgrades or replacements with asset renewal needs and to avoid the early replacement or write-off of assets prior to the end of their economic service life.

Future network development projects also include targeted investment to improve network performance, as measured by SAIDI and SAIFI. These investments reflect customer expectations and broader service delivery outcomes identified through our analysis of network performance trends.

The electricity sector is undergoing a period of significant transformation. Technological innovation, together with New Zealand's net-zero greenhouse gas emissions target for 2050, is expected to materially influence electricity demand and consumption patterns. We recognise the potential for changes in demand characteristics driven by evolving customer behaviour and anticipate increased customer expectations for services that enable the integration of distributed energy resources (DER) and participation in flexibility and demand response services.

We manage demand uncertainty through an adaptive planning approach. This includes ongoing monitoring of demand trends, periodic review and update of demand forecasts, and flexibility in the timing of planned investment. Where demand growth is lower than forecast, investment may be deferred; conversely, where demand growth exceeds forecasts, investment may be brought forward to maintain service performance and security standards.

Further detail on our network development approach and planned investments is provided in Chapter 6.

4.8.4 LV & Distributed System Operator (DSO) Strategy

Counties Energy's transition to a Distribution System Operator (DSO) is a strategic shift designed to deliver customer-centric transformation that enables us to deliver more flexible, inclusive, and resilient energy services to our customers. As energy flows become more dynamic and distributed, our role evolves towards actively managing the network, enabling greater customer choice, improved reliability, and access to new energy services. Through smart infrastructure and enhanced LV network visibility and control, we support the integration of solar, batteries, electric vehicles and other smart devices, empowering customers to participate in the energy system. To further support the transition to a Distribution System Operator (DSO) model, our low voltage strategy incorporates several key initiatives. We are actively leveraging 5-minute interval metering data to gain granular insights into consumption and generation patterns across the network. This data enables more precise monitoring and supports the development of a robust network connectivity model, which maps the real-time relationships between assets, customers, and distributed energy resources. Additionally, we are implementing dynamic operating envelopes that allow flexible management of local network constraints, ensuring optimal integration of new technologies while maintaining power quality and reliability for all customers.

4.8.5 Power Quality Strategy (including Voltage Management)

Counties Energy owns and operates a metering business, acting as the Metering Equipment Provider (MEP) to connections throughout the wider Franklin region. Our smart meter fleet covers more than 99.9% of residential customers in the area, with lesser coverage for commercial and industrial segments. This has historically given us excellent visibility of low voltage performance on the network which forms an important launchpad for the low voltage initiatives described here and in section 8.4.

Our power quality strategy prepares the network for greater uptake of customer-centred technologies, like EVs and solar, by improving visibility, control, and power quality. It supports our transition to a Distribution System Operator (DSO) model through targeted planning and operational workstreams. Our strategy focuses on delivering voltage within the required thresholds, primarily focusing on our customers connected to low-voltage networks. Voltage excursions are typically caused in three ways:

Network Design or Configuration for Connected Demand: Although each connection will have an agreed maximum capacity, the network is designed assuming that not every customer will draw their maximum at the same time, a concept known as diversity. Our networks have been built using after-diversity maximum demand (ADMD). The ADMD specific to a localised area can be affected by the amount, and timing, of customer consumption and can sometimes differ from the assumptions made during network design. Changing customer behaviours, particularly around the charging of electric vehicles and other energy storage systems, are notable examples of this in recent years. This, in turn, can cause voltage excursions outside of requirements, usually aligning to periods of high localised consumption – which would typically result in low voltages aligned with periods of higher load (typically mornings or evenings in winter when the demand for lighting and heating is the highest). Historically, a one-way power flow from grid to customer has also been assumed. This, as well as our ADMD assumptions, is being challenged increasingly as our customers begin to take advantage of opportunities offered by consumer energy resources – notably distributed generation such as photo-voltaic/solar. High voltages are increasingly caused by distributed generation on sunny days, reversing power flow and challenging the historical one-way design assumptions of the network.

4.8.5 Power Quality Strategy (including Voltage Management) (continued)

Momentary Fluctuations: These are events where voltage will briefly fall below (also known as dip or sag) minimum requirements or rise above (also known as swell) maximum requirements. These events usually correspond to fault events where network protection is operating and almost always last for less than a second. These fault events may be on the Counties Energy network, but fluctuations can also be driven by transmission grid events elsewhere in New Zealand. Most customers will only ever notice these as a brief flickering of lights, and most appliances will continue functioning. Some commercial or industrial customers may have more sensitive plants which may be impacted, although often this can be improved by looking at the ride-through capability of control systems or internal power supplies. Short of preventing every fault on the network, these events cannot be entirely avoided. Our protection and control systems are designed with an objective to reduce the impact of momentary fluctuations to our customers, although there are public safety and reliability trade-offs that are considered. We have a fleet of permanent power quality monitors installed at our zone substations that, amongst other things, monitor for momentary fluctuations on our HV networks. We monitor and report on these internally.

Weak Power Events: Voltage excursions due to single-phase fuse operation on the HV network are treated as "weak power" events. As network fuses rely on a field technician to manually reset, these events can last over an hour.

Our network design processes aim to deliver voltages to our customers within the required thresholds and, as far as possible, enable distributed generation within the network's capabilities. We have embraced the regulation change in late 2025 to increase the regulatory voltage range from ± 6% to ±10% as a pragmatic approach to enabling additional solar generation and have already implemented this change within our processes. Voltage quality is measured at the point of supply, which is the point where the supply crosses from the Counties Energy network into the private property boundary. In many cases, long customer-owned service lines can often amplify the voltage excursion experienced at the customer's property.

Many customers are not aware that they may own, or jointly own with their neighbours, the lines across private land that connect their property to the Counties Energy lines on the public road or at the high-voltage transformer. If these lines are no longer suitable for the connected loads or distributed generation, responsibility for addressing these limitations rests with the private line owners.

4.8.5 Power Quality Strategy (including Voltage Management) (continued)

Monitoring of Voltage Quality

Prior to 2019, identification of voltage excursions usually relied on customers advising us of this matter. This then changed to take advantage of our access to smart meter information, accessible via our INDI platform. Since then, we have been able to proactively monitor extended or regular voltage excursions (whether high or low), and initiate investigations via a risk-based approach long before customers advise us. This aims to address non-compliance in a risk-prioritised way, either driven by the magnitude of the quality excursion, or the number of customers impacted. We can also use the smart meter information, including site-specific consumption data, to begin investigations without always having to deploy monitoring equipment to site, and having to wait for the results.

We expect to further mature in our proactive voltage management processes once we have access to full power quality (voltage) information from our smart meter fleet, linked to our LV analytics platform. Improved processes in how we record and manage the voltage settings applied to our large fleet of distribution transformers are also on our improvement plan in the upcoming year or so.

How We Respond to Voltage Quality Issues

Whether triggered by our proactive monitoring, or raised by a concerned customer, we take voltage management seriously. Our network reliability team handle these investigations, with cases recorded in our CRM system and customers kept fully informed throughout. The findings and recommended solution for each investigation can vary a lot from site to site. Sometimes the issue can be addressed by changing the settings on our transformers, or by minor network reconfiguration, which are funded by our Voltage Management Programme (refer to section 7.4.2). In other cases, the issue is identified on a private-owned service line, or within the property installation, which requires a solution by the customer.

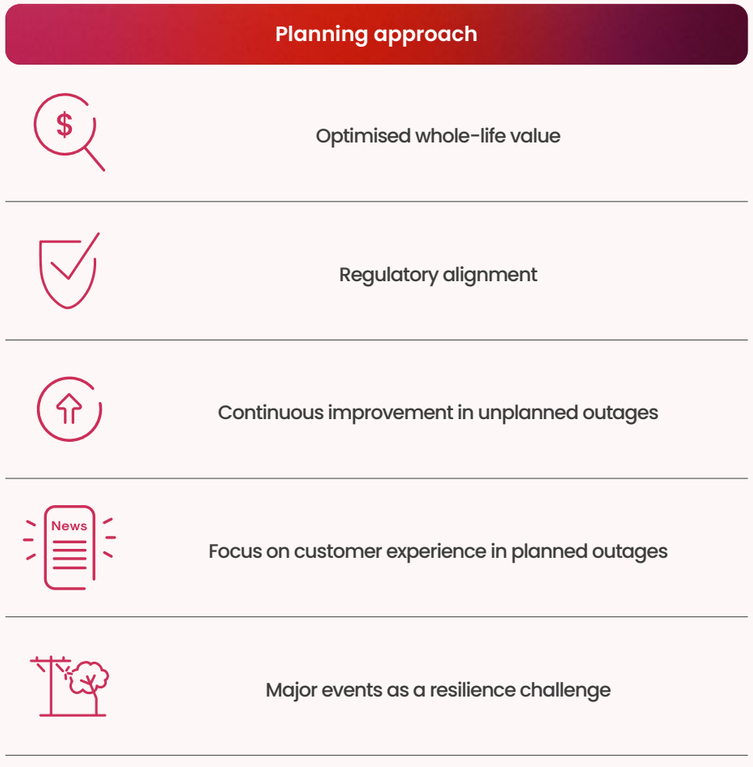
Overhead team working in Pukeoware

4.8.6 Reliability Strategy

Our reliability strategy is focused on delivering consistent service performance that meets or exceeds customer expectations. It encompasses targeted investment in network reliability and undergrounding initiatives, each contributing to improved SAIDI and SAIFI outcomes, enhanced customer experience, and long-term network resilience. Counties Energy recognises the direct effect network reliability has on the experience of our customers connected to the network, and it is therefore a core business priority reflected in our value of 'Always On'. Changes in our operating environment from 2016 influenced a period of unfavourable network reliability over the following years, causing our customers to experience a greater number of minutes per year of supply outages than we would like. These changes included more severe wind or weather events relative to the prior 10 years, a significant reduction in live work undertaken, new reclosing protocols reducing the number of attempted recloses after an unplanned interruption, and enhanced traffic management requirements. We have been on a journey since 2020 to turn this around and are committed to continuously improving our network reliability. We have already made good improvements but recognise there are still more improvements to be made.

Our approach to driving reliability is illustrated in the following diagram.

Figure 4.4 Reliability approach



4.8.6 Reliability Strategy (continued)

Whole-Life Value: We are aware investment decisions affect the prices customers pay for electricity services. With this in mind, we are conscious of driving reliability improvements through cost-efficient long-term initiatives rather than short-term improvements, which may improve reliability faster but incur higher overall costs for customers long term. It is a primary focus of our asset management activities to ensure all expenditure is targeted to achieve the best overall network reliability, recognising that the asset is generally a long-term one and thus a minimum whole-life approach to costs is usually the most appropriate.

Regulatory Alignment: As a 100-percent consumer-owned EDB, we are obliged to meet Information Disclosure (ID) requirements but are exempt from the quality standards of non-exempt EDBs. Nonetheless, we recognise the regulatory regime as a widely consulted and agreed methodology in the industry which we see as best practice. Therefore, we aim to align closely with the regulatory methodology used by non-exempt EDBs as far as possible. From 1 April 2025, the new electricity price quality path (DPP4) took effect for non-exempt Electricity Distribution Businesses (EDBs) and will apply for the five-year period through to 31 March 2030. For unplanned outages, we align our measuring and reliability reporting to this methodology. This includes the identification and normalisation of results for Major Event Periods (further detail on this under "Major Events" on the following page. For planned outages, while our approach differs from the specific DPP4 calculation methodology, it is aligned with its underlying intent of delivering a positive customer experience. Rather than using weighting factors to calculate planned SAIDI and SAIFI, we apply a set of targeted metrics and service levels that directly measure outage frequency, duration, and customer impacts, including the quality and timeliness of notifications and the management of planned outage cancellations. This approach provides meaningful insight into planned outage performance and customer outcomes, without the additional complexity of weighted indices that we consider less intuitive for customers.

Unplanned Outages: We aim to continuously improve our unplanned reliability performance, as set out in our reliability service levels (refer 4.10.2.1). Within this, we manage our business-as-usual reliability through our reliability metrics. We recognise that unplanned SAIDI and SAIFI are a direct result of three input factors which are monitored as reliability metrics:

- Number of events – Linked to failure/fault rates.
- Number of customers impacted per event – Linked to the topology/design of the network, and where on the network the events occur.
- Duration of outage – Linked to the initial scale of the event and how quickly supply is restored.

It should be noted that SAIFI is a product of events and customers impacted, with SAIDI being the product of SAIFI and duration (CAIDI).

Figure 4.5 Component parts of SAIFI and SAIDI

Events (Outages) X Customers Impacted = SAIFI (per ICP) X CAIDI = SAIDI

We report internally on each of these metrics by event category. We have targets for these going forward that align with our service levels, which are used as part of our asset management system to continuously monitor asset performance.

4.8.6 Reliability Strategy (continued)

Customer-Centric Reliability Reporting: Relying on SAIDI and SAIFI alone has the limitation that reliability performance is averaged across all network-connected customers. There are likely to be extremes within this, where customers supplied from reliable urban networks may go years between interruptions. The converse is true for customers on long remote rural networks, where multiple interruptions can occur during a single year. We enhanced our systems a few years back so we can record outages down to a local transformer level. From this new data set, we have been able to set new service levels for customer outage experience – noting at this time, like SAIFI and SAIDI, these only relate to outages on the HV network. These new metrics are CEMI (Customer Experiencing Multiple Interruptions) and CELID (Customer Experiencing Long Interruption Durations). In FY27, we will roll out the final steps required to use the associated reporting around these metrics to drive asset management focus on our worst-served customers. These are also reported in this AMP as service levels (refer 4.10.2.1).

Planned Outages: Rather than managing solely on the total frequency and duration of planned outages, we focus on the customer experience of our planned outages. We believe this aligns with the intent of the DPP4 methodology for planned outages.

We monitor and report on:

- Whether sufficient advance notice has been given;
- Planned works started on time (but not early);
- Planned works finished on time;
- Cancellations kept to a minimum, and notified in advance wherever possible; and
- Repeat interruptions for planned works for the same customers within a 12-month period also kept to a minimum (which are measured as planned CEMI and CELID).

These are also reported in this AMP as service levels (refer 4.10.2.1).

Field crew attending a tail gate briefing prior to starting work

4.8.6 Reliability Strategy (continued)

Major Event Periods: The latest regulatory reporting (DPP4) methodology for unplanned reliability provides an industry-agreed method to distinguish regular day-to-day reliability from days when major events are occurring, such as significant weather events. The normalisation method uses a rolling 24-hour period to trigger the major event, with normalisation applied per 30-minute period. Boundary values have been defined from historical averages based on our reliability performance between FY15 and FY24. In practice, these events are generally triggered if more than ~15% of our customers are impacted, or we incur more than ~10% of our annual reliability target, within 24 hours. In times like these, we are likely operating outside of our normal response protocols and so our prioritisation and response are likely to be different to normal. Consequently, in our reporting, we treat any event that falls within a SAIFI or SAIDI major event window as being part of, or being impacted by, the major event. Our reporting therefore has a separate category for "Major Events". This aligns with our approach to the management of Major Events as a resilience challenge, a different approach to our normal day-to-day management of reliability. This also leads our reporting by cause to be a more accurate reflection of day-to-day network reliability.

Weak Power (Part-Phase Outages): These are where only some of the high-voltage phases of a normally three-phase system have been affected by an outage. Depending on the local network arrangement, a customer can have a range of experiences from full voltage, to reduced voltage, to an outage. This is unusual for underground networks and is more common for overhead networks, especially in rural areas. We have been recording these in our internal systems since June 2021. Although these are not included in the SAIDI/SAIFI reporting, it is recognised these types of outages impact customers too, and the recorded information is part of our reliability feedback in our asset management system.

Auto-Reclose Interruptions: These occur where circuit protection interrupts supply to a section of the network but then attempts several automatic supply restorations ("recloses") a few seconds apart. If these are successful, customers connected to the network section may see up to three short interruptions within a period lasting less than a minute, with each interruption lasting only a few seconds. These schemes are designed to prevent temporary faults which have not caused permanent network damage, such as wildlife or glancing vegetation contact, from causing extended outages. With the duration lasting less than a minute, these events are not counted in the SAIDI/SAIFI reporting, although they can be summarised into a metric known as Momentary Average Interruption Frequency Index (MAIFI), which is similar to SAIFI but for momentary (<1 min) interruptions. The strategy for these is the same as weak power events described above. Although they are not included in the SAIDI/SAIFI reporting, it is recognised these types of outages impact customers too, and the recorded information is part of our reliability feedback in our asset management system.

4.8.7 Resilience Strategy

We recognise we are a Lifeline Utility as defined by the Civil Defence Emergency Management (CDEM) Act 2002 and that the interruption of electricity, especially for extended periods, can have a significant impact on our customers and their communities.

We are also aware of the interdependencies between electricity supply and other important community lifeline services such as water supply, sewerage disposal, and telecommunications. As our customers and communities progressively decarbonise through electrification and become increasingly more reliant on technology requiring electricity, we foresee these dependencies becoming even more critical.

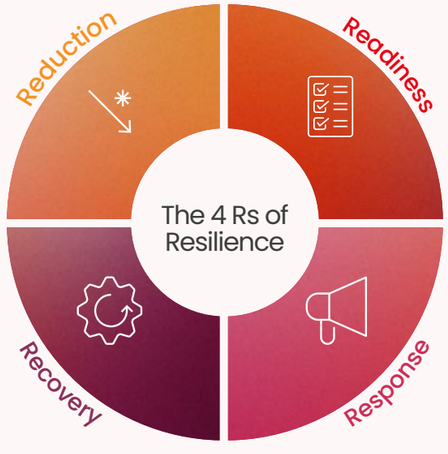
Identifying and understanding our exposure to high-impact-low-probability (HILP) significant disruptive events that could disrupt our ability to supply electricity is a priority for us. These risks are identified, analysed, controlled and treated as part of our core business risk management processes.

Since preventing these events entirely can be prohibitively expensive, our focus is on preparation, reducing exposure, supply restoration as soon as possible, clear communication, robust safety measures, and the provision of essential business functions in the event they do occur.

Our resilience strategy strengthens the network's ability to respond to and recover from adverse conditions through risk-informed planning, infrastructure adaptation, and emergency response readiness. It supports long-term service continuity by integrating climate readiness, asset vulnerability analysis, and cross-sector collaboration.

The strategy is built around the commonly understood 4Rs framework - Reduction, Readiness, Response, and Recovery - to ensure a robust and adaptive electricity network.

Figure 4.6
The Four Rs of Resilience



4.8.7 Resilience Strategy (continued)

Reduction happens in anticipation of significant disruptive events occurring and focuses on minimising risk through thorough risk management, effective contingency planning, liaison with wider stakeholders, proactive asset hardening, vegetation management, and resilient design standards.

Readiness emphasises preparedness prior to an event occurring via scenario planning, resource planning, and development of effective communications plans. Combined with measures taken in the reduction phase, these measures reduce vulnerability and enhance the ability to withstand significant events.

Response is the immediate actions taken following an event, in line with the plans made in the reduction and readiness phases. This includes assessing the network impact, automated fault isolation, rapid restoration protocols, scalable outage management systems, triggering stakeholder communications plans, and availability of key equipment such as mobile generators.

Recovery ensures restoration of service as swiftly as possible, effective stakeholder communications during the restoration and learning from events through post-incident reviews and continuous improvement programmes.

Counties Energy embeds the 4Rs into asset strategy and operational planning, aiming to deliver a future-proof network that maintains reliability, customer trust, and community wellbeing.

Field crew working at a substation

4.8 A Strategic Approach to Asset Management (continued)

4.8.7 Resilience Strategy (continued)

We take our obligations seriously to:

- **Maintain Operational Resilience** - Ensuring we can function to the fullest extent possible during and after an emergency.
- **Develop and Share Emergency Plans** - Create formal, written plans for emergency functioning and share them with national authorities and other Lifeline functions when requested.
- **Coordinate Nationally and Regionally** - Participate in the development of national and regional emergency management strategies and provide technical advice and information during an event.
- **Implement Robust Planning** - Integrate comprehensive risk management and business continuity plans into operations and collaborate within regional Lifelines groups.

As our network spans different regional council areas, we participate in both the Auckland and Waikato Lifelines groups. These voluntary groups involve local authorities, utilities, and transport representatives focused on pre-event planning. While Lifelines groups may monitor utility impacts during major events, their main role is to improve preparedness and raise public awareness of utilities' importance by sharing knowledge about vulnerabilities and interdependencies.

Our communities have told us that resilience matters, and we're listening. To strengthen our ability to support our customers for prolonged outages during significant events, we are investigating the establishment of dedicated community resilience hubs. These hubs would provide essential services such as backup power, device charging, and safe spaces during severe weather events or disruptions. We are exploring the possibility of starting with two sites over the next two years, working closely with local stakeholders and community groups to ensure these hubs meet community needs and enhance preparedness for the future.

In late 2025, we engaged an independent comprehensive review of our emergency preparedness and resilience initiatives – the results from this can be found in section 4.11.8.

4.8.8 Vegetation Strategy

Counties Energy's vegetation strategy supports network resilience and reliability by proactively managing tree-related risks through targeted inspections and Light Detection and Ranging (LiDAR) based assessments. It prioritises critical circuits and aligns with regulatory requirements to minimise outages and maintain service continuity.

We undertake vegetation management to ensure safety around our network and that network performance meets expectations. Our vegetation management is approached in accordance with the Electricity (Hazards from Trees) Regulations 2003, including the updates to these made in 2024. There are, however, still significant components of our vegetation programme which have to operate outside the scope of these regulations – notably around fallen or debris hazard trees, although we recognise that ongoing industry and regulator work is happening in this space. We remain actively involved in this through our involvement in the Tree Regulations Working Group within Electricity Networks Aotearoa.

Our vegetation strategy focuses on vegetation management as a preventative rather than a reactive activity. It is reliability-focused whilst supporting public safety, aiming to avoid trees contacting lines becoming a hazard. We first completed a full LiDAR survey in 2020, with another in 2023 and the next survey planned in 2027. These surveys, with subsequent data analytics, have been used to define and prioritise our inspection programme, enabling a proactive, risk-based approach.

Vegetation crew at work using an EWP

4.8.8 Vegetation Strategy (continued)

Key assumptions made in determining our vegetation management programmes:

- **Vegetation growth rates are predictable within bands**
  Growth by species, location, and season is assumed to broadly align with historical trimming cycles and growth rates. Our next LiDAR cycle is expected to inform this assumption.
- **Clearance standards remain stable**
  Regulatory requirements, safety codes, and internal clearance policies are not expected to materially change. (Although we are aware of upcoming changes in this space, particularly around fall hazard trees, we haven't amended our forward forecasts until there is clarity on requirements. However, we are not expecting any significant impact to forward investment levels based on what we know today).
- **Vegetation work materially reduces fault and safety risk**
  Trimming is assumed to lower vegetation related outages, public safety risk, and fire risk in a noticeable way.
- **Risk based prioritisation is valid**
  Circuits with higher criticality, fault history, exposure, or fire risk are assumed to benefit most from proactive vegetation management.
- **Access and landowner cooperation will be achievable**
  Reasonable access, permissions, and compliance with notices are assumed within planned timeframes.
- **Contractor capacity and productivity assumptions hold**
  Skilled vegetation contractors, equipment, and productivity rates are assumed to be available despite market constraints.
- **Weather impacts are within expected ranges**
  Storm frequency and severity are assumed to align with, or at least not significantly increase compared to, long term averages used in planning.
- **Funding levels are sufficient to maintain cycle times**
  Funding and opex allowances are consistent with the plans set out in this AMP.
  No major step-changes in allowed opex or emergency reprioritisation.
- **Environmental and consenting constraints are manageable**
  Ecological, cultural, and local authority constraints are assumed to be known and accommodated in programme design.

4.8.8 Vegetation Strategy (continued)

This approach balances:

- Encroachment severity;
- Fault history;
- Customer impact; and
- Network criticality.

Our 33 kV and 110 kV subtransmission circuits are fully surveyed annually due to the criticality of these lines, with the remainder of the distribution network programmed for inspection using the outputs from the LiDAR survey. The majority of our vegetation plan is delivered by our utility arborist crews within our Field Operations team.

This includes:

- Undertaking tree surveys;
- Tree owner liaison; and
- Undertaking proactive and reactive cuts.

Our team is assisted by external contractors when workload requires, or where specialist skills or equipment is needed. A site scoping visit is first undertaken in line with our risk-based inspection programme. All trees presenting a risk to lines, either through encroachment or growing over lines (breaching "clear to sky"), are identified, depending on the voltage and criticality of the line. Once a tree has been identified as presenting a hazard to the line, a notice will be issued to the tree owner, and a conversation initiated to identify the best course of action for the specific trees. First cuts are undertaken and paid for by us, providing the required criteria are met, and second and subsequent cuts are the responsibility of the tree (land) owner or future owners. In some cases, where it is advantageous for either Counties Energy or the tree owner to remove the tree, this can be facilitated by negotiation. We find this is often the best course of action for long-term interests of everyone – the tree owner, Counties Energy and our customers that can look forward to a more reliable supply.

During the scoping, we also use the opportunity to survey sites with out-of-zone vegetation that poses a risk to the network, such as vegetation likely to shed debris onto the lines or those flagged by LiDAR as potential sites where the tree could fall across the lines. For these out-of-zone sites, an arboricultural assessment is made based on tree species and health. This is used to inform the site's risk assessment, which informs the justification and prioritisation of any required remedial works. For these out-of-zone trees, we advise the owner and work with them to eliminate identified high-risk situations.

Information about trees near power lines is available on our website:
countiesenergy.co.nz/safety/trees-near-power-lines/

4.8.9 Maintenance Strategy

Our maintenance strategy ensures safe and reliable network operation by balancing repair and replacement decisions using whole-of-life cost and Value of Lost Load (VoLL) analysis.

It includes:

- Preventative maintenance (routine inspections, testing, and vegetation control to prevent issues);
- Corrective maintenance (scheduled repairs based on asset condition and risk); and
- Reactive maintenance (urgent fixes for immediate failures or safety concerns).

Our maintenance and inspection programmes are customised to address both known risks and uncover potential unknown issues. We schedule these activities based on industry standards and manufacturer recommendations, carrying out frequent inspections to identify defects and evaluate asset conditions. These inspections enable us to provide updates on asset health and respond quickly to resolve any problems, ensuring reliability and minimising downtime.

Along with our traditional inspection methods we have adopted additional inspection methods to better identify the condition of our assets. We implement targeted programmes for our network to identify potential threats, which are addressed through our defect remediation process.

These are:

- **Maintenance Activities:** Maintenance and inspection proactively address risks, ensure assets meet standards or recommendations, identify defects for repair, and evaluate asset condition through routine checks.
- **Unmanned Aerial Vehicle (UAV) Inspections:** Enhance defect identification and improve prioritisation of renewal investments.
- **LiDAR Surveys:** Detect vegetation encroachment, low conductor clearance, and regulatory breaches, supporting proactive asset replacement.
- **Machine Learning Technology:** We have partnered with another electricity distribution business, leveraging a capability they have previously developed, to thoroughly investigate conductor conditions and identify common defects using machine learning techniques on large image sets obtained from UAV inspections.

We continue to proactively enhance our inspection and maintenance methods as technology advances. These improvements will support more informed investment decisions while ensuring the network remains reliable and efficient. Looking ahead, we aim to increasingly shift our maintenance scheduling from time-based to risk-based approaches, aligning inspections with asset age or condition. As a result, assets nearing the end of their life expectancy will receive greater attention compared to newly installed ones. This strategy will provide added value to our renewal investment plans.

4.8.10 Renewal and Replacement Strategy

Our renewal and replacement strategy ensures long-term asset performance by replacing equipment based on age, condition, and failure risk, supported by whole-of-life cost and asset health modelling. Low-risk assets may follow a run-to-failure approach, while critical assets are prioritised for renewal using technologies like UAVs and LiDAR to guide investment timing. We replace assets based on the risk they pose, with risks assessed through condition-related defects identified via inspections and maintenance activities.

4.8.11 Undergrounding Strategy

Our undergrounding strategy supports safer, more resilient, and visually unobtrusive networks by prioritising underground circuits in new subdivisions. Overhead-to-underground conversions are assessed where they offer clear safety or reliability benefits and align with broader urban planning initiatives. We have no firm commitments to underground existing lines. However, we recognise there are resilience and visual appeal benefits to communities for lines to be underground in urban areas. New network in urban areas is nearly always installed underground, which is supported by the local authority planning rules. Undergrounding is, however, always a consideration whenever work is being scoped on existing lines, supported by our safety-in-design principles by which we work. These are projects where another investment driver requires work on the line, and undergrounding becomes the justified selected solution. We do take the opportunity to underground lines only when we believe there are sound technical, safety or financial reasons to do so. In some cases, this has seen us contribute to existing customer-initiated works to enable a better outcome for our communities. Occasionally, proactive undergrounding projects are identified as part of our reliability strategy, and form part of our reliability investment programme. Examples of this include high-voltage lines that supply many customers running close to a high number of notable native or historical trees with high amenity value. In this case, ongoing vegetation management may be a technically viable solution, but the overall benefit to the community and connected customers is greater with the lines removed. These projects, are however, an exception rather than the rule.

4.8.12 Privately-owned High Voltage Service Lines

Privately owned service lines are high, or low, voltage lines on private property that connect customers to the electricity network but are not owned or maintained by Counties Energy, with responsibility for condition, safety, and upkeep resting with the landowner(s) supplied by the line.

Private ownership of service lines presents ongoing safety, reliability, and customer experience challenges across the industry, with the risk increasing with the high voltage lines.

Counties Energy has an established project team that works with our customers to address the risks of high voltage lines through proactive engagement and the application of a structured, risk-based approach. Our strategy does not pre-determine that all service lines will be brought under network ownership and is continually evolving to ensure safety, reliability and responsiveness for our customers.

4.8.12 Privately-owned High Voltage Service Lines (continued)

To date, the project has transferred approximately 47 km of overhead lines and 600 poles into Counties Energy ownership, representing around 20% of known high-voltage lines in our region. Our approach has evolved to recognise the complexities of joint ownership and, in some cases, customer preference to retain private ownership.

Our current focus is high-voltage spur lines, categorised by isolation demarcation. This project is planned to continue throughout the planning period. Lines without clear isolation are assessed for isolator installation before being considered for ownership transfer. Customer responsibilities and options are communicated throughout, with any ownership transfers following a structured, risk-based prioritisation framework beginning with defect-free lines (to expedite transfers), followed by high-risk or high-cost lines, with vegetation being addressed through separate agreements to mitigate ongoing management requirements.

Known Risks and Issues

Private service lines face similar risks as network-owned assets, including poles and crossarms. Additional considerations include:

- Poorly maintained or deteriorating privately owned lines.
- Legacy conductor types (e.g., copper, swan) with high failure rates.
- High-voltage service lines supplying multiple properties with unclear ownership.
- This realigned strategy ensures safety, reliability, and cost efficiency while responding to evolving asset conditions and customer expectations.

4.8.13 Asset Information Strategy

Reliable asset information is the foundation of effective asset management. Our strategy focuses on ensuring accurate, timely, and secure data supports decision-making across the asset life cycle. It focuses on data integrity, integrating systems, and embedding data governance processes that provide confidence in the information used for planning, investment, and operational activities.

4.8.14 Digital Strategy

Our digital strategy drives innovation and future-readiness across Counties Energy. By investing in advanced technologies and digital platforms, we enable smarter, more flexible network operations and deliver new services that anticipate evolving customer needs. We focus on harnessing data, automation, and digital engagement to create seamless, reliable, and customer-centric energy experiences, ensuring our communities benefit from the latest advancements in the energy sector.

4.9 Strategies to improve our Asset Management Maturity: Our Data, Systems and Information Management

This section outlines the processes, systems, and controls that underpin asset management data across the full life cycle of assets and further drives improvement in our ISO alignment. It demonstrates how we ensure data integrity, integration, and utilisation to support asset health modelling and capital investment planning.

Delivering future outcomes relies on access to high-quality, verified asset data, from site inspections through to smart-meter data for LV analytics, and the investigation of drone technology to accelerate fault identification and power restoration.

Counties Energy relies on a suite of integrated systems to manage asset data, operational performance, and customer engagement across the entire asset life cycle. These systems enable accurate data capture, real-time monitoring, and informed decision-making, ensuring compliance with regulatory standards and supporting future planning.

4.9.1 Asset Management Data Requirements

Data requirements are identified through a structured asset management framework aligned with ISO 55001 principles. These requirements cover planning, design, construction, operation, maintenance and decommissioning stages. Annual reviews ensure alignment with regulatory obligations, customer expectations and emerging technologies.

4.9.2 Limitations and Improvement Initiatives

Quality data is essential, and while we maintain robust systems for asset data management, some limitations remain in the completeness and granularity of historical condition data, particularly for legacy assets and older network components. These gaps can affect the precision of health modelling and long-term forecasting. To address this, we have an established data quality improvement programme, including enhanced field data capture, systematic audits, and integration of advanced sensing technologies. Additionally, our data quality reporting framework, supported by Power BI dashboards and governance reviews, surfaces poor-quality data, highlights gaps, and enables timely correction through targeted remediation actions.

4.9.3 Enterprise Asset Management System

Our investment in an Enterprise Asset Management (EAM) system, IBM Maximo, further facilitates accurate data and supports informed decision-making across the entire asset life cycle, ensuring consistency from planning through to decommissioning. These initiatives are designed to progressively close data gaps, strengthen confidence in asset health assessments, and further bolster our capital planning capability.

4.9 Strategies to improve our Asset Management Maturity Our Data, Systems and Information Management (continued)

4.9.4 Data Quality and Accuracy Controls

To ensure our data is continually improving, we have employed the following controls to ensure the integrity, accuracy, and reliability of asset management data:

- Established data governance group responsible for driving quality improvements through centralised decision-making across core systems.
- Automated validation rules embedded in EAM and ADMS.
- Scheduled audits and exception reporting for compliance.
- Cybersecurity protocols and encryption to safeguard integrity.
- Role-based access controls to maintain accountability.

4.9.5 Integration of Systems and Processes

Systems are interconnected via secure Application Programming Interfaces (APIs) and middleware, enabling seamless data flow between planning, operations, and customer service platforms. Integration supports real-time decision-making and reduces duplication.

4.9.6 Use of Data in Asset Health Models

Condition data, failure history, and load profiles feed into the asset health models. These models assess probability of failure and criticality, enabling risk-based prioritisation. Predictive analytics extend asset life and optimise maintenance schedules.

4.9.7 Application of Model Outputs in Capex Planning

Health model outputs inform long-term investment planning by identifying assets at risk and prioritising renewal programmes. This ensures capital expenditure aligns with reliability, safety, and sustainability objectives.

4.10 Service Levels

As outlined in Section 4.6, we have developed a set of AMOs to provide measurable actions that deliver our strategic goals and align with our asset management policy principles. We have set performance measures and targets to ensure we meet our overall AMOs of safety and compliance, strategic alignment, people and capability, customer and community focus, and innovation and data-driven asset optimisation.

4.10.1 Safety and Compliance

We prioritise health, safety, and regulatory compliance in the planning, delivery, and operation of our network to protect our people, the public, our assets, and the environment. Safety performance is governed through a riskbased approach focused on identifying critical risks, implementing effective controls, and monitoring performance through a balanced set of leading and lagging indicators.

Our safety targets and reporting reflect the distinction between:

1. **Harm prevention** (serious harm and high potential events), and

2. **Injury outcomes** (recordable injuries). While Total Recordable Injury Frequency Rate (TRIFR) remains monitored, it is not relied upon as the primary measure of safety performance because it is a lagging indicator and can be disproportionately influenced by reporting practice and low-severity events. We therefore place greater emphasis on measures that strengthen prevention, particularly critical risk controls and learning from events, alongside transparent reporting of injury outcomes.

   During FY23, the SHIELD HSE reporting system was implemented to improve the consistency, quality, and visibility of reporting across incidents, observations, and audit data. This improves governance oversight, supports earlier identification of emerging trends, and enables more targeted interventions (for example, improvements to safety documentation, training, and early injury management).

   From FY27 to FY29, we will apply more systematic critical analysis of tasks and their inherent risks to evaluate the effectiveness of controls. This will progressively lift the maturity of our operational risk management system and improve our prevention of high potential incidents.

4.10.1.1. Safety and Compliance – Historic Performance and Future Targets

Table 4.1 summarises historic performance and forward targets for our key safety measures, providing a transparent basis for monitoring performance, identifying variance, and guiding continuous improvement.

		Actual (Past)				Targets (Future)					
Measure		FY23	FY24	FY25	FY26 (to 30 Sep)	FY26	FY27	FY28	FY29	FY30	FY31-FY36
Safety											
A	Fatalities	0	0	0	0	0	0 – Currently tracking on this number for FY26				
B	High-potential Incidents	13	17	24	9	<9	< 9 – Currently tracking on this number for FY26				
C	TRIFR*	2.39	38.44	12.32	12.48	<12	< 12 – Currently tracking on this number for FY26				

Table 4.1 Measures for health and safety

*TRIFR=Total Recordable Injury Frequency Rate

Our Safety and Compliance targets have been set considering the following measure justification on the following page:

4.10 Service Levels (continued)

4.10.1 Safety and Compliance (continued)

A. Fatalities

Counties Energy aims to complete work as safely as reasonably practicable in every situation. High Energy Control Assessment (HECA), Critical Risk Controls, bow-tie analysis and Field Safety Assessments are part of a suite of leading actions, that aim to identify critical fault paths and implement effective controls, to prevent serious incidents from occurring.

B. High potential Incidents

High potential incidents are any incident where there was a significant risk to people or property. Recent legislative changes require both significant and potentially significant incidents to be reported to WorkSafe. This reinforces the need to continue refining how high potential incidents are defined, identified and managed across the business.

C. TRIFR

Through ongoing engagement with cross-industry bodies, including the Electricity Engineers' Association (EEA), we actively identify and adopt emerging and improved risk assessment practices and tools. Alignment with the EEA Critical Risk Maturity Model strengthens our ability to consistently classify, assess and manage critical risks and controls, supporting improved learning from events and reducing the likelihood of high potential incidents.

The injury figures presented in the TRIFR table are derived from the following annual totals:

FY23: 1 injury **FY24: 18 injuries** **FY25: 6 injuries** **FY26: 5 injuries**

During FY23, Counties Energy implemented the SHIELD health and safety reporting system. This system has enabled more consistent and detailed reporting of incidents, along with the centralisation of audit data and safety observations. The improved visibility of this information has supported more targeted interventions in areas where trends indicate a higher risk of incidents.

As a result, SHIELD has supported:

- The development of improved safety documentation;
- More targeted and effective training programmes;
- Better management of existing injuries; and
- Proactive prevention of harm events.

It is important to note that although 18 injuries were reported in FY24, none were classified as serious harm events. The recorded Lost Time Injuries (LTIs) consisted of a spider bite and two strained backs. Additionally, the introduction of "Smart Moves" occupational physiotherapy services has had a significant positive impact on reducing musculoskeletal injuries, which previously made up the majority of reported cases.

Given the improved reporting accuracy and increased capture of lower-level injuries following the implementation of SHIELD, TRIFR is no longer considered a reliable standalone indicator of safety performance. The rise in reported injuries reflects better reporting practices rather than a decline in actual safety outcomes.

Moving forward, the focus will shift toward more meaningful lead and lag indicators, including proactive risk management, early intervention measures, and the severity and potential impact of incidents, rather than relying primarily on TRIFR.

4.10.2 Customer and Community Focus

We deliver reliable network performance and engage meaningfully with customers and communities to reflect their values and expectations. Network performance is managed to meet or exceed agreed customer service levels.

4.10.2.1. Customer and Community Focus – Network Performance, Historic Performance and Future Targets

We manage network performance to meet or exceed agreed customer service levels.

		Actual (Past)				Targets (Future)					
Measure		**FY23**	**FY24**	**FY25**	**FY26 (to 30 Sep)**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31–FY36**
Unplanned Outages											
A	Unplanned SAIDI	152.85	124.67	79.20	61.80	100.56	95.14	90.03	85.16	82.10	82.10
B	Unplanned SAIFI	2.514	2.094	1.315	0.841	1.646	1.552	1.464	1.388	1.329	1.329
C	Unplanned CEMI (4 interruptions)	N/A	89.5%	97.1%	94.6 %	90%	90%	90%	90%	90%	90%
D	Unplanned CELID (270 minutes)	N/A	85.8%	92.1%	88.8 %	90%	90%	90%	90%	90%	90%
Planned Outages											
E	Planned SAIDI	228.34	272.73	220.37	145.52	161.33	159.15	149.00	192.35	148.18	142.99
F	Planned SAIFI	0.77	0.78	0.63	0.473	0.605	0.502	0.476	0.589	0.473	0.459
G	Planned CEMI (2 interruptions)	93.4 %	95.6 %	95.6%	96.3 %	90%	90%	90%	90%	90%	90%
H	Planned CELID (720 minutes)	91.7 %	93.1 %	91.8%	93.8 %	90%	90%	90%	90%	90%	90%
I	Planned Notifications	69.8%	81.6%	81.6%	86.7 %	90%	90%	90%	90%	90%	90%
J	Timeliness (Start)	81.7%	79.1%	87.8%	86.2 %	90%	90%	90%	90%	90%	90%
K	Timeliness (End)	49.7%	40.7%	48.4%	57.4 %	75%	75%	75%	75%	75%	75%
L	Cancellations	100.0%	93.1%	92.8%	88.0 %	90%	90%	90%	90%	90%	90%

Table 4.2 Customer and community focus historic performance and future targets

4.10.2 Customer and Community Focus (continued)

The previous table demonstrates the outcomes of a sustained business focus on reducing the impact of unplanned interruptions on our customers over the past five years. While the table itself reports performance outcomes rather than priorities, the improving overall trend evident in recent years reflect the effectiveness of targeted investment and operational initiatives. FY25 delivered a particularly strong result, amplified by favourable conditions throughout the year, and this is clearly visible in the reported performance. FY26 to date has proven more challenging with a year-end result expected above target; however, when considered alongside an unusually favourable FY25, results remain consistent with an underlying trend of improvement. Notwithstanding this progress, our efforts will continue to be focused on consistently achieving service levels in future years.

Planned SAIFI and SAIDI have remained elevated in recent years, largely reflecting sustained and high levels of network investment requiring planned outages to safely deliver asset renewal, network growth and reliability programmes. While this has placed upward pressure on planned interruption metrics, these impacts are expected to moderate over the forecast period as investment profiles stabilise and continued improvements are made in the planning and scheduling of works. Overall, customer experience measures associated with planned outages are generally performing close to targets. However, further improvement is required in consistently aligning planned and actual restoration times. Ongoing refinements to outage planning, communication, and execution are expected to support improved planned interruption performance and customer outcomes over time.

4.10.2.2. Descriptions for Measures and Targets

A. Unplanned SAIDI

SAIDI stands for System Average Interruption Duration Index.

It's a measure of how long, on average, our customers are without power during a year due to unplanned events – noting that outages related to major events such as storms/severe weather have normalisation adjustments applied.

SAIDI currently only tracks outages involving high-voltage assets, meaning up to the local transformer for customers. It does not include outages on low-voltage networks or landowner-owned service lines.

We measure unplanned SAIDI using the same methodology applied in the electricity price quality path (DPP4), which took effect for non-exempt Electricity Distribution Businesses (EDBs) in April 2025 and will apply for the five-year period through to 31 March 2030. For unplanned outages, we align our measuring and reliability reporting to this methodology. This includes the identification and normalisation of results for Major Event Periods (further detail can be found in section 4.8.6).

Our forward SAIDI targets have been set considering:

- Historical performance;
- Improvements expected as a result of our continuous focus on network reliability improvement; and
- Compliance with a DPP4 quality path from FY26 (despite our exemption from this as a community-owned EDB).

4.10.2 Customer and Community Focus (continued)

4.10.2.2. Descriptions for Measures and Targets (continued)

B. Unplanned SAIFI

SAIFI stands for System Average Interruption Frequency Index.

It measures how often the average customer experiences a power outage (in excess of one minute) in a year due to unplanned events.

Our unplanned SAIFI is measured and forward targets set alongside unplanned SAIDI, using the same methods (refer previous section).

C. Unplanned CEMI

CEMI stands for Customer Experiencing Multiple Interruptions. It sits alongside SAIFI, but instead of looking at the network-average number of interruptions, CEMI represents the outlying areas of our network where customers may have a number of interruptions much different to the average. A limit is set, where a number of interruptions more than the limit is considered excessive. The measure is then a percentage of our customers who have fewer interruptions than this limit.

Our limit for unplanned outages is four interruptions within a 12-month period. This has been set aiming for an improvement on our performance over the last few years.

Our target of 90% therefore means we expect at least 90% of our customers to have four or fewer unplanned outages in a year.

The interruptions counted for CEMI are the same included in SAIFI, therefore CEMI currently only tracks outages involving high-voltage assets, meaning up to the local transformer for customers. It does not include outages on low-voltage networks, landowner-owned service lines, interruptions as part of major events or auto-reclose events.

Data to report on this metric is not available prior to FY24.

D. Unplanned CELID

CELID stands for Customer Experiencing Long Interruption Durations. It sits alongside SAIDI, but instead of looking at the network-average number for duration, CELID represents the outlying areas of our network where customers may have outage durations much different to the average. A limit is set, where a total number of outage minutes more than the limit is considered excessive. The measure is then a percentage of our customers who have fewer outage minutes than this limit.

Our limit for unplanned outages is 270 minutes (4.5 hours) within a 12-month period. This has been set aiming for an improvement on our performance over the last few years.

Our target of 90% therefore means we expect at least 90% of our customers to have 270 minutes or fewer of unplanned outages in a year.

The interruptions counted for CELID are the same included in SAIDI, therefore CELID currently only tracks outages involving high-voltage assets, meaning up to the local transformer for customers. It does not include outages on low-voltage networks, landowner-owned service lines, interruptions as part of major events or auto-reclose events.

Data to report on this metric is not available prior to FY24.

4.10.2 Customer and Community Focus (continued)

4.10.2.2. Descriptions for Measures and Targets (continued)

E. Planned SAIDI

SAIDI stands for System Average Interruption Duration Index.

It's a measure of how long, on average, our customers are without power during a year due to planned outages – which are required for Counties Energy to safely complete maintenance or upgrade works, or to connect new customers to the network.

Planned SAIDI also currently only tracks outages involving high-voltage assets, meaning up to the local transformer for customers. It does not include outages on low-voltage networks or landowner-owned service lines.

We measure planned SAIDI without any normalisations or adjustments applied, providing customers have been given sufficient notice of the outage.

Our forward SAIDI targets have been set considering:

- Historical performance;
- The volume of investment set out in this plan; and
- Improvements expected as a result of our ongoing work to optimise outage planning.

F. Planned SAIFI

SAIFI stands for System Average Interruption Frequency Index.

It measures how often the average customer experiences a power outage in a year due to planned outages.

Our planned SAIFI is measured and forward targets set alongside planned SAIDI, using the same methods.

4.10.2 Customer and Community Focus (continued)

4.10.2.2. Descriptions for Measures and Targets (continued)

G. Planned CEMI

CEMI stands for Customer Experiencing Multiple Interruptions. It sits alongside SAIFI, but instead of looking at the network-average number of interruptions, CEMI represents the outlying areas of our network where customers may have a number of interruptions much different to the average. A limit is set, where a number of interruptions more than the limit is considered excessive. The measure is then a percentage of our customers who have fewer interruptions than this limit.

Our limit for planned outages is two interruptions within a 12-month period. This has been set aiming for an improvement on our performance over the last few years.

Our target of 90% therefore means we expect at least 90% of our customers to have 2 or fewer planned outages in a year.

The interruptions counted for CEMI are the same included in SAIFI, therefore CEMI currently only tracks outages involving high-voltage assets, meaning up to the local transformer for customers. It does not include outages on low-voltage networks, landowner-owned service lines or interruptions as part of major events.

For major network upgrades in a local area, extra outages may be needed. We will coordinate with local communities to keep everyone informed and ensure the work is delivered effectively.

H. Planned CELID

CELID stands for Customer Experiencing Long Interruption Durations. It sits alongside SAIDI, but instead of looking at the network-average number for duration, CELID represents the outlying areas of our network where customers may have outage durations much different to the average. A limit is set, where a total number of outage minutes more than the limit is considered excessive. The measure is then a percentage of our customers who have fewer outage minutes than this limit.

Our limit for planned outages is 720 minutes (12 hours) within a 12-month period. This has been set aiming for an improvement on our performance over the last few years.

Our target of 90% therefore means we expect at least 90% of our customers to have 720 minutes or fewer of planned outages in a year.

The interruptions counted for CELID are the same included in SAIDI, therefore CELID currently only tracks outages involving high-voltage assets, meaning up to the local transformer for customers. It does not include outages on low-voltage networks, landowner-owned service lines or interruptions as part of major events.

For major network upgrades in a local area, extra outages may be needed. We will coordinate with local communities to keep everyone informed and ensure the work is delivered effectively.

4.10.3 Customer and Community Focus: Customer Engagement and Satisfaction – Historic Performance and Future Targets

We engage meaningfully with customers and communities to reflect their values and expectations. Stakeholders are actively involved in asset planning and decision-making to ensure community priorities are understood and reflected.

4.10.3 Customer and Community Focus: Customer Engagement and Satisfaction – Historic Performance and Future Targets (continued)

Measure		Actual (Past)	Targets (Future)							
		FY23	FY24	FY25	FY26 (to 30 Sep)	FY26	FY27	FY28	FY29	FY30	FY31–FY36
A	Customer panels held	Customer panel established in FY24	2	2	2	2	2	2	2	2	2
B	Overall customer satisfaction	57%	71%	See note*	81%	80%	80%	80%	80%	80%	80%
C	Customer satisfaction in new connections	Not measured	88%**	92%**	81%	80%	80%	80%	80%	80%	80%
D	Customer satisfaction in faults	Not measured	91%	92%	89%	85%	85%	85%	85%	85%	85%

*Table 4.3 Customer and community: customer engagement and satisfaction - historic performance and future targets (*Surveys reviewed and redesigned in FY25 to run biannually; **small sample sizes)*

The latest overall satisfaction score for Counties Energy for services we offer is pleasing at 81%, with future trackers ensuring we remain at 80% or over. Given the relatively small sample sizes for new connection satisfaction scores, we will incentivise surveys in FY26 to lift reportable response rates.

Our customer engagement and satisfaction targets have been set considering:

Criticality of fault response to customer experience

- Customer satisfaction scores relating to fault responses have been set at the highest level among all tracked satisfaction measures. Faults represent the most significant and high-impact interaction customers have with Counties Energy, as they typically occur unexpectedly and can directly affect comfort and daily activities. Performance during fault events strongly influences overall customer trust and perception of reliability. As a result, higher targets in this area reflect the organisation's commitment to minimising disruption, restoring supply promptly, and communicating clearly with customers during outage events.

Overall customer satisfaction target as a minimum performance threshold

- The overall customer satisfaction target of 80% has been established as a minimum benchmark rather than an aspirational ceiling. This reflects confidence in maintaining the previous performance level while recognising the positive impact of planned initiatives in the delivery pipeline. These initiatives include the implementation of a customer self-service portal, enhancements to digital communication channels, and targeted customer engagement campaigns. Collectively, these improvements are expected to strengthen customer experience over time, supporting sustained satisfaction levels at or above the minimum target.

Reliability and representativeness of survey data

- Given the relatively small sample sizes associated with new connection satisfaction surveys, future targets have been set conservatively to ensure results remain statistically meaningful and representative. To support more reliable reporting, Counties Energy will incentivise survey participation from FY26 onward, with surveys reviewed and redesigned as required. This approach aims to improve response rates and data quality, enabling more accurate tracking of customer sentiment and better-informed decision-making over time.

4.10.4 Innovation and Data Driven Asset Optimisation - Monitor and Optimise Asset Utilisation for Network Efficiency and Reliability

We develop dynamic asset capacity calculation strategies to support dynamic operating envelopes and maximise network utilisation. Asset utilisation is continuously monitored and optimised to improve efficiency and reliability.

		Actual (Past)					Targets (Future)					
Measure		FY23	FY24	FY25	FY26 (to 30 Sep)		FY26	FY27	FY28	FY29	FY30	FY31-FY36
Asset Utilisation												
A	Peak Utilisation of Installed Firm Capacity at Zone Substations	71%	60%	58%	59%	59%	62%+	62%+	62%+	62%+	62%+	62%+
B	Load Factor	0.58	0.54	0.57	0.58	0.58	0.60+	0.60+	0.60+	0.60+	0.60+	0.60+
C	Loss Ratio	4.6%	4.9%	4.2%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%

Table 4.4 Innovation and data-driven asset optimisation - asset utilisation historic performance and future targets

4.10.4 Innovation and Data Driven Asset Optimisation - Monitor and Optimise Asset Utilisation for Network Efficiency and Reliability (continued)

A. Peak Utilisation of Installed Firm Capacity at Zone Substation

The Peak Utilisation of Installed Firm Capacity at Zone Substations metric measures how close each zone substation is to its firm capacity limit at times of peak demand. It indicates available capacity headroom, helps identify existing or emerging constraints, and supports planning decisions on the timing and type of network or non-network solutions needed to meet forecast demand growth.

In FY24, peak utilisation reduced by 10% following the commissioning of the Barber Road Substation, which introduced 40 MVA of installed firm capacity and replaced two smaller substations with a combined firm capacity of 15 MVA. This materially increased available capacity headroom and reduced overall utilisation.

A future target of 62% has been set in anticipation of increased residential demand coincident with network peaks; however, recent demand trends indicate a shift away from traditional peak periods. While overall energy throughput continues to grow, peak demand is increasing at a slower rate, suggesting peak utilisation is likely to remain flat or decline, thereby deferring the need for peak-driven network investment.

B. Load Factor

The Load Factor metric measures how evenly electricity demand is spread over time by comparing average network load with peak demand, providing an indication of how efficiently network assets are utilised. A higher load factor reflects more consistent use of capacity and reduced reliance on short-duration peaks, helping distinguish whether investment is driven by energy growth or peak demand. A future target of 0.6 has been set to reflect Counties Energy's strategy of shifting and shaping load to better utilise assets outside peak periods, with recent demand trends suggesting this metric will continue to improve as customers adopt smarter energy management practices.

C. Loss Ratio

The Loss Ratio metric measures the proportion of electricity lost on the distribution network between points of injection and delivery to consumers, reflecting both technical losses (such as line and transformer resistance) and non-technical losses (including metering inaccuracies and unaccounted-for energy). It provides an indicator of network efficiency and asset performance and is used to monitor trends, benchmark performance, and inform loss-reduction initiatives. A future target of 4.0% has been set based on historical performance and forecast trends, with increasing levels of distributed generation reducing the impact on technical losses and supporting a gradual decline in the loss ratio over time.

4.10.5 Strategic Alignment - Environmental & Sustainability

4.10.5.1. Integrate Sustainability into Asset Planning Design and Lifecycle Management

We align asset investment plans with corporate strategy and long-term business goals.

Following the 2025 independent Resilience Management Maturity Assessment Tool (RMMAT) review undertaken (refer to section 4.11.8.1), Counties Energy will adopt a new resilience service level, which includes our plans for climate change adaption and readiness. This service level formalises the expectation that resilience practices are consistently defined, implemented, and reviewed in a structured way, supported by strengthened cost-benefit analysis to prioritise initiatives and track progress over time.

We aim to include additional service levels related to environment and sustainability in future versions of this asset management plan.

		Actual (Past)				Targets (Future)					
Measure		FY23	FY24	FY25	FY26 (to 30 Sep)	FY26	FY27	FY28	FY29	FY30	FY31-FY36
Resilience											
A	RMMAT score	N/A	N/A	N/A	2.56	2.56	2.56	2.56	2.75	2.75	3.00

Table 4.5 Strategic Alignment - RMMAT scores historic performance and future targets

A. Resilience Management Maturity Assessment Tool (RMMAT) Score

Our RMMAT assessment undertaken in late 2025 returned an average score across all questions of 2.56. This is the first formal assessment undertaken since 2018. In the longer term, we are targeting an average maturity rating of "Competent" (3.0) across all resilience topic areas.

Forward targets have been set in line with our improvement plans, with an improvement forecast for FY29 and a target of 3.0 set for FY31.

4.10.5 Strategic Alignment - Environmental & Sustainability (continued)

4.10.5.2. Optimisation of Lifecycle Costs and Value Maximisation

We optimise lifecycle costs and value maximisation as we recognise that it is important for our customers that we have efficient operating costs. We measure operating costs per consumer (ICP) and system length. We aim to ensure that our asset management and business operating decisions do not drive unnecessary costs into the business. Our costs have increased in recent years as a result of inflationary pressures. Additionally, new digital tools typically have higher operating expenditure because they rely on ongoing subscriptions, cloud hosting, data storage, cybersecurity, and continuous vendor support rather than one-off capital purchases. In addition, they require regular updates, integration, and specialist skills to operate and maintain, shifting costs from upfront capex to recurring opex.

		Actual (Past)				Targets (Future)					
Measure		FY23	FY24	FY25	FY26 (to 30 Sep)	FY26	FY27	FY28	FY29	FY30	FY31-FY36
Resilience											
A	Operating Cost per ICP	$521	$536	$515	$565 (forecast)	$586	$593	$593	$588	$595	$582
B	Operating Cost per circuit km	$6,903	$7,194	$6,931	$7,698 (forecast)	$7,982	$8,119	$8,168	$8,141	$8,277	$8,138

Table X Strategic Alignment – optimisation of lifecycle costs and value maximisation historic performance and future targets

A. Operating Cost per ICP

This measure is calculated from our total operating costs (network and non-network), divided by the total number of connected ICPs.

Forward targets have been set in line with our forecast operational expenditure (expressed in constant prices).

B. Operating Cost per Circuit km

This measure is calculated from our total operating costs (network and non-network), divided by the total circuit length (all voltages).

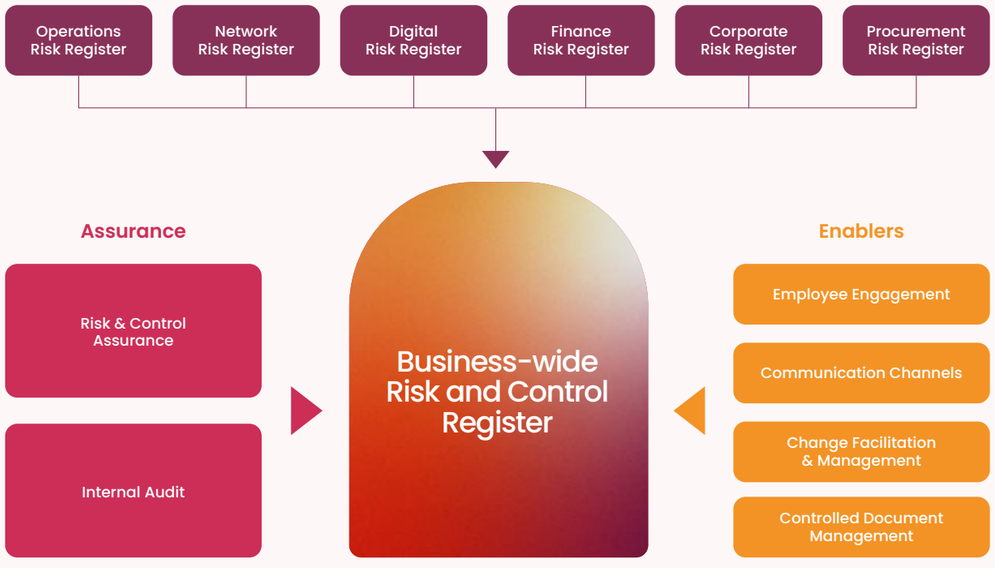
Forward targets have been set in line with our forecast operational expenditure (expressed in constant prices).

4.11 Our Risk Management Framework

Our approach to risk management remains largely consistent with previous years. However, our appetite for continuous improvement continues to evolve our approach, ensuring we take every opportunity to manage the complex arrangement of systems and projects more effectively.

Risk management is a core component of asset management, integral to good management practice, corporate governance and central to effective asset stewardship. We are committed to maintaining an environment that effectively minimises risk exposure to acceptable levels and ensures compliance with legislation as well as relevant standards and codes. We continue our work to align our Risk Management Framework with ISO 31000:2009 Risk Management – Principles and Guidelines. This ensures that all our risks are identified, understood and managed consistently through effective controls across all levels of our business.

Figure 4.7
Risk management framework



Several enablers support our risk management culture, including engagement and communication, change management and controlled document management as key components of our quality management system.

Improvements to our internal information management systems and the addition of a central change hub build a proactive approach to managing risk as our processes and practices mature. This will ensure better alignment and sustained communication across all stakeholders, ensuring that changing risks and updated controls are communicated, documented and implemented according to our risk management policy.

4.11.1 Our Risk Management Policy

This establishes the context for all our activities and ensures that risk management processes are integrated with all organisational policies, standards, processes and practices to support efficiency and effective management. This policy outlines the roles and accountabilities for risk management across the business.

4.11.2 Our Risk Management Accountabilities and Responsibilities

The following table presents the roles and responsibilities for risk management throughout the company.

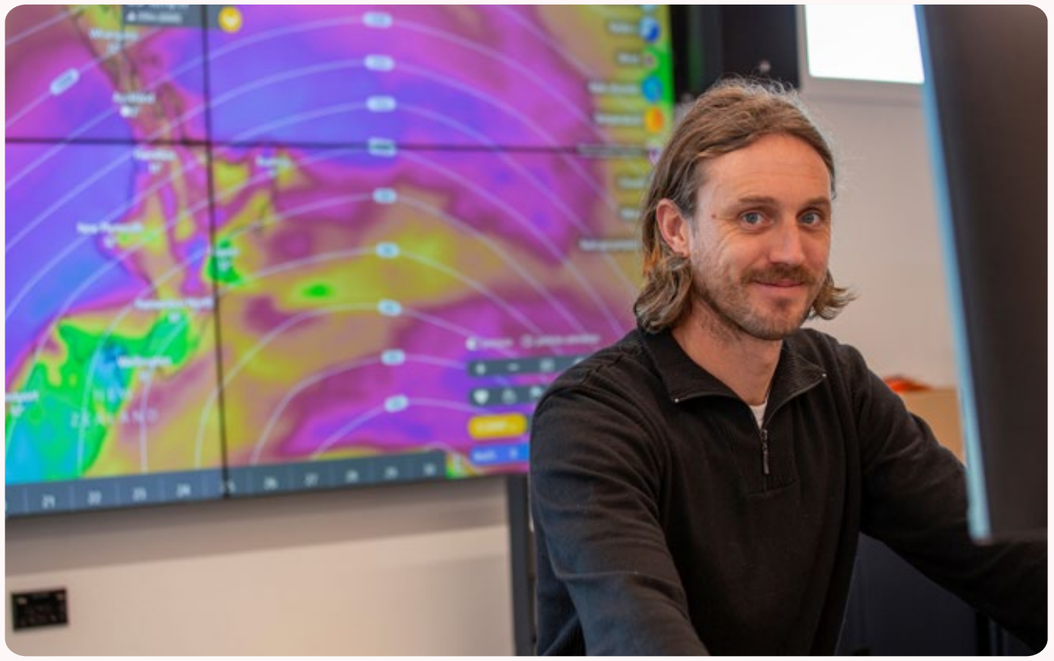
Position	Roles and Responsibilities
Board of Directors	Corporate governance
	Independent review of risks and associated mitigations
Chief Executive	Risk management sponsor
	Representative to the Board of Directors
	Oversight of the risk management process
Leadership Team (LT)	Ensure risk is identified and managed to acceptable levels
	Risk management framework is in place and continuous
	Legislative and governance obligations are met
	Integration of risk management with policies, processes and practices
Chief Financial Officer	Risk management administrator, in addition to LT responsibilities
	Schedule formal review sessions
	Ensure governance reporting obligations met
Managers and Team Leaders	Promote risk management culture
	Identify, manage and monitor risks in their groups
	Participate in risk planning, training and review sessions
	Assign and undertake responsibilities

Table 4.6 Risk management accountabilities and responsibilities

4.11.2 Our Risk Management Accountabilities and Responsibilities (continued)

Position	Roles and Responsibilities
Risk Owners	Support risk management within their area of responsibility.
	Initial assessment of risks and responding appropriately relative to objectives.
	Identifying appropriate controls and treatments and assigning relevant owners.
	Ongoing management of owned risks within acceptable risk tolerance levels, including monitoring of control implementations through ongoing communication with control owners and adjusting risk assessments as necessary.
Control Owners	Support risk management within their area of responsibility.
	Implementation of control or treatment within agreed timeframes and communicating progress to the risk owner.
	Ongoing assessment of effectiveness of controls and responding appropriately relative to objectives, communicating any changes to the risk owner.
Staff members	Identify any new or changes to risks in their area.
	Support risk and control owners where required.

Table 4.6 Risk management accountabilities and responsibilities



4.11.3 Our Risk Management Process

Our risk management process is designed to ensure risk management decisions are based on a robust approach, assessments are conducted consistently, and a common language is used and understood across our business. Our risk management process comprises the following steps:

Establish the Context - Many factors are considered, including internal and external parameters such as operating environment, stakeholders, internal structure and capabilities, and the business's risk appetite.

Risk Identification - Our risks are identified through operational processes, including hazard identification by employees in the field, team and project meetings, our Health and Safety management process, and our Public Safety Management System. Risk identification is also undertaken by members of the Leadership Team and senior staff as part of the audit and review process.

For identification purposes, we have grouped our risks into five types. These are:

- **Financial** – Risks with consequential impact on cash flow, balance sheet and financial liability.
- **Safety** – A risk event that adversely impacts the health and safety of the public, staff or contractors of the organisation.
- **Operational** – Risks affecting the efficient operation of the company, including asset management, service delivery, continuity and recovery. This includes customer relations and reputation.
- **Regulatory** – Risk of the company failing to meet current or foreseeable legal obligations.
- **Environmental** – Potential or actual negative environmental or ecological impacts, regardless of whether these are reversible or irreversible.

4.11.4 Our Risk Analysis and Evaluation Approach

We use both qualitative and quantitative methods during the risk analysis stage. All identified risks are analysed in terms of likelihood and consequence criteria in the context of our business objectives and in the context of the risk types outlined previously. As risk assessment is subjective, formal evaluation is undertaken by a committee to ensure a balanced view is agreed on. The tables below provide the ratings for probability, frequency and consequence specific to asset management (long-term) risks.

Level	Rating	Annual Probability of the Event Occurring	Description
5	Almost Certain	1 event in 1 to 2 years, > 50%	The event is almost certain to occur
4	> 50%	1 event in 2 to 5 years, > 50%	The event is likely to occur within 5 years
3	Likely	1 event in 5 to 10 years, < 20%	The event could possibly occur in the next 5 to 10 years
2	< 50%	1 event in 10 to 20 years, < 10%	The event is unlikely to occur, possibly within 10 to 20 years
1	Possible	1 event in 100 years, < 1%	The event may occur only in exceptional circumstances

Table 4.7 Likelihood rating

Level	Description	Examples of Consequence
5	Severe	Major unplanned service outage for over seven days
		Very serious, irreversible environmental impairment of ecosystem functions
		One or more fatalities and/or severe injury to staff, customers or the public
4	Major	Major unplanned service outage for up to seven days only
		Very serious, long-term environmental impairment of ecosystem functions
		Serious injuries to staff, customers or the public, requiring hospitalisation and/or lost workdays
3	Moderate	Unplanned service outage for up to five days
		Serious medium-term environmental effects
		Serious injuries and/or disability to one or more staff members, customers or members of the public
2	Minor	Unplanned service outage for up to three days unless it affects a key customer or occurs at a significant time (e.g. major sporting event or public holiday)
		Moderate short-term environmental effects but not affecting ecosystem functions
		Injury to a staff member, customer or member of the public requiring medical treatment
1	Insignificant	Unplanned service outage for less than 24 hours unless it occurs at a significant time (e.g. major sporting event or public holiday)
		No measurable impact on biological or physical environment

Table 4.8 Consequence rating

4.11.4 Our Risk Analysis and Evaluation Approach (continued)

These two aspects are brought together in a five-by-five matrix:

		1	2	3	4	5
		Minor	Moderate	Serious	Major	Severe
5	Almost Certain	Low	Medium	High	Extreme	Extreme
4	Likely	Low	Low	Medium	High	Extreme
3	Possible	Insignificant	Low	Medium	High	Extreme
2	Unlikely	Insignificant	Low	Low	Medium	High
1	Rare	Insignificant	Insignificant	Low	Medium	Medium

Table 4.9 Risk matrix

Additional risk assessment techniques are being investigated as informed by ISO 31000 to ensure identification, assessment and control development is applicable to the risk and those who interact with it. This approach will significantly improve our ability to align our risk registers and scoring methodologies as we aim to closely align to ISO 31000.

Vegetation clearing after storm damage

4.11.5 Our Risk Controls, Treatments and Reports

Identifying Threats

We actively identify threats for each asset type by examining both internal and external factors. Internally, we focus on operational resilience, procedures, compliance with standards, risk tolerance, as well as performance history. Externally, we evaluate changes in industry practices, regulatory updates, economic conditions, environmental influences, and our customers' and stakeholders' needs. Threats are identified proactively through regular maintenance and inspection, analysis of asset failures, consideration of safety for workers and the public, as well as monitoring performance data and customer feedback. We rely on insights from ongoing inspections, historical faults, and industry benchmarks to detect and address vulnerabilities before they affect performance or safety.

Establishing Treatment Plans

Treatment plans are strategies put in place to reduce exposure to various risks, including financial, operational, performance, compliance, and safety concerns. These plans represent systematic, proactive methods for managing threats to our network. We address each threat by choosing to avoid, mitigate, transfer, or accept it through these treatment plans. The goal is to protect our workers and the public, lower capital and operating expenses, extend asset lifespan, and improve the performance and reliability of our network. Listed below are the activities we carry out to manage threats on our network.

We monitor, treat, control, and manage all of our known risks in accordance with the risk score. Responsibilities for managing risk are clearly allocated. Currently, our approach is shifting to ensure both risk and controls have dedicated owners. This approach ensures risk is managed where it exists as opposed to where it is created.

We mitigate a risk depending on the numeric score allocated in the analysis and evaluation stage. Risk treatment involves selecting one or more options for modifying risks, which can include the following:

- Avoiding the risk by not commencing or continuing the activity;
- Removing the risk source;
- Changing the probability (including steps to reduce criticality)
- Changing the consequences;
- Sharing the risk with another party or parties (e.g. contracts and insurance); and
- Retaining the risk by informed decision.

4.11.5 Our Risk Controls, Treatments and Reports (continued)

One-off risk mitigations are treatments, whereas ongoing mitigations are referred to as controls. Both will have defined owners and review dates, which are periodic and ongoing in the case of controls. This approach allows us to apply varying controls as required to ensure that the risk is managed by affected stakeholders within their respective risk appetites. Currently, more effort is planned to ensure these controls are assigned an owner, are effective and reviewed regularly.

Information from the risk management process is recorded, reported and monitored using our Network Risk Register. This assists us in monitoring and reviewing risks in alignment with our business objectives.

Residual Risk Score	Report to
Extreme	Board of Directors and Leadership Team
High	
Medium	Leadership Team and Operational Managers
Low	Operational Managers and Staff
Insignificant	

Table 4.10 Network risk register

The Board of Directors receive a periodic report summarising the top risks we face, and the treatment applied to them. The Leadership Team and other senior managers meet periodically to review our risk management position. Risk reviews and reports are also completed annually.

4.11.6 Our Network Asset Management Risk Approach

Our asset management risk approach is applied in multiple, complementary layers to ensure risks are effectively managed from company-level oversight through to asset-level execution. At the highest level, the Network Risk Register captures material safety, reliability, compliance and financial risks and provides governance, visibility, and prioritisation of network-wide exposures. These are assessed by semi-quantitative methods as described previously in section 4.11.4. In some cases, additional tools such as bow-tie analysis are applied.

Asset criticality and vulnerability models are quantitative and numbers-based, assessing exposure at the individual asset level, mapping into a system-wide understanding of customer, safety, and network impacts, informing where failure would matter most. These models drill into public safety exposure, network performance impact, and environmental exposure – with a future intent to include further layers around exposure to climate change-related hazards such as higher wind speeds, flooding and landslips.

Building on these, the Asset Risk Management Model (ARMM) (further detail in 6.4.5.4) integrates asset condition, likelihood of failure, and consequence to assess and compare risk consistently across the asset base - both today and forecasting for the future.

Failure Modes and Effects Analysis (FMEA) is used to understand how assets fail, the drivers of risk, and the effectiveness of existing controls and mitigations.

At the most granular operational level, defect risk assessments are applied to individual defects identified through inspections and field activities, enabling timely, proportionate operational responses. These are also assessed by semi-quantitative methods using a 5 x 5 framework, although the likelihood and consequence assessments are scaled down from company-level to asset-level to ensure appropriate levels of granularity and visibility.

Together, these layers link strategic risk management to practical, evidence-based asset decisions.

4.11.7 Our Project-level Risk Management Planning

In addition to corporate-level risk management activities, a risk management plan is produced for each activity or project the business undertakes. Each project risk management plan specifies the risks relevant to that project, including the risk treatments and any applicable Job Safety and Environmental Analyses (JSEAs) and work standards. The design and implementation stages of each project's risk management plan consider our overall business objectives.

4.11.8 Resilience as a Lifeline Utility

Identifying and understanding our exposure to high-impact-low-probability (HILP) significant disruptive events that could affect our ability to supply electricity is a priority for us. These risks are identified, analysed, controlled and treated as part of our core business risk management processes. Since preventing these events entirely can be prohibitively expensive, our focus is on preparation, reducing exposure, restoring power as soon as possible, clear communication, robust safety measures, and the provision of essential business functions in the event they do occur.

Further information on our Resilience Strategy can be found in section 4.8.7.

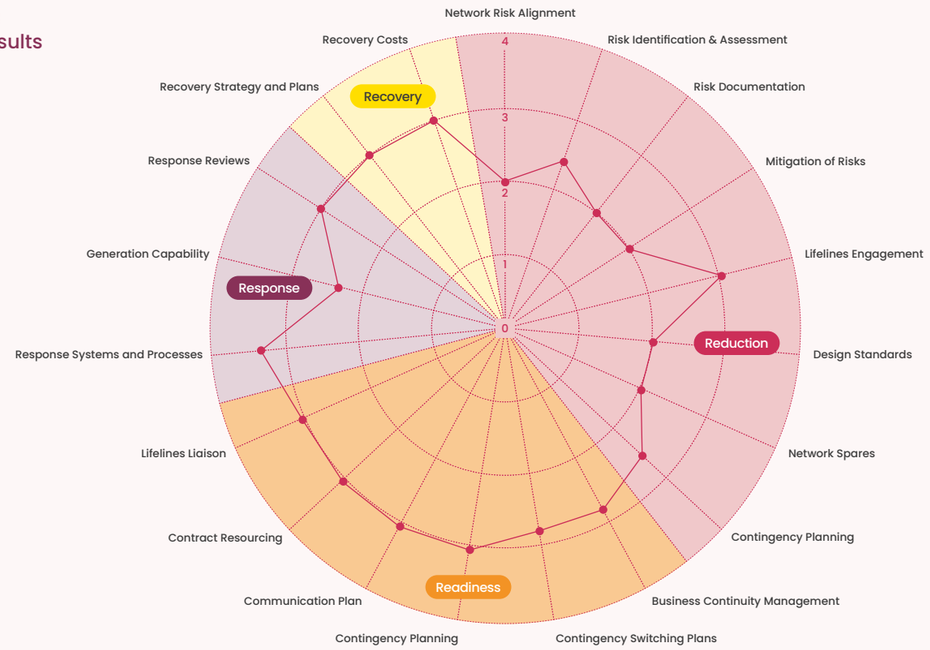
4.11.8.1. Resilience Management Maturity Assessment (RMMAT)

In late 2025, Counties Energy engaged an independent comprehensive review of its emergency preparedness and resilience initiatives using the latest Resilience Management Maturity Assessment Tool (RMMAT) published by the Electricity Engineers' Association (EEA). This tool was first published in 2022 and has recently been enhanced with new focus areas such as climate adaptation, cybersecurity, and workforce resilience. It adds seven new RMMAT questions from the previous version and strengthens cost-benefit analysis requirements.

The assessment covered 78 topic areas with input from representatives across the business. The tool, and the methodology for the assessment take a very similar format to the Asset Management Maturity Assessment Tool (AMMAT) (refer to section 4.7). Maturity is scored from 0 (Not Aware) through to 4 (Excellent), with a score of 3 being Competent, which is the desired level throughout.

The result of the assessment is shown below.

Figure 4.8
RMMAT results



4.11.8 Resilience as a Lifeline Utility (continued)

4.11.8.1. Resilience Management Maturity Assessment (RMMAT) (continued)

It found that we have made significant progress in embedding resilience across our operations since the last review which was completed in 2018. Notably, readiness, response, and recovery capabilities are close to industry good practice, with some response systems, such as our ability to leverage smart meter data for post-storm restoration, rated as leading best practice. However, the review highlighted that risk reduction remains an area for further development, particularly in clearly identifying and prioritising top network risks, and ensuring that mitigation strategies are robust and well documented.

Key improvement areas we intend to improve going forward include:

- Implementing a more robust critical spares policy.
- Strengthening emergency generator supply arrangements.
- Accelerating the transition of crisis management plans to align with national incident management standards.
- Establishing more formal mutual aid agreements with other network companies.
- Reassessing design standards in light of climate change.
- Documenting strategies for "building back better" after significant disruptive events.

By addressing these focus areas, Counties Energy aims to further enhance our resilience and ensure reliable service for our customers in the face of evolving risks.

Barber Road Substation

4.11.8 Resilience as a Lifeline Utility (continued)

4.11.8.2. Network Resilience

Our network is located in a relatively safe area when compared to other areas of New Zealand, with low seismic risk and limited exposure to coastal erosion or inundation, except for a few low-lying regions near the Firth of Thames and Port Waikato. While Auckland is an active volcanic zone, local volcanoes are dormant and ashfall risk from active volcanoes elsewhere in the country is considered rare due to our geographic position. A local eruption could present significant challenges, although this is very unlikely.

Weather events, especially those from the west, pose the most significant threat, with major disruptions caused by wind and storms – most notably recently in April 2018. Intense rainfall in the past has also led to landslips, which, although not network wide, can cause local disruption if the power supply is interrupted and access is blocked. The Āwhitu Peninsula and areas of our network in the North Waikato can be susceptible to this.

The primary high-impact risk events we face are severe weather or cybersecurity events, both of which are increasingly prevalent. Our strategy is to employ good asset management processes, and to have systems in place to manage these risks to our network. Section 4.11.8.1 provides our 2025 RMMAT results.

Cybersecurity is a risk to our core digital capabilities, and such an event would have impact network-wide. Our foundational approach to this is described further in section 8.3.

Severe weather on the other hand can be more localised. Our asset criticality models assess network performance in terms of customer impact should an asset be impacted, which enables us to focus resilience improvement initiatives on the most critical assets that we expect would impact the greatest number of customers during an adverse event. In recent years, specific assessments have been undertaken on certain critical assets, such as assessing flood risk for all of our zone substations and critical communications sites, as well as line clash risk on long critical spans during high wind events. Our partnership with ClimSysems (refer section 2.5.2) is building our maturity in modelling the potential impacts of climate change on our network assets, and we are also aware that our local authorities are also continuously developing their flooding and landslide assessment models. At present however, the linkages of these insights into our asset risk models is limited. We intend to improve these linkages in the near future to enable more mature modelling of resilience-related risks as well as enabling scenario modelling for varying intensities of weather-related events.

4.11.8 Resilience as a Lifeline Utility (continued)

4.11.8.3. Emergency Response and Contingency Plans

We prioritise comprehensive pre-event planning for HILP events to reduce both their likelihood and potential consequences. Our assets are engineered to maintain resilience in accordance with established security of supply, planning guidelines, and design criteria for standard operating conditions. However, natural disasters and emergency situations may exceed these specifications, potentially leading to outages or other supply-related issues.

Recognising that constructing our network to withstand major HILP events would be cost prohibitive, we have developed robust response policies, procedures, and contingency plans. Critical emergency spares are held in reserve to facilitate rapid restoration of power supply. Our contingency arrangements outline appropriate actions for anticipated incidents, such as operational strategies for loss of SCADA and communications networks, switching protocols in the event of zone substation failures, and system operator grid emergency procedures.

In evaluating network investment projects, resilience under abnormal conditions is carefully assessed during option selection. Throughout the implementation phase — particularly for projects affecting zone substations and subtransmission assets — we apply a critical infrastructure outage standard designed to minimise the probability and impact of any HILP occurrence.

4.11.9 Our Key Network Risks

Our overall assessments for our top network risks are shown below.

		1	2	3	4	5
		Minor	Moderate	Serious	Major	Severe
5	Almost Certain	Low	Medium	High	Extreme	Extreme
			(H)			
4	Likely	Low	Low	Medium	High	Extreme
				(D) (E) (F) (G)		
3	Possible	Insignificant	Low	Medium	High	Extreme
					(A) (B) (C)	
2	Unlikely	Insignificant	Low	Low	Medium	High
1	Rare	Insignificant	Insignificant	Low	Medium	Medium

Table 4.11 Network risk assessment

A) Severe storm event
B) Cybersecurity breach
C) Sudden changes in demand not supported by network capacity
D) Harm from public contacting poles (e.g. car v pole)
E) Harm from public contacting LV assets above ground
F) Harm from theft of in-service assets
G) Unclear ownership of privately owned assets
H) Inaccurate and inconsistent asset data across core systems that are used to make network decisions

4.12 Our Operational Health & Safety

Health and Safety are non-negotiable. Our Occupational Health and Safety Management System (OHSMS) emphasises proactive hazard identification, thorough risk assessment, and the implementation of effective and sustainable control measures. Safe systems of work, including permit-to-work processes, isolation procedures, live-line work protocols, and job safety analyses, are rigorously applied to ensure that every task is planned and executed safely. We invest in competency development, training, and refresher programmes to equip our workforce with the skills, knowledge, and confidence needed to work safely in complex and high-risk environments.

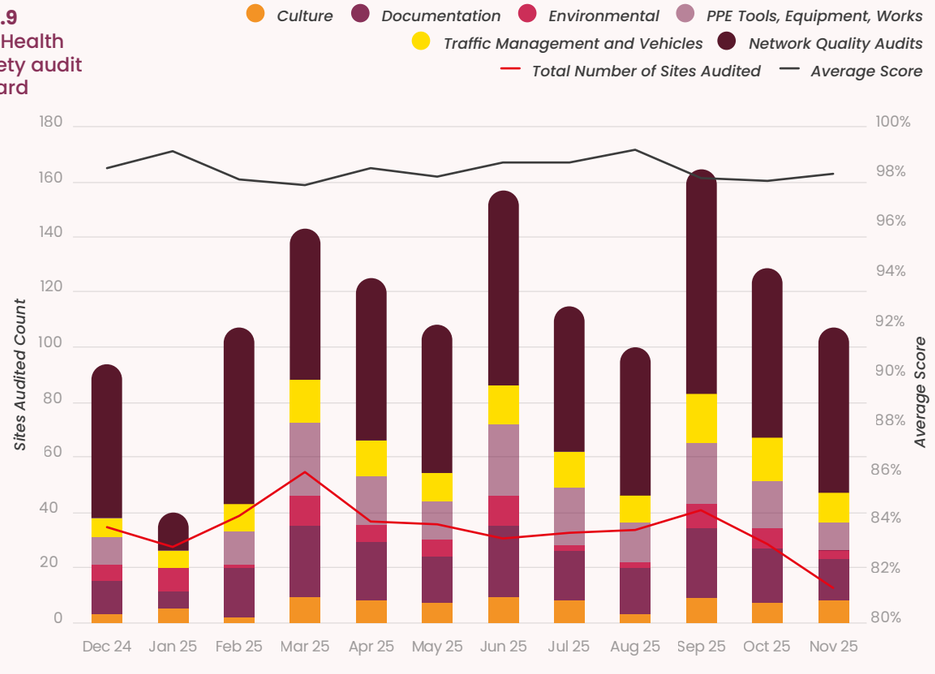
We promote a strong safety culture where individuals at all levels are empowered to speak up, stop work, or escalate concerns whenever safety may be compromised. Leadership at all levels plays an active role in reinforcing safety expectations, modelling safe behaviours, and ensuring that OHSMS responsibilities are clearly defined and understood. Our approach also recognises the importance of holistic wellbeing, incorporating fatigue management, ergonomic practices, mental health support, and wellness initiatives into daily operations.

OHSMS performance is monitored through audits, inspections, incident investigations, and real-time data analytics, enabling the identification of trends, establishing protocols to mitigate emerging risks, and optimising our safety management system. Lessons learned are shared across the organisation to foster continuous improvement. Through disciplined governance, transparent reporting, and a commitment to zero harm, we ensure that OHSMS is embedded in our asset management decision-making, ensuring safety is a key contributor to reliability, resilience, and sustainability.

Figure 4.9 is a summary of monthly internal audits that cover a range of issues tracked. The target is 100%, and we generally track at 98% or above, a pleasing result.

To ensure we are keeping up with Health & Safety standards, external safety audits are carried out to identify any gaps we may have in relation to ISO 4000, the international standard for occupational health and safety management systems and the General Risk and Workplace Management Regulations.

Figure 4.9
Internal Health and Safety audit dashboard



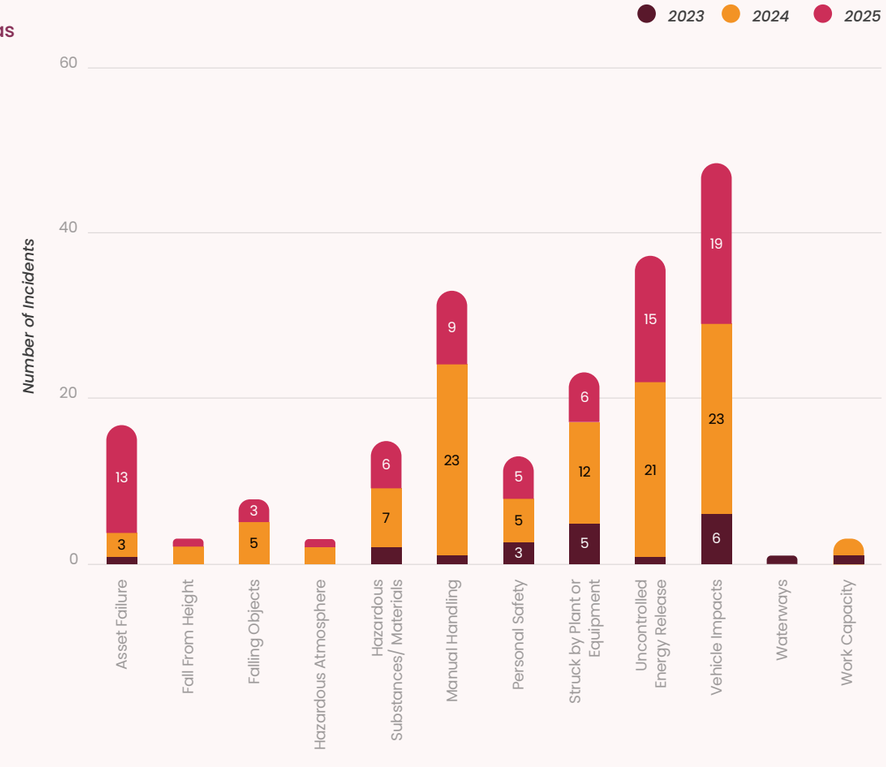
4.12 Our Operational Health & Safety (continued)

We also track critical health and safety risks. We've aligned our categories to those used by the Electrical Engineer's Association to ensure consistency with broader industry practice. This alignment allows us to benchmark our performance more effectively and strengthens the comparability of our data with national safety insights.

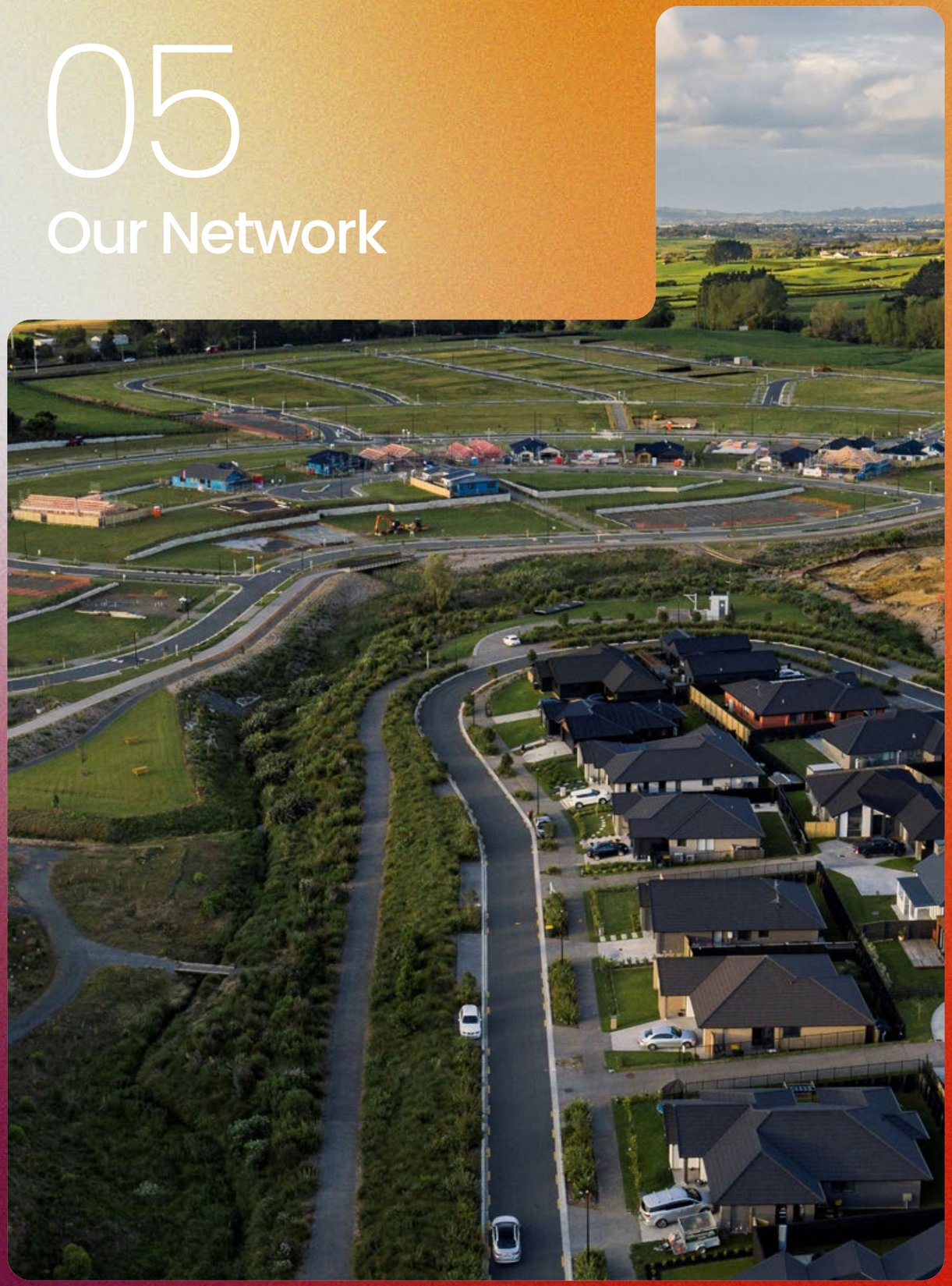
In early 2026, Counties Energy rolled out a targeted programme focused on the critical risks identified by our analysis. Through this critical risk programme, we aim to build deeper organisational awareness of high-consequence hazards, enhance frontline capability, and continue to mature our overall safety culture. These priority areas are Vehicle Impacts, Uncontrolled Energy Release, Struck-by Plant, Falling Objects, and Asset Failure. Each of these risks represents a low-frequency but high-consequence event type — incidents that, if they occur, have the potential to cause serious harm, significant asset damage, or major operational disruption.

To ensure we meaningfully uplift our safety performance, each critical risk area will be the focus of a dedicated three-month cycle. During these cycles, we will introduce and reinforce targeted procedures, communication campaigns, guidance material, and field audits tailored specifically to the risk in focus. This structured, cyclical approach will support consistent learning, help embed safer behaviours and ensure that improvements are sustained across our operations. The programme will also provide a mechanism for monitoring the effectiveness of our controls and identifying further opportunities to strengthen risk management practices.

Figure 4.10
Health and Safety critical risk focus areas



05
Our Network



5.1 About This Chapter

This chapter covers the details of our distribution network and all associated assets, including architecture, age, condition, and maintenance programmes.

5.2 Overview and Customer Distribution

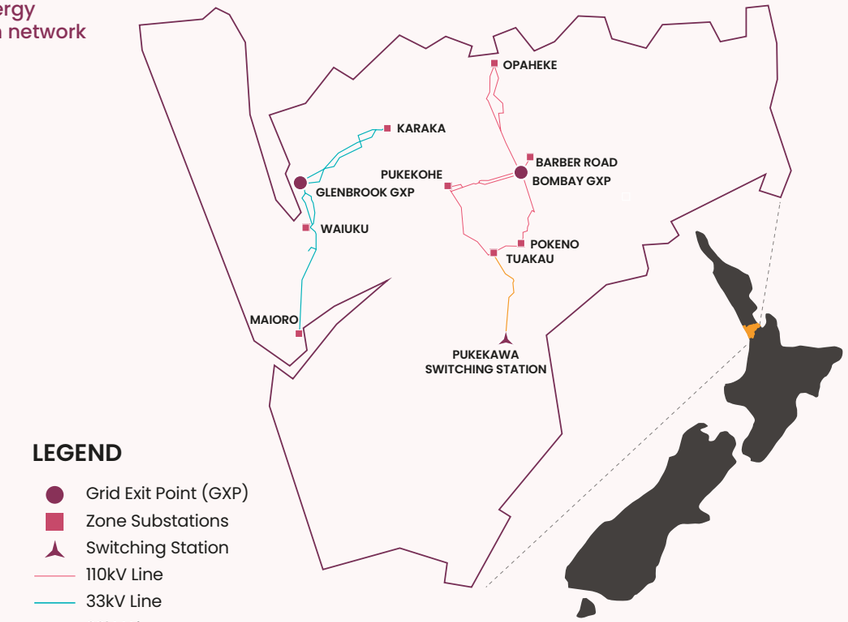
Counties Energy has two points of supply from Transpower's national grid via Grid Exit Points (GXPs) at Glenbrook and Bombay. The Glenbrook GXP supplies our western substations at 33 kV, while the Bombay GXP supplies the eastern substations at 110 kV. The number of active installations and the installed distribution capacity controlled by each GXP are shown below.

GXP	Zone Substation	Active ICPs					
		Total	Residential	Commercial	Industrial	ICPs with Distributed Generation	% of total ICPs
Bombay 110 kV	Barber Road	4,330	3,459	855	16	288	8.7
	Ōpaheke	10,829	9,795	981	53	372	21.6
	Tuakau	5,650	4,557	1,068	25	258	11.3
	Pōkeno	2,132	2,029	95	8	240	4.3
	Pukekohe	14,645	12,542	2,037	66	549	29.3
Glenbrook 33 kV	Waiuku	7,462	6,380	1,068	14	363	14.9
	Karaka	4,415	3,805	605	5	173	8.0
	Maioro	557	386	167	4	104	1.3

GXP	Zone Substation						Distribution	
		Installed Capacity (MVA)	Firm Capacity (MVA)	Load 2025 (MVA)	Total Energy Delivered to ICPs (GWh)	Energy from Distributed Generation (GWh)	Substations	Capacity (kVA)
Bombay 110 kV	Barber Road	2 x 20/40	40	12.1	60.1	3.12	833	56,271
	Ōpaheke	2 x 20/40	40	32.3	127.5	1.04	583	119,095
	Tuakau	3 x 20/40	40	12.7	143.5	50.52	796	59,922
	Pōkeno	2 x 30/40	40	12.1	35.2	0.70	52	19,690
	Pukekohe	2 x 30/60	60	38.8	168.5	1.49	729	114,535
Glenbrook 33 kV	Waiuku	2 x 10/20	20	16.6	68.1	11.94	694	54,942
	Karaka	2 x 10/20	20	13.0	37.6	0.67	492	37,540
	Maioro	2 x 7.5/9.4	9.4	8.5	48.8	0.34	121	5,895

Table 5.1 Overview of network substation and customer information

Figure 5.1 Overview of the Counties Energy subtransmission network



5.2.1 Subtransmission

Our subtransmission network consists of subtransmission lines at 110 kV from the Bombay GXP and 33 kV from the Glenbrook GXP as detailed below. The architecture of the network is typically radial subtransmission circuits connecting to buses or configured as transformer-feeders where no bus is installed.

- The Pukekohe Substation is supplied via two 110 kV lines from Bombay, with a 110 kV bus.
- The Ōpaheke Substation is supplied via two 110 kV lines from Bombay configured as transformer-feeders.
- The Barber Road Substation is supplied via two 110 kV lines from Bombay configured as transformer-feeders.
- The Tuakau and Pōkeno Substations are supplied on a ring circuit via two 110 kV lines – one from Bombay and one from Pukekohe.
- The Karaka Substation is supplied via two 33 kV lines from Glenbrook, with a 33 kV bus.
- The Waiuku Substation is supplied via two 33 kV lines from Glenbrook, with a 33 kV bus.
- The Maioro Substation is supplied via a single 33 kV line from Waiuku.

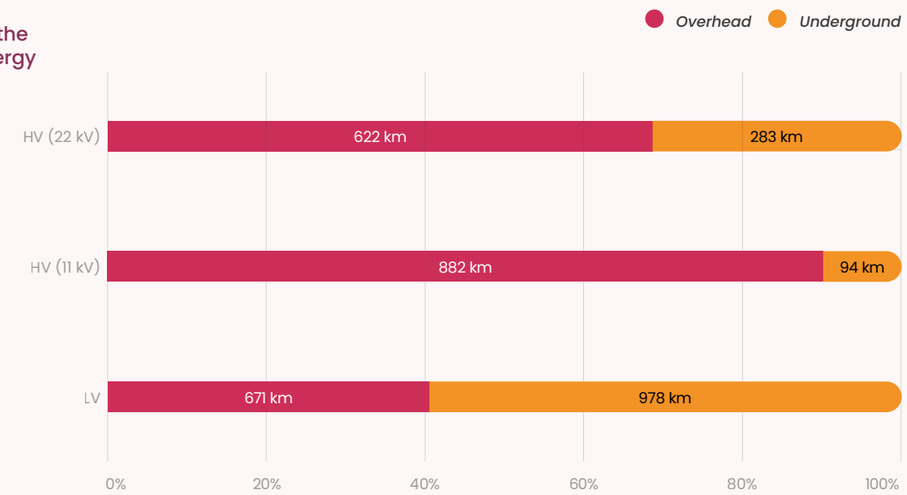
5.2.2 Distribution

Our zone substations supply 57 distribution feeders operating at 22 kV or 11 kV. The 22 kV distribution network is in our Eastern region and covers the majority of the main backbone links, with only a small number of areas still reticulated at 11 kV. The Western region operates at 11 kV. A fleet of 22 kV/11 kV transformers are used on the network to provide interconnection between circuits operating at each voltage.

Our 50,000 customers are supplied from 4,348 distribution substations. These transform the 22 kV or 11 kV distribution voltage to 400V/230V reticulation voltage and typically include distribution transformers, high-voltage fuses or circuit breakers and low-voltage fuses. These may be mounted on poles, as is often the case in rural areas, or within ground mounted units which is predominantly the case in urban areas.

The figure below shows the circuit length and ratio of overhead to underground networks by operating voltage.

Figure 5.2
Overview of the Counties Energy distribution network



5.3 Our Assets

The condition of our network assets is systematically monitored and assessed using a structured approach. For all network assets, we model the present asset health, which is presented in this section and reported in our Information Disclosure schedules (12a). Our Asset Health Indicator (AHI) scores and age parameters are set in accordance with Electricity Engineers Association (EEA) AHI grades.

For certain asset groups, we rely on age-based evaluations, enhanced with condition information where available, whereas for others we apply a risk-based framework that incorporates a range of factors. Notably, we have built ARMM models (refer 6.4.5.4) for selected asset classes. This industry-recognised methodology enables us to determine and forecast future asset health by considering performance, safety, cost implications, and environmental impacts in a consistent manner.

By integrating ARMM and other data-driven tools, we attain a comprehensive understanding of asset health across the network. This process allows us to prioritise maintenance, repairs, and replacements based on a thorough risk assessment. As our risk modelling capabilities mature with the accumulation of additional or higher quality asset data, we can further refine our decision-making regarding the timing and scope of necessary interventions.

For this AMP, our asset health reporting for distribution (22/11 kV) and LV lines, distribution poles and distribution crossarms is now driven by our ARMM models. This change is explained in more detail in section 5.3.3. All other asset classes use our more traditional asset health models for now, although many of these will transition to ARMM in the future.

AHI Score		Description	Probability of Failure
H1		End-of-life (EOL)	Very High
H2		EOL drivers present	High
H3		Onset of reliability	Medium
H4		Normal in-service deterioration	Low
H5		As new	Unusual

Table 5.2 Asset condition – AHI scores

5.3.1 Subtransmission

5.3.1.1. Subtransmission Lines and Structures

The subtransmission network carries electricity from Transpower's Grid Exit Points to zone substations. We have a total of 122.17 km of subtransmission lines on the network, consisting of the following types:

- All Aluminium conductor;
- All Aluminium Alloy Conductor (AAAC); and
- Aluminium Conductor Steel Reinforced.

The lines are supported by the following

- Concrete Poles;
- Wood Poles;
- Steel poles;
- Pre-stressed concrete poles (PSCP); and
- Steel Lattice Towers.

5.3.1 Subtransmission (continued)

5.3.1.1. Subtransmission Lines and Structures (continued)

Our 110 kV subtransmission lines are generally newer than our 33 kV lines, with the earliest having been installed in the mid-1990s. Intermediate poles on the 110 kV lines generally use insulators directly mounted to the poles, therefore requiring no crossarms. Termination and angles structures, however, do often use crossarms, which are usually steel. The 33 kV lines in the Western region are generally older and have a design similar to our conventional distribution structures.

We have a short (~3 km) subtransmission line which is supported by nine steel lattice towers that were originally installed in 1929. All of these towers underwent full refurbishment between 2023 and 2024, during which the original copper conductors were replaced with AAAC conductors. The project was successfully completed in September 2025.

Asset	Type	Quantity	Life Expectancy	Average Age
Subtransmission Structures	Concrete Poles	694	80 Years	33 Years
	Wood Poles	2	45 Years	50 Years
	Steel Poles	196	55 Years	11 Years
	PSCP	465	80 Years	23 Years
	Other	4	55 Years	11 Years
	Steel Lattice Towers	9	80 Years	96 Years
33 kV Conductor	AAC	55.39 km	80 Years	43 Years
	ACSR	0.51 km	60 Years	59 Years
110 kV Conductor	AAC	63.25 km	80 Years	21 Years
	AAAC	3.02 km	80 Years	1 Year
Crossarms	Wood	769	45 Years	42 Years
	Steel	709	80 Years	15 Years
	Other	1	55 years	29 Years

Table 5.3 Asset summary – subtransmission lines and structures

5.3.1 Subtransmission (continued)

Subtransmission Line - Age

Figure 5.3 Age profile – Subtransmission Line

Subtransmission Line – AHI Score

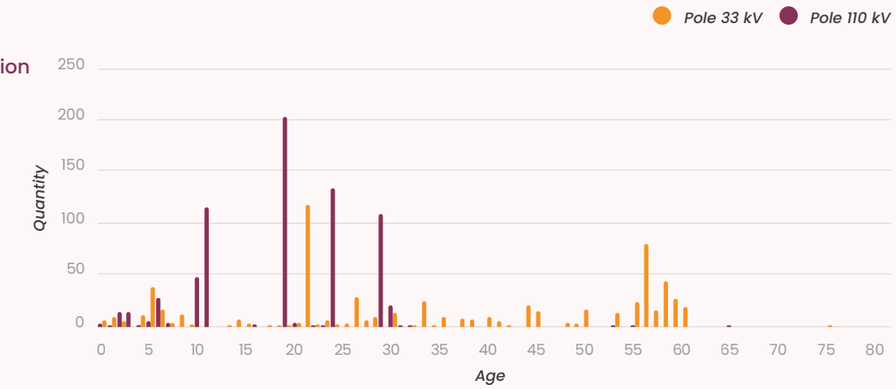
Figure 5.4 Asset health profile – Subtransmission Line

Mostly all of our subtransmission cables are in an 'as new' condition, reflecting the relatiely young age of assets in this class. The oldest subtransmission cable installed on our network was installed in 1986.

5.3.1 Subtransmission (continued)

Subtransmission Poles and Structures - Age

Figure 5.5 Age profile – Subtransmission Poles and Structures



Subtransmission Pole – AHI Score

Figure 5.6 Asset health profile – Subtransmission Poles and Structures

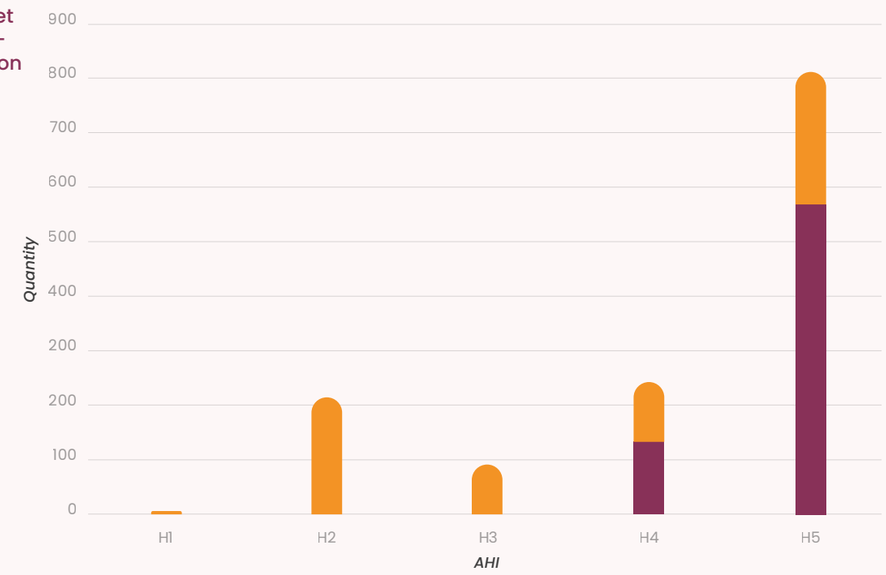


Figure 5.6 shows that the majority of our subtransmission poles and structures are in 'as new' or good condition. As with subtransmission lines, our 110 kV networks are generally newer than our 33 kV networks, which is reflected in the graph. The assets highlighted within the H2 band are made up of older assets that have a range of emerging condition concerns that have been identified during our maintenance inspections (such as concrete starting to spall). These will be attended to in the planning period as part of our defect remediation strategy.

5.3.1 Subtransmission (continued)

5.3.1.2. Subtransmission Cable

We have a total of 1.2 km of subtransmission cables on the network consisting of the following types.

- 33 kV Aluminium Cross-linked polyethene (XLPE);
- 33 kV Copper Cross-linked polyethene (XLPE); and
- 110 kV Aluminium Cross-linked polyethene (XLPE).

These cables exist only at the last sections closest to our newer substations, as the older substation designs typically involve overhead lines terminating directly to outdoor switchyards. As a result, the population is small and the average age relatively young.

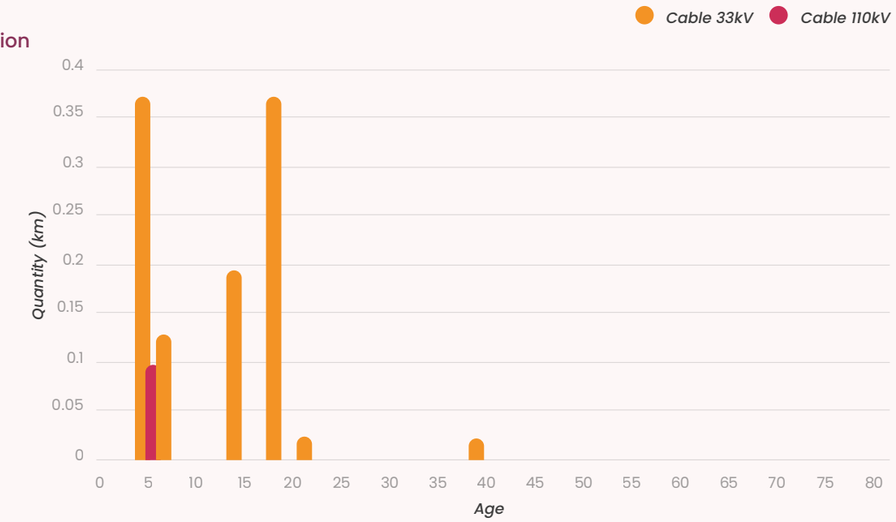
Asset	Type	Quantity	Life Expectancy	Average Age
Subtransmission Cable	33 kV Al XLPE	0.97 km	55 Years	17 Years
	33 kV Cu XLPE	0.15 km	55 Years	14 Years
	110 kV XLPE	0.09 km	55 Years	6 Years

Table 5.4 Asset summary – subtransmission cable

5.3.1 Subtransmission (continued)

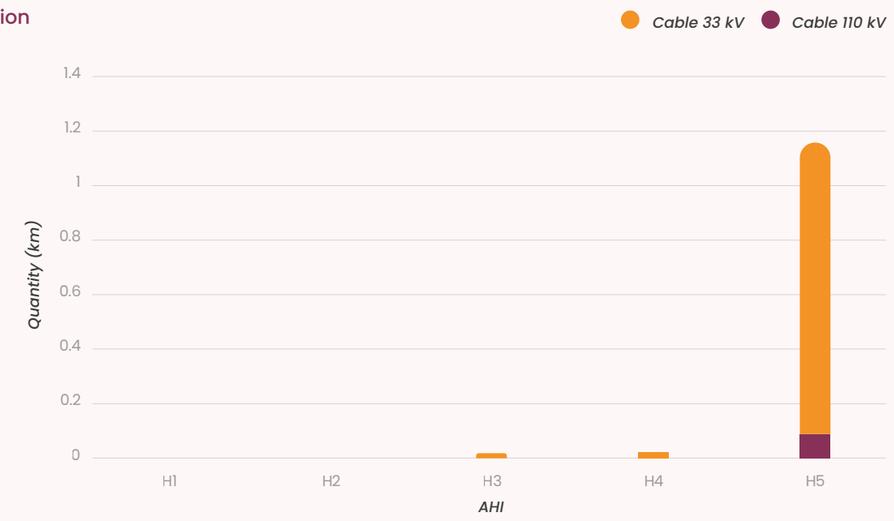
Subtransmission Cables – Age

Figure 5.7 Age profile - Subtransmission Cable



Subtransmission Cables – AHI Score

Figure 5.8 Asset health profile - Subtransmission Cable



5.3.2 Zone Substations

Zone substations form the critical interface between the subtransmission network and the distribution network, receiving electricity from Transpower Grid Exit Points. These substations typically comprise:

- A substation building and associated yard;
- Power transformers, and;
- Switchgear, located either indoors or outdoors.

Power transformers reduce subtransmission voltages (commonly 110 kV or 33 kV) to distribution levels of 22 kV or 11 kV, enabling safe and efficient delivery to downstream networks.

Switchgear provides essential functionality for network protection and operational flexibility, ensuring safe isolation and fault management across the system.

5.3.2.1. Zone Substation Buildings and Grounds

We operate eight zone substations and one switching station across the network, with the latter not containing any power transformers. The system is divided into two distinct regions, the Eastern Network, operating at 110 kV/22 kV; and the Western Network, operating at 33 kV/11 kV.

Western Network 33 kV /11 kV	Eastern Network 110 kV/22 kV
Waiuku Substation	Ōpaheke Substation
Maioro Substation	Tuakau Substation
Karaka Substation	Pōkeno Substation
	Pukekohe Substation
	Barber Road Substation
	Pukekawa Switching Station

Table 5.5 Counties Energy network regions

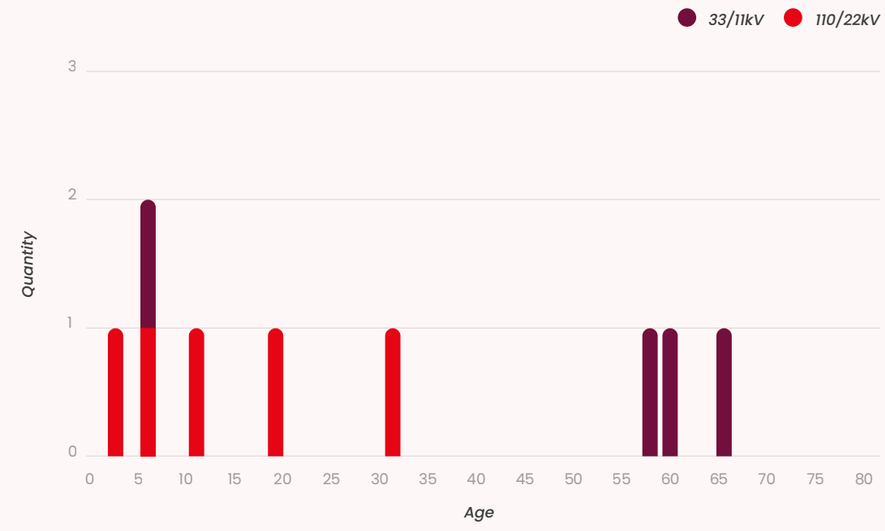
Three of our zone substation buildings are recently constructed and meet all modern standards. Three more are slightly older, dating from the last 20 years and, although in good condition, require or required some remedial works to improve seismic resilience. This work is either complete or in the upcoming plan. The remaining three are of older Franklin Electric Power Board designs. Of these, the Pukekawa switching station underwent a comprehensive refurbishment and upgrade in 2024 to meet seismic Importance Level 4 (IL4) standards. As a result, its asset health classification improved from H1 to H3, reflecting enhanced structural resilience and compliance.

Conversely, the Maioro Substation building remains at an H1 health rating, primarily due to its age and insufficient seismic resilience. We plan to address this risk in the 2027 financial year. The decision to rebuild or demolish will be made in due course, depending on discussions with a key industrial customer that is supplied from the site. The Karaka Substation will be retired in the planning period.

5.3.2 Zone Substations (continued)

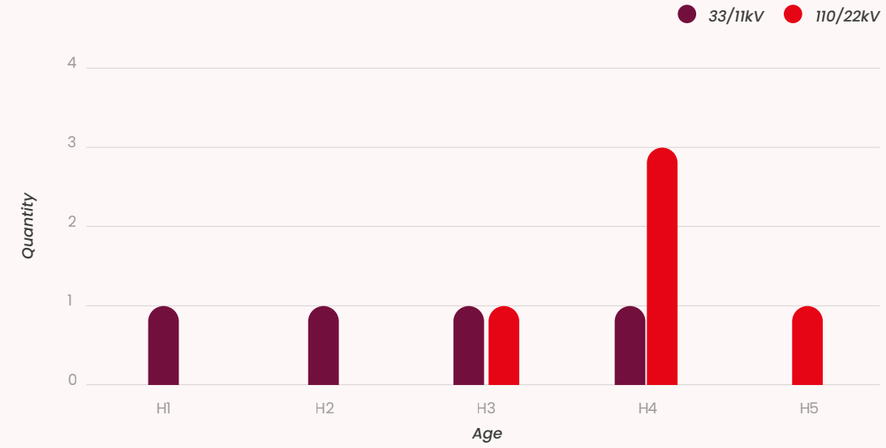
Zone Substation Building and Grounds – Age

Figure 5.9 Age profile – zone substation buildings and grounds



Zone Substation Building and Grounds - AHI

Figure 5.10 Asset health profile – zone substations buildings and grounds



5.3.2 Zone Substations (continued)

5.3.2.2. Power Transformers

Power transformers at our zone substations perform a critical function by stepping down subtransmission voltages (110 kV or 33 kV) to distribution voltages (22 kV or 11 kV).

We currently operate 17 power transformers across the network, with installation dates ranging from 1967 to 2022. Units installed prior to 1996 were predominantly 33/11 kV transformers.

Since 1996, eleven 110/22 kV transformers have been commissioned to support the strategic conversion of the Eastern Region to 110 kV subtransmission and mostly 22 kV distribution voltage. In 2022, a third 110/22 kV transformer was installed at Tuakau substation, serving as a critical spare for the 110/22 kV fleet. Similarly, a critical spare for the 33/11 kV fleet was installed at Waiuku substation.

As part of the Eastern area development programme, transformers at Ramarama and Mangatāwhiri Substations were retired following the establishment of the Barber Road Substation.

Recent condition assessments have resulted in health classification adjustments for transformers at Maioro and Karaka Substations moving from H1 to H2, reflecting a more comprehensive evaluation of condition factors beyond age alone.

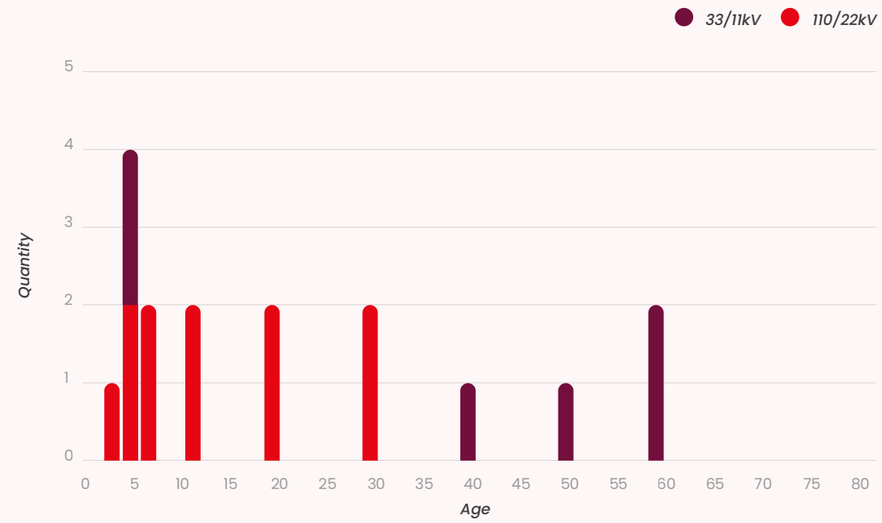
Transformers currently rated H2 include:

- Maioro T1 and T2 – Two 33/11 kV 7.5/9.4 MVA transformers at Maioro Substation. These are forecast to reach end-of-life within the planning period. The chosen replacement solution is dependent on discussions with a key industrial customer that is supplied from the site, but these are planned to be addressed in FY32.
- Karaka T2 – Two 33/11 kV 10/20 MVA transformers at Karaka Substation, providing n-1 capacity of 20 MVA. This site will be superseded by the proposed Waiau Pa Substation, due to be commissioned in FY30, which will see these transformers retired.

5.3.2 Zone Substations (continued)

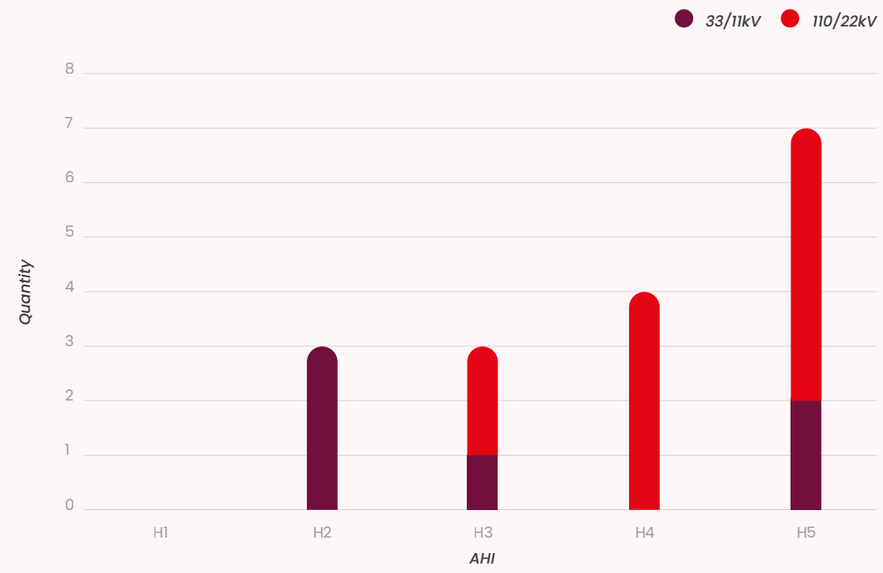
Zone Substations Power Transformers – Age

Figure 5.11 Age profile – power transformers



Zone Substations Power transformers - AHI Score

Figure 5.12 Asset health profile – power transformers



5.3.2 Zone Substations (continued)

5.3.2.3. Zone Substation Switchgear

Zone substation switchgear is a crucial component of the electrical network, responsible for controlling, isolating, and protecting circuits within a substation. Switchgear assemblies typically include circuit breakers and isolation switches and are closely integrated with current and voltage transformers. These transformers interface with protection relays, enabling precise monitoring and rapid response to faults, thereby ensuring effective electrical protection for the network.

There are two primary types of zone substation switchgear based on their installation environment and voltage class: outdoor and indoor. Outdoor switchgear is predominantly used for higher voltage applications, specifically for 33 kV and 110 kV systems. These installations are designed to withstand environmental exposure and are often found in open-air switchyards.

Indoor switchgear, on the other hand, is utilised for 11 kV and 22 kV applications. Historically, indoor switchgear was constructed using oil as the interrupting medium. However, this design has largely been superseded by the industry to improve maintenance intensity and safety. The newer generation of indoor switchgear employed SF_6 (Sulfur hexafluoride) gas, which offered improved reliability and a reduced footprint. More recently, vacuum interrupter technology has become the industry standard for new installations, offering enhanced operational safety, lower environmental impact, and reduced ongoing maintenance requirements.

The majority of subtransmission switchgear is outdoor switchgear. Over the past few years, we have replaced all our outdoor oil circuit breakers with SF_6 gas circuit breakers. These oil circuit breakers had exceeded their expected service life, require intensive maintenance and are no longer available for replacement parts. In 2019, we installed an indoor 110 kV gas-insulated switchgear at the Pōkeno substation.

The 33 kV outdoor switches have health scores of H2 at Karaka and Maioro Substations. Karaka Substation 33 kV switches will be replaced in FY30 with Waiau Pa substation while replacements for substation switches are planned alongside the transformer replacements in FY32.

Indoor switchgear has been used for all 11/22 kV applications. Indoor switchgear has a smaller footprint, is contained within an appropriate building, and is generally more reliable than outdoor switchgear.

The new switchboards commissioned at the Waiuku Substation in 2019, Pōkeno Substation in 2020 and Barber Road Substation in 2021, feature arc flash venting and arc flash dedication to quickly isolate arc faults and significantly reduce the operation safety risk to our field staff from an internal switchboard failure.

The 22 kV switchgear at our Ōpaheke substation is under replacement and work is expected to be completed by the end of 2026.

The switchgear at the Maioro Substation and its associated control equipment are at end-of-life, are among the last remaining of their type in New Zealand, and have very few spare parts available to keep them operational. It is also our last remaining site using oil filled circuit breaker units, which present higher risks to our operators as the consequences of failure are much higher than more modern designs. As such, its health score is reported as H1 and replacement is planned for FY27/FY28.

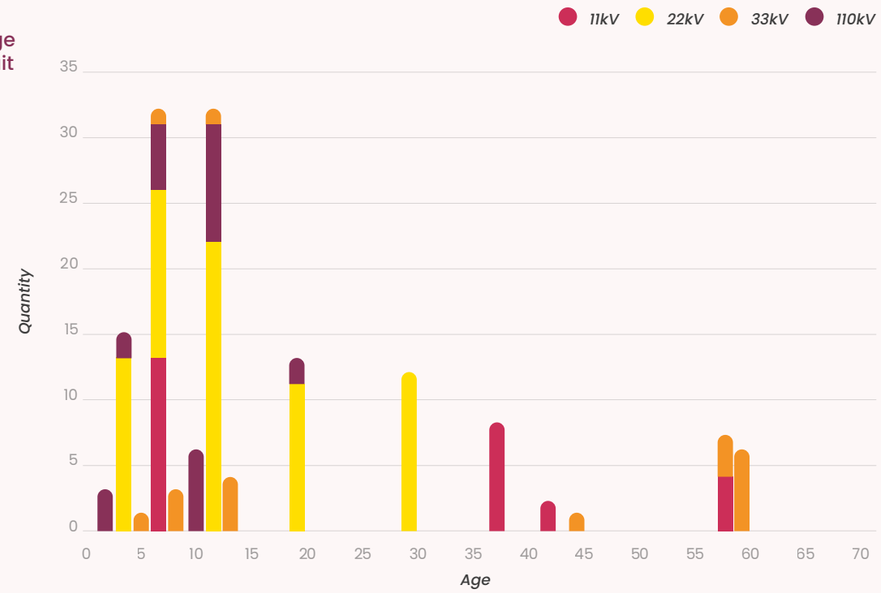
The Karaka Substation switchgear's health score is reported as H2 and will be superseded in FY30 with development of Waiau Pa Substation.

5.3 Our Assets (continued)

5.3.2 Zone Substations (continued)

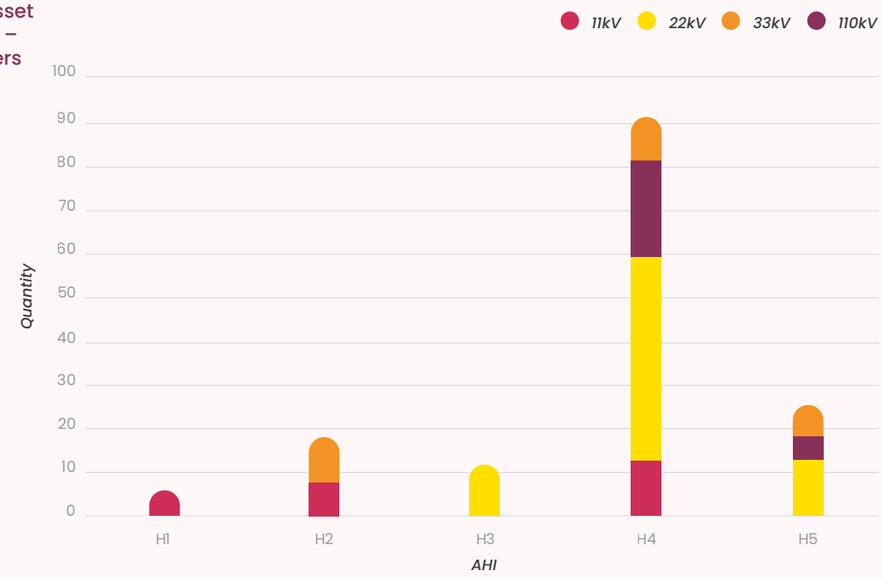
Substation Circuit Breakers and Switches – Age

Figure 5.13 Age profile – circuit breakers and switches



Substation Circuit Breakers and Switches – AHI Score

Figure 5.14 Asset health profile – circuit breakers and switches



5.3.2 Zone Substations (continued)

5.3.2.4. Auxiliary Battery Banks

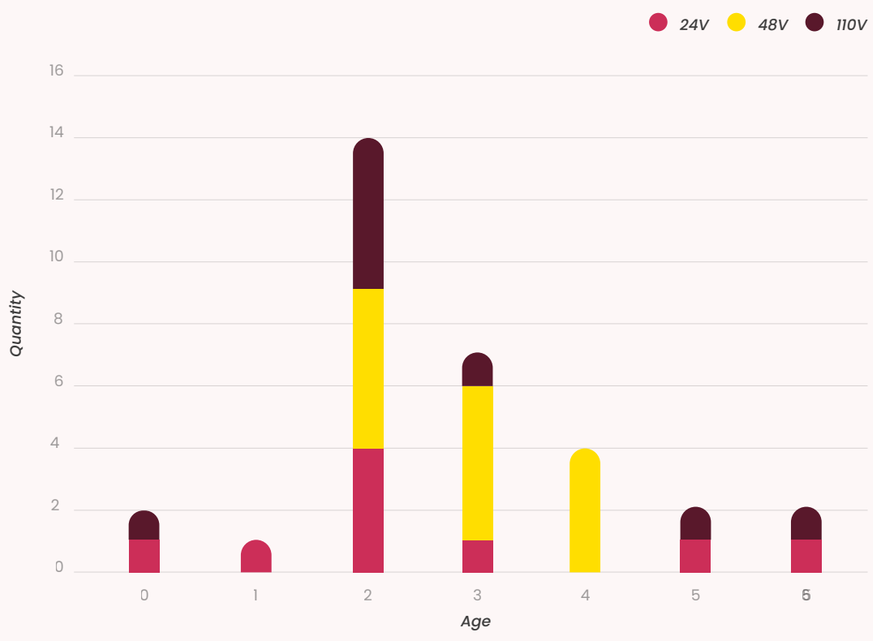
110 V, 48 V, and 24 V DC battery banks are installed in our network to supply power to the protection schemes, control and metering equipment, and components (such as circuit breaker operating coils) that require DC power to operate.

They are the most critical asset on the network, as critical protection and communications systems rely on them during system events. We manage them accordingly with regular time-based replacement programmes, which is reflected in their age and health.

We have 32 battery banks installed on our network, with installation dates ranging from 2009 to 2018. We have nine units of 110V battery banks, 14 units of 48V battery banks, and nine units of 24V battery banks.

Battery Bank – Age

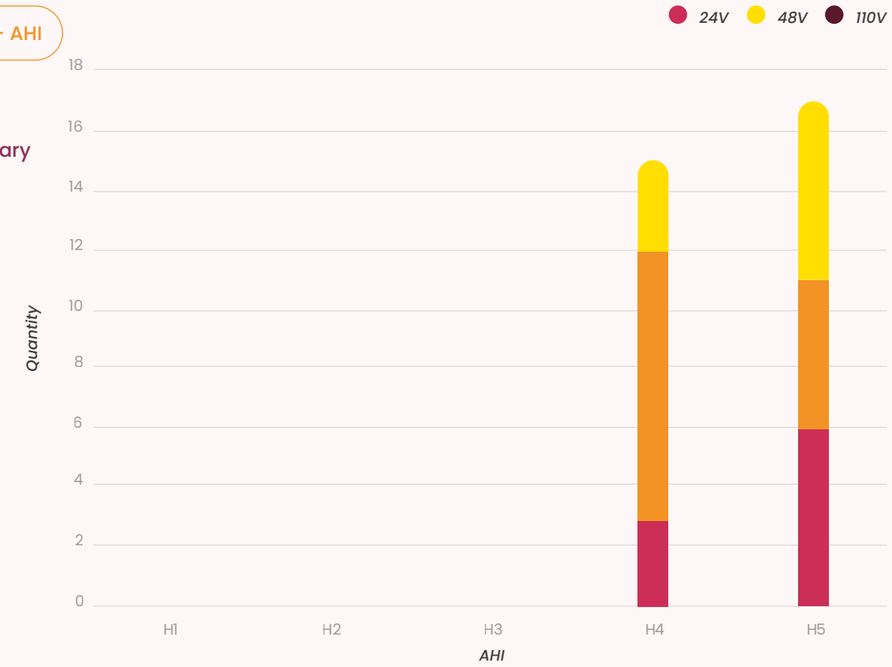
Figure 5.15 Age profile – auxiliary batteries



5.3.2 Zone Substations (continued)

Battery Bank - AHI

Figure 5.16 Asset health profile – auxiliary batteries



5.3.3 Distribution (22/11 kV) and LV Lines

Electricity is supplied to customers from zone substations through a high-voltage distribution network operating at 22 kV and 11 kV. Downstream, power is delivered via a 400 V low-voltage (LV) network, comprising both overhead lines and underground cables.

As the conversion of the Eastern Region network from a traditional 11 kV network to 22 kV network started in the 1990s, this required the replacement of insulators, as well as many (but not all) poles and crossarms. As such, typically the high-voltage networks operating at 22 kV are newer, stronger, and in better health than the 11 kV networks.

> **In the last five years, we have invested heavily in distribution replacement, including in the Eastern Network Development Programme around the Barber Road Substation.**

As a result, asset health on our high-voltage networks, especially our backbone networks, is improving. The conductors on much of our backbone network are also newer AAC or AAAC types. The older copper and ACSR types are usually found on the lower-criticality spur lines.

Our network includes a significant number of overhead assets, which inherently present higher exposure to environmental risks and increased maintenance requirements. As the highest volume asset class representing the bulk of our investment, this was the first asset class we focused on when developing our Asset Risk Management Models (refer to section 6.4.5.4).

5.3.3 Distribution (22/11 kV) and LV Lines (continued)

Asset	Type	Quantity	Life Expectancy	Average Age
Poles	Concrete/Steel	24,524	80 Years	29 Years
	Wood	1,663	45 Years	20 Years
	Other	83	45 Years	17 Years
Crossarms	Wood	29,921	45 Years	30 Years
	Steel	11,854	80 Years	11 Years
	Other	169	80 Years	35 Years
22 kV Conductors	AAC	335.79 km	80 Years	31 Years
	AAAC	70.93 km	80 Years	27 Years
	ACSR	162.36 km	80 Years	44 Years
	Copper	49.19 km	65 Years	57 Years
	Unknown	4.03 km		15 Years
11 kV Conductors	AAC	290.64 km	80 Years	32 Years
	AAAC	126.75 km	80 Years	24 Years
	ACSR	335.47 km	80 Years	45 Years
	Copper	123.49 km	65 Years	50 Years
	Unknown	6.07 km		20 Years
LV Conductors		670.63 km	80 Years	27 Years[2]

Table 5.6 Asset summary – distribution and LV lines

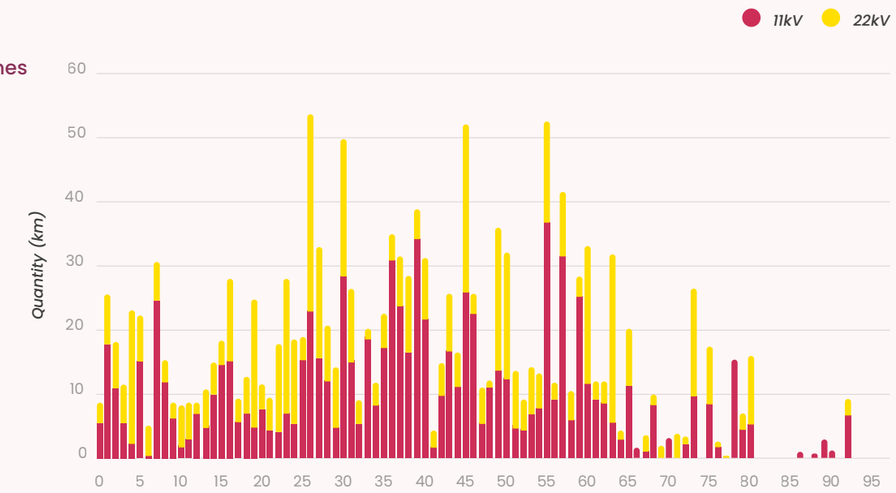
2 Note: 562 km of our LV conductor has an unknown installation date (but likely prior to 1997). The average age of 27 years only reflects known information.

5.3 Our Assets (continued)

5.3.3 Distribution (22/11 kV) and LV Lines (continued)

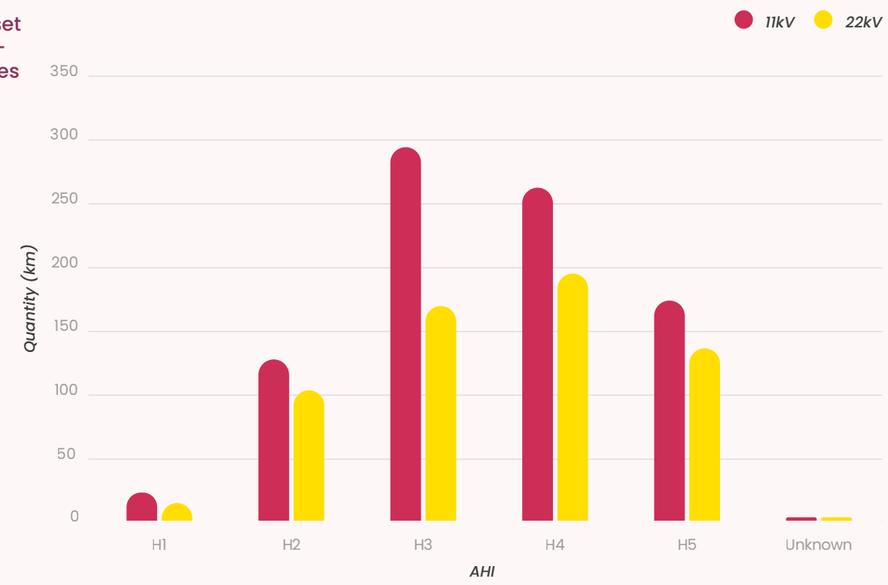
Distribution Lines – 11 kV and 22 kV – Age

Figure 5.17 Age profile – distribution lines



Distribution Lines – 11kV and 22kV – AHI Score

Figure 5.18 Asset health profile – distribution lines



5.3.3 Distribution (22/11 kV) and LV Lines (continued)

Distribution Lines – 11kV and 22kV – Health Comparison with CNAIM Modelling

Figure 5.19
Asset health profile using CNAIM modelling for distribution lines

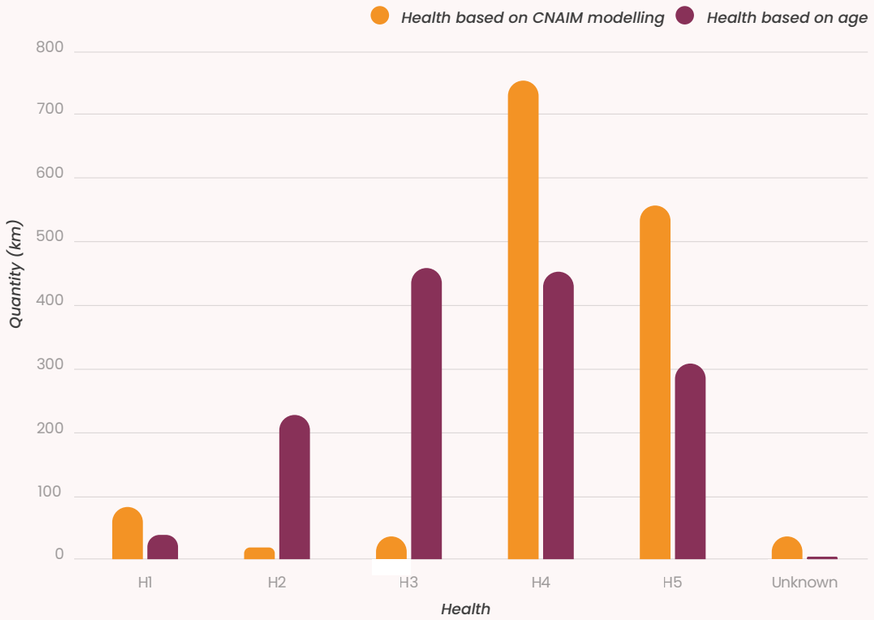


Figure 5.19 illustrates the change in asset health outcomes that results from the transition from our previous Asset Health Index (AHI) methodology to the CNAIM-aligned (Common Network Asset Indices Methodology) Asset Risk and Maintenance Model (ARMM). Under the former AHI approach, asset health was driven largely by age, with condition acting as a secondary modifier. The CNAIM method places significantly greater emphasis on observed condition and asset-specific factors, including location-specific modelling effects, as described further in section 6.4.5.4. As a result, older assets with no reported condition issues are now presenting as being in better relative health than under the age-driven approach, providing a more realistic reflection of actual network condition.

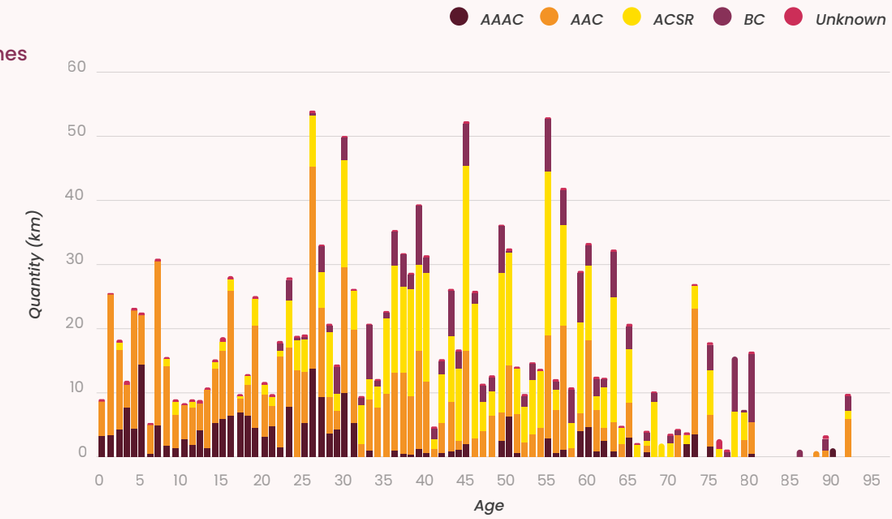
Conversely, older assets with moderate or poor condition performance are more clearly differentiated and are now more likely to present with a health-score of H1, ensuring emerging risk is appropriately highlighted. For distribution lines, this is typically driven by condition evidence such as atmospheric or galvanic corrosion, broken strands, conductor bird-caging, or a high number of joints within a span, the latter indicating repeated historic repairs. Overall, this shift demonstrates how our ARMM modelling improves health profile accuracy by amplifying the impact of condition information over simpler age-based methods, supporting more targeted and risk-informed investment decisions. Our sizeable Overhead High Voltage Conductor Renewal Programme (refer chapter 7) will address these low health assets, prioritised by risk, over the planning period – driven but the outputs of our ARMM model.

5.3 Our Assets (continued)

5.3.3 Distribution (22/11 kV) and LV Lines (continued)

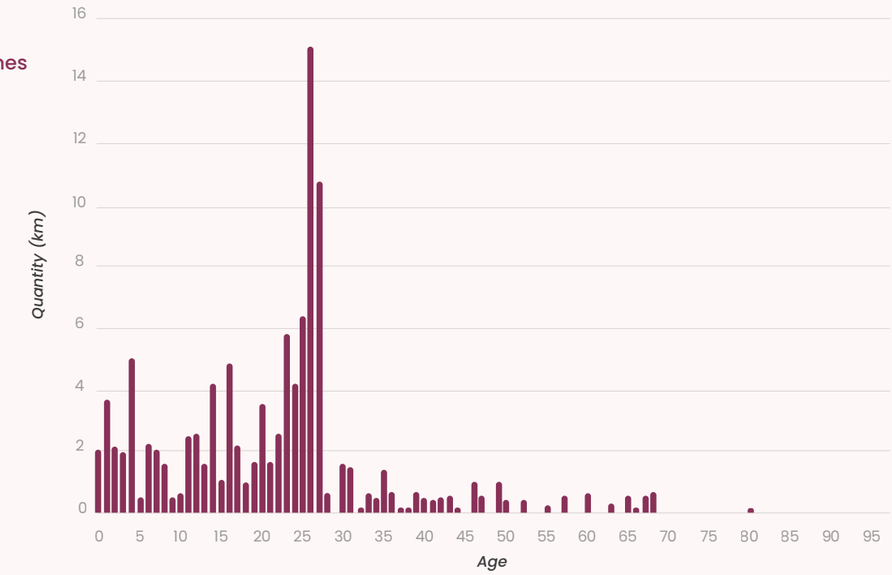
Distribution Lines - By Conductor Type -Age

Figure 5.20
Age profile – distribution lines by conductor



Distribution Lines – Low Voltage – Age

Figure 5.21
Age profile – distribution lines low voltage



There are around 562 km of low-voltage lines (out of our total population of 671 km) for which the installation age is unknown.

5.3.3 Distribution (22/11 kV) and LV Lines (continued)

Distribution Lines – Low Voltage – AHI Score

Figure 5.22 Asset health profile – distribution lines low voltage

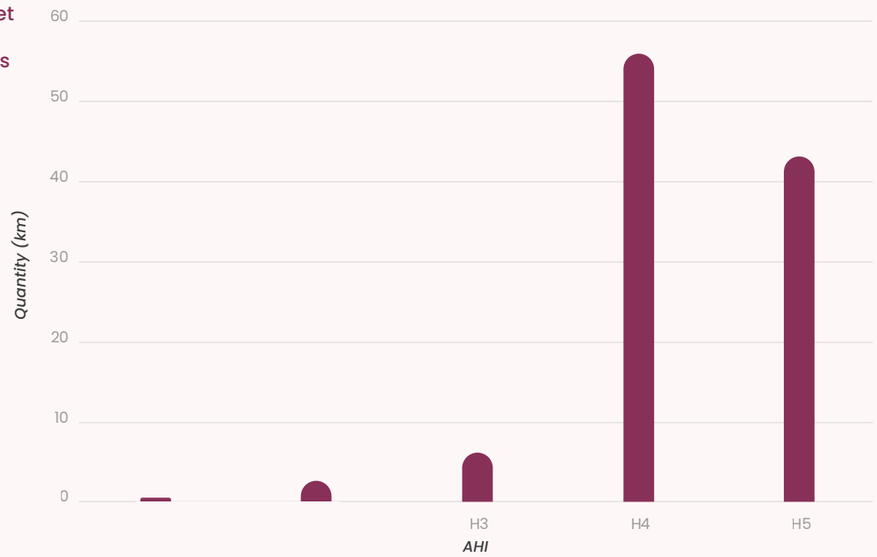


Figure 5.22 presents the asset health profile for low voltage distribution lines, based on a combination of available age and condition information, and shows that the majority of the fleet is currently assessed as being in good health. However, a significant proportion of LV lines installed prior to 1997 have limited or unknown age data, representing a key gap in our asset information. As a result, health assessment for this asset class relies more heavily on observed condition than age. Improving the completeness and accuracy of LV line age information is therefore a focus area going forward and will further enhance the robustness of health and risk modelling for this part of the network.

5.3.3 Distribution (22/11 kV) and LV Lines (continued)

5.3.3.1. Distribution Poles and Crossarms

Our electricity distribution network comprises more than 26,000 poles, with approximately 93% constructed from concrete — a material that has been the preferred choice since the 1940s. The remaining poles are made from hardwood, softwood, and iron rail.

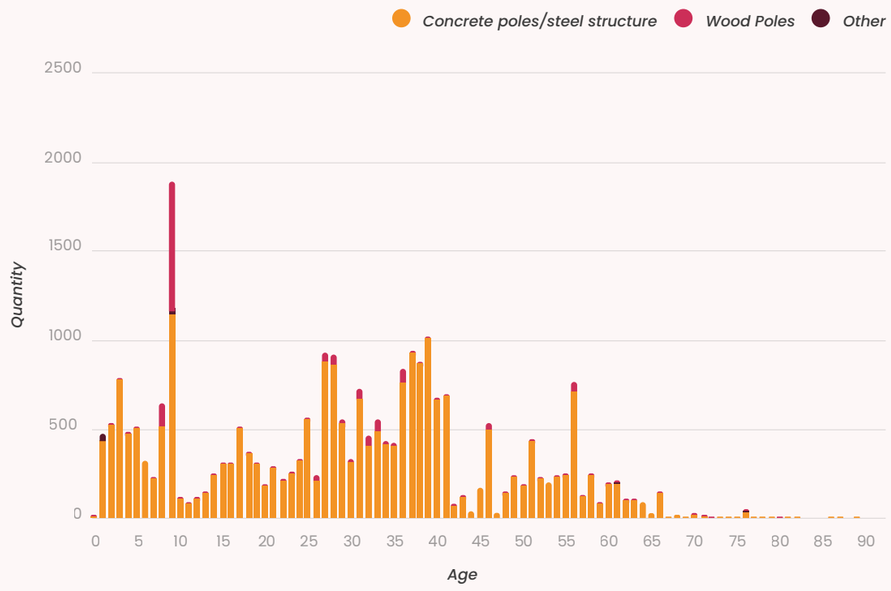
Crossarms, which support the overhead conductors, are primarily manufactured from wood or steel, with a small proportion from fibreglass. Since 2020, steel crossarms have been adopted for high-voltage circuits, 11 kV and 22 kV, as part of our network resilience improvements. These steel designs provide increased conductor spacing, reducing the likelihood of outages caused by conductor clashing or debris entanglement. Hardwood crossarms continue to be used on low-voltage lines.

> Over the past 25 years, the distribution network has undergone significant growth and renewal, with systematic replacement of aging assets to maintain reliability and safety standards.

5.3.3 Distribution (22/11 kV) and LV Lines (continued)

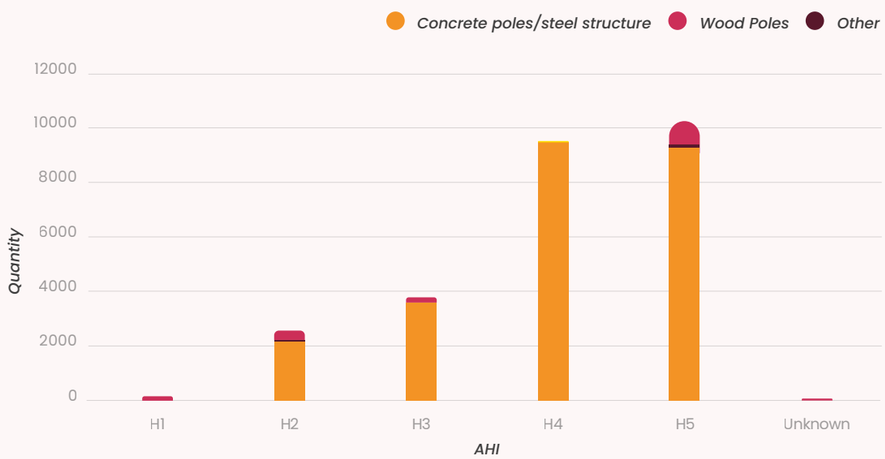
Distribution Poles – Age

Figure 5.23 Age profile – distribution poles



Distribution Poles – AHI Score Based on Age

Figure 5.24 Asset health profile – distribution poles



5.3.3 Distribution (22/11 kV) and LV Lines (continued)

Distribution Poles - Health Comparison with CNAIM Modelling

Figure 5.25 Asset health profile using CNAIM modelling for distribution poles

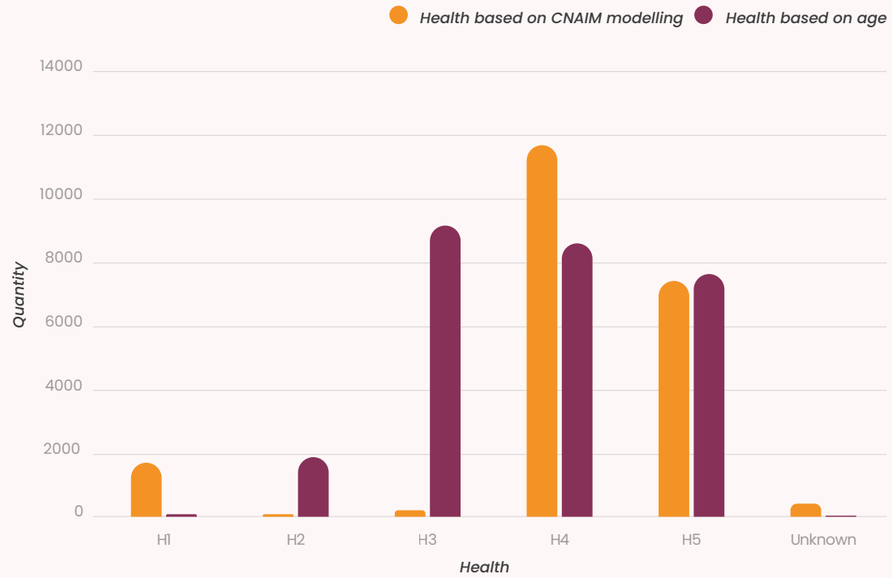
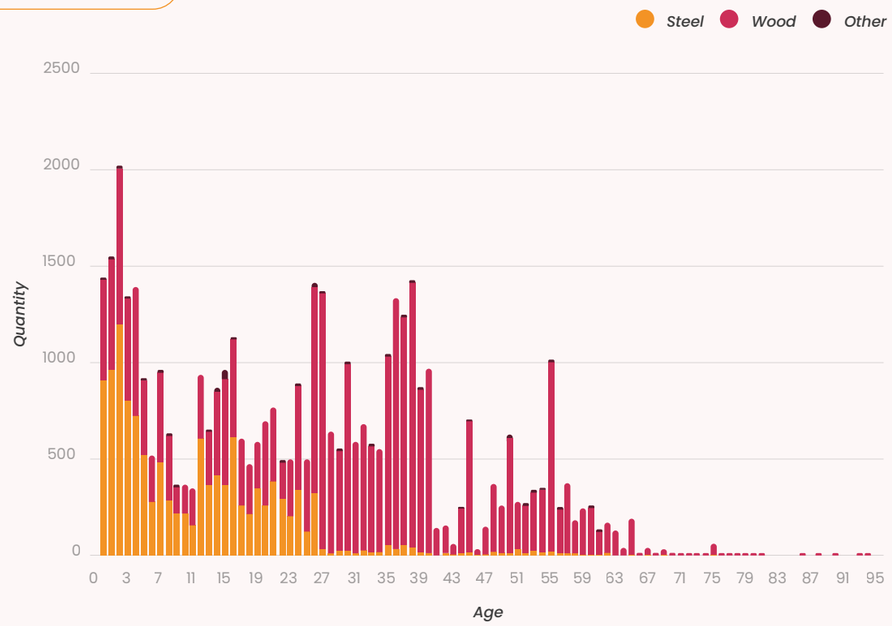


Figure 5.25 presents the asset health profile for distribution poles and, like distribution and LV lines, reflects a similar shift in outcomes resulting from the transition from the previous AHI methodology to the CNAIM-aligned ARMM approach. As with other asset classes, the earlier AHI relied primarily on age, with condition acting as a secondary input, whereas the ARMM method places greater emphasis on observed condition and incorporates location-specific modelling effects. This results in older poles with no recorded condition issues now presenting as being in better relative health, while poles with moderate or poor condition are more clearly differentiated and more likely to present with a health score of H1. For distribution poles, this is typically driven by condition observations such as concrete cracking or spalling, which indicate deterioration affecting structural capacity. Within the planning period, our defect remedial strategy will target the lowest health poles, prioritised by risk. In addition, the sizeable Overhead High Voltage Conductor Renewal Programme (refer Chapter 7) will result in a reasonable number of older poles being replaced to meet updated construction and loading standards, providing further improvement to overall pole health across the network.

5.3.3 Distribution (22/11 kV) and LV Lines (continued)

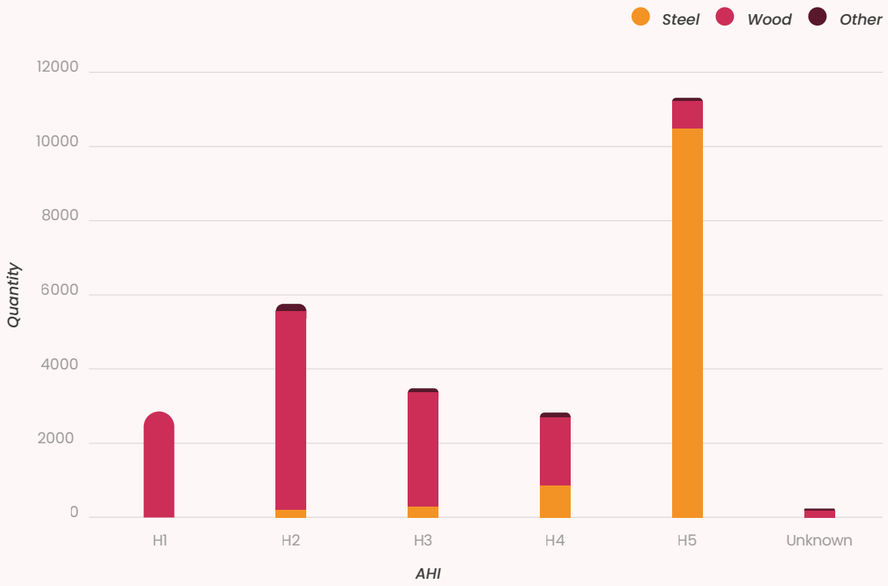
Distribution Crossarms – Age

Figure 5.26 Age profile - distribution crossarms



Distribution Crossarms – AHI Based on Age

Figure 5.27 Asset health profile - distribution crossarms



5.3.3 Distribution (22/11 kV) and LV Lines (continued)

Distribution Crossarms – Health Comparison with CNAIM Modelling

Figure 5.28 Asset health profile using CNAIM modelling for distribution crossarms

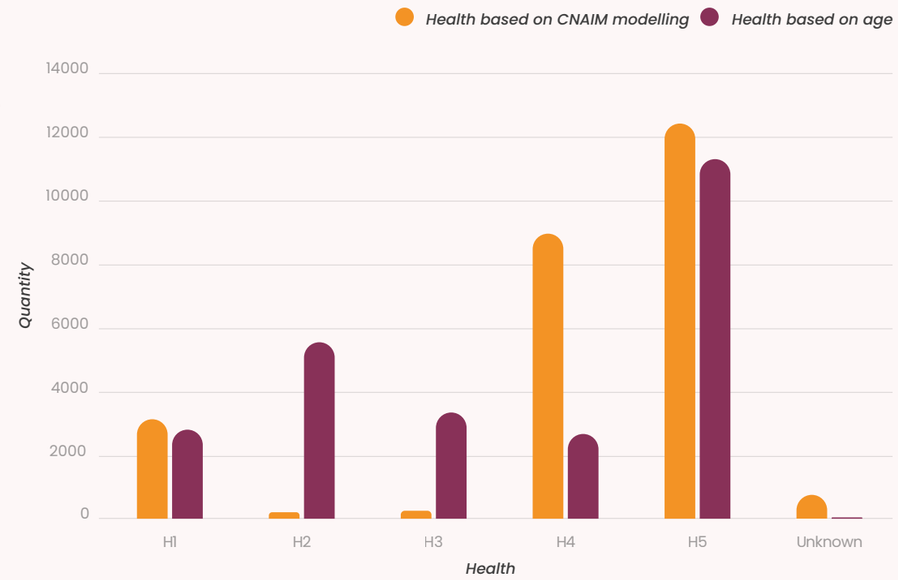


Figure 5.28 presents the asset health profile for distribution crossarms and shows a similar change in outcomes arising from the transition from the former AHI methodology to the CNAIM-aligned ARMM approach. As with other asset classes, the previous AHI relied largely on age, with condition acting as a secondary input, whereas ARMM places greater emphasis on observed condition and applies location-specific modelling effects. This results in older crossarms with no recorded condition issues now presenting as being in better relative health, while crossarms with moderate or poorer condition are more clearly distinguished and more likely to to present with a health score of H1. For distribution crossarms, condition deterioration is typically driven by observed signs of mechanical degradation within the older wooden crossarm fleet, particularly rot affecting structural integrity. Within the planning period, our defect remedial strategy will target low-health crossarms, prioritised by risk. In addition, the Overhead High Voltage Conductor Renewal Programme (refer Chapter 7) will also drive the replacement of a reasonable number of older crossarms as part of broader line rebuilds to meet current construction standards, contributing to overall improvements in crossarm health across the network.

5.3.4 Distribution and LV Cables

Our electricity network utilises different cable types to suit operational requirements and voltage levels:

22 kV and 11 kV distribution circuits:

- Cross-linked polyethylene (XLPE); and
- Paper insulated, lead covered (PILC).

400 V low-voltage circuits:

- Cross-linked polyethylene (XLPE);
- Polyvinyl chloride (PVC); and
- Paper insulated, lead covered (PILC).

Prior to the mid-1990s, there were very few areas of the network which were installed underground, limited only to the urban townships of Pukekohe, Waiuku and the surrounding areas of Papakura. The 22 kV conversions, initially in Pukekohe, later extending to Ōpaheke and then Tuakau, required a reasonable length of new 22 kV rated cable to be installed. Further network growth and other network investment since then has added to this population. As such, much of our underground network is relatively young.

Underground vs Overhead

Underground cables incur higher installation and lifecycle costs compared to overhead lines. However, they deliver improved reliability and require less ongoing maintenance.

Urban Development Practices

In most new urban developments, electricity supply is now provided via underground cables. This approach aligns with local regulations that restrict the installation of new overhead lines and poles. Additionally, developers typically prefer underground supply for aesthetic reasons in new neighbourhoods.

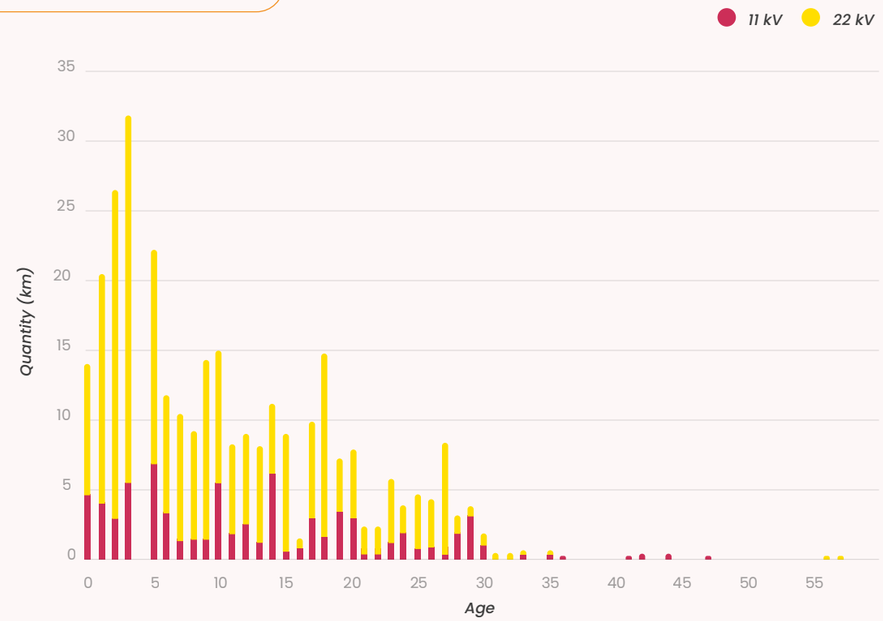
5.3.4 Distribution and LV Cables (continued)

Type	Quantity	Life Expectancy	Average Age
Distribution Cable 11 kV			
PILC	5.39 km	80 Years	32 Years
XLPE	83.68 km	55 Years	10 Years
Other	0.03 km		5 Years
Distribution Cable 22 kV			
PILC	0.98 km	70 Years	22 Years
XLPE	253.15 km	55 Years	11 Years
LV Cable			
LV Cable	977.54 km	55 Years	15 Years
Street Light Cable	34.95 km	55 Years	6 Years

Table 5.7 Asset summary – distribution and LV cables

Distribution Cable – 11 kV and 22 kV – Age

Figure 5.29 Age profile – distribution 11kV and 22kV cable



5.3.4 Distribution and LV Cables (continued)

Distribution Cable – 11 kV and 22 kV – AHI Score

Figure 5.30
Asset health profile – distribution 11kV and 22kV cable

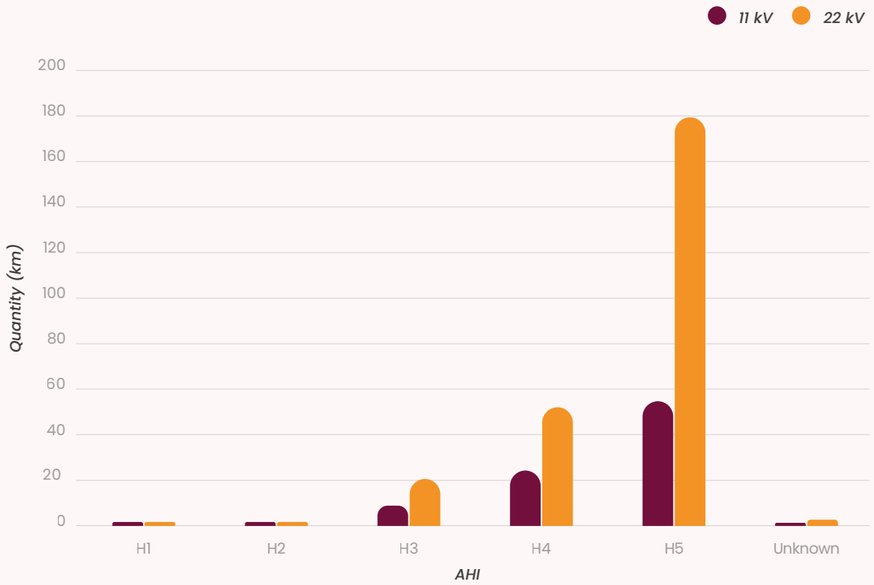
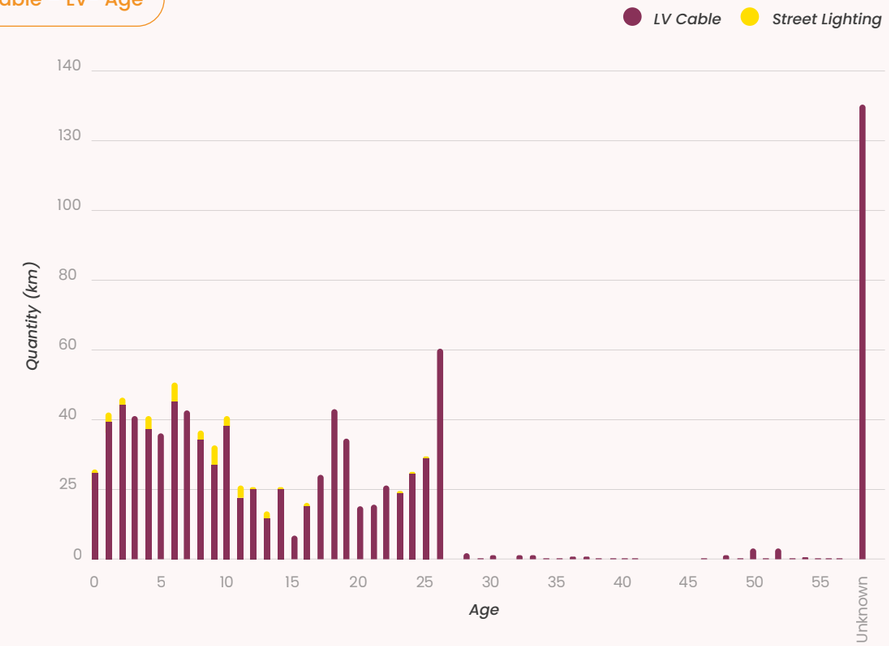


Figure 5.30 presents the asset health profile for 11 kV and 22 kV distribution cables and shows a fleet that is predominantly young and in good health. Prior to the 1990s, the network was almost entirely overhead, with very limited underground cable installed at 11 kV. The introduction and expansion of the 22 kV network from the mid-1990s required the systematic replacement of older, lower-rated cables with 22 kV-rated cable, meaning that much of the legacy underground cable population has since been replaced. In addition, urban growth over the last 10–15 years has driven a reasonable volume of new underground cable installation. As a result, the current cable fleet is relatively modern, with generally good condition and performance, which is reflected in the health profile shown here.

5.3.4 Distribution and LV Cables (continued)

Distribution Cable – LV- Age

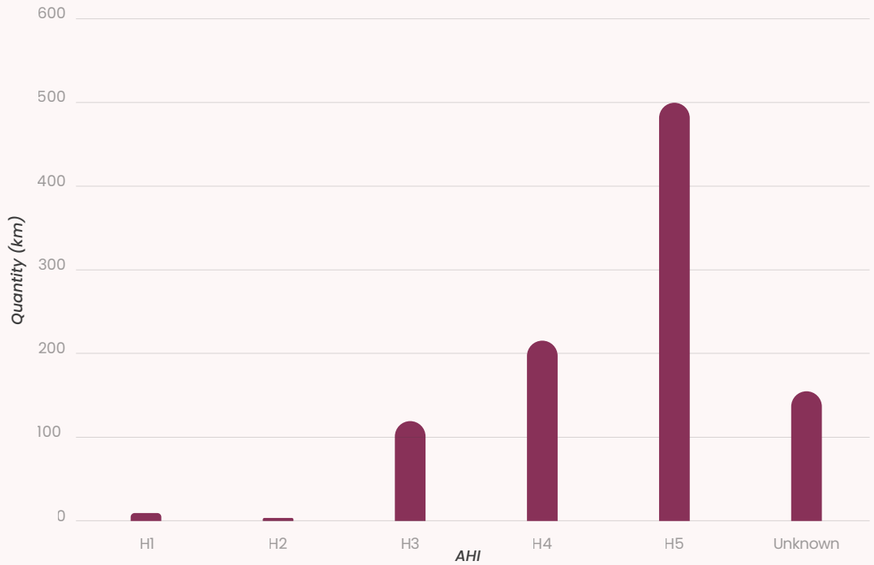
Figure 5.31
Age profile – LV cable



5.3.4 Distribution and LV Cables (continued)

Distribution Cable – LV- AHI Score

Figure 5.32
Asset health profile – LV cable



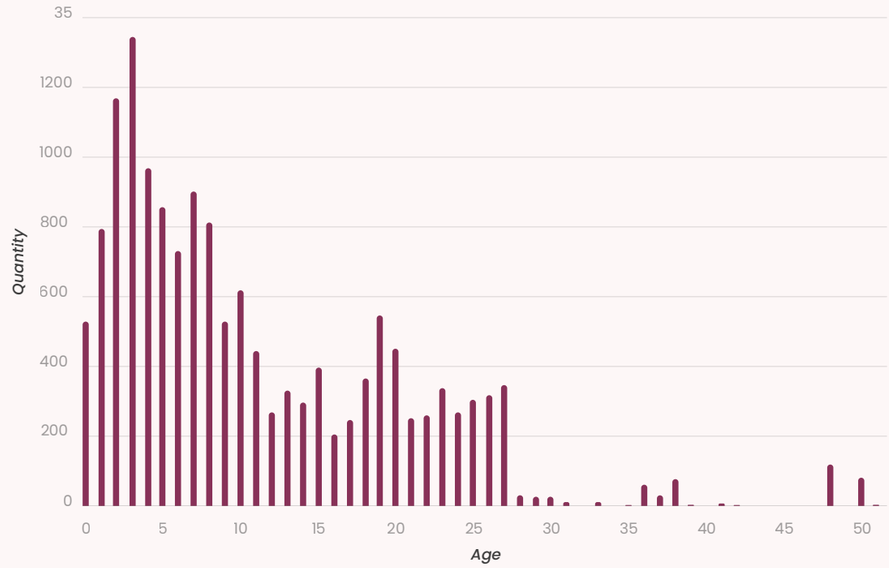
The asset health profile for low voltage distribution cable is based on a combination of available age and condition information and indicates that the majority of the fleet is assessed as being in good health. As with other LV assets, there is limited age information available for cable installed prior to 1997, which represents a key gap in our asset data. Consequently, health assessment for this asset class relies more heavily on observed condition than age. The relatively favourable health profile also reflects the comparatively modern nature of the LV cable fleet, with a significant proportion installed as part of more recent urban development and network upgrades. Improving the completeness and accuracy of LV cable age data is a focus area going forward and will further strengthen health and risk modelling for this asset class.

5.3.5 LV Service Pillars and Pits

Pillars and pits form part of the low-voltage distribution network and are primarily used for customer connection points:

- **Pillars** typically house fuses for individual customer connections and, in some cases, act as interconnection points between adjacent low-voltage circuits. Pillars are our current design standard as they support improved accessibility, safety and long-term maintainability of the network.
- **Pits** are less commonly used in the network. Their application is not preferred in new installations due to higher maintenance needs and limited operational benefits.

Figure 5.33
Age profile – distribution pillars



There are 3,610 pillars out of the total population of 16,321 whose ages have not yet been determined.

The asset health profile for low voltage service pillars and pits is based on available age and condition information and indicates that the majority of the fleet is in good overall health. While data gaps remain for older assets, the extent of missing age information is smaller than for LV lines and cables, providing greater confidence in the assessed health outcomes. A significant proportion of the pillar population is relatively new, reflecting urban growth and subdivision development over recent years, which has driven the installation of modern LV service infrastructure. Condition issues for LV service pillars are typically associated with enclosure condition, particularly where assets are located in publicly accessible areas and are therefore exposed to accidental damage, weathering, vegetation ingress, and vermin. Ongoing improvement of asset data quality and targeted condition monitoring will further strengthen health and risk assessments for this asset class over time.

5.3.6 Distribution Substations and Transformers

Distribution substations are equipped with transformers that step down high voltages (22 kV or 11 kV) to serviceable levels for customers (400 V/230 V). These substations also incorporate essential protection and safety features, including fuses and earth grids.

Distribution switching stations are equipped with switchgear, such as ring main units (RMUs) and circuit breakers, to enable sectional control, isolation, and protection of network assets. This arrangement supports safe maintenance activities and efficient fault isolation, minimising customer impact during outages.

Specialised 22/11 kV transformers are employed to interconnect the 11 kV and 22 kV networks. These assets provide operational flexibility that supports staged voltage upgrades where capacity and performance requirements justify the investment. Each upgrade is assessed against alternative solutions to ensure cost-effectiveness and alignment with long-term network strategy.

Asset	Type	Quantity	Life Expectancy	Average Age
Distribution Transformers	Pole Mounted	3181	45 Years	10 Years
	Ground Mounted	1069	45 Years	13 Years
22/11 kV Transformers	Autotransformers	50	45 Years	10 Years

Table 5.8 Asset summary – distribution transformers

Distribution Transformers – Age

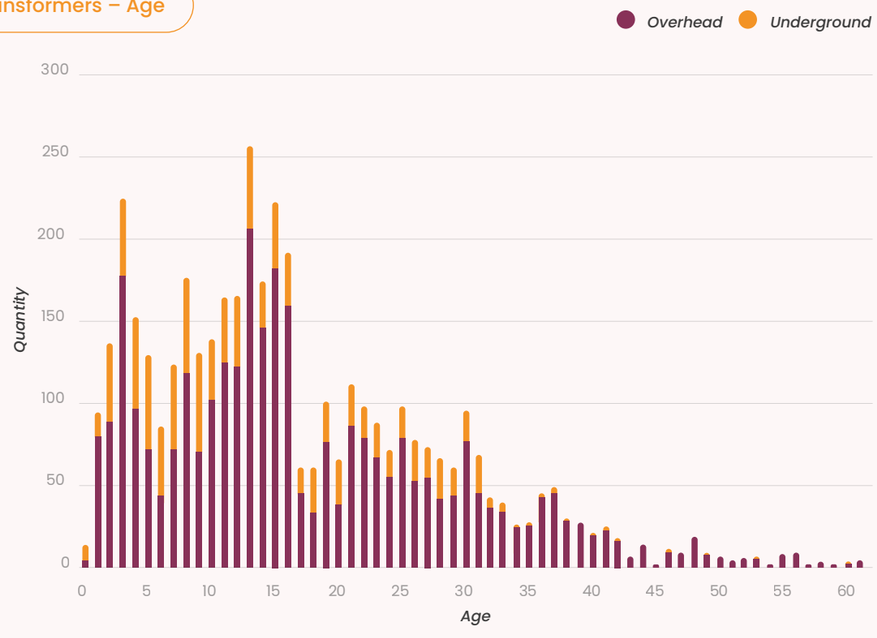


Figure 5.35 Asset Health profile – distribution transformers

5.3 Our Assets (continued)

5.3.6 Distribution Substations and Transformers (continued)

Distribution Transformers – AHI Scores

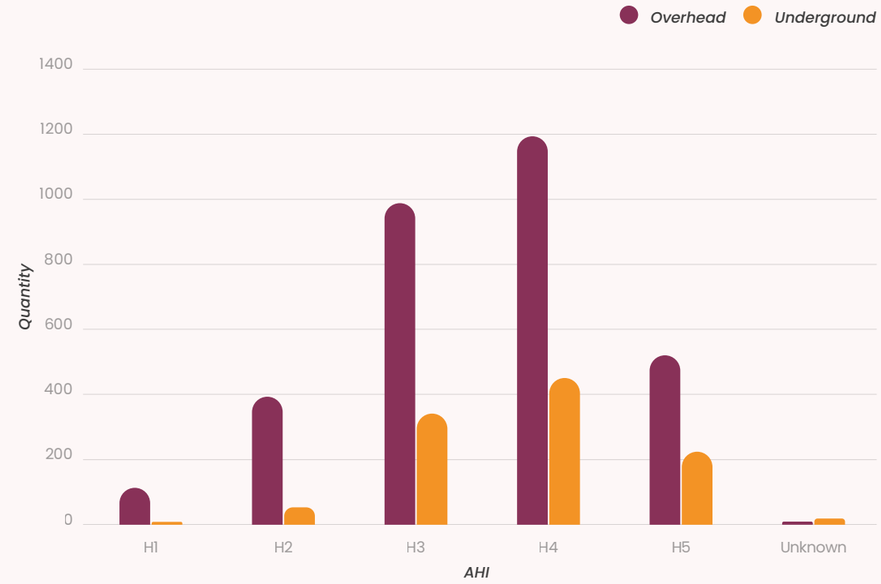
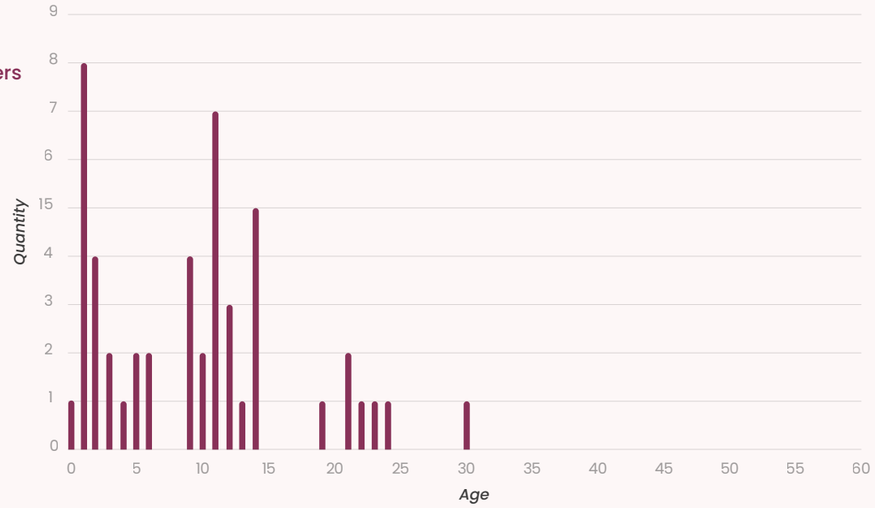


Figure 5.35 shows the asset health profile for distribution transformers and reflects differences in age and construction across the fleet. Overhead distribution transformers are typically older than ground-mounted units, as ground-mounted transformers became more prevalent with the expansion of underground networks from the early 1990s. Consistent with other asset classes, assets on the 11 kV network are generally older than those on the 22 kV network, with feeder conversion programmes over the past 30 years resulting in the replacement of many older 11 kV transformers with newer 22 kV units. Transformers assessed as being in lower health are typically older units with observed condition issues identified through routine maintenance inspections. These are most commonly related to corrosion of steel tank enclosures, occasionally resulting in minor oil leaks. Within the planning period, our defect remedial strategy will target these lower-health transformers, prioritised by risk, to manage asset condition, safety, and reliability outcomes.

5.3.6 Distribution Substations and Transformers (continued)

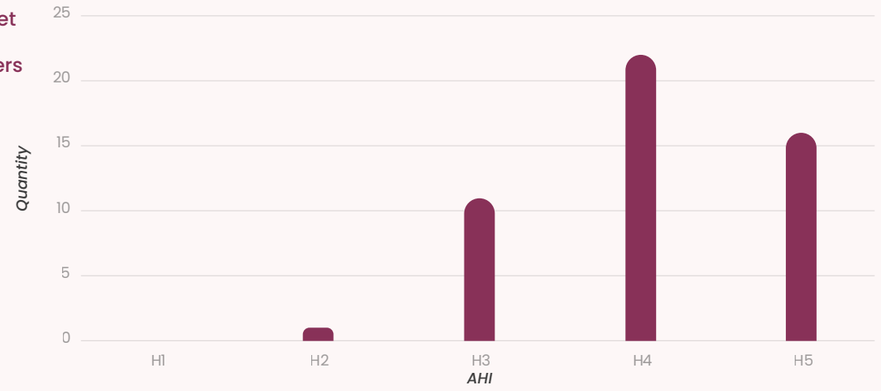
Distribution Autotransformers - Age

Figure 5.36 Age profile – autotransformers



Distribution Autotransformers - AHI Score

Figure 5.37 Asset health profile – autotransformers



The asset health profile for the relatively small population of distribution autotransformers shows outcomes broadly consistent with those of the wider distribution transformer fleet, but with an overall younger age profile. Autotransformers are subject to similar condition and performance drivers as other distribution transformers; however, the fleet is comparatively modern, with the oldest unit approximately 30 years old. Assets assessed as being in lower health are typically those with observed condition concerns identified through routine maintenance inspections, most commonly relating to corrosion of steel tank enclosures and, in some cases, minor oil leakage. Within the planning period, our defect remedial strategy will address these lower-health autotransformers, prioritised by risk, to ensure safe, reliable, and compliant operation of this specialised asset class.

5.3.7 Distribution Switchgear

Distribution switchgear serves a critical role in protecting and isolating the network, minimising the impact of outages caused by faults or planned maintenance by enabling the sectionalisation of affected network segments.

For the overhead network, we employ a variety of devices including air break switches (ABS), gas-insulated switches (GIS), reclosers, drop-out links, vacuum switches, and fuses to ensure effective control and protection.

Our ABS units are our older design of overhead switchgear and new examples of these have not been installed for nearly 20 years. Certain types of ABS with known concerns have been proactively replaced in the last few years and almost entirely removed from the network. The remaining population is expected to remain serviceable for the medium term with the required maintenance plans put in place. Gas switches have been the standard since new ABS units were phased out. A number of replacement projects, reliability investments and ongoing customer growth in the last 10 or so years have seen a reasonable population of new units installed, reflected in the low average age.

Within the underground network, ring main units (RMUs) are utilised. These RMUs incorporate load break switches for isolation purposes, as well as fuses or circuit breakers to safeguard transformers. The oldest units on the network date back to the early days of the 22 kV conversions in the mid-1990s and are only expected to reach replacement age towards the end of the planning period. The rest of the population has been installed since, with a reasonable population being installed in the last five years alongside a large volume of growth on the network. All of the older 11 kV oil or cast-resin insulated designs have been removed from the network in recent years.

Asset	Type	Quantity	Life Expectancy	Average Age
Ground Mount Switchgear	Ring Main Units	499	40 Years	6 Years
Pole Mount Switchgear	Air Break Switch (ABS)	71	35 Years	23 Years
	Gas Insulated Switch	324	35 Years	4 Years
	Spur Line Isolator	1759	35 Years	23 Years
	Recloser	42	40 Years	9 Years
	Vacuum Switch	7	40 Years	2 Years

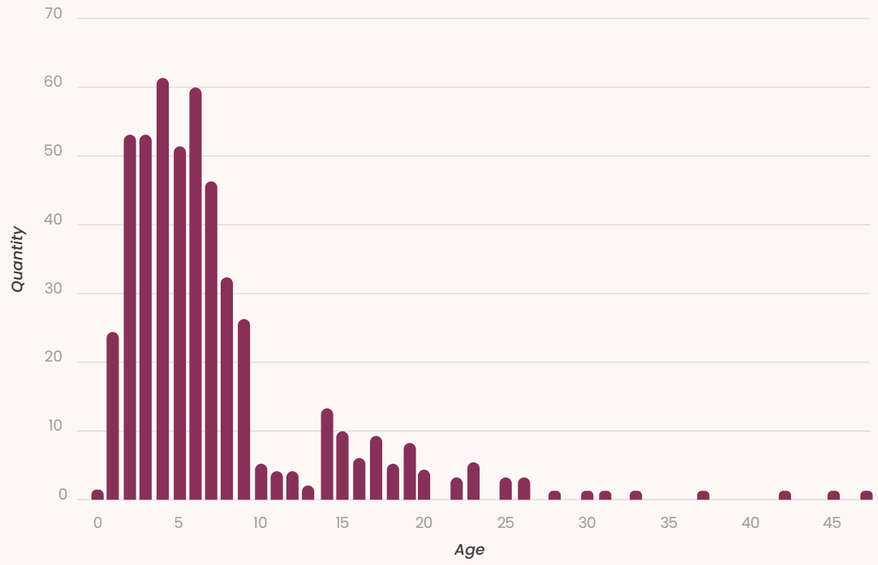
Table 5.9 Asset summary – distribution switchgear

5.3.8 Distribution Ground Mounted Switchgear

5.3.8.1. Ring Main Units

Distribution Switchgear – Ring Main Units – Age

Figure 5.38 Age profile – ring main units



5.3.8 Distribution Ground Mounted Switchgear (continued)

5.3.8.1. Ring Main Units (continued)

Distribution Switchgear - Ring Main Units – AHI Score

Figure 5.39 Asset health profile – ring main units

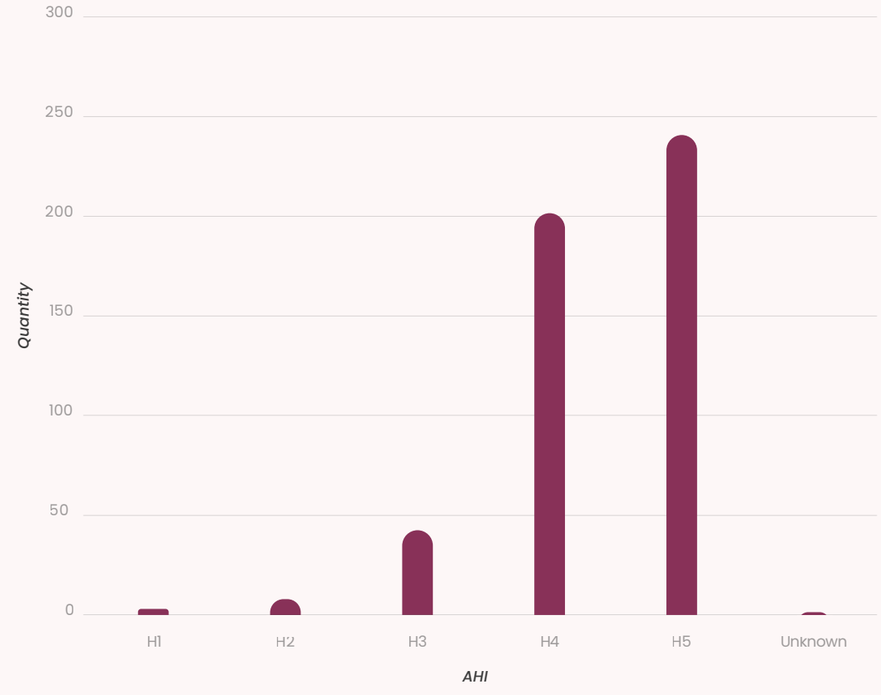


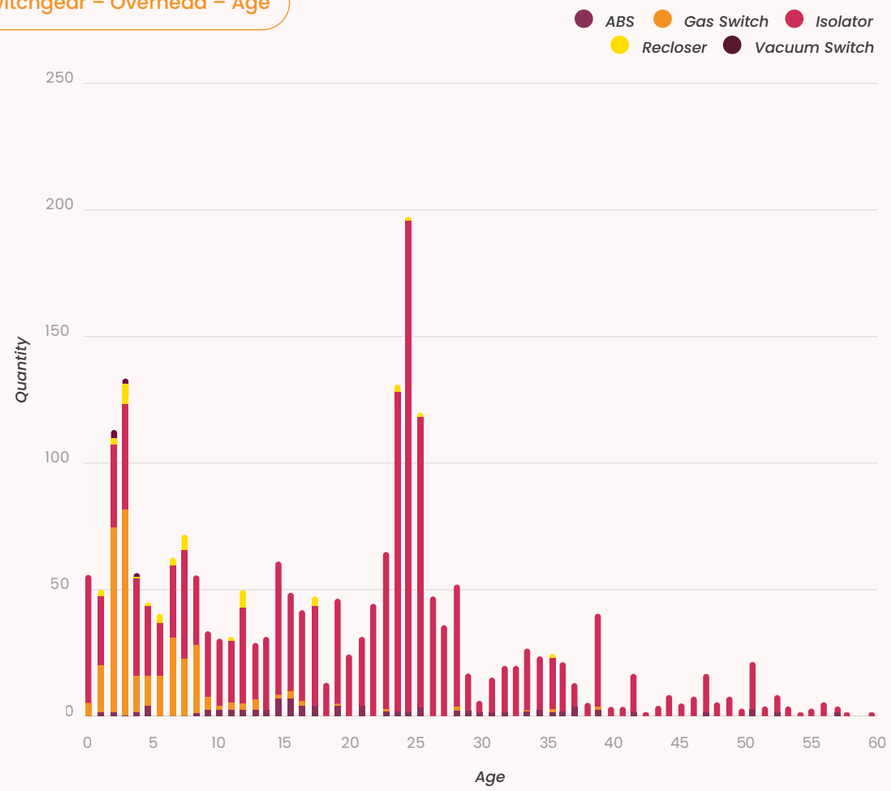
Figure 5.39 presents the asset health profile for distribution ring main units (RMUs) and reflects a relatively modern fleet with generally high asset health. All legacy oil-filled and solid-resin insulated RMU designs have been progressively replaced in recent years, with the current fleet now comprising entirely modern gas-insulated RMUs. The oldest units date back to the early 1990s, and a notable proportion of the fleet has been installed over the past 10 years in response to urban growth and subdivision development. RMUs assessed as being in lower health are typically the older units, with observed condition concerns identified through maintenance inspections, most commonly corrosion of enclosures or, less frequently, issues associated with maintaining SF^6 gas pressure. A targeted replacement programme for these lower-health units is planned within the planning period (refer Chapter 7), supporting continued safe and reliable operation of the network.

5.3.8 Distribution Ground Mounted Switchgear (continued)

5.3.8.2. Distribution Overhead Switchgear

Distribution Switchgear – Overhead – Age

Figure 5.40 Age profile – overhead switchgear



5.3.8 Distribution Ground Mounted Switchgear (continued)

5.3.8.2. Distribution Overhead Switchgear (continued)

Distribution Switchgear – Overhead – AHI Score

Figure 5.41 Asset health profile – overhead switchgear

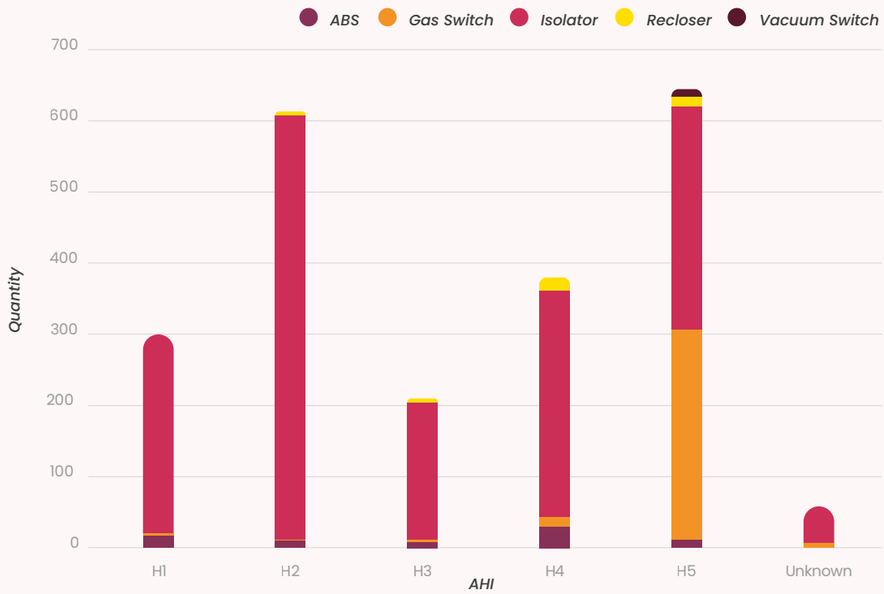


Figure 5.41 presents the asset health profile for overhead distribution switchgear, the majority of which comprises pole-mounted isolators and fuses. The backbone switching devices within this asset class (excluding isolators) are generally assessed as being in good health, reflecting their critical role in operating a safe and reliable network. Older air-break switchgear (ABS) of known designs susceptible to failure during operation have been progressively replaced over time. While some older ABS units remain in service, condition information indicates these assets are currently in good condition and serviceable, with ongoing condition and regular monitoring in place to manage risk going forward. The isolator population accounts for most of the reported H1 and H2 health outcomes; however, this is largely driven by age data, where some inaccuracies are known to exist. Typical condition issues for isolators include corrosion of mechanical components and, for older installations, mechanical failure associated with deterioration or rot of supporting wooden crossarms. Regular maintenance inspections ensure isolators are routinely assessed, with any concerning observations prioritised and addressed through our defect remedial strategy to manage safety and reliability risk.

5.3.9 Communications / SCADA

Counties Energy operates dedicated communications networks to support the safe and reliable operation of our electricity distribution system. These are the network components of our Supervisory Control and Data Acquisition (SCADA) system. These networks enable secure communication between the Network Operations Centre (NOC), zone substations, and compatible field devices. Collectively, these make up the network component SCADA system.

The communications infrastructure comprises:

- **Radio masts** connected via point-to-point microwave links;
- **Fibre optic networks,** which provide high-capacity data transfer and include surplus capacity leased to third parties;
- **Voice radio systems** integrated with operational vehicles for field communications; and
- **Remote terminal units** installed in the field.

By maintaining these private networks, Counties Energy avoids reliance on public telecommunications services for business-critical operations. This approach enhances our network resilience and ensures continuity of control and monitoring functions during external disruptions.

Asset	Quantity	Life Expectancy
Radio Sites	15	20 Years
Remote Telemetry Units	404	20 Years
Fibre (Overhead)	77.5 km	40 Years
Fibre (Underground)	68.9 km	40 Years
Fibre Pits	488	40 Years

Table 5.10 Asset summary – communications assets

5.3.9 Communications / SCADA (continued)

5.3.9.1. Radio Sites

Counties Energy operates 15 radio sites across the network to support critical communications. Each site typically consists of:

- A pole or tower supporting antennas and microwave links.
- A communications hut, which may be an outdoor-rated roadside cabinet or a small portable building housing radio equipment and backup power supplies. These backup systems enable continued operation for a defined period during grid supply interruptions.

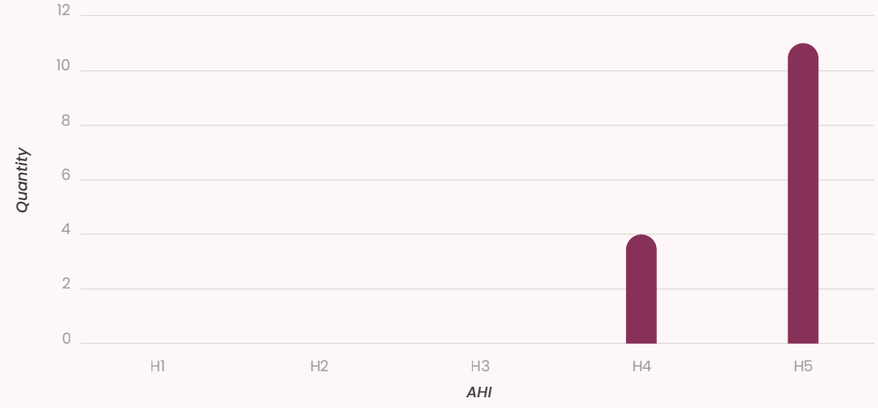
Site Locations and Ownership:

- Zone Substations: Two sites are integrated within our zone substations, with equipment housed inside the substation building and powered from the substation communications supply.
- Private Property: Four sites are located on private land under lease agreements, easements, or rights under the Electricity Act 1992.
- Roadside Corridor: Seven sites are positioned within the road corridor, including two that utilise existing power poles for antenna mounting.
- Company-owned Land: Four sites are situated on land owned by Counties Energy.

Between 2022 and 2025, our radio network underwent a comprehensive rebuild. This programme replaced end-of-life equipment and upgraded the system to a higher-capacity platform meeting current communications and cybersecurity standards. While some masts were retained, nearly all other components — including antennas, microwave links, and control equipment — were newly installed.

Radio Sites – AHI Score

Figure 5.42 Asset health profile – radio sites



5.3.9 Communications / SCADA (continued)

5.3.9.2. Remote Terminal Units

Remote Telemetry Units (RTUs) are critical devices that enable real-time monitoring and control of network assets. They facilitate remote operation of our substations and other equipment by collecting operational data and executing control commands.

RTUs are deployed at:

- Zone substations
- Network reclosers
- Remotely controlled distribution switchgear
- Selected key customer sites

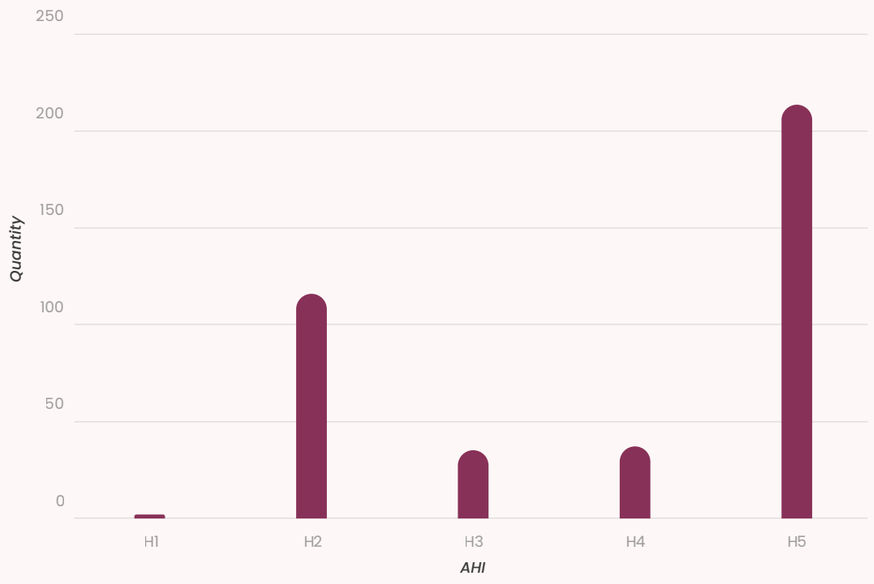
Asset Population and Renewal

Our network currently includes 404 RTUs. As part of the radio network replacement (2022–2025) and the subsequent Automation Rebuild programme, a significant number of new RTUs were installed to support upgraded switchgear and enhanced automation capabilities.

Many legacy RTUs remain in service but are scheduled for decommissioning in 2026. Following this rationalisation, the RTU population is expected to reduce to approximately 260 units, reflecting a streamlined and modernised automation platform.

Remote Terminal Units – AHI Score

Figure 5.43 Asset health profile – remote terminal units



5.3.9 Communications / SCADA (continued)

5.3.9.3. Fibre Networks

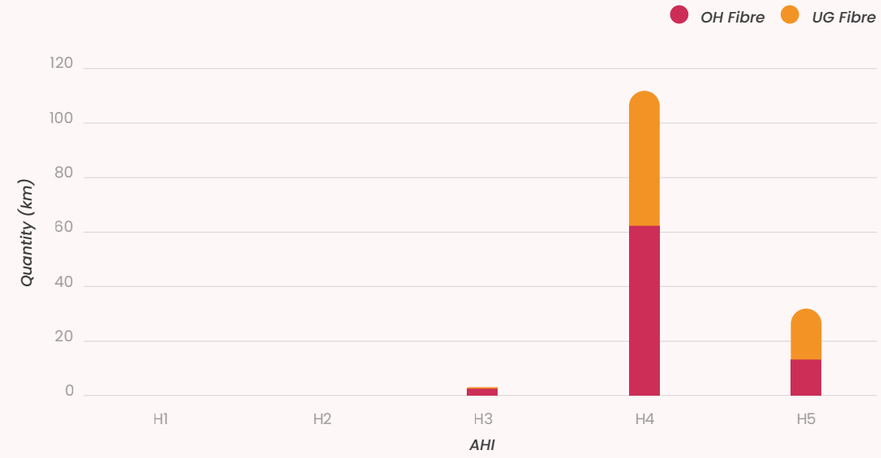
Counties Energy operates 146 km of fibre optic network to support high-capacity communications across our distribution system. The network configuration is as follows:

- Overhead installation: 53% of fibre is mounted on existing power poles, typically positioned just below electricity conductors.
- Underground installation: 47% of fibre is installed in underground routes, supported by 488 fibre pits that provide access and jointing locations.

Our oldest fibre assets date back to the early 2000s; however, the network is predominantly modern, with 85% of fibre less than 15 years old. This age profile reflects ongoing investment in our communications infrastructure to meet increasing operational and cybersecurity requirements.

Fibre Networks – AHI Score

Figure 5.44 Asset health profile – fibre networks



Asset	Quantity	Life Expectancy
Capacitor Banks	17	55 Years
Voltage Regulators	15	55 Years
Protection Relays	186	40 Years
Load Control Relays	2892	20 Years
Ripple Injection Plant	6	20 Years

Table 5.11 Asset summary – other assets

5.3.10 Other Network Assets

5.3.10.1. Voltage Regulators

As electricity flows through distribution lines, voltage naturally decreases with distance from the source. On extended line sections, this voltage drop can result in supply levels falling below acceptable limits for customers at the far end of our network.

To mitigate this, voltage regulators are installed at strategic points along longer feeders. These devices boost voltage partway along the circuit, ensuring compliance with statutory voltage requirements and maintaining service quality for all customers.

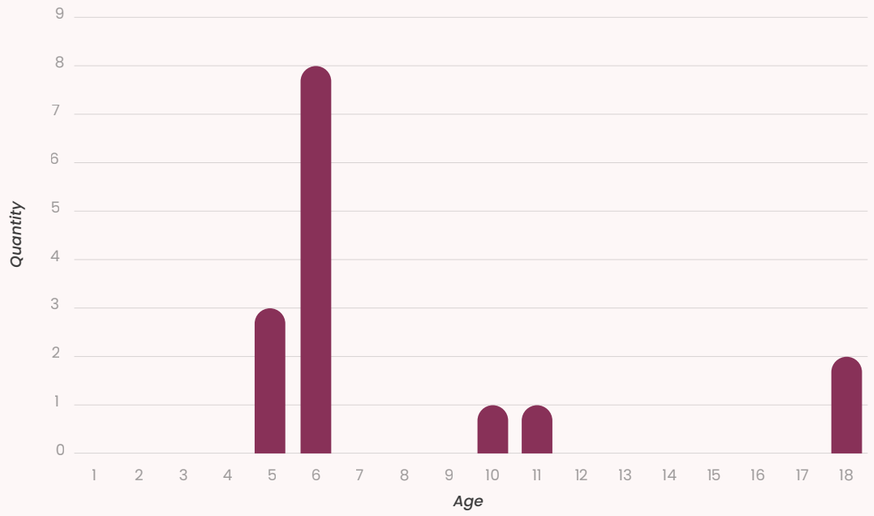
The network currently operates 15 voltage regulators across six sites:

- Three sites utilise arrangements of three regulators working in parallel; and
- Three sites employ pairs of regulators in a coordinated configuration.

This deployment strategy provides flexibility and reliability, supporting consistent voltage delivery across diverse network conditions.

Voltage Regulators – Age

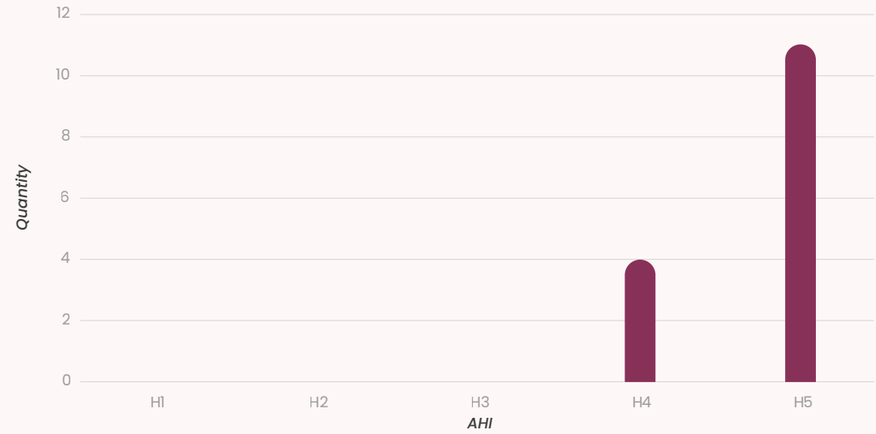
Figure 5.45 Age profile – voltage regulators



5.3.10 Other Network Assets (continued)

Voltage Regulators – AHI Score

Figure 5.46 Asset health profile – voltage Regulator



The asset health profile for voltage regulators reflects a small population with a relatively young age profile compared to the expected asset life of approximately 55 years. Overall, the regulator fleet is assessed as being in good health, with most primary assets well within their useful lives. While the regulator units themselves are not forecast for replacement within the planning period, the associated control units have shorter expected lives due to their electronic components. A programme of controller replacements is therefore planned within the planning period, ensuring continued performance and reliability, while the underlying voltage regulator assets are not expected to require replacement until beyond the planning horizon.

5.3.10 Other Network Assets (continued)

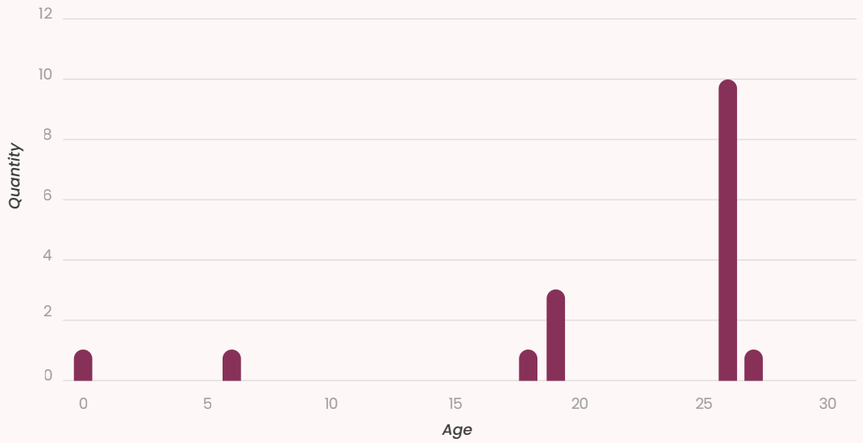
5.3.10.2. Capacitor Banks

Capacitors are installed on the distribution network to improve voltage stability and power quality, particularly on long lines where voltage fluctuations can occur. By providing reactive power support, capacitors help maintain voltage within statutory limits and enhance our overall network efficiency.

Our network currently includes 17 capacitors distributed across various locations. Installation dates range from 1998 for the oldest units to 2025 for the most recent additions, reflecting ongoing investment in voltage management assets to support reliability and performance.

Capacitor Banks - Age

Figure 5.47 Age profile – capacitor banks



5.3.10 Other Network Assets (continued)

Capacitor Banks – AHI Score

Figure 5.48 Asset health profile – capacitor banks

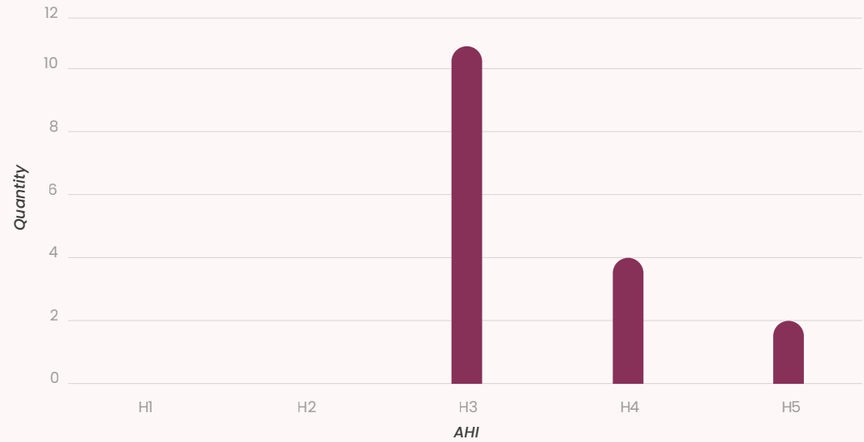


Figure 5.48 shows the asset health profile for capacitor banks, which represents a relatively small asset population with an overall favourable health position. The majority of capacitor banks are assessed as being at or below approximately half of their expected asset life, reflecting a generally young to mid-life fleet. The health profile for this asset class is primarily age-based, with limited adjustments applied for observed condition. Where condition issues are identified, these are most commonly related to corrosion of the capacitor bank enclosures. Overall, the health profile indicates that capacitor banks are not expected to require significant renewal within the planning period, with ongoing condition-based maintenance in place to manage emerging risks.

5.3.10.3. Protection Relays

Protection relays are critical safety devices designed to detect abnormal conditions on our electricity network, such as faults or overloads. When an issue is identified, the relay initiates automatic isolation of the affected section to protect public safety and prevent equipment damage.

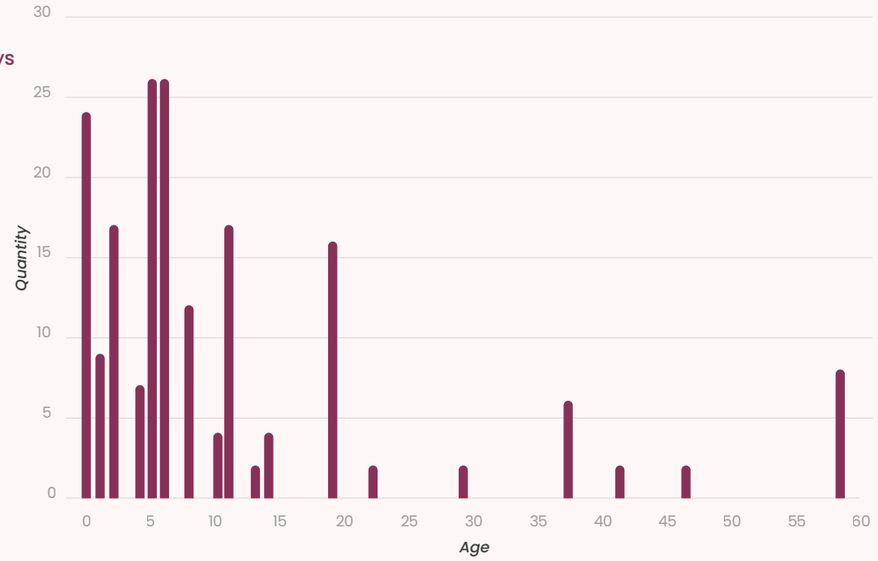
Our network currently operates 186 protection relays installed at key locations, including at major substations and at Transpower's Bombay and Glenbrook sites. These assets form an essential component of the network's protection and control systems.

Relays at Ōpaheke Substation have reached end-of-life and are scheduled for replacement in 2026. This replacement programme will ensure compliance with modern protection standards and maintain system reliability.

5.3.10 Other Network Assets (continued)

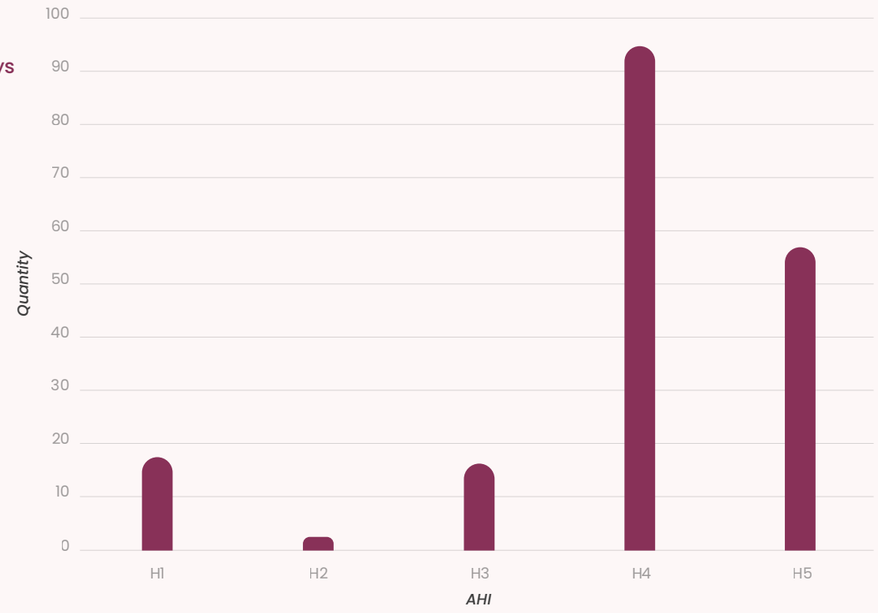
Protection Relays - Age

Figure 5.49
Age profile – protection relays



Protection Relays - AHI Score

Figure 5.50
Asset health profile – protection relays



5.3.10 Other Network Assets (continued)

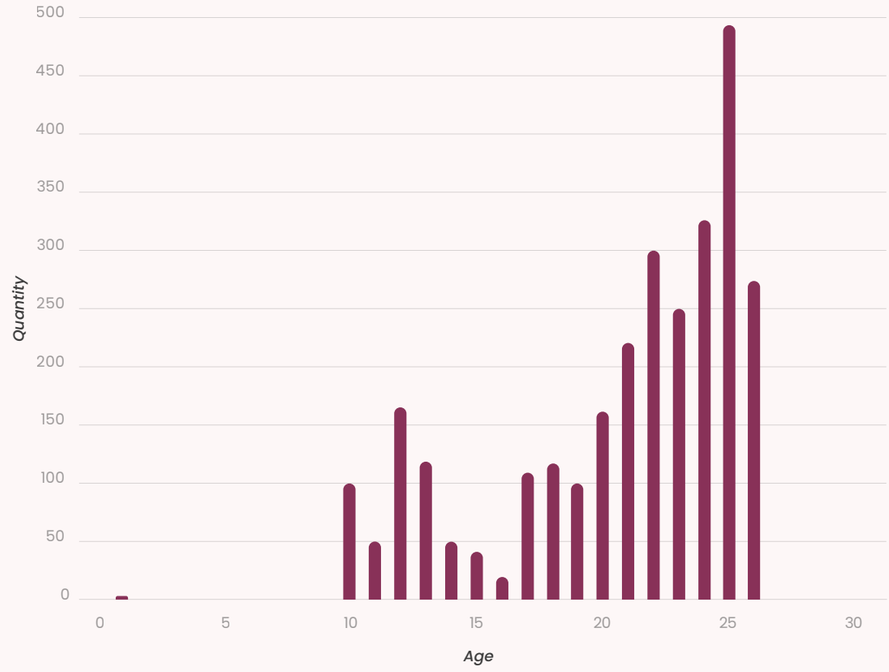
5.3.10.4. Load Control Relays

Load control relays are devices used to manage peak demand by remotely controlling certain customer loads. Historically, these relays were installed alongside older electricity meters to enable demand-side management across our network.

Our network currently includes approximately 2,892 load control relays connected to legacy metering systems. With the widespread deployment of smart meters, which incorporate load control functionality, the need for separate relay devices has significantly reduced. This transition supports streamlined operations and reduces maintenance requirements while maintaining effective load management capability.

Load Control Relays – Age

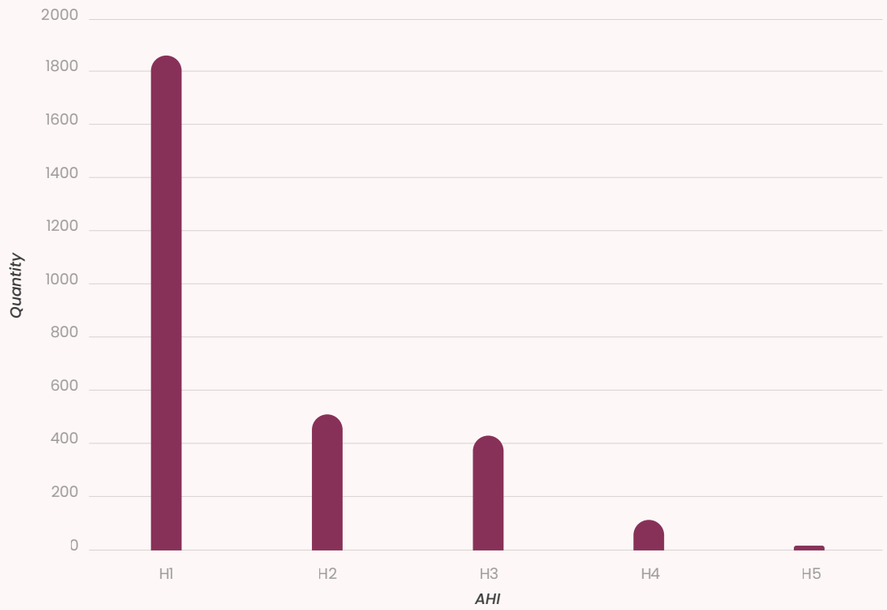
Figure 5.51
Age profile – load control relays



5.3.10 Other Network Assets (continued)

Load Control Relays – AHI

Figure 5.52 Asset health profile – load control relays



Load control relays are increasingly integrated within modern smart meters, removing the need for separate relay devices in most new installations. However, for older metering technologies, or where Counties Energy is not the metering equipment provider (MEP), standalone load control relays are still required and remain in service. These relays are maintained as part of the broader metering installation rather than as standalone network assets.

Consistent with broader industry trends toward smart-meter-enabled load control and other forms of distributed flexibility, the long-term need for separate load control relays is expected to reduce over time. As such, the role and extent of this asset class may change in future versions of this plan as legacy metering is progressively replaced, and alternative load control approaches continue to develop.

5.3.10 Other Network Assets (continued)

5.3.10.5. Load Control (Ripple Injection) Plant

Load control equipment is deployed across the network to help manage electricity demand during peak periods and maintain system stability. The system comprises two key components:

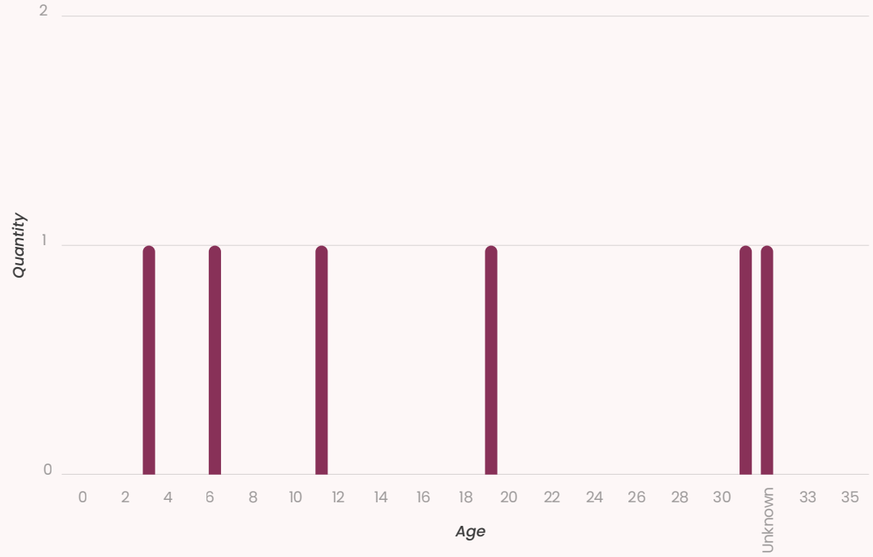
- **Ripple Injection Plants – Installed at zone substations, these units generate and transmit control signals through the distribution network; and**
- **Load Control Relays – Located at customer premises, these devices respond to ripple signals by temporarily switching off high-demand appliances, typically electric water heaters.**

When demand reduction is required, the Network Operations Centre (NOC) issues a remote command to the ripple injection plants. These plants transmit a 317 Hz signal to the relays at customers' premises, disconnecting designated loads for a short duration. This process helps balance network load during peak periods.

The network operates six ripple injection plants located at Glenbrook, Ōpaheke, Pukekohe, Pōkeno, Tuakau, and Barber Road. This infrastructure provides an effective demand-side management capability, supporting reliability and operational efficiency.

Ripple Injection Plant - Age

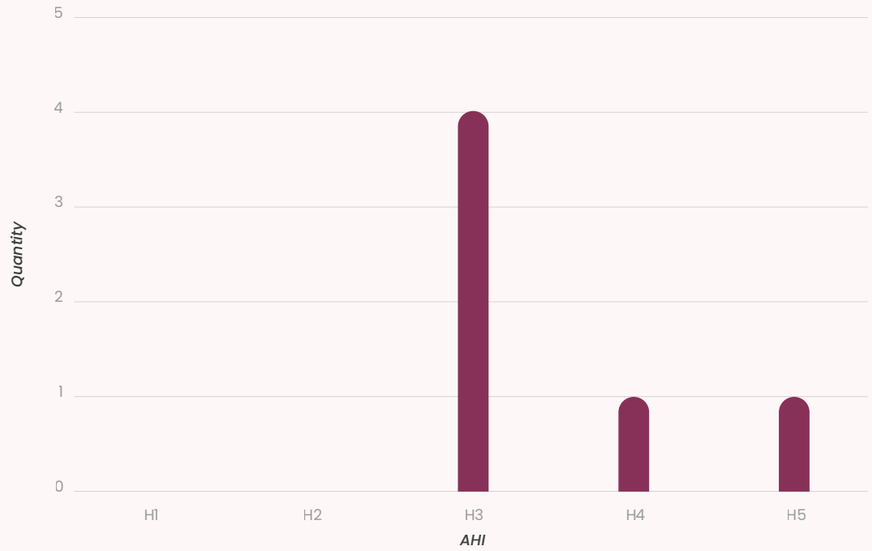
Figure 5.53 Age profile – ripple injection plant



5.3.10 Other Network Assets (continued)

Ripple injection Plant - Age

Figure 5.54
Asset health profile – ripple injection plant



The asset health profile for ripple injection plant reflects a small population of assets, the majority of which are assessed as being in the latter half of their expected asset lives. While still serviceable, the age profile indicates that a number of assets are approaching an appropriate renewal horizon relative to expected life. At present, replacement of ripple injection plant at three sites is scheduled towards the end of the planning period (refer Chapter 7). However, industry trends indicate that traditional ripple-based load control may reduce in prominence over time, as alternative approaches such as smart-meter-enabled load control, greater retailer-led demand response, and distributed flexibility services become more common across New Zealand. These developments may influence the future role, timing, and scope of ripple injection plant investment, and as such, replacement plans for this asset class may be revisited in future versions of this plan as industry practice and technology continue to evolve.

5.3.11 Assets Owned by Counties Energy at Grid Exit Points (GXPs)

As part of our distribution network, we have some assets installed at Transpower's GXPs. These are included within the asset categories outlined earlier in this section, but are set out here for clarity.

Bombay GXP

Within the Transpower substation, we have the following equipment installed on site:

- Support structures and conductor for the 110 kV subtransmission circuits connected to the site;
- Subtransmission line protection relays;
- Metering equipment;
- SCADA RTU and associated equipment; and
- DC auxiliary battery bank.

Glenbrook GXP

Within the Transpower substation, we have the following equipment installed on site:

- Support structures and conductor for the 33 kV subtransmission circuits connected to the site;
- Subtransmission line protection relays;
- Metering equipment;
- SCADA RTU and associated equipment; and
- Fibre optic cables to the 33 kV Glenbrook load control plant.

The 33 kV Glenbrook load control plant is located near the Transpower Glenbrook substation on land owned by Counties Energy.

5.4 Asset Summary

Type	Quantity	Life Expectancy
Subtransmission		
Subtransmission Structures		
Concrete Poles	694	80 Years
Wood Poles	2	45 Years
Steel Poles	196	55 Years
PSCP	465	80 Years
Other	4	55 Years
Steel Lattice Towers	9	80 Years
33 kV Conductor		
AAC	55.39 km	80 Years
ACSR	0.51 km	60 Years
110 kV Conductor		
AAC	63.25 km	80 Years
AAAC	3.02 km	80 Years
Crossarms		
Wood	769	45 Years
Steel	709	80 Years
Other	1	55 years
Subtransmission Cable		
33 kV XLPE	0.97 km	55 Years
33 kV CU	0.15 km	55 Years
110 kV XLPE	0.09 km	55 Years
Zone Substations		
Network Buildings		
Buildings	9	50 Years
Power Transformers		
110/22 kV	11	60 Years
33/11 kV	6	60 Years
Circuit Breakers		
110 kV CBs	23	45 Years
33 kV CBs	9	45 Years
22 kV CBs	71	45 Years

5.4 Asset Summary (continued)

Type	Quantity	Life Expectancy
Station Disconnectors		
110 kV	4	45 Years
33 kV	18	45 Years
Auxiliary Battery Banks	32	8 Years
Distribution and LV Lines		
Distribution Poles		
Concrete/Steel	24,524	80 Years
Wood	1,663	45 Years
Other	83	45 Years
Distribution Crossarms		
Wood	29,921	45 Years
Steel	11,854	80 Years
Other	169	80 Years
22 kV Conductors		
AAC	335.79 km	80 Years
AAAC	70.93 km	80 Years
ACSR	162.36 km	80 Years
Copper	49.19 km	65 Years
Unknown	4.03 km	
11 kV Conductors		
AAC	290.64 km	80 Years
AAAC	126.75 km	80 Years
ACSR	335.47 km	80 Years
Copper	123.49 km	65 Years
Unknown	6.07 km	
LV Conductor		
LV Conductor	670.63 km	80 Years
Distribution and LV Cables		
Distribution Cable 11 kV		
PILC	5.39 km	80 Years
XLPE	83.68 km	55 Years
Other	0.03 km	

5.4 Asset Summary (continued)

Type	Quantity	Life Expectancy
Distribution Cable 22 kV		
PILC	0.98 km	70 Years
XLPE	253.15 km	55 Years
LV Cable		
LV Cable	977.54 km	55 Years
Street Light Cable	34.95 km	55 Years
Pillars/pits	19,443	55 Years
Distribution Substations and Transformers		
Distribution Transformers		
Pole Mounted	3181	45 Years
Ground Mounted	1069	45 Years
22/11 kV Transformers		
Autotransformers	50	45 Years
Distribution Switchgear		
Ground Mount Switchgear		
Ring Main Units	499	40 Years
Pole Mount Switchgear		
Air Break Switch (ABS)	71	35 Years
Gas Insulated Switch	324	35 Years
Spur Line Isolator	1759	35 Years
Recloser	42	40 Years
Vacuum Switch	7	40 Years
Other Network Assets		
Voltage Regulator	15	55 Years
Capacitor Banks	17	55 Years
Protection Relays	186	40 Years
Communications		
Radio Sites	15	20 Years
Remote Telemetry Units	404	20 Years
Fibre (Overhead)	77.5 km	40 Years
Fibre (Underground)	68.9 km	40 Years
Fibre Pits	488	40 Years

5.4 Asset Summary (continued)

Type	Quantity	Life Expectancy
Other Network Assets		
Voltage Regulators	15	55 Years
Capacitor Banks	17	55 Years
Protection Relays	186	40 Years
Load Control Relays	2892	20 Years
Ripple Injection Plant	6	20 Years

Table 5.12 Asset summary

5.5 Asset Performance

This section evaluates asset performance using both event counts and their broader implications on our customers. In line with our strategic focus and reliability strategy outlined in section 4.8.6, the analysis extends beyond fault rates to include the System Average Interruption Frequency Index (SAIFI), ensuring that our approach prioritises customer impact as a central measure of network reliability. The analysis period for this section spans the last three complete financial years (FY23 to FY25), plus FY26 YTD. This is for all events from 01 April 2022 to 30 September 2025.

5.5.1 Unplanned Event Categories

Event Category	Information Disclosure Category	Description
Typically Significant Causes		
Equipment - Overhead	Defective equipment	Events caused by overhead network equipment.
Vegetation	Vegetation	Events caused by vegetation contacting our network – trees near lines, windborne debris contacting lines, or trees falling through or across lines.
Third Party Incident	Third party Interference	Events caused by third parties such as vehicles impacting poles or substations, vandalism or theft, third parties striking underground cables or contacting overhead lines.
No Cause Found	Unknown	Events where the cause is not found and the network is restored - understood to be typically vegetation, wildlife or transient equipment issues.
Wildlife	Wildlife	Events caused by birds, vermin or possums.
Typically Minor Causes		
Equipment - Underground	Defective Equipment	Events caused by non-overhead network equipment such as cables, or equipment in distribution substations.
Equipment - Zone Substation	Defective Equipment	Events caused by equipment in zone substations.
Network Incident	Human Error	Events as a result of actions by Counties Energy or our contractors.
Adverse Conditions	Lightning Adverse Weather Adverse Environment	Events caused by flooding, landslide, lightning, bushfires or tornadoes (but not high wind or rain).
Major Events		
Major Events	N/A	Any event starting within the Major Event Window as defined by the DPP4 normalisation rules.

Table 5.13 Unplanned event categories

5.5 Asset Performance (continued)

5.5.1 Unplanned Event Categories (continued)

Of the nine event categories (excluding Major Events):

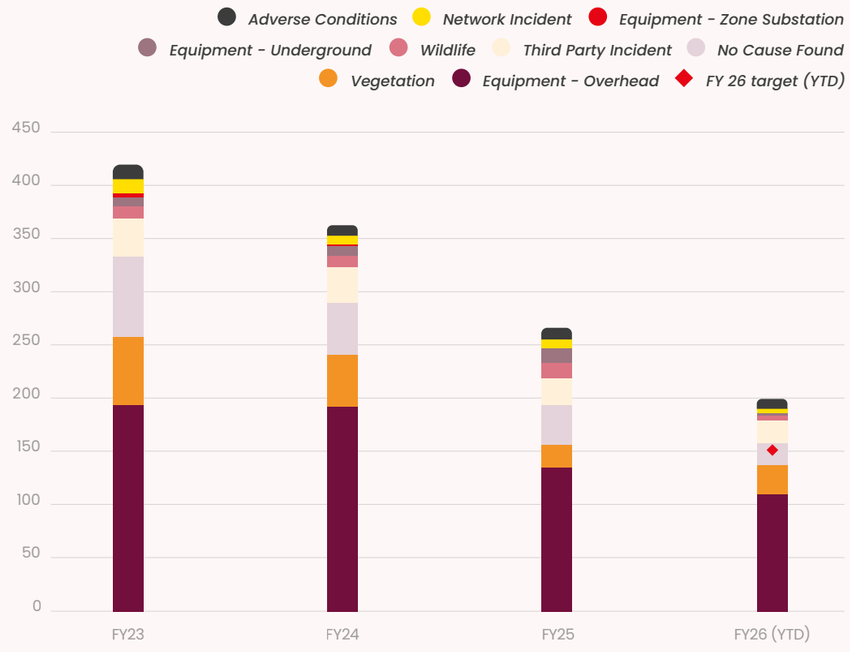
- **Five are regarded as typically significant contributing causes to SAIDI.**
- **Four are typically minor in terms of both event frequency and SAIDI contribution. Historically, "Typically Minor Causes" events have contributed less than 10% of annual SAIDI. Due to low event numbers, these categories exhibit high volatility and limited trendability.**

It is noted that events in this category, such as a zone substation equipment failure or a tornado, can quickly evolve into events with significant network impact. However, such occurrences would often transition into the Major Events classification. The term 'Minor' reflects the event's usual low SAIDI contribution.

However, our focus on asset management activities in this space remains high, as we recognise that these assets are often of high criticality.

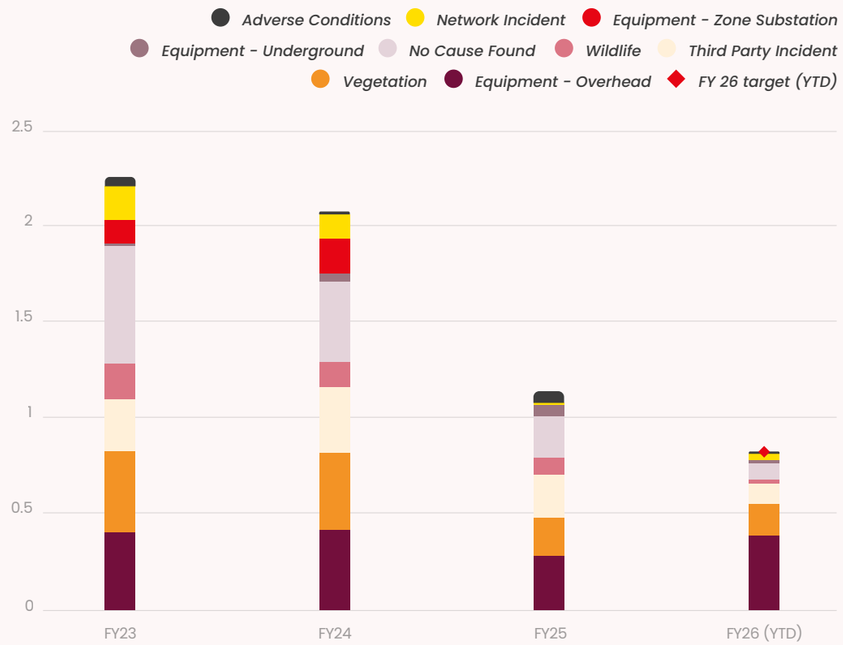
5.5.2 Asset Performance Trends

Figure 5.55 Asset performance trends - event counts



5.5.2 Asset Performance Trends (continued)

Figure 5.56
Asset performance trends - SAIFI



The graphs illustrate event counts and SAIFI for the analysis period, excluding Major Events. Over recent years, both fault rates and SAIFI have declined, indicating that our asset-criticality focused strategy is improving customer experience.

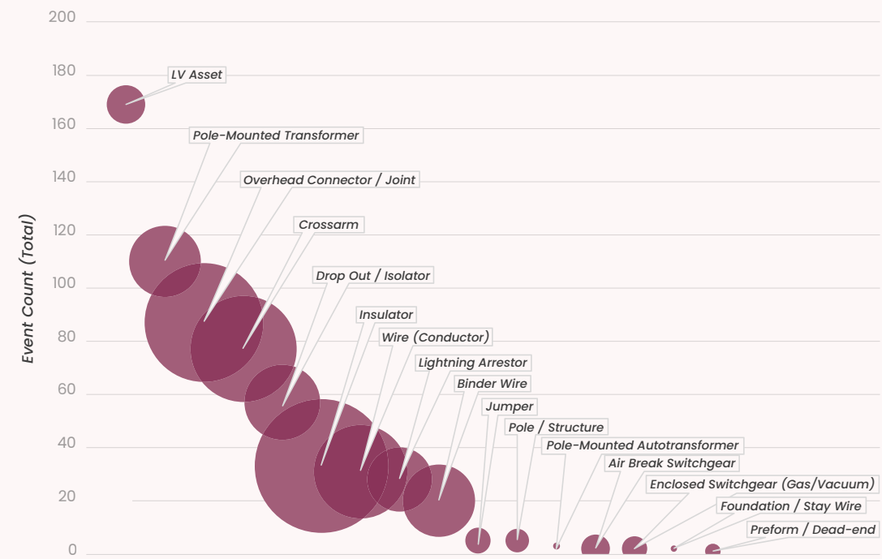
Further detail for each category can be found next.

5.5.2 Asset Performance Trends (continued)

Equipment Overhead

The graph below plots the total number of events by failure cause over the analysis period. The circles represent event SAIFI (customer impact), demonstrating that event frequency does not correspond directly to customer impact.

Figure 5.57
Event count and SAIFI by failure cause



Notable callouts here include:

- **Crossarms and Insulators** represent one of the more significant contributors to the failure trends, making up 17% of events and 38% of SAIFI within the analysis period.
- Since FY23, 44% of events have involved the **LV network or overhead transformers,** though they account for just 8.6% of SAIFI due to their lower customer impact.
- **Overhead connectors** are also a notable failure trend, representing 14% of events but also 18% of SAIFI within the analysis period.

Further details on these threats and what our treatment plans are can be found in section 6.5.

5.5 Asset Performance

5.5.2 Asset Performance Trends (continued)

Vegetation

Figure 5.58
Event count by financial year for vegetation

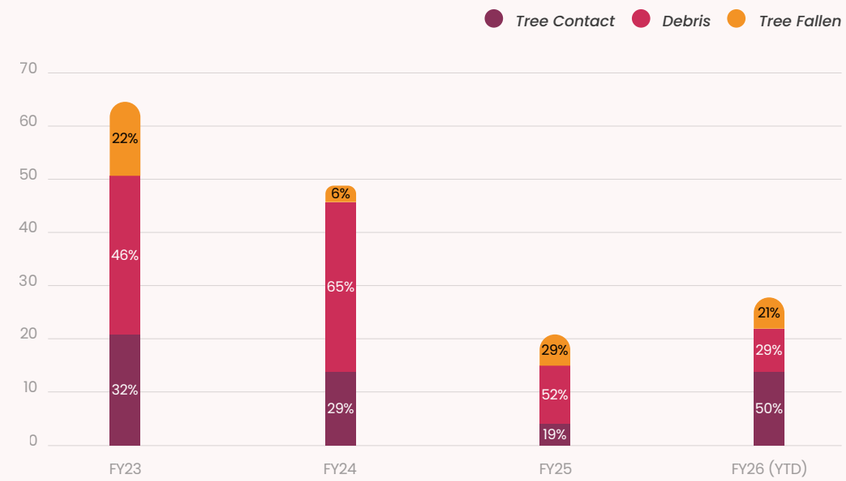
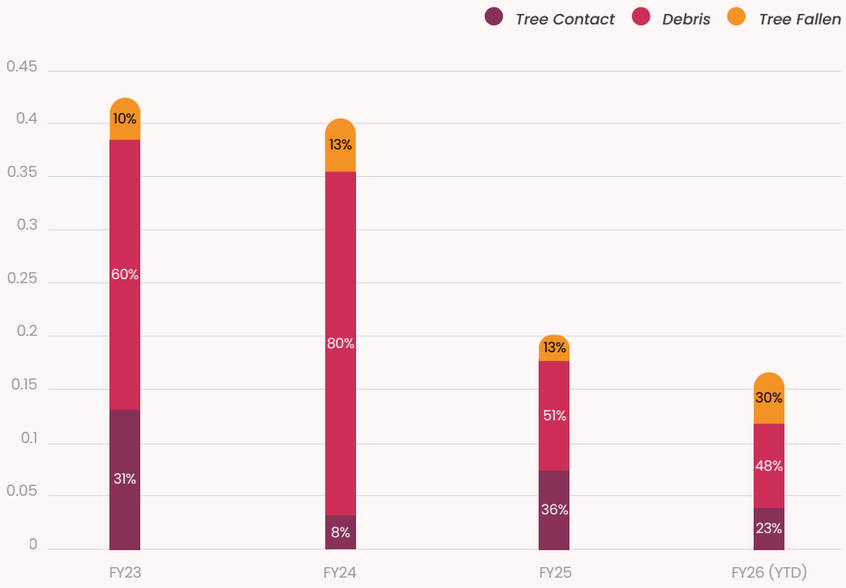


Figure 5.59
Event SAIFI by financial year for vegetation



5.5 Asset Performance (continued)

5.5.2 Asset Performance Trends (continued)

The graphs on the previous page illustrate vegetation event counts and SAIFI for the analysis period, excluding Major Events. The category is broken into:

Tree Contact	Vegetation contact with the line.
Debris	Part of a tree (i.e. bark or branch) has blown into, or fallen onto, the line.
Tree Fallen	The whole tree has fallen through, or across, the line (due to natural causes, but not if related to in-progress tree work).
Grass / Creeper	Tall grass, vines or creepers

Table 5.14 Event Categories and SAIFI

Overall over recent years, our fault rates and SAIFI have declined, indicating that our strategy focussing on asset-criticality is improving customer experience.

Tree Contact is likely related to trees that are within the Growth Limit Zones defined by the Electricity (Hazards from Trees) Regulations 2003 and are categorised accordingly. Debris and Tree Fallen events are typically related to trees that are outside regulated zones. The customer impact of out-of-zone trees is still the bulk of vegetation-related customer impact.

Further information on our Vegetation Strategy can be found in section 4.8.8.

5.5.2 Asset Performance Trends (continued)

No Cause Found

Figure 5.60 Event count by financial year for “No Cause Found”

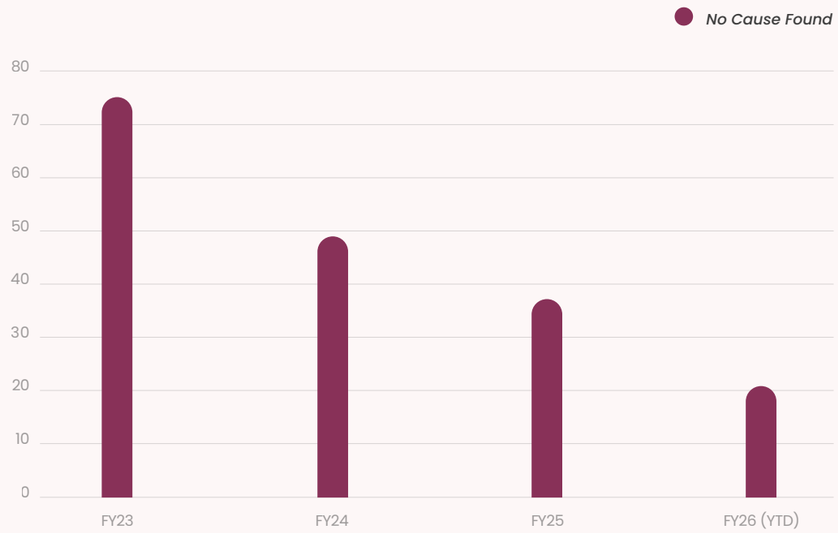
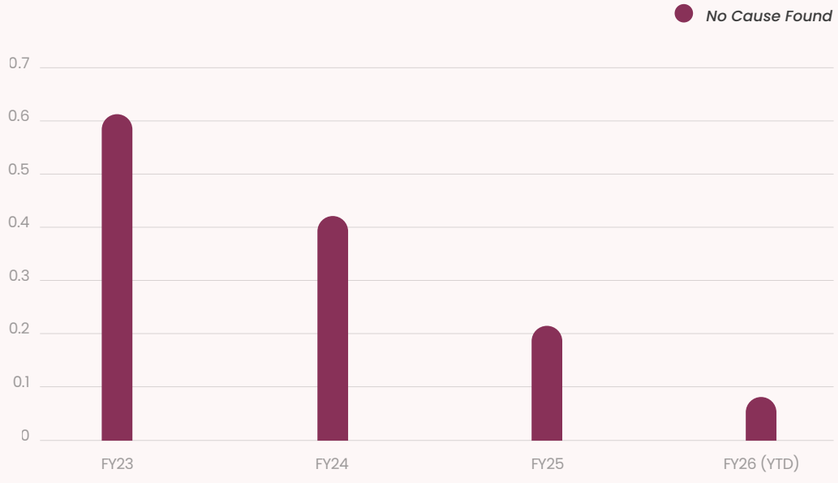


Figure 5.61 SAIFI by financial year for “No Cause Found”



5.5.2 Asset Performance Trends (continued)

The graphs on the previous page illustrate event counts and SAIFI for the analysis period (excluding Major Events) relating to "No Cause Found".

Events are classified as No Cause Found when investigations reveal no clear evidence of a likely cause. Based on operational experience, these events typically originate from an approximate equal share of:

- **Vegetation contact:** Brief glancing contact from trees close to conductors, often assisted by wind, or debris from trees further away that momentarily touches the line before falling clear.
- **Wildlife contact:** Instances where the animal responsible was not identified.
- **Transient equipment failures:** Issues such as deteriorating insulators or short-lived conductor contact that may temporarily clear, only to recur later. These failures are often triggered by local weather changes and therefore occur under certain conditions.

Data indicates a declining trend in number of events over recent years, and an even stronger uplift in customer experience. We believe this partly correlates to our vegetation trends but is also reflective of the effort we put in to follow up on No Cause Found events, treating them as a leading indicator of a potential future power issue. This proactive approach prevents further disruptions for our customers.

From 2023 to 2025, our network-wide fleet of remote-control switchgear was expanded and upgraded to provide and record fault location data for all faults, including transient faults cleared by auto-reclosers. In addition, our electronic protection relays supply fault current monitoring information, helping us group and identify faults more effectively.

Our operational procedures require a mandatory patrol of any network that has tripped and locked out (i.e. failed to auto-reclose). This patrol is carried out even if the network is restored before completion. We also patrol any circuit that experiences two or more successful auto-reclose events within a rolling seven-day period. Depending on the circuit, these patrols must be completed within one to five days, and findings are fed back through corrective or reactive maintenance processes based on urgency. Patrols are guided by location data from remote switchgear and protection relays.

5.5 Asset Performance

5.5.2 Asset Performance Trends (continued)

Third Party Incident

Figure 5.62
Event count by financial year for third party incident

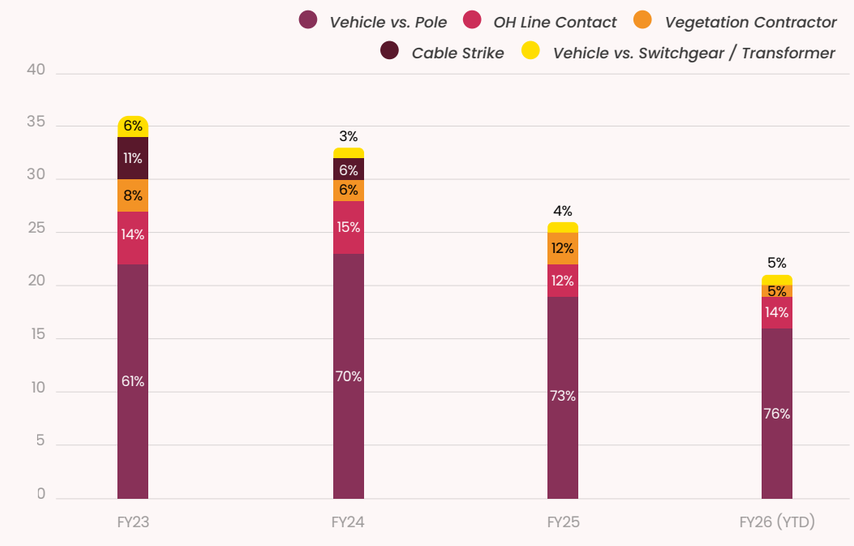
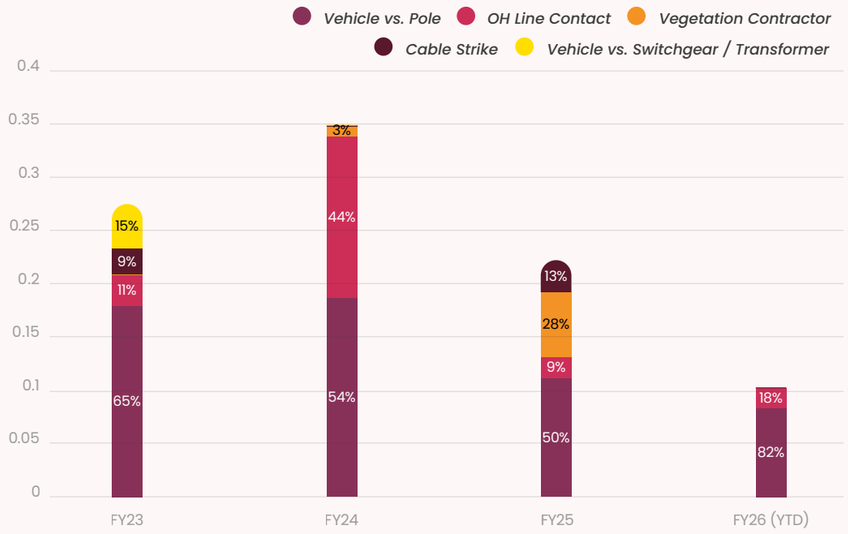


Figure 5.63
SAIFI by financial year for third party incident



5.5 Asset Performance (continued)

5.5.2 Asset Performance Trends (continued)

The graphs on the previous page illustrate event counts and SAIFI for the analysis period (excluding Major Events) for Third Party Incidents.

Events are recorded as Third Party Incident when the event was caused by a third party impacting or interacting with our network. The category is broken down into:

- **Vehicle Versus Pole:** A vehicle impacting one of our poles.
- **OH Line Contact:** An object or thing in the control of a third party that impacts our overhead lines. This can be mobile plant, high loads, metallic balloons or high-pressure water jets from irrigation sprayers.
- **Vegetation Contractor:** Vegetation impacting lines as a result of work undertaken by a third party (not work being undertaken by Counties Energy or our contractors).
- **Vehicle Versus Switchgear/Transformer:** A vehicle impacting one of our ground-mounted switchgear or transformer assets.
- **Cable Strike:** Contact with our underground cable assets as a result of work undertaken by a third party (not work being undertaken by Counties Energy or our contractors).
- **Vandalism or Theft:** Vandalism, malicious intent or theft of our assets.

We have an asset vulnerability model which identifies network assets located near sections of road with high numbers of reported crashes. This is used as part of our safety-in-design processes to inform asset planning and, in some cases, will result in assets being installed with additional protection, engineered differently, or relocated.

In early 2025, a dedicated full-time Asset Protection Controller role was established within the field operations team. The role is responsible for ensuring that work undertaken near Counties Energy assets is carried out safely, compliantly, and with appropriate risk management. This includes managing the close-approach consenting process, acting as an on-the-ground presence across the network, building relationships with third parties working near our lines, and educating them about the location of our assets and how to work safely around them.

5.5 Asset Performance

5.5.2 Asset Performance Trends (continued)

Wildlife

Figure 5.64
Event count by financial year for wildlife

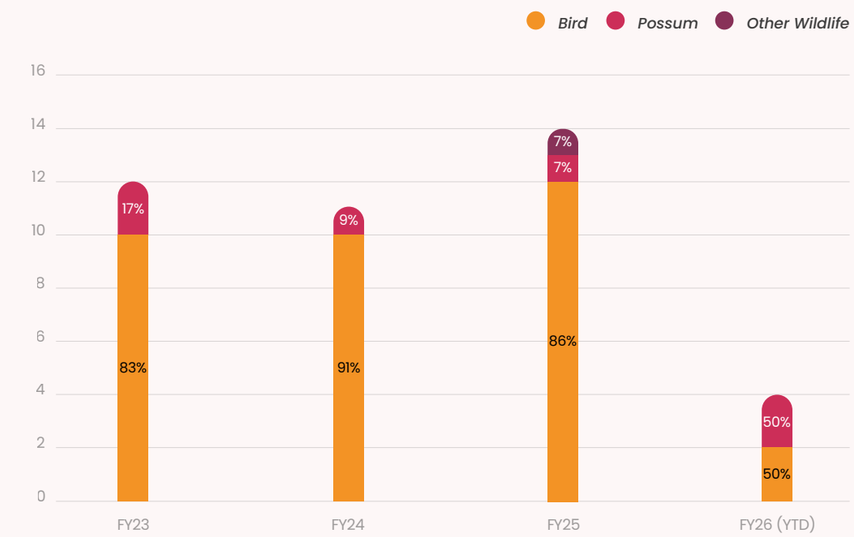
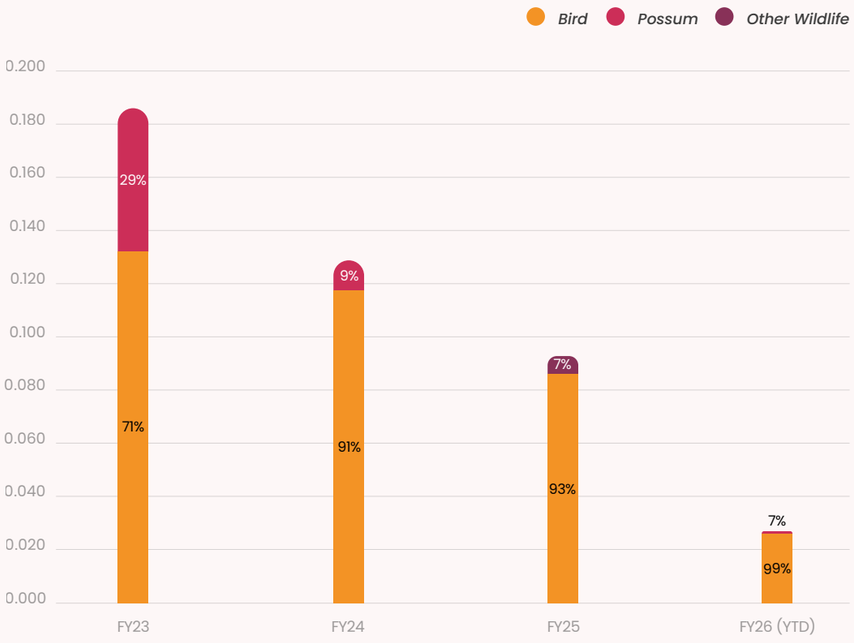


Figure 5.65
SAIFI by financial year for wildlife



5.5 Asset Performance (continued)

5.5.2 Asset Performance Trends (continued)

The graphs on the previous page illustrate event counts and SAIFI for the analysis period (excluding Major Events) for wildlife. The category is broken into the types of wildlife that interact with our assets.

Most wildlife strikes involve birds. The frequency of these incidents changes with the season and time of day. Yearly differences are also noticeable, likely reflecting variations in local wildlife populations and their activity levels.

Many events that result in extended customer interruptions occur on urban networks where auto-reclosing functionality is not enabled, unlike rural networks where this feature is standard. We also recognise that older pole designs were more susceptible to bird strikes, contributing to reliability issues.

Since 2020, we have adopted updated design standards that increase clearances between live components. As a result, every structure replacement or upgrade enhances network resilience to bird strikes. This approach aligns with our long-term reliability strategy and supports incremental improvement through lifecycle asset renewal.

We continuously monitor the geographic distribution of events and maintain the capability to implement targeted, localised replacements should areas of repeat concern emerge. This proactive approach ensures that reliability risks are mitigated before they escalate into significant customer impacts.

In locations where it is appropriate, we deploy conductor-mounted bird diverters, these are high-visibility devices clipped onto overhead power lines to make them more noticeable to birds and reduce collisions. These devices serve a dual purpose:

- **Wildlife Protection:** Reducing the risk of harm to bird populations.
- **Network Reliability:** Preventing outages caused by bird strikes, which can lead to extended customer interruptions.

Our experience shows that bird diverters are effective when installed in targeted areas, complementing our broader strategy of design improvements and proactive asset management. This approach reflects our commitment to both environmental responsibility and network resilience.

5.5.2 Asset Performance Trends (continued)

Typically Minor Causes

Events classified in here include:

- Equipment Failures on Underground, or on Ground Mounted Assets;
- Equipment Failures at Zone Substations;
- Adverse Conditions – Weather conditions outside of design limits such as tornadoes, lightning, seismic events, landslip, flood or wildfire; and
- Network Incidents – Events caused by the actions of Counties Energy or our contractors that have resulted in an unplanned event.

Historically, "Typically Minor Causes" events account for less than 10% of annual SAIDI. Due to their low number, these events are challenging to trend and show volatility in performance metrics. However, we recognise that incidents such as zone substation equipment failures or tornadoes can quickly escalate into Major Events. Therefore, while "Minor" refers to low business-as-usual SAIDI impact, asset management focus remains a priority since these assets are often critical.

5.5.2 Asset Performance Trends (continued)

Figure 5.67 Event count by financial year for "Typically Minor Causes"

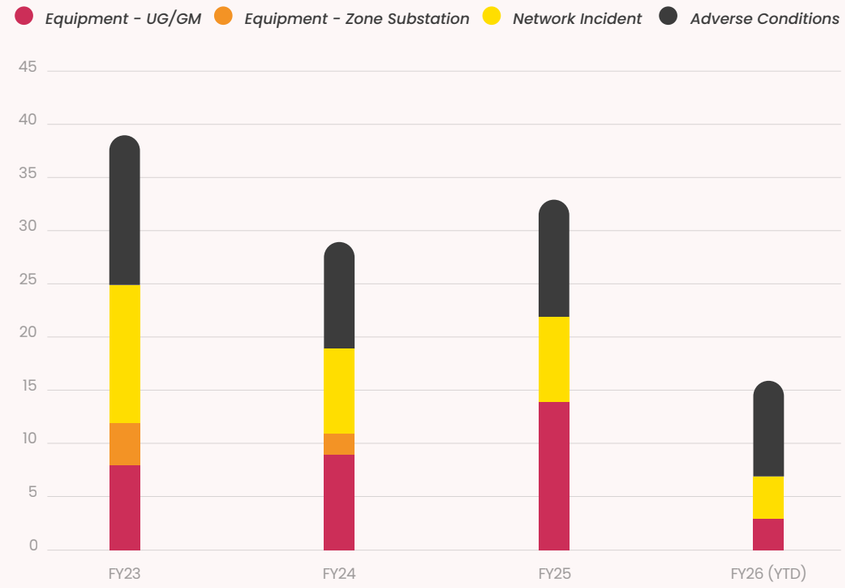
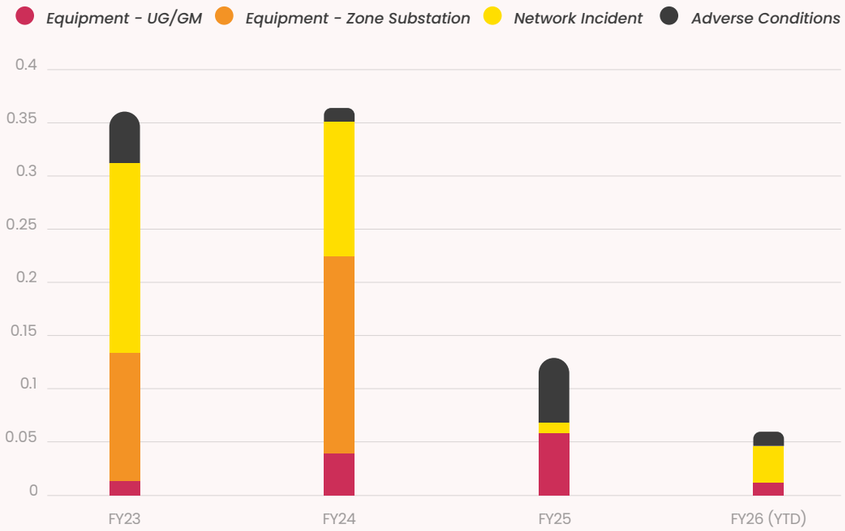


Figure 5.68 SAIFI by financial year for "Typically Minor Causes"



The graphs illustrate event counts and SAIFI for the analysis period, excluding Major Events.

5.5.3 Major Event Periods

Reporting on Major Events Periods is a core component of our reliability strategy (refer to section 4.8.6).

The following table shows the summary of periods identified in FY25 as Major Events.

Note that FY25 was within the previous regulatory period (DPP3), therefore the normalisation rules applicable for the DPP3 period apply. These are now updated for the latest DPP4 period which started on 01 April 2025.

	Major Event Window		Duration (Hours)	SAIFI Event?	SAIDI Event?	Primary Cause Description
	Start of First Event	**End of Last Event**				
1	11/04/2024 02:22	12/04/2024 18:40	40	Yes	Yes	Stormy/windy weather
2	29/05/2024 00:10	31/05/2024 21:17	69	No	Yes	Stormy/windy weather
3	02/01/2025 08:33	02/01/2025 16:57	8	No	Yes	High SAIDI event on feeder

Table 5.15 Summary of periods in FY25 identified as "Major Events"

5.5.3 Major Event Periods (continued)

FY25 Major Event One

A day of wet and windy weather saw a number of events on various feeders across the network. The sum of these events triggered the DPP3 SAIFI and SAIDI major event period thresholds.

In total, 0.173 SAIFI was normalised to 0.032, and 15.15 SAIDI was normalised to 1.21.

A notable event in here, the largest in SAIDI, was an Equipment Overhead event on the Kaiaua feeder, likely caused by the high winds, which impacted more than 1000 customers. Usually, this area relies on support from our neighbouring EDBs should our primary lines have an issue, but due to the regional weather impact, the backup line was also unavailable. As a result, a large number of customers had to remain without supply for a longer period than usual, incurring more than 8.0 SAIDI minutes.

Figure 5.69
SAIFI for major event one

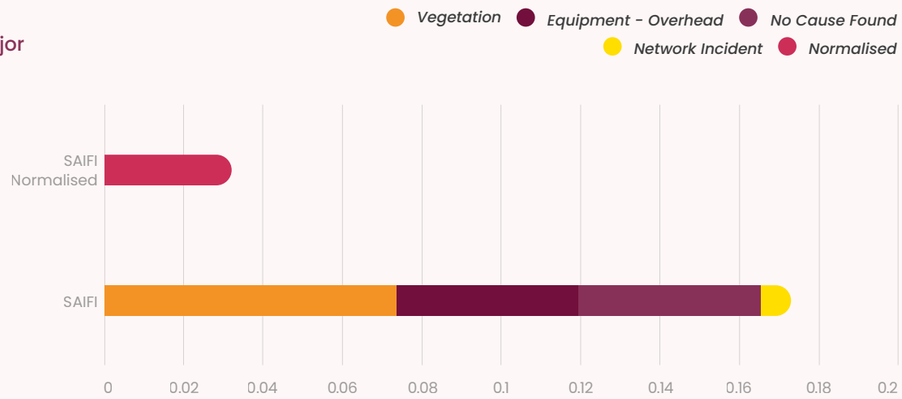
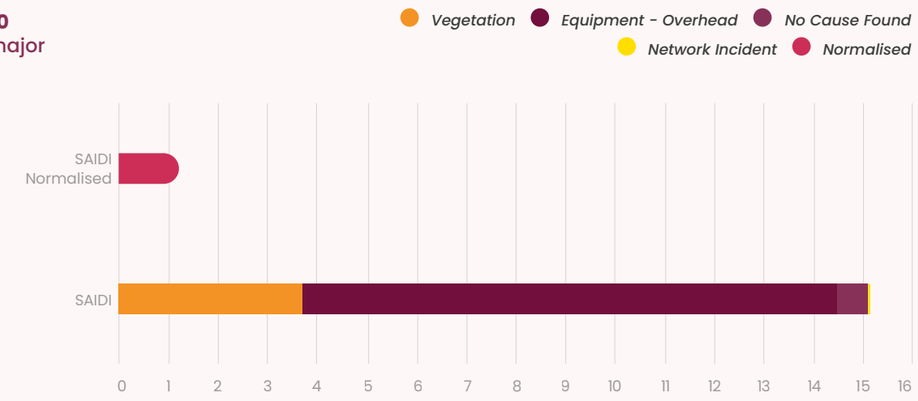


Figure 5.70
SAIDI for major event one



5.5.3 Major Event Periods (continued)

FY25 Major Event Two

A day and a half of wet and windy weather saw a number of events on various feeders across the network. The sum of these events triggered the DPP3 SAIDI major event period threshold, but not the SAIFI threshold as it was only marginally under.

In total, 0.132 SAIFI was incurred (not normalised), and 15.75 SAIDI was normalised to 2.51.

Figure 5.71
SAIFI for major event two

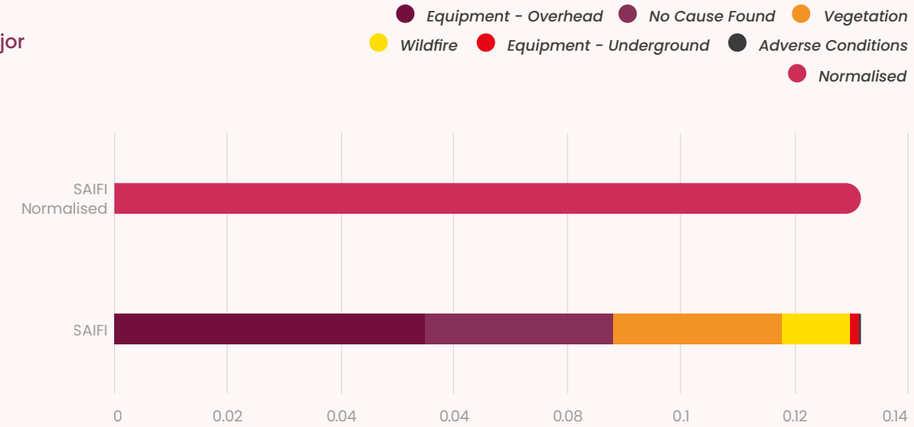
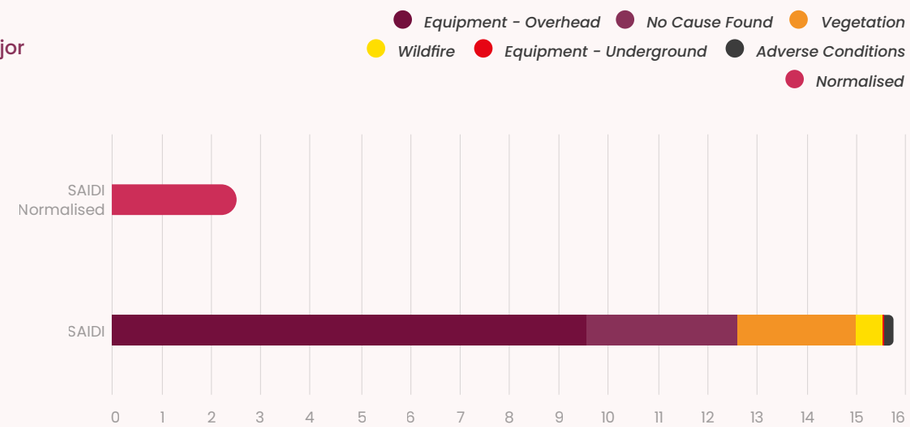


Figure 5.72
SAIDI for major event two



5.5.3 Major Event Periods (continued)

FY25 Major Event Three

This event was caused by a single event on our second largest feeder, impacting over 3000 urban customers. The original cause was a tree branch falling on a high-voltage line that should have only impacted approximately 100 customers. However, the operation of our back-up protection system caused the wider outage. The event also caused a voltage rise on other parts of our HV network, which exposed a set of incorrectly installed lightning arrestors, causing another short outage.

The sum of these two events triggered the DPP3 SAIDI major event period threshold, but not the SAIFI threshold.

In total, 0.072 SAIFI was incurred (not normalised), and 7.38 SAIDI was normalised to 0.137.

Figure 5.73
SAIFI for major event three

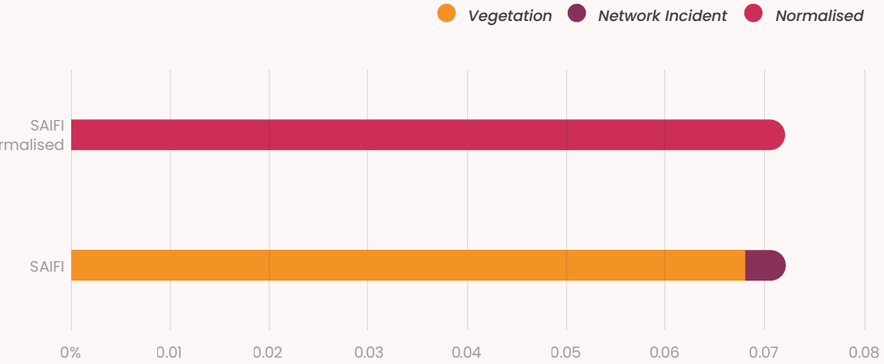
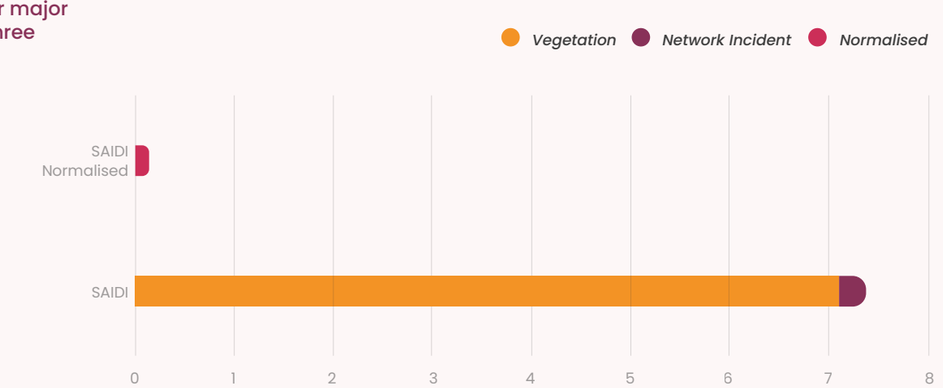


Figure 5.74
SAIDI for major event three



5.6 Non-Network Assets

5.6.1 Buildings and Facilities

Building assets include office buildings, staff facilities, yards and storage areas, and associated infrastructure that support operational delivery.

Development, Maintenance and Renewal Policies

Our building and facilities requirements are reviewed frequently, to identify if there are any changes that may be required to ensure the efficient operational delivery of our business. Therefore, the development and renewal of our building assets is on an 'as necessary basis.'

These assets are managed under preventative maintenance schedules supported by service contracts, with renewal and refurbishment activities prioritised based on asset condition, safety and operational requirements. Energy consumption is actively monitored and improved through upgrades to building systems and ongoing operational optimisation.

Recent and Planned Capital Investment

During FY25, capital expenditure focused on targeted improvements to support operational resilience and safety, including:

- Completion of surface and stability refurbishments in yard and storage areas.
- Improvements to staff facilities within larger team buildings.
- Replacement of aged infrastructure, including security gates.

Preventative maintenance regimes and service contracts have been implemented for the new office building. Power consumption has been progressively reduced through optimisation and replacement of building control systems. We continue to expand our solar portfolio across our Glasgow Road campus, with additional buildings coming online over time.

Maintenance and Renewal Outlook

Over the next five years, buildings and facilities will continue to be managed through:

- Ongoing preventative and condition-based maintenance of buildings and associated infrastructure.
- Targeted refurbishments and renewals as assets reach predefined condition or performance thresholds.

As the main building on the Glasgow Road site (the office building) is new, there are no known material expenditures on the structure for the next five years. Some minor expenditure is expected to improve the driveways and parking around and in front of the building.

5.6 Non-Network Assets (continued)

5.6.2 Tools and Equipment

Tools and equipment include portable and fixed operational equipment used across all teams.

Development, Maintenance and Renewal Policies

Our development, maintenance and renewal policies for these assets ensure they are managed through a structured safety and renewal framework designed to ensure compliance, reliability and cost-effective replacement.

A six-monthly testing and tagging programme is consistently applied across all teams, enabling the identification and replacement of faulty or end-of-life equipment in a controlled and auditable manner. Following a review of this programme, minor adjustments have been implemented to improve efficiency, with lower-cost and lower-risk items replaced directly where this is more economical than testing. Recycling programmes are in place for retired equipment.

Maintenance and Renewal Outlook

Planned activities over the forecast period include:

- Continuation of six monthly testing and tagging cycles.
- Progressive replacement of tools and equipment reaching end of service life.
- Ongoing optimisation of renewal practices to balance cost, safety and environmental outcomes.

5.6.3 Vehicle Fleet and Machinery

The vehicle fleet comprises heavy lift trucks, heavy machinery (including chippers and excavators), and light utility vehicles that support operational, maintenance and field-based activities. Fleet assets are renewed at end of economic life in accordance with established renewal policies, with consideration given to safety, emissions reduction, operational suitability and whole-of-life cost.

Development, Maintenance and Renewal Policies

Development, maintenance and renewal policies for these assets are guided by our vehicle policy. Company vehicles are replaced based on kilometres travelled and age, as directed by the Chief Executive. Utes are generally not replaced before five years of service or 180,000 km. Trucks are assessed individually, typically on a 5-10 year cycle. Passenger vehicles are considered for replacement at 100,000 km or five years, whichever occurs first.

Recent and Planned Capital Investment

In FY25, fleet related capital investment included:

- **Procurement of two heavy lift trucks to replace vehicles that had reached end of economic life.**
- **Replacement of heavy machinery, including chippers and excavators, where required.**

All newly ordered lift vehicles are specified with rechargeable electric lift batteries to operate hydraulics, eliminating the need for diesel engine idling and reducing emissions and noise. Several existing heavy lift vehicles have also been retrofitted with electric lift systems to deliver further efficiency and emissions improvements.

Light Fleet and Electric Vehicle Transition

Hybrid vehicles have replaced more than 15% of light utility vehicles where usage patterns support this transition, resulting in reduced purchase costs, fuel consumption and emissions.

Our electric vehicle (EV) adoption strategy for our fleet remains under development due to evolving market maturity and infrastructure considerations.

To support informed decision-making:

- **Two electric vehicles have been purchased and are undergoing extensive operational trials.**
- **EVs are expected to become an integral part of selected fleet segments over the next 4–5 years, as vehicle performance, range and charging infrastructure continue to improve.**

5.6.3 Vehicle Fleet and Machinery (continued)

Maintenance and Renewal Outlook

Over the next five years, fleet and machinery management will focus on:

- **Ongoing replacement of heavy and light vehicles at end of economic life.**
- **Continued retrofit of existing vehicles where feasible to improve efficiency and reduce emissions.**
- **Gradual increase in hybrid and electric vehicle adoption where operationally suitable.**

Mobile Generators

Counties Energy owns two mobile generators. The first is a 100 KVA unit purchased in 2017, now nine years old and in good condition. The second is a 45 KVA unit purchased in 2018, now eight years old and also maintained in good condition.

5.6.4 Digital

The digital investment for the planning period is $49.1m; averaging circa $5m p.a. More detail on the strategic programme of work can be found in Chapter 8.0.

Counties Energy continues to invest heavily in the digital area to improve systems, automate business processes and ensure cybersecurity requirements are addressed. Digital investment has become paramount in today's utility sector, driven by rapid developments in machine learning (ML), artificial intelligence (AI), spatial imagery, and advanced network orchestration. These technologies are transforming operational efficiency, asset management, and customer service by enabling predictive maintenance, real-time monitoring, and data-driven decision-making. ML and AI facilitate the analysis of vast datasets, helping utilities anticipate demand, optimise resource allocation, and identify potential faults before they escalate, thereby minimising downtime and reducing operational costs.

Furthermore, the integration of spatial imagery and advanced network orchestration allows for enhanced grid visibility and control, supporting the transition to distributed energy resources and smart grid solutions. As utility networks become increasingly complex, digital investments ensure organisations remain agile and resilient, capable of adapting to evolving regulatory requirements and customer expectations. In this context, a robust digital strategy is essential to unlock the full potential of emerging technologies, ensuring sustainable growth and improved service delivery across the sector.

Development, Maintenance and Renewal Policies

We have digital development, maintenance and renewal policies in place to ensure we deliver a robust and reliable electricity service every day, unlock new energy services and experiences, and reimagine a new energy future through our role as a DSO.

Given the pace of technology, Counties Energy develops long-term and short-term technology roadmaps.

Maintenance and Renewal Outlook

Shown next are key investment areas planned for FY27 and FY28.

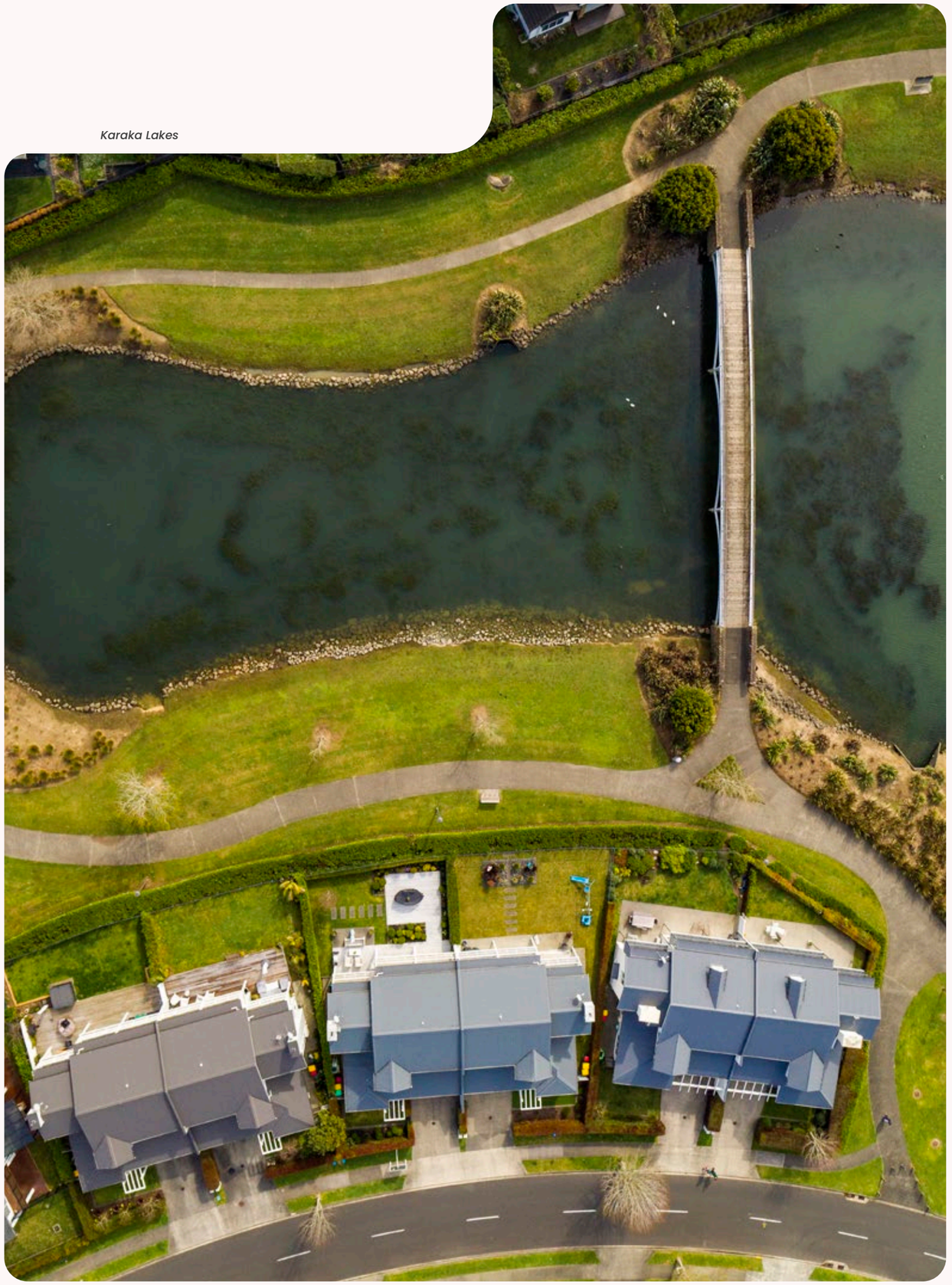
5.6 Non-Network Assets (continued)

5.6.4 Digital (continued)

Pillars	Platforms	Description	Investment Timeframe	Cost ($000s)
CORE SYSTEMS				
Smarter Assets	ADMS Enhancement – OMS	Implementing GE Outage Management System within the ADMS Platform	FY27-FY28	1,600
	Maximo – Asset Management System	Enhancing the base EAM to include various asset categories and their preventative maintenance schedules	FY27-FY28	450
	GE Smallworld GIS	Enhancing the base GIS platform as the primary source of truth	FY27-FY28	200 (Per Annum)
	5-min Smart Metering Data	Implementation of high-frequency data capture and store from existing smart meters	FY27-FY28	2,300
Business Excellence	Business Central & Project Management	Upgrade of the Microsoft Business Central platform, and provision of capital project management system.	FY27-FY28	450
	Digital & Mobility Transformation	Application of digital technology across all business functions, including vegetation	FY27-FY28	550
Our Customers	Salesforce and Customer Channels	CRM, Outage Hub, capacity maps, digital channels	FY27-FY28	300 (Per Annum)
Digital Foundations	Data Management and Integration	Snowflake Datawarehouse, analytics and system integrations	FY27-FY28	300
	Other Core Systems	IT system, OT/IT networking and security enhancements	FY27-FY28	1,250
ROUTINE REPLACEMENT				
	Core Network Infrastructure	Network infra such as switches, servers, UPS, etc. to maintain network reliability	Annual	200 (Per Annum)
	PCs, Laptops, and Field Mobile Devices	Replacement of devices to ensure fit for purpose	Annual	125 (Per Annum)

Table 5.16 Digital investment areas

Karaka Lakes



06

Our Planning & Investment Approach

6.1 About This Chapter

This chapter outlines Counties Energy's approach to planning and investing. It discusses the investment drivers we consider, the planning methodologies we use, the future network requirements, scenarios, forecasts and assumptions we must plan for, and the design standards embedded into our planning and investment.

6.2 Investment Macro Drivers

Investment over our 10-year planning horizon is guided by a defined set of primary and secondary macro drivers that support prudent long-term stewardship of our network and the outcomes expected by customers. The primary investment drivers are growth, renewals, reliability, resilience, decarbonisation, and customer expectations.

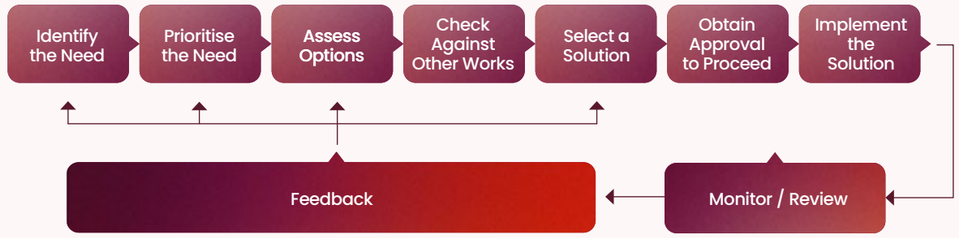
Growth-related investment responds to the forecast increases in demand, new connections, and changing load profiles, including the accelerating uptake of electrification and distributed energy resources. Renewals investment addresses assets at, or approaching end-of-life to better manage condition-related risk and sustain network performance. Reliability investment focuses on maintaining and improving our service performance, while resilience investment strengthens our network's ability to withstand and recover from major events and longer-term climate-related impacts.

Decarbonisation is a key driver, reflecting the role of the distribution network in enabling low-carbon technologies and supporting the transition to a more electrified energy system. Customer expectations increasingly influence investment decisions, including expectations for timely and simpler connection of new load and distributed generation, greater transparency, and the availability of flexible and non-standard connection solutions where these deliver more efficient outcomes. Secondary investment drivers include safety, evolving regulatory and policy settings, increasing digitalisation of our network and business processes, operational efficiency, innovation, environmental considerations, land access and constructability constraints, and broader stakeholder and community outcomes. These secondary drivers are considered alongside the primary drivers to ensure our investment decisions are balanced, adaptable, and deliver long-term value for customers.

6.3 Investment Planning Process

Our network investment process consists of decision-making steps to ensure we make the correct investment decisions and adequately consider any viable alternatives. A high-level overview of this process is shown below.

Figure 6.1
Investment Planning Process Overview



The key steps in our investment planning process for network-initiated projects are:

1. **Identification of the Need** – The need for investment arises from routine business cycle activities such as:

- Our network planning process identifying constraints on the system;
- Our maintenance process, including asset condition surveys; and
- Network fault and performance data, including the network performance trend analysis.

These processes produce a list of issues which may require investment.

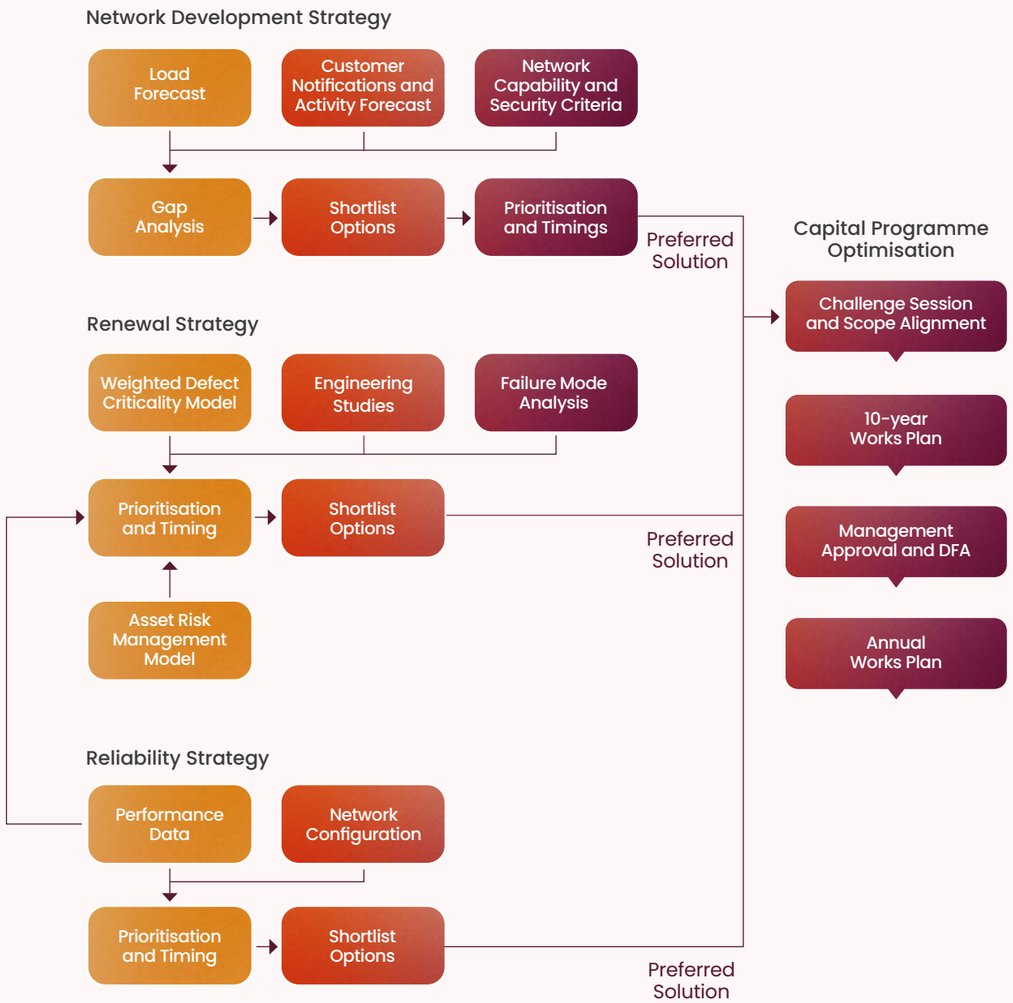
2. **Prioritisation of the Need** – Prioritised by risk (including safety, security, reliability, environmental and regulatory), timings and criticality.
3. **Assess Options** – Optionality is developed with risks, benefits and high-level costs. Benefits will include all aspects, including those directly seen by our customers (such as improved SAIDI and SAIFI performance) and wider benefits from improved network resilience. From this, a preferred option is recommended.
4. **Coordination Assessment** – Projects are assessed for any overlap between drivers.
5. **Select a Solution** – The solution is selected based on the option providing the highest benefit relative to risk.
6. **Approvals to Proceed** – The business case outlining the preferred solution is presented for the appropriate level of management approval.
7. **Implementation of the Solution** – Design and delivery.
8. **Review/Feedback** – After completion, the project implementation and results are reviewed, and feedback is provided to inform and continuously improve the steps in the process for future projects.

6.3 Investment Planning Process (continued)

The investment decision-making process is simplified for customer-initiated projects, such as network extensions and subdivision reticulation. A solution is identified to meet the customer's capacity, security and cost requirements. The timing of these investments is to suit the customer and is not discretionary.

Figure 6.2 demonstrates how the planning activities within each strategy are coordinated and aligned, and consolidated for delivery into the 10-year plan and annual works plan.

Figure 6.2
Integration of Planning Activities



6.4 Network Planning for the Future

Counties Energy is entering a transformational era in the electricity sector, driven by rapid technological change, decarbonisation goals, and evolving customer expectations. Our region is experiencing unprecedented growth, and we are committed to ensuring our network remains safe, reliable, resilient, and sustainable while enabling continued innovation and flexibility for the future.

Meeting Regional Growth and Demand

Our service area spans a diverse mix of urban and rural communities, each with unique energy needs. Significant development is underway in Pukekohe, Paerata, Drury, Karaka, Glenbrook, Pōkeno, and Waiuku. These growth corridors are driving sharp increases in electricity demand and new connection requirements. At the same time, rural areas require targeted solutions to maintain resilience and reliability, particularly as climate change increases the risk of severe weather events.

To keep pace with this growth, our 10-year investment plan focuses on upgrading and expanding our network capacity, ensuring infrastructure development aligns with population trends, housing intensification, and industrial expansion. This includes strengthening both high-voltage systems for industrial loads and low-voltage networks for residential areas.

Enabling Decarbonisation and Electrification

New Zealand's commitment to achieving net zero greenhouse gas emissions by 2050 is reshaping the energy landscape. Counties Energy is playing a critical role in enabling this transition by supporting the electrification of transport and process heat, reducing reliance on fossil fuels, and integrating more renewable energy sources.

The uptake of electric vehicles (EVs), electrification of industrial processes, and the shift to electricity for heating and cooling will significantly increase demand and alter consumption patterns.

The city of the future shows where distributed energy resources - such as rooftop solar, community batteries, electric vehicles, and microgrids - are seamlessly integrated with a strong core electricity network. While energy is increasingly generated and managed locally, the central network continues to play a critical role in providing system strength, reliability, and backup supply. Smart substations, advanced metering, and coordinated control systems enable two-way power flows, ensuring the network can safely balance local generation with wider regional demand. Together, distributed resources and the core network form a resilient, flexible energy system that supports decarbonisation, growth, and reliable supply.

6.4 Network Planning for the Future (continued)

Integrating Distributed and Consumer Energy Resources

The future energy ecosystem will be more decentralised and interactive. Distributed Energy Resources (DERs), such as utility-scale solar and wind generation and battery storage, will become increasingly important. At the same time, Consumer Energy Resources (CERs) – including EVs, rooftop solar PV, residential batteries, and Home Energy Management Systems (HEMS) – will empower customers to generate, store, and manage their own energy.

Counties Energy is investing in advanced technologies to enable bi-directional power flows, real-time monitoring, and dynamic load management. This modernisation will allow us to integrate DER and CER effectively, optimise network performance, and unlock opportunities for demand flexibility.

Building a Smarter, More Resilient Network

Our modernisation strategy is centred on creating a digital, data-driven network that can adapt to changing conditions and customer behaviours. This includes deploying smart grid technologies, enhancing automation, and investing in advanced analytics to improve forecasting and decision-making.

Resilience is a key priority. As climate change increases the frequency and severity of storms and flooding, we are strengthening our infrastructure and emergency response capabilities to minimise outages and restore power more quickly.

The city of the future

6.4 Network Planning for the Future (continued)

6.4.1 Network Planning Approach

Our network planning approach is aligned with our corporate strategy and vision to "unlocking the full energy potential of our region, to secure a sustainable and prosperous future for generations to come". It is designed to enable a smarter, more resilient, and more flexible network that supports the evolving energy landscape, including electrification, distributed generation, and decarbonisation.

Long-Range Planning

We focus on shaping the network for the next decade and beyond, considering:

- **Growth and new supply areas:** Anticipated demand from residential developments, industrial precincts, and commercial hubs, alongside electrification trends and electric vehicle (EV) uptake.
- **Future-ready feeder capacity:** Ensuring the distribution network can meet security, capacity, and flexibility requirements under diverse scenarios.
- **Subtransmission and zone substations:** Assessing adequacy to maintain resilience and accommodate emerging technologies such as grid-scale batteries and renewable integration.

Short-Range Planning

Our near-term priorities centre on improving operational performance and adaptability, including:

- Network safety and reliability as non-negotiable foundations.
- Planning for uncertainty: Incorporating flexibility to manage variable generation, demand-side participation, and new energy technologies.
- Security of supply and customer connections with rapid response to growth and electrification.
- Voltage and power quality management: Advanced control strategies, power factor correction, and dynamic voltage regulation.
- Efficiency and sustainability: Reducing losses, improving service quality, and optimising asset utilisation.

We maintain extended planning horizons to address long lead times for land acquisition, designations, and easements, ensuring timely delivery of strategic upgrades.

6.4 Network Planning for the Future (continued)

6.4.1 Network Planning Approach (continued)

6.4.1.1. Network Planning Drivers and Assumptions

Our network investment programme is based on the following key drivers and assumptions:

- The network must comply with all applicable safety, technical, and legislative requirements.
- Investment options should, where economically efficient, retain flexibility to accommodate future changes in demand, technology, and network configuration.
- We will invest, where economically justified, to meet required security and reliability standards.
- We will invest to meet forecast demand and growth requirements in the most efficient way.
- Investment decisions will be made to minimise the risk of inefficient asset stranding over the life of the asset.
- Large connections, including data centres and large-scale generation, are excluded as they create discrete step changes that materially distort forecast accuracy.

6.4.1.2. Energy Efficiency Considerations

As part of our network planning process, we incorporate energy efficiency considerations into all stages of network design and operation. Key considerations include:

- **Voltage and Network Loading:** We select appropriate operating voltages and configure the network to operate efficiently, with the objective of minimising electrical losses.
- **Energy-efficient Equipment:** All new assets, particularly transformers, are required to comply with relevant IEC (International Electrotechnical Commission) and AS (Australian Standards) for energy efficiency, including applicable Minimum Energy Performance Standards (MEPS).
- **Design and Reinforcement Options:** When assessing network reinforcement options, we evaluate the impact on network losses and overall efficiency. These considerations form part of the option assessment and preferred solution selection process.
- **Metering:** We ensure metering assets are calibrated and compliant with the Electricity Industry Participation Code to minimise unaccounted-for energy and improve visibility of losses across the network.

Through these measures, we aim to promote efficient energy use and deliver least-cost outcomes consistent with prudent network management and the long-term benefit of consumers.

6.4.2 Future Ready Investment and Network Design

We rigorously evaluate every investment option against non-network alternatives and advanced technologies that can enhance flexibility, reliability, and sustainability. Our approach integrates the latest innovations to create a smarter, more adaptive electricity network, prioritising the optimisation of existing assets and greater network utilisation before committing to major upgrades.

Our design principles ensure safety, adaptability, and efficiency:

- **Safety First:** Public and employee safety is at the core of every development.
- **Phased Solutions:** Where appropriate, staged upgrades can defer major subtransmission and distribution investment.
- **Radial Network with Interlinks:** Primary radial design with feeder interconnections for flexibility.
- **Continuous Reconfiguration:** Adjusting network topology to respond to load growth and demand changes.
- **Optimised Feeder Upgrades:** Better utilisation of tie-lines and alternative feeds to defer zone substation upgrades.
- **Proactive Planning:** Securing line routes and substation sites well ahead of forecasted demand.
- **Balanced Security of Supply:** Ensure appropriate levels of security and resilience are maintained, recognising that full redundancy for all customers is not economically viable.
- **Smart Construction Techniques:** Delta line construction, pole-mounted circuit breakers, automation, and fault passage indicators for improved performance.

This approach positions our network to deliver more sustainable, reliable, and customer-centric energy services, while enabling greater innovation and resilience in a rapidly evolving energy ecosystem.

6.4.3 Network Design Standards

This section outlines our design standards for our subtransmission, zone substations, and distribution network, balancing security of supply, operational resilience, and future growth.

It sets out permitted line voltages, circuit arrangements and transformer requirements for high-reliability substations; defines preferred feeder architectures and placement principles to minimise outage impact; and specifies equipment and conductor ratings that ensure safe operations while accommodating short duration peaks.

6.4.3 Network Design Standards (continued)

Together, these guidelines standardise best practice design (e.g., non-oil circuit breakers, unit protection, enhanced arc containment, and scalable switchboards) so our network can safely host increased demand and DERs, maintain performance during contingencies and high-impact, low-probability (HILP) events, and expand efficiently as our service area evolves and grows.

6.4.3.1. Subtransmission and Zone Substation Design

Counties Energy operates seven Class C4 substations and one Class C3 substation. Transformer impedances are set to limit fault currents to 16 kA at 22 kV and 13.1 kA at 11 kV, with allowances for future generation. Class C4 substations feature at least two circuits from the GXP, which are arranged in ring or parallel configurations, and include two transformers to ensure that, following a fault, 100% of peak load minus 12 MVA can be supplied continuously, with full restoration within three hours. Preferred transformer capacities are 40 or 60 MVA for 110/22 kV substations and 20 or 30 MVA for 33/11 kV substations. Smaller Class C3 substations may be connected via spur lines, though ring feeders are preferred for growth and enhanced security. Single transformers are acceptable where contingency provisions exist for HILP events.

We have been developing subtransmission design standards over the past five years. For our 33 kV networks, we have (and use) a number of Counties Energy standardised designs. Our 110 kV networks are more complex, so although we have a number of standardised designs, we still have more to complete. Substation designs are even more complex, so although we typically use standardised equipment wherever possible, designs are developed and approved for each site.

6.4.3.2. Distribution Network Design

We design our network for the most efficient power flow from substations to customers. In rural areas, smart switching divides lines into sections for faster outage restoration, while urban networks are interconnected to allow electricity rerouting to help minimise disruptions. We place main lines away from busy roads or underground where possible to improve safety, and to avoid clustering overhead lines on high-traffic routes.

District Plans allow overhead lines up to 110 kV in non-residential and rural zones. New and upgraded substations follow best practices, including non-oil circuit breakers and multiple fire zones. Main feeder routes are placed off high-traffic routes or underground if hazards exist, and we generally avoid double-circuit overhead lines to reduce the risk of larger outages.

We have enhanced our design standards over the past five years, and we now have (and use) Counties Energy standardised designs for all distribution asset classes, except where local needs require custom solutions, which require special approval. Our in-house assessor ensures network builds meet standards and identifies improvements. We align our equipment and configurations with other New Zealand EDBs wherever possible to increase availability, shorten lead times, reduce supply chain costs, and boost the ability for resource sharing and collaboration between EDBs if needed during major events that span regions. As part of an industry engineering group across North Island EDBs, we focus on standardisation, though our more unusual 22 kV network limits this somewhat. In 2025, we switched our standard backbone conductor from Cricket to Krypton to better align with industry norms. We will continue to look for further opportunities for cross-EDB standardisation in the future.

6.4.3 Network Design Standards (continued)

6.4.3.3. Equipment Ratings

The following equipment ratings are applied in our designs and to determine equipment constraints:

- Zone substation transformers operating at 100% nameplate rating, with short-term overload up to 120%.
- Switchgear, lines and cables operating at 100% nameplate rating.
- Distribution transformers operating at 100% nameplate rating, with short-term overload up to 150% for transformers with a low load factor.
- Constraint ratings.

We use the following thresholds when undertaking utilisation analysis to flag assets for investigation:

- Single zone substation transformer or switchgear operating at 80% nameplate rating.
- For an N-1 limit, we flag for investigation at 90% of the firm limit, with intervention typically planned between the 110% - 130% range.
- For distribution transformers, any assets with peak loads of 130% - 150% of nameplate rating, and a load factor of >80% are flagged for investigation and intervention.

We apply the following thresholds in our utilisation analysis to identify assets that need further review:

- **Zone Substations:** Any single transformer or switchgear operating at 80% of its nameplate rating is flagged for investigation.
- **Distribution Feeder Conductors or Cables:** Any asset operating at 80% of its nominal rating is flagged for investigation.

6.4.3 Network Design Standards (continued)

6.4.3.4. Constraint Management and Capacity Options

When a constraint or risk threatens Counties Energy's ability to meet security standards, we evaluate a range of solutions. These include optimising the existing network, using flexibility to manage constraints and security risks, upgrading current assets, installing new infrastructure, or deploying alternative technologies such as batteries or generators. The choice of option depends on factors such as the magnitude and timing of the constraint, the duration of exposure for the asset, its location, and the primary driver behind the issue.

Counties Energy's current connections process will determine any constraints relevant to a customer's application. These constraints are then assessed to determine any upgrades required to facilitate the connection. Non-network solutions like flexible connections are also assessed to determine if they're a viable option. This information is then communicated to the customer to aid their decision-making.

6.4.3.5. Security of Supply Criteria

Security of supply refers to our network's ability to continue to meet electricity demand when equipment fails. The criteria we apply are based on the service levels expected by customers, while also considering historical network performance and geographical constraints.

Supply Class	GPD [MVA]	Examples	Reliability Criteria
C1	0 – 0.5	Urban LV distribution transformer	Repair time
C2	0 – 1.5	HV radial feeder (or spur from the main feeder)	Repair time
C3	0 - 12	Rural zone substations and feeders (11 kV and 22 kV)	50% GPD <3hrs; 100% GPD repair time
C4	12 - 40	Zone substations and subtransmission feeders (33 kV or 110 kV)	100% GPD less 12 MVA immediately; Remaining 12 MVA <3hrs
C5	Large customers	Large industrial customers	As per supply agreement

Terms used in the table:

- **GPD** – Group Peak Demand.
- **Repair Time** – The total time from the start of the outage until the customer(s) have power restored (i.e. the total outage time as seen by the customer).
- **Immediately** – Means either an uninterrupted supply or restoration in less than one minute.

Table 6.1 Security of supply criteria

6.4.3 Network Design Standards (continued)

6.4.3.5. Security of Supply Criteria (continued)

Our network design enables us to reconfigure it to provide supply from alternative sources as required. Our feeders are designed to keep voltage levels within the required standards during normal operation. In rare cases, such as during repairs or switching, these levels may temporarily vary.

As towns grow and rural areas become more developed, some rural feeders end up serving urban customers. Rural feeders are usually overhead lines, and have lower reliability than urban feeders due to greater exposure to factors such as vegetation, wildlife, and weather. Urban feeders, however, often include underground cables, which are more reliable. To improve service as urban areas expand, we sometimes reconfigure parts of rural feeders to connect to urban networks. This usually involves using existing switches, and occasionally upgrading lines, to ensure customers get a more dependable supply.

For larger customers, we set supply security levels based on their size, location, and any special conditions in their agreements. In some cases, these customers may select higher security levels. However, for most customers, who share network assets, individual service levels aren't practical, so we focus on meeting the targets defined in the table above. We monitor network performance using industry measures like SAIDI, SAIFI, and CAIDI, which track both planned and unplanned outages.

Aerial view of Gellert's Nurseries in Karaka

6.4.4 Demand, Scenarios and Forecasts

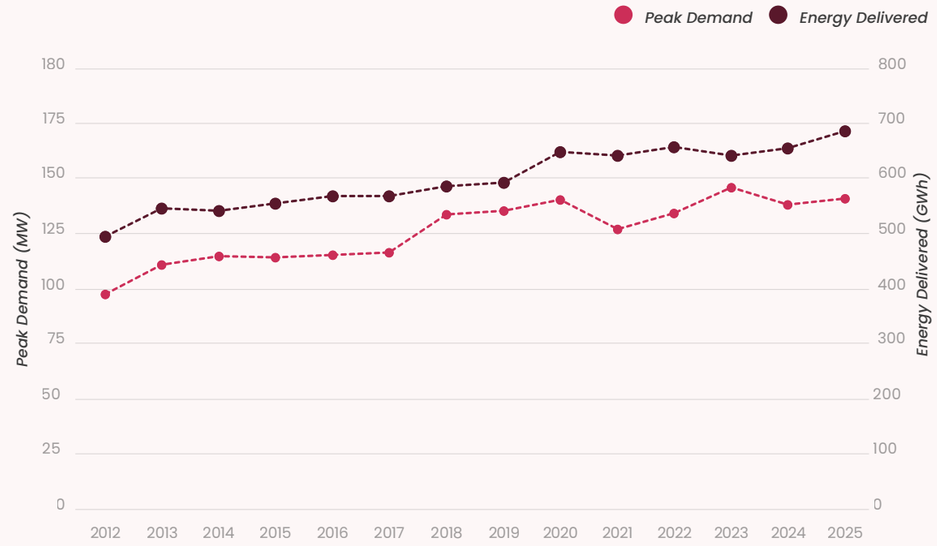
Aotearoa New Zealand's energy landscape is undergoing rapid transformation, and Counties Energy plays a pivotal role in enabling decarbonisation and supporting the electrification of the economy to achieve New Zealand's net zero greenhouse gas emissions target by 2050.

This transition is complex and shaped by the unique characteristics of our region. Counties Energy operates across a diverse area that includes rapidly growing urban centres and extensive remote rural communities, each with distinct energy needs. Significant population growth and housing intensification in areas such as Drury, Hingaia, Pukekohe, Pōkeno, and Paerata are driving sharp increases in electricity demand, while rural parts of the network require targeted solutions to maintain and improve resilience and reliability.

Counties Energy must also prepare for the increased uptake of electric vehicles, electrification of process heat, and distributed energy resources such as solar generation and battery storage. These changes will require a tailored investment strategy that balances high-voltage capacity for industrial loads with low-voltage upgrades for residential intensification, alongside advanced digital systems to manage bi-directional power flows and customer flexibility.

Our system peak demand and energy delivered trends are shown below.

Figure 6.3
System Peak Demand and Energy Delivered



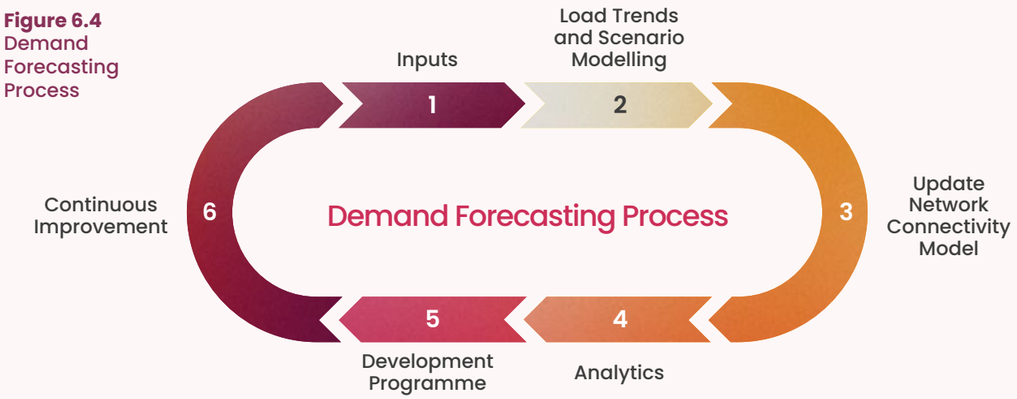
6.4.4 Demand, Scenarios and Forecasts (continued)

6.4.4.1. Forecast Approach

Maximum demand on our system is a key driver for network growth investment. Our demand forecast defines future network requirements and is critical for identifying constraints and determining the timing of capacity and security-related investments. While forecasting future demand is inherently uncertain and subjective, it provides an indication of when potential capacity or security constraints may arise.

Our demand forecasting methodology follows the process shown below.

Figure 6.4 Demand Forecasting Process



Step 1 Inputs

We use the following inputs to develop our demand forecast:

- **Demand data:** We use 15-minute average demand data collected from our SCADA system to monitor loads on all substations and feeders on our network. In addition, smart metering data is used to validate the demand observed via SCADA. We use this data to analyse trends, load shifts and power factor for each feeder;
- **Embedded generation:** SCADA and metering data for generators;
- **Coincident demands:** We extract the coincident maximum demand from the quarter-hourly data for our zone substations, feeders and embedded generation;
- **Key customer demand:** We review energy data for key customers using demand meters installed at various premises. We also consult with our major customers to identify any planned future expansion and changes in their demand;
- **Subdivision activity:** We track subdivision activities by feeder for the planning period based on our knowledge of local authority and developer's plans. Where load requirements are unavailable, we assume ADMDs of 3.5 kVA per lot for new domestic subdivisions. Demand estimates for industrial/commercial subdivisions are based on customer requests or known forecasted demand;
- **Land zoning:** To set long-term loading expectations, we consider the relevant Council zoning plans to identify the ultimate developments expected for an area and their impact on our network; and
- **General demographic and economic trends:** We collect demographic trend information from publicly available census data and new connections to our substations. We use this data to verify our demand forecast.

Step 2 Load Trends and Scenario Modelling

The inputs gathered in Step 1 are used to verify our previous forecasts, update any load trends and undertake scenario modelling. We start by developing forecasts for individual feeders based on historical trends and the anticipated growth in various sectors the feeder supplies. We then roll the individual feeder forecasts up to the zone substation and ultimately back to the two Transpower GXPs supplying our network, Bombay and Glenbrook.

Step 3 Update Network Connectivity Model

The distribution network evolves through the year due to configuration changes resulting from load transfer between feeders, renewal-driven improvements, abnormal operating conditions, and new developments. We regularly update our network connectivity model to include these changes. This helps identify any shortfalls and constraints appearing on the network.

We record system changes and network reconfigurations to monitor load transfer between feeders and in various areas. We review these changes and consider spikes in active and reactive demands to verify the maximum demand for each feeder or zone substation.

Step 4 Analytics

The outputs from the load trends and our network connectivity model (using DigSILENT PowerFactory modelling software) identify issues or potential issues related to voltage breaches, thermal breaches, loading and configuration risks.

Once the constraints and their timing are identified, options are considered to determine the best solution. The selected option may include the following:

- Augmentation to increase capacity;
- Network reconfiguration to improve utilisation;
- Grid-scale battery solutions to provide voltage support or backup supply;
- Remote area power supplies instead of traditional network build;
- Load control to manage specific peaks; and
- Demand-side management.

6.4.4 Demand, Scenarios and Forecasts (continued)

Step 5 Development Programme

The solutions identified in Step 4 above help inform the investment proposals for the network development programme over the period covered by this plan. While this process is used to identify these proposals, further detailed analysis is undertaken to inform the business case that is prepared before eventual investment. Where the timing of requirements aligns, we incorporate this programme with our asset replacement, maintenance and reliability programmes.

Step 6 Continuous Improvement

Counties Energy undertakes continuous monitoring of our network, investments, and network performance to ensure the value identified in the above proposals is delivered. The review process ensures we continually learn and improve our inputs into future demand forecasting.

In the last year, advanced analytics has been used to determine peak demand contributions for different customer segments, which has enabled even more granular demand forecasts.

6.4.4.2. Counties Energy's Future Demand Scenarios

To navigate this period of rapid change, Counties Energy must plan for a range of possible futures. Uncertainty around the extent of technology adoption, changes in customer behaviour, and the amount of regional growth means there is no single pathway forward. To ensure resilience and flexibility, we have developed four electricity demand scenarios that explore different trajectories for electrification, distributed energy resources, and consumption patterns. These scenarios will guide our investment decisions and help us prepare for the opportunities and challenges of a decarbonised energy future and are the primary mechanism by which we manage the uncertainty inherent in forecasting new demand, generation and storage capacity. Our four demand scenarios are:

- **Base Scenario** - In line with forecasts that previous CAPEX profiles have been developed on, with tweaks based on observed network trends. This scenario forms the basis for the 10-year plan.
- **Growth Scenario** - Assumes higher population growth, which is driving higher uptake in new technology e.g. EVs and solar, but there is less investment in innovation and demand-side response.
- **Innovation Scenario** - Retains the median population growth (as per the base scenario) but sees a higher uptake in new technology and demand-side response.
- **Constraint Scenario** - Slower economic growth results in lower population growth, and low new technology uptake.

6.4 Network Planning for the Future (continued)

6.4.4 Demand, Scenarios and Forecasts (continued)

A summary of inputs is shown in the table below.

	Scenario Inputs			
Inputs	**Base**	**Growth**	**Innovation**	**Constraint**
		Residential Growth		
Organic growth	Medium	High	Medium	Low
New residential	Council plans	Fast	Council plans	Slow
ADMD of new Residential Customers	Observed rate	High	Observed rate	Low
		Commercial Growth		
New commercial	5 year avg.	2 year avg.	2 year avg.	50% of 5yr
ADMD of new Commercial Customers	Observed rate	High	Observed rate	Low
		Industrial Growth		
Contribution to system peak	Observed rate	High	Observed rate	Low
		Transport Electrification		
EV uptake	Medium	High	Medium	Low
Energy usage	Naïve	Energy Optimised	Network Optimised	Naïve
		Solar		
Solar uptake	Medium	High	Medium	Low
Solar with BESS uptake	Low	Medium	High	Low

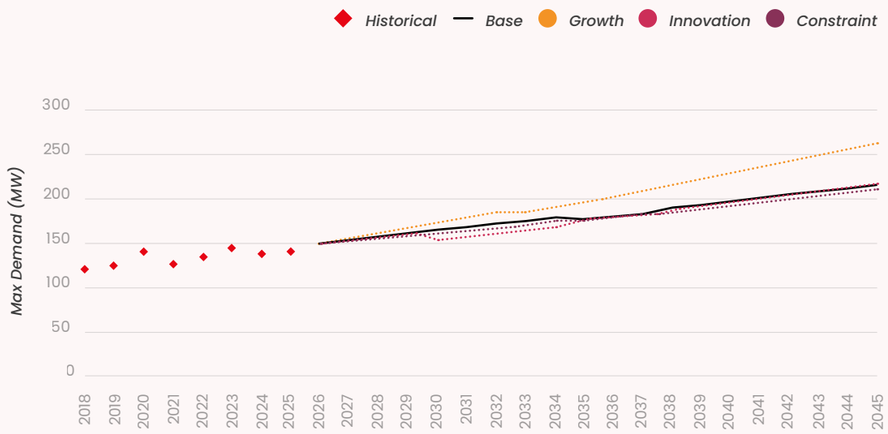
Table 6.2 Summary of inputs for future demand scenarios

Sensitivity analysis is applied to identify and quantify the extent to which individual variables influence the peak demand forecast and, by extension, the long-term capital programme. The risks arising from these sensitivities are managed through periodic review, aligned to their relative impact. All inputs are reviewed annually, with higher-impact variables subject to more frequent scrutiny.

6.4.4 Demand, Scenarios and Forecasts (continued)

The total network demand forecast is shown below across all scenarios.

Figure 6.5 Scenarios for Total Network Demand



6.4.4.2.1. Major Customers

Electricity demand within the Counties Energy network is characterised by a relatively high level of concentration among a small number of large consumers that are critical to regional economic activity and essential infrastructure services. The ten largest customers collectively account for approximately 24% of total electricity demand, indicating a concentrated demand profile at the upper end of the customer base.

The four largest customers — Watercare, New Zealand Steel, Synlait Milk, and a2 Milk Company — together represent approximately 17.5% of total network demand. These customers span essential water services, heavy industry, and large scale dairy processing. Given their scale and operational characteristics, they require ongoing engagement to ensure that network capacity, security, power quality, and investment planning remain aligned with their current and future demand requirements.

Analysis of monthly demand trends over the 2021–2025 period indicates this concentration is both structural and operational in nature. Water infrastructure demand exhibits periods of elevated contribution, while dairy processing loads display pronounced seasonal variability. This reinforces the importance of proactive network planning and close coordination with major customers to manage peak demand, optimise asset utilisation, and plan timely capacity augmentation where required.

In addition to the largest individual customers, Counties Energy supplies a range of other industrial, manufacturing, and infrastructure-related customer groups that contribute materially to aggregate demand. These include:

6.4.4 Demand, Scenarios and Forecasts (continued)

- **Food, beverage, and dairy manufacturing and packaging,** which together account for approximately 5.2% of total demand, reflecting the strong presence of dairy and food processing activity within the region.
- **Metal and construction material** manufacturing, contributing around 2.0% of total demand, driven by materials production and processing activities that are typically energy intensive.
- **Heavy and civil engineering construction,** representing approximately 1.6% of total demand, with demand linked to large infrastructure and development projects across our network area.
- **Retail trade,** including supermarkets and other large retail operations, which collectively contribute a smaller but stable share of overall electricity demand.

Demand from these sectors has remained broadly stable in recent years, subject to some seasonal variation, and is closely linked to regional economic conditions, population growth, and infrastructure development. Collectively, large industrial, manufacturing, and infrastructure customers continue to play a significant role in shaping Counties Energy's demand profile and are a key consideration in our long term network development and investment planning.

6.4.4.2.2. Distributed Generation

Increasing uptake of distributed generation (DG), particularly rooftop solar PV, is changing how electricity distribution networks in New Zealand are planned and operated, with more consumers both using and exporting electricity through distribution networks. Nationally, public reporting shows sustained growth in installed distributed generation over time, reflecting a material shift in the scale and visibility of DG connected at distribution level.

For Counties Energy, this trend is expected to continue and is reflected in our focus on enabling greater DG while maintaining safety, security and network performance, supported by clear technical requirements for connection and operation (including power quality and protection coordination) and, where needed, congestion management consistent with the EIPC (Electricity Industry Participation Code 2010).

In parallel, New Zealand is seeing increasing development of larger scale renewable generation, including utility and grid scale solar, supported by declining technology costs and a growing pipeline of proposed solar farm developments. While these projects may connect at different voltage levels and under different commercial and technical arrangements than small consumer installations, they can still materially affect distribution networks by changing power flow patterns and the need for active network management.

6.4.4 Demand, Scenarios and Forecasts (continued)

Utility Scale Generation

Several Counties Energy customers own and operate distributed generation assets connected at the 11 kV and 22 kV distribution voltage levels. While the network can generally accommodate distributed generation connections within defined capacity ranges, actual hosting capacity can be constrained by local network conditions, including circuit capacity, fault levels, voltage regulation, and power quality limits. In broad terms, the network is typically able to support generation connections of up to 4 MW at 11 kV, between 4 MW and 12 MW at 22 kV, and larger scale generation connections above 12 MW at subtransmission voltage levels.

Connections at or near these thresholds require detailed assessment and, in some cases, network reinforcement or operational constraints to ensure the ongoing safe, reliable, and efficient operation of the network for the long-term benefit of all consumers. In the last year, we have noted an increase in utility scale generation applications.

As at March 2026, a small number of major distributed generation (DG) assets make a material and increasing contribution to energy supplied within the Counties Energy network. Collectively, these major DG connections inject approximately 61 GWh per annum, equivalent to around 8.8% of the network's total annual delivered energy of 689 GWh. These sites are:

- A **7MW landfill generation plant at Hampton Downs landfill.** This plant provides the majority of the injected energy and exhibits a stable and sustained injection profile, with total injection of around 50 GWh, and peak injections clustered near 3.3 MWh.
- A **5MW plant in Papakura** (consisting of a 3.5 MW gas generator and a 1.5 MW diesel generator). This plant displays intermittent, dispatch driven injection patterns. As such, it has many short duration high-peak export periods around 2 MWh, however its total annual injection is low at around 0.8 GWh.
- A **2MW windfarm in Āwhitu** that is characterised by fluctuations with weather and wind conditions. The plant had a peak injection of 1.4 MWh, with a total annual injection of around 7.5 GWh.
- A **2MW solar farm in Glenbrook** that displays seasonal variations. The plant had a peak injection of 1.1 MWh, with a total annual injection of around 3.36 GWH.

While DG remains a minor contributor at a network-wide level, generation of this scale can have a material impact on local network loading, voltage profiles, and power flow conditions. We are also noting an increase in applications for utility scale DG, including battery energy storage systems (BESS), and will continue to work with our customers to accommodate these onto our network.

6.4.4 Demand, Scenarios and Forecasts (continued)

Impact of Solar

Historically, distributed solar generation has had minimal impact due to peak solar generation being at times that are not coincident with peak demand on the network. However, systems with battery attachments provide the opportunity for discharging solar generated energy during peak times, therefore impacting network peak demand.

Battery attachment rates in New Zealand have risen from almost zero in 2020 to around 35 percent in 2025 YTD. There is a lot of variation between regions, and the 2025 rate for the Counties Energy area is lower at 10 percent.

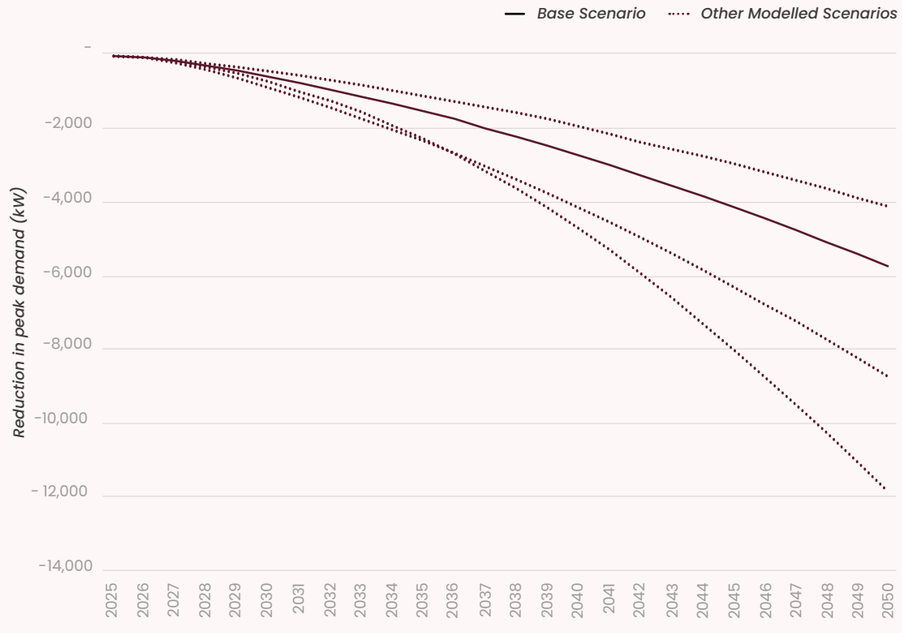
In building a forecast of solar generation for the network, we have relied on our own internal records for solar and battery installations on the network, alongside territorial authority property datasets and a PVWatts* model to forecast future changes in generation by season and location.

The above, combined with our existing ICP forecast and existing battery attachment trends, have allowed us to generate a forecast for solar and battery adoption in the Counties Energy area. Data was segmented by statistical area boundaries as well as substation and transformer supply areas, to provide a granular view of adoption patterns.

Future solar uptake was forecast with a generalised linear model, developed based on factors such as area characteristics, property features and demographic factors. Three linear models were applied to reflect the Climate Change Commission's forecast scenarios — Low, Medium (or Base), and High. In addition, a sigmoidal model was included to capture acceleration and saturation phases typical of technology diffusion (Innovation scenario).

*PVWatts is an application developed by the National Renewable Energy Laboratory (NREL) on behalf of the US Department of Energy. It estimates the electricity production of a photovoltaic system based on fundamental parameters such as dimensions, latitude and longitude.

Figure 6.6 Battery and Solar Impact on Network Peak Projections



6.4.4 Demand, Scenarios and Forecasts (continued)

The base scenario projected a residential solar growth rate of 0.3% per year, reaching 14.5% by 2050. For the other scenarios modelled, results were between 78% and 183% of the base scenario. Battery connected solar reached between 4.8% and 8.8% of all residential ICP's in the same time period.

The projected net impact on peak demand is 6.2 MW in 2050 in the base scenario. For the other scenarios modelled, results varied between 74% and 198% of the base scenario.

6.4.4.2.3. Impact of EV Charging

New Zealand's trend towards decarbonisation will continue to impact distribution networks, especially through transport decarbonisation and electric vehicle charging. In preparing this Asset Management Plan we have analysed electric vehicle uptake and charging patterns to date and created a model for forecasting several scenarios for these patterns in the future.

Electric vehicle uptake data was sourced from the NZTA Motor Vehicle Register based on the postcodes that make up the Counties Energy network. A statistical model was built to align the electric vehicle uptake in any given Counties Energy area with electricity consumption data, based on data back to 2018.

Historical data on the frequency and magnitude of charging events was gathered from our low voltage analytics platform, GridSight. When analysing network-wide low-voltage data, only large chargers (7kW and above) could be practically discerned from other low voltage loads (such as heat pumps and spa pools), but this aligns with a risk-based approach, given smaller chargers will have lesser impact on network peaks.

A regression model linking EV count to average charging frequency was used and five scenarios for EV uptake were considered:

- **Base, Low and Fast** uptakes from the Ministry of Transport for the Second Emissions Reduction Plan (ERP2) 2024.
- **Base and High Carbon Price** scenarios from the 2025 ETC setting advice by the Climate Change Commission.

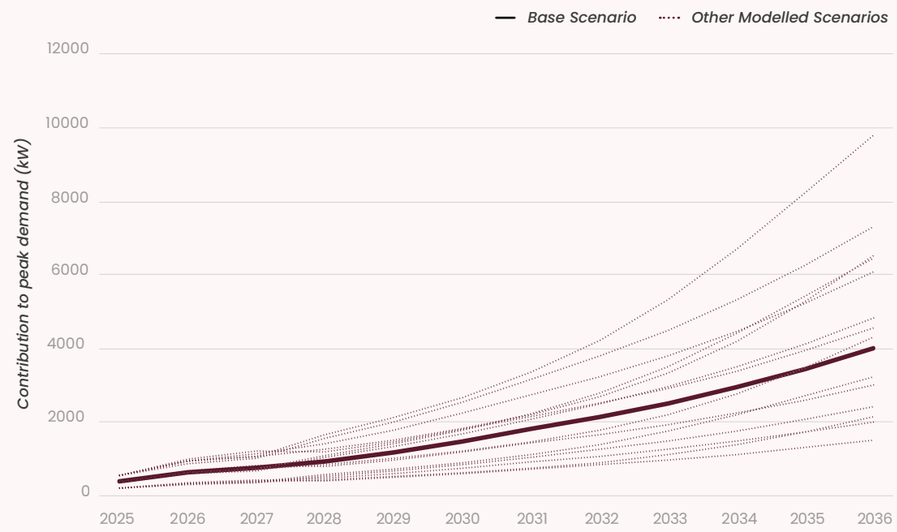
For EV charging behaviour, the following three scenarios were adapted from the Modelling Peak Electricity Demand to 2050 model developed by Sapere for the Electricity Networks Aotearoa (ENA):

- **Naïve** - In this scenario, net demand growth is left unchecked by any signals or remote switching.
- **Energy optimised** - In this scenario, discretionary load control is applied by energy traders (e.g. retailers, generators, aggregators) seeking to minimise the cost of purchasing in the wholesale market or simply using load control to optimise revenue opportunities.
- **Network optimised** - In this scenario discretionary load control is undertaken by EDBs wishing to minimise the impact of peaks on network capacity requirements.

6.4.4 Demand, Scenarios and Forecasts (continued)

The results show a significant impact on the Counties Energy network as expected. In the base scenario, the total number of EVs in the Counties Energy area is projected to double by 2027, increase five-fold by 2032, and reach 10 times the 2025 level by 2036. Weekly charging events are projected to increase from 240 in 2025 to 7,359 in 2050. For the other five scenarios and three charging behaviours modelled, results were between 87% and 125% of the base scenario.

Figure 6.7
EV Charging Scenarios



These charging events were overlaid with the overall network load profile, to model the impact on network peak. On this basis we expect EV charging to contribute in the order of 4 MW to the network peak by the end of the planning period in the base scenario, but there is a high degree of variability between scenarios – in particular with regards to the three behaviour scenarios identified above.

Timing of future investment therefore depends heavily on what behaviour patterns develop over time and on the availability and effectiveness of tools electricity networks have to influence that behaviour at peak times, to smooth peaks and to increase network utilisation.

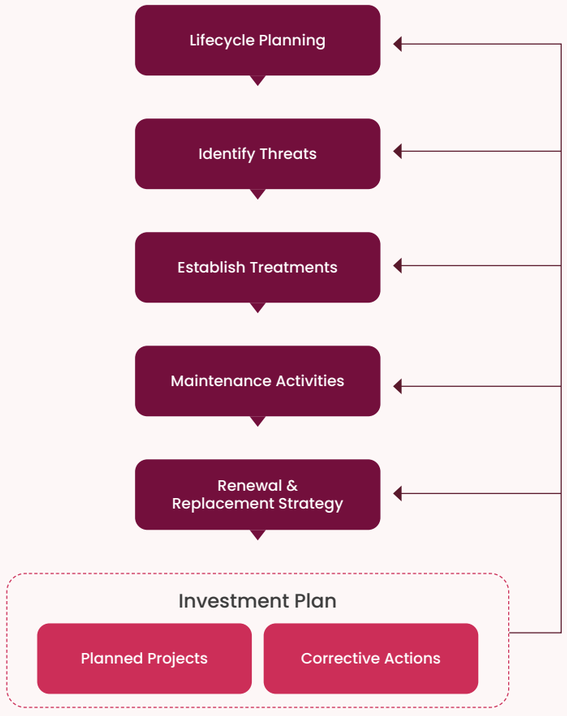
6.4.5 Asset Lifecycle Planning

Our asset lifecycle planning methodology is systematic and centres on both investment and asset management to optimise asset reliability and long-term value. The process begins with the formulation of strategies for effective asset management, followed by identification of risks that may compromise asset integrity or service delivery.

Upon assessing these risks, we implement mitigation measures and undertake maintenance activities to preserve asset condition. As assets age, we develop renewal or replacement plans to uphold high-service standards and manage costs efficiently over time. These initiatives are incorporated into our investment plan, which prioritises future projects and actions to ensure strategic alignment with organisational objectives and sustainability. Each asset type within our network is managed through a structured framework, emphasising reliability, safety, and enhanced performance via risk assessment, preventative maintenance, targeted upgrades, and timely interventions.

The following figure depicts the process of lifecycle planning and investment for renewal and replacement projects.

Figure 6.8 Lifecycle Planning Process



6.4.5 Asset Lifecycle Planning (continued)

6.4.5.1. Identifying Threats

We actively identify threats for each asset type by examining both internal and external factors. Internally, we focus on operational resilience, procedures, compliance with standards, risk tolerance, as well as performance history. Externally, we evaluate changes in industry practices, regulatory updates, economic conditions, environmental influences, and our evolving customers' and stakeholders' needs.

Threats are identified proactively through regular maintenance and inspection, analysis of asset failures, consideration of safety for workers and the public, as well as monitoring performance data and customer feedback. We rely on insights from ongoing inspections, historical faults, monitoring data, and industry benchmarks to detect and address vulnerabilities before they affect performance or safety.

6.4.5.2. Establishing Treatment Plans

Treatment plans are put in place to reduce our exposure to various risks, including financial, operational, performance, compliance, and safety concerns. These plans represent systematic, proactive methods for managing threats to our network.

We address each threat by choosing to avoid, mitigate, transfer, or accept it through these treatment plans. The goal is to protect our workers and the public, to lower our capital and operating expenses, extend our asset lifespan, and improve the performance and reliability of our network. Outlined next are the activities we carry out to manage threats on our network.

6.4.5 Asset Lifecycle Planning (continued)

6.4.5.3. Maintenance and Inspection Programmes

Our maintenance and inspection programmes are customised to address both known risks and uncover potential unknown issues. We schedule these activities based on industry standards and manufacturer recommendations, carrying out frequent inspections and gathering smart data to identify defects and evaluate asset conditions. These inspections enable us to provide updates on asset health and respond quickly to anticipate and resolve any problems, ensuring reliability and minimising downtime.

Key assumptions made in determining our maintenance programmes:

- **Asset information, including condition and performance data is reasonably accurate**
  For example, inspections, defects and fault history information is fit-for-purpose, even though it may not be perfect.
- **Failure behaviour follows historical trends**
  Past fault rates and degradation patterns are assumed to be a good proxy for future performance.
- **Maintenance reduces risk and defers replacement**
  Planned maintenance is assumed to measurably lower failure probability or consequence – either directly via servicing tasks, or indirectly by informing corrective/refurbishment/replacement programmes.
- **Service level targets remain stable**
  SAIDI/SAIFI targets, customer expectations, and Commerce Commission requirements are not expected to materially change over the planning period (other than the points discussed in Chapter 3).
- **Funding and opex allowances are consistent with the plans set out in this AMP**
  No major step-changes in allowed opex or emergency reprioritisation.
- **Access and outage windows will be achievable**
  This includes land access, traffic management, planned outages, and customer coordination.
- **Contractor and internal capability will be available**
  Skills, capacity, and productivity assumptions hold despite market pressures.
- **External risks are manageable within tolerances**
  Weather, vegetation growth, supply chain issues, and regulatory change are assumed to stay within expected bounds.

6.4.5 Asset Lifecycle Planning (continued)

Along with our traditional inspection methods we have adopted additional inspection methods to better identify the condition of our assets. We implement targeted programs for our network to identify potential threats, which are addressed through our defect remediation process. These are:

- **Maintenance Activities:** Maintenance and inspection proactively address risks, ensure assets meet standards or recommendations, identify defects for repair, and evaluate the asset condition through routine checks.
- **UAV Inspections:** Enhance defect identification and improve prioritisation of renewal investments.
- **LiDAR Surveys:** Detect vegetation encroachment, low conductor clearance, and regulatory breaches, supporting proactive asset replacement.
- **Machine Learning Technology:** We have partnered with another electricity distribution business, leveraging a capability they have previously developed, to thoroughly investigate conductor conditions and identify common defects using machine learning techniques on large image sets obtained from UAV inspections.

We continue to proactively enhance our inspection and maintenance methods as technology advances. These improvements will support more informed investment decisions while ensuring our network remains reliable and efficient. Looking ahead, we aim to shift our maintenance scheduling from time-based to risk-based approaches, aligning inspections with asset age or condition. As a result, assets nearing the end of their life expectancy will receive greater attention compared to newly installed ones. This strategy will provide added value to our renewal investment plans and enhance the efficiency of our asset maintenance investment.

More details on maintenance and inspection for all our assets can be found in section 6.5.

6.4.5 Asset Lifecycle Planning (continued)

6.4.5.4. Asset Risk Management Model (ARMM)

Over the last five years, our asset management strategy has shifted to a proactive, risk-based approach. We have developed Asset Risk Management Models (ARMM) utilising the Common Network Asset Indices Methodology (CNAIM), a regulatory framework adopted across the sector in the United Kingdom and by several electricity distribution businesses in New Zealand.

The models start with forecasting asset health based on age and then refines this assessment by incorporating location-specific factors and available condition data to estimate the probability of failure. This probability is combined with asset criticality to generate a consistent, monetised view of network risk, which informs our planning and investment decisions. The scope of this risk assessment covers safety, environmental impacts, outage duration, network performance, and associated costs.

To date, we have built ARMM models for distribution and LV lines, overhead distribution switchgear and overhead distribution transformers. The models allow us to assess the fleet of assets for investment requirements, and optimise maintenance and replacement timescales and investment requirements related to projected risk values.

We have used the distribution and LV lines model to size and plan our conductor replacement programmes in this asset management plan, as well to report on asset health metrics in section 5.3.3 of this plan and in the information disclosure schedule 12a.

We plan to replicate this across all other distribution asset classes in the next few years.

6.4.5.5. Renewal & Replacement Planning

Our renewal and replacement planning focuses on maintaining a safe, reliable, and cost-effective network by prioritising asset replacements based on intelligently assessed risk and condition. Assets are replaced when defects are identified or when they reach the end of their service life, with a transition towards a risk-based approach across all asset classes to guide future investment decisions.

The table below outlines our current approach, which determines the circumstances under which network assets are replaced.

6.4 Network Planning for the Future (continued)

6.4.5 Asset Lifecycle Planning (continued)

Asset Type	Replacement drivers
Subtransmission	
Subtransmission Poles and Towers	Age, condition and build standard updates
Crossarms	Age, condition and build standard updates
Other Overhead Dressings	Age and condition
33 kV & 110 kV Conductor	
Overhead Conductors	Age and condition
Insulators and other Line Hardware	Age and condition
Subtransmission Cable	
Terminations Poles	Age, condition and standard updates
Other Hardware	Age and condition
Other Overhead Dressings	Age and condition
Zone Substations	
Network Buildings	Age, condition and updates to regulatory standard
Power Transformers	Age, condition, and growth
Circuit Breakers	Age, condition and obsolescence/lack of critical spares due to supplier discontinuing the model
Station Disconnectors	Age, condition and obsolescence/lack of critical spares due to supplier discontinuing the model
Auxiliary Battery Banks	Age
Distribution and LV Lines	
Distribution Poles	Age, condition and build standard updates
Distribution Crossarms	Age, condition and build standard updates
Insulators and other Line Hardware	Age and condition
22 kV Conductors	Age, condition and criticality based on risk modelling in ARMM
11 kV Conductors	Age, condition and criticality based on risk modelling in ARMM
LV Conductors	Age and condition

Table 6.3 Our replacement drivers

6.4.5 Asset Lifecycle Planning (continued)

Asset Type	Replacement drivers
Distribution and LV Cables	
Distribution Cable 11 kV	Age
Distribution Cable 22 kV	Age
LV Cable	Age
Termination Structures	Age and condition
Pillars, Pits and Link Boxes	Age and condition
Distribution Substations and Transformers	
Pole Mount Transformers	Age, condition, growth and build standard updates
Ground Mount Transformers	Age, condition, growth and build standard updates
Autotransformers	Age, condition, growth and build standard updates
Distribution Switchgear	
Overhead Switchgear	Age, condition and build standard updates
Ground Mount Switchgear	Age, condition and build standard updates
Communication	
Radio Sites	Age, condition and obsolescence/lack of critical spares due to supplier discontinuing the model
Remote Telemetry Units	Age, condition and obsolescence/lack of critical spares due to supplier discontinuing the model
Fibre (Overhead)	Age and condition
Fibre (Underground)	Age and condition
Fibre Pits	Age and condition
Other Network Assets	
Voltage Regulator	Age and condition
Protection Relays	Age
Capacitor Banks	Age
Load Control Relays	Age and condition
Ripple Injection Plant	Age

Table 6.3 Our replacement drivers (continued)

6.4.5 Asset Lifecycle Planning (continued)

6.4.5.5. Renewal & Replacement Planning (continued)

a) Asset Renewal Based on Age

When condition data is unavailable, our renewal and replacement programme is based on asset age, with assets scheduled for replacement as they near the end of their projected service life. Exceptions are made when defects, specific conditions, or other risks are identified; in these cases, replacements occur following targeted risk assessments.

The age-based renewal method simplifies planning by using asset age as a clear replacement criterion, aiding budgeting and long-term capital decisions. Proactive replacements lower the risk of failures, improve safety, and help maintain regulatory compliance. Updating assets before failure also enhances reliability, allows for modern technology adoption, and manages costs by reducing the higher maintenance costs on older equipment.

Going forward, our strategy will involve adopting a comprehensive risk-based methodology for asset replacement. By systematically recording condition factors through inspections, monitoring data, and maintenance operations, we aim to optimise and strengthen our overall approach.

b) Condition Based Renewal

Condition-based renewal provides a targeted approach to manage our assets by focusing on the actual health and performance of assets rather than age alone. We regularly update and replace our fleet, using condition monitoring, supported by scheduled inspections that identify risks to network performance, safety, or security. When issues are detected, we carry out renewal and replacement programmes regardless of asset age, ensuring that critical assets are prioritised even if they are relatively new.

This strategy optimises investment while extending the useful life of assets where possible. It also enhances reliability by reducing unplanned outages and improving service continuity. Additionally, we account for environmental factors such as in coastal regions, where harsher conditions accelerate wear and shorten asset lifespans, requiring more frequent intervention. By leveraging advanced monitoring technologies and predictive analytics, condition-based renewal enables smarter, data-driven decisions that maintain safety, compliance, and cost efficiency across the asset lifecycle.

Long term, our goal is to record defects across all asset classes so investments can be based on condition and risk instead of age. Although we have condition data for most assets, some are still replaced by age due to their type or manufacturer requirements.

c) Asset Refurbishment

Asset refurbishment is an option utilised for some of our asset classes. Zone substation power transformers are an example of this, typically being refurbished at mid-life. The transformers at Ōpaheke were the most recent example of this, although there are presently no others planned within the planning period.

Certain distribution assets may sometimes be decommissioned from their sites prior to reaching their anticipated service life, often due to network relocation, increased capacity requirements, or similar investment considerations unrelated to asset replacement. For high-value distribution equipment — such as high-voltage transformers and switchgear—a systematic process is implemented to evaluate their condition, refurbish them as necessary, and return them to inventory for future use. This approach effectively reduces costs for future projects by minimising the need to purchase new equipment as well as reducing our waste footprint.

6.4.5 Asset Lifecycle Planning (continued)

d) Defects Remedial Strategy

Our defect remedial programme stems from our regularly scheduled inspections across the entire fleet, which follow a time-based approach. The inspection frequencies for all of our assets are shown in section 6.5. Defects found during these inspections guide our defect remedial programme. Those defects rated as moderate or higher are corrected, with much of this work centred on our overhead network, such as replacing poles, crossarms, equipment, and line hardware. Table 6.4 outlines the procedures we use to manage risks associated with all identified defects.

We assess risks for each defect using both qualitative and semi-quantitative methods that assign scores. Risk categories considered in our assessments include customer impact, feeder performance, safety, and financial implications. The current semi-quantitative analysis assesses each identified threat based on its consequences, frequency, and likelihood.

Looking forward, we aim to enhance the management of our defects programme by transitioning to a more precise, risk-based approach. This will involve updating our risk assessment procedures and protocols. At present, high-scoring risks are addressed reactively and promptly, but we intend to identify these significant risks earlier, before they fully develop.

Threat Extent	Score Levels	Threat Management Protocol
Extreme	Score> 400	Immediate action required and the network control room is notified for an emergency shutdown if necessary. Defects or risks are resolved within 7 days, as they pose significant danger to the public or property. These items are scheduled and handled as urgent defects, using our capital expenditure budgets.
High	200 to 399	Expected to fail within three months; action is needed soon, but immediate isolation is not required as there is no current public safety or network risk. These items are scheduled and handled as urgent defects, using our capital expenditure budgets.
Moderate	70 to 199	Has a high chance of failing within the year, which could endanger public safety or the network. These items are addressed through our remedial and renewal programmes using capital expenditure budgets.
Low	20 to 69	Minor defect with low public or network risk; may fail within 1–3 years. These items are scheduled for replacement as part of the established 10-year planning cycle.
Minimum	0 to 19	These defects are considered acceptable; however, monitoring continues until the subsequent inspection.

Table 6.4 Defect management strategy

6.4.5 Asset Lifecycle Planning (continued)

e) Overhead Conductor Renewal Strategy

Our approach to overhead conductor replacement is guided by comprehensive risk modelling. We utilise the Asset Risk Management Model (ARMM) for our distribution conductors, which evaluates both asset health and criticality to identify areas of elevated risk that warrant focused intervention. The evaluation of asset criticality is determined by analysing the consequences of failure, using the categories outlined below:

- **Financial implications, including costs for repair and replacement.**
- **Safety considerations for both workers and the public.**
- **Environmental context, such as costs related to urban areas, school zones, and coastal locations.**
- **Network performance, evaluated through SAIDI and SAIFI metrics, the number of faults, and their impacts.**

Our conductor replacement programme is structured around risk modelling for the upcoming 10-year period. The risk model serves as a strategic guide to highlight current areas of concern; however, it is not solely relied upon when planning replacements. Comprehensive onsite inspections are carried out prior to project initiation to validate the risks and conditions identified by the model, ensuring that investments are warranted. If discrepancies arise between the model's assessment and field conditions, projects are reprioritised accordingly, and data is corrected to update the model.

This is a continual process focused on enhancing our data quality and refining the risk model, thereby ensuring every investment is warranted and that a safe, reliable network is maintained. The output for our risk modelling is further shown in section 6.5.3.3.

f) Replacement Due to Regulatory Amendments

We upgrade or replace assets in response to changes in regulatory or industry standards. Upon any amendments, we assess our assets to identify potential compliance gaps and develop appropriate corrective actions. For instance, our seismic reinforcement projects for several substation buildings are scheduled for completion in 2026.

g) Obsolete Asset Replacement

We proactively replace outdated assets when manufacturers can no longer supply the critical spare parts required for ongoing maintenance. While we continue to operate these assets for as long as sufficient spares remain available, once supplies are depleted we transition to modern equivalent products with more reliable parts availability to ensure uninterrupted service to our customers.

6.4.5 Asset Lifecycle Planning (continued)

h) Enhancements Due to Developments

We adjust our asset configurations in developing and urban areas when replacements are needed or when assets show signs of deterioration. For example, in busy urban environments and places with heavy pedestrian activity such as school zones, we replace aging overhead lines by installing underground assets. These decisions are made individually according to our undergrounding strategy.

This approach not only upgrades the infrastructure but also reduces risks from third-party incidents like pole-vehicle collisions and improves public safety. It additionally enhances the aesthetics of developing urban spaces. Moreover, we coordinate major substation replacement projects with planned growth initiatives, upgrading infrastructure collaboratively with other infrastructure providers and utility companies to maintain continuous and efficient power supply. One such instance is the renewal of our Karaka Substation, which is scheduled alongside the development of the Waiau Pa Substation. More information can be found in section 7.3.1.

6.4.5.6. Critical Spares

Critical spares are managed using a three tier framework aligned with industry practice to ensure timely restoration of supply following asset failures.

Tier 1 (critical) spares relate to high impact, long lead time (or now obsolete) substation assets or components where failure would result in significant customer or safety risk, such as spare protection panels, control panels, switchgear modules and selected switchgear or power transformer components. These spares are held to enable restoration or temporary reconfiguration of critical sites.

Tier 2 (emergency) spares support assets with lower system impact or where alternative network or operational mitigations exist, but where replacement lead times still warrant holding stock to manage risk. This includes mostly distribution switchgear and transformers. These are held and managed alongside our normal inventory, but minimum quantities are held and managed for critical spare use. Quantities are determined by our engineering team as a function of expected need and risk.

Tier 3 (network/operational) spares are non critical or readily available items that are typically sourced through normal supply chains and managed as part of normal inventory. Although a minimum quantity is held specifically for reactive purposes, these items are used almost daily.

All critical spares are held at our Pukekohe site, except where arrangements are in place with suppliers to hold stock on our behalf. In some cases, selected high impact spares — such as spare protection or control panels, or power transformers — are held at operational sites where this provides faster restoration capability or is operationally impractical to store centrally. We have a spare power transformer available for our 33/11 kV and 110/22 kV sites.

This approach balances network risk, cost, storage constraints and supplier capability while ensuring appropriate resilience for credible failure scenarios.

A key finding from our recent RMMAT assessment (refer 4.11.8.1) was that our critical spares management could be enhanced with further robust processes put in place. Some improvements have already been made, but further work on this is planned in the next few years.

6.4.5 Asset Lifecycle Planning (continued)

6.4.5.7. Innovation in Lifecycle Planning

We continue to adopt innovative approaches that allow us to defer asset replacement while maintaining appropriate levels of safety, reliability and service, and we remain proactive in identifying further opportunities to do so. A key example in recent years has been the development of our Asset Risk and Management Models (ARMM), which draw on asset, condition, performance and criticality data to develop a deeper understanding of asset health and risk. This insight supports a shift away from age-based replacement toward more targeted, risk-based investment prioritisation.

We are also trialling and adopting new inspection technologies. We were an early adopter of LiDAR amongst New Zealand EDBs and completed a wide-scale UAV survey in 2023. In 2025, we partnered with another EDB that applied an established and proven UAV surveying method for overhead conductors, combining high-resolution aerial imagery with AI algorithms to analyse large volumes of photos and derive detailed conductor condition information at scale. Together, these innovations support more informed decision-making, extend asset life where appropriate, and help defer capital investment while continuing to deliver strong outcomes for customers.

6.4.6 Reliability Planning

It is recognised that reliability outcomes can be influenced by any work undertaken on the network, regardless of the workstreams – whether a project is initiated due to asset replacement, network development or by a customer request. As such, reliability planning is an integral part of our works initiation process across all work types.

a) Network Criticality Model

In 2021, Counties Energy created a network criticality model using our GIS data to evaluate the impact of outages on every part of the 11 kV and 22 kV networks. By applying algorithms to asset location and connectivity data, the model assesses typical unplanned event scenarios and restoration times to estimate SAIFI/SAIDI impacts by location. This information informs our asset risk management, vegetation control, and reliability investments.

b) Project Charter Review / Technical Approval

Our internal project management framework mandates that key business stakeholders review the project charter for every network project. In addition, any significant changes to the network must receive technical approval from a comparable group of stakeholders. The Reliability team participates in these evaluations, using the network criticality model to assess proposals and ensure each project achieves optimal reliability results.

6.4 Network Planning for the Future (continued)

6.4.6 Reliability Planning (continued)

c) Regular Fault Review / Cause Analysis

Events impacting our HV and subtransmission networks are recorded by our Network Operations Centre (NOC), with a regular event review meeting held between network operators, field teams, engineers and asset managers. In this review, events are discussed, the data accuracy of captured events is validated and any lessons learnt or required improvement actions are captured. The event data then becomes part of the foundations of our reliability reports, which form one of our continuous improvement feedback loops in our asset management system.

In addition to the HV event data, our reactive field work management tool was updated in mid-2024 to significantly improve the capture of failure information from field staff working directly on faults. This applies to all work orders at all voltage levels, and this information is also used in our regular event review meeting. There are still improvements to be made in the utilisation and reporting of this data, as well as improving the consistency and data quality. We continue to work in this space, and it is expected this will eventually become our primary source of failure information, unlocking significant improvements in how we effectively manage our LV assets.

Our targeted reliability investment programmes are formed from learnings from the above three inputs, where specific intervention is required to drive improved reliability outcomes and existing projects are unlikely to address the concerns. The projects that make up this programme are described in Chapter 7.0.

6.5 Managing Our Assets

6.5.1 Subtransmission

Our subtransmission assets are vital to our network, as failures can disrupt service for many customers over extended periods. To maintain their reliability and availability, we conduct thorough inspections, corrective maintenance, and targeted asset renewal. We prioritise follow-up actions and investigate failures to prevent recurrence.

The majority of our subtransmission network is made up of overhead lines, and aside from being a higher priority, they are managed much like our distribution lines. Any defects are treated as urgent corrective work. Replacement is forecast based on age and condition as at present, our ARMM models do not cover subtransmission assets, but these will be integrated going forward.

Over the planning period, subtransmission investment is focused on sustaining the safe and reliable operation of the existing network rather than wholesale replacement. Key activities include targeted insulator replacement on 110 kV lines to address emerging condition and performance risks - reflecting their shorter expected service lives compared to the rest of the line components, alongside ongoing vegetation management and localised condition-based replacement of components where deterioration is identified by our maintenance progammes. While these interventions will manage risk within the planning period, the majority of large-scale subtransmission replacement is forecast to occur beyond the 10-year horizon, reflecting the generally long remaining lives of core structures and conductors.

6.5.1.1. Key Threats and Treatment Plans

Known Threats	Treatment Plans
Lines	
• Vegetation interruptions • Contamination build-up on insulators • Conductor joint and clamp failures • Earthing conductor failures • Network performance • Adverse weather conditions (cyclones and severe storms)	• Vegetation risk is managed through the implementation of a comprehensive vegetation programme (refer to section 4.8.8), utilising Lidar technology and routine inspections to systematically identify at-risk locations. • We regularly wash our insulators to reduce contamination and prevent failures. • A regular inspection programme is in place to detect and replace faulty joints and terminations, with acoustic and UAV surveys used where appropriate. • Network performance risks are mitigated through proactive inspection and maintenance of our lines.
Poles	
• Vehicle accidents • Site access • Network performance • Adverse weather conditions (cyclones and severe storms)	• We promote community awareness among drivers regarding this risk and maintain an adequate stock of critical spare parts to facilitate prompt replacement after any accident. However, it is important to note that this risk cannot be eliminated. • We ensure continued access to our poles to effectively manage and reduce risks associated with site entry when required. • By regularly inspecting and maintaining our poles according to a set schedule, we proactively prevent risks to network performance.

Table 6.5 Key threats and treatment plans for our subtransmission assets

6.5.1 Subtransmission (continued)

6.5.1.1. Key Threats and Treatment Plans (continued)

Known Threats	Treatment Plans
Crossarms	
• Crossarm age and condition causing failures • King bolt failures • Insulator failures • Binder wire failures due to poor workmanship and undersized material. • Old vs new build standards • Specific type of insulator failures • Material quality of crossarms and other overhead dressings • Average crossarm asset information quality • Adverse weather conditions (cyclones and severe storms)	• Overhead pole top components, such as insulators, connectors, crossarms, king bolts, and associated accessories, are assessed using walking patrols, UAV surveys, and acoustic evaluations to determine asset condition. A structured inspection schedule and corrective action plan have been established to address identified defects and mitigate failure risks. • We have standardised our new insulators across the network by increasing their height and creepage distance to mitigate risks associated with wildlife and vegetation debris. They are also a polymer design that is more resistant to corrosion. • Failure of legacy porcelain insulators is an issue notably impacting customers. Aside from sizeable proactive replacement programmes, we deploy acoustic testing technologies and are adjusting our electrical protection configurations to limit the impact to our customers. • We perform routine network quality assessments to ensure both construction and supply meet established quality standards, thereby minimising potential quality risks. • We recognise that the data regarding our crossarm fleet contains inaccuracies; however, we are actively addressing this issue by conducting scheduled inspections to enhance our data integrity. We are exploring the use of AI-based image recognition tools to improve this. • We ran a bespoke analysis across our UAV information and identified a reasonable number of previously poorly installed binder wires on our backbone HV network. We have revised our binder wire standard to make installations less prone to human error and are replacing undersized binder wires as part of our defect remediation program to reduce future issues. • Kingbolt failures associated with wooden arms remain an issue. These are very hard to identify visually. We are considering proactive replacement programmes on critical network sections.
Cables	
• Terminations and joint failures • Third-party damage causing cable strikes and outages due to excavations or drillings. • Network performance	• All joints and pole terminations undergo thorough inspection through overhead pole assessments to minimise the risk of failure and optimise performance. • Third parties operating in proximity to these assets must obtain a close approach permit. Where necessary, suitable standovers are implemented to mitigate associated risks.

Table 6.5 Key threats and treatment plans for our subtransmission assets

6.5.1 Subtransmission (continued)

6.5.1.2. Maintenance Activities

Our inspection cycles for subtransmission assets are:

Activity	Type	Frequency
Subtransmission Lines		
Overhead Line Feeder Patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	Five yearly
Insulator Washing – Glenbrook and Maioro Area	Routine Servicing	Two yearly
Insulator Washing other Substations	Routine Servicing	Five yearly
Vegetation Survey	Inspection	Area specific
Subtransmission Cables		
110 kV AIS Cable Maintenance	Preventative Maintenance	Annual

Table 6.6 Our inspection and maintenance cycles for our subtransmission assets

6.5.2 Zone Substations

Zone substations are vital network assets with a significant impact if they underperform. As visible parts of their communities, they must be safe, secure, clean, and unobtrusive. Our objectives include:

- **Maintaining safety and security;**
- **Meeting network and environmental standards (seismic, oil containment, discharge, noise, etc.); and**
- **Protecting substations from vermin, nesting animals, and vandalism.**

Regular inspections help identify plant deterioration or maintenance needs.

Maintenance and replacement requirements for zone substations are determined on age and condition, as the small asset populations allow for conventional management tools.

Zone substation investment over the next 10 years is driven by a combination of condition-led intervention, asset age, and resilience requirements. The Ōpaheke 22 kV switchboard replacement is scheduled for completion in FY27, having been brought forward ahead of its expected life due to deteriorating condition. Maioro is the next priority, reflecting both asset age and emerging condition risks, with Karaka and Pukekohe planned later in the period as part of normal age- and condition-based renewal. In parallel, an ongoing seismic strengthening programme and targeted investment to maintain the functionality of critical battery systems will continue to improve resilience and ensure safe, reliable operation of these sites.

6.5.2 Zone Substations (continued)

6.5.2.1. Key Threats and Treatment Plans

Known Threats	Treatment Plans
Buildings and Grounds	
• Unauthorised access • Vandalism, theft and graffiti • Earthquake – seismic risk • Flooding – 1 in 450 years • Network performance	• We reduce risks of unauthorised access, vandalism, theft, and graffiti by enhancing public awareness, adding signage, and monitoring and controlling entry to substations from our control rooms. Each site requires two levels of entry for protection. • We have identified switch room buildings with seismic risks and are strengthening them. Two sites will be built in FY26, one was finished in FY25, and additional sites are scheduled for future years. • Flooding assessments have been finished for all of our key sites, and we know of one site that requires attention. Although mitigation measures are in place, the risk remains very low.
Power Transformers	
• Oil leaks • Fire • OLTC operations • Overloading • Long lead time for procurement • Cost • Network performance	• We routinely inspect all power transformers to reduce failure risk, including DGA and OLTC maintenance. • Firewalls have been installed between buildings and transformers to reduce fire hazards. Additional sites have been selected for future firewall installations, with design planning scheduled over the next two years. • We maintain critical spares for our power transformers in case of emergencies. • The risk of overloading is addressed by scheduling new substation projects in subsequent years, aligned with projected growth requirements.
Indoor and Outdoor Switchgear	
• Humidity and condensation damaging our equipment • Pests or bird nests causing damage to our equipment • Partial Discharge • Long lead time for procurement • Cost • Network performance	• We conduct monthly inspections of outdoor switchgears to prevent damage from bird nests and debris. • All switch rooms are equipped with air conditioning and ventilation systems to reduce humidity and minimise the risk of condensation. In addition, a pest control system is implemented for all indoor switch rooms. • To reduce the risk of failures, switchgears are regularly tested for Partial Discharge according to a set schedule. • We maintain essential spare parts for both our indoor and outdoor switchgears to ensure readiness in case of emergencies.
DC Battery Bank Systems	
• Short lifespan needing regular replacement • Loss of storage capacity • Corrosion	• We have a replacement plan in place to address the short lifespan risks associated with all our batteries and chargers. • The batteries are subject to regular inspection and maintenance procedures, coordinated with our substation maintenance schedule.

Table 6.7 Key threats and treatment plans for our zone substation assets

6.5.2 Zone Substations (continued)

6.5.2.2. Maintenance Activities

We inspect and maintain zone substation assets as follows:

Activity	Type	Frequency
Zone Substation Buildings & Grounds		
Routine Substation Inspection	Inspection	Monthly
Building WOF	Inspection	Annual
Compliance Report for Council	Inspection	Annual
Switchroom Air Conditioning	Maintenance	Six monthly
Substation Earth Grid Inspection	Inspection	Annual
Substation Earth Grid Test	Routine Test	Three yearly
Outdoor Busbar and Equipment Inspection	Inspection	Annual
Power Transformers		
Routine Visual Inspection	Inspection	Annual
Oil Testing and Condition Assessment	Inspection	Annual
Detailed Inspection and Maintenance	Routine Maintenance	Three yearly
Transformer and OLTC Maintenance	Routine Servicing	Three yearly
Zone Substation Switchgear		
110 kV or 33 kV Circuit Breaker Inspection (includes partial discharge scan and thermal imaging)	Inspection	Annual
110 kV/33 kV Gas Insulated CB Maintenance	Routine Maintenance	10 yearly or 5000 operations
Line Disconnector and Air Break Switch Maintenance	Routine Maintenance	Three yearly
22 kV or 11 kV Switchboard Inspection (includes partial discharge scan and thermal imaging)	Inspection	Annual
22 kV or 11 kV Circuit Breaker Maintenance (Gas/Vacuum)	Routine Maintenance	Five yearly
22 kV/11 kV Circuit Breaker Maintenance (Oil)	Routine Maintenance	Three yearly or three fault operations
Auxiliary Battery Banks		
DC System Inspection	Visual Inspection	Monthly
DC System Maintenance	Inspection and Test	Annual

Table 6.8 Our inspection and maintenance cycles for our zone substation assets

6.5.3 Distribution (22/11 kV) and LV Lines

Our main priority when managing overhead distribution lines is safety. We pay close attention to defects found in high-risk locations, such as near schools, commercial areas, and densely populated neighbourhoods. By focusing on safety, we often also reduce the number of network failures. After safety, our corrective maintenance and replacement programmes are heavily prioritised by the number of customers that would be impacted should the particular section of network fail.

We monitor common failure modes and known risks, integrating these insights into our maintenance schedules, inspection guidelines, and decisions about asset replacement.

Our core maintenance inspections are time based and primarily consist of detailed visual inspections of overhead lines, poles, crossarms, and related components.

In recent years we have been adding to these methods new forms of inspection based on the latest technologies:

- **Unmanned Aerial Vehicles (UAVs):** These can provide richer condition information and alternative viewing angles of pole top assets than traditional ground-based inspections.

- **Conductor Health using AI:** We have partnered with another EDB to leverage an innovative conductor condition capability they have previously developed, powered by AI image recognition algorithms using images captured by UAV, to provide conductor health information. As part of this work, we are providing engineering input to help expand the existing models to include aluminium conductor steel reinforced (ACSR) conductors.

- **Light Detection and Ranging (LiDAR):** We utilise this technology from high-level flights by fixed-wing aircraft to confirm conductor clearances and also provide vegetation encroachments to inform our vegetation management programme (refer to section 4.8.8). We have completed a full network survey in 2020 and 2023, and intend to repeat this again in 2027.

- **Acoustic Survey:** We often engage one of our inspection partners who has a mature capability to inspect assets using ultrasonic acoustic surveying technology, originally developed in Korea. This technology is effective at identifying decaying high-voltage insulators which are next to impossible to find by visual inspection.

6.5.3 Distribution (22/11 kV) and LV Lines (continued)

Our inspections assess the condition of the asset and identify key defects based on known failure modes with remediation priorities. This information is used when prioritising and scoping works, as well as informing our Asset Health models.

Using data from all inspections, we've developed ARMM models for high-voltage conductors, poles, and crossarms (refer to section 6.4.5.4). These models support better decisions regarding renewal and replacement. We currently use these models to report our asset health and determine our proactive replacement programmes for our high-voltage conductor assets, although there is still work to be done in enhancing and fully integrating our conductor condition information from our UAV and LiDAR surveys. Replacement of poles and associated components remains mostly condition based for now.

Investment in distribution and LV lines over the next 10 years is dominated by a large overhead conductor replacement programme, informed by outputs from our ARMM models. As the majority of the backbone network is in good overall health, this programme is primarily replacing highercriticality spur lines, where reasonable volumes of smalldiameter copper and ACSR conductors approaching the end of expected service lives are still present. The programme will drive coordinated replacement of associated poles, line hardware, and underbuilt LV networks, delivering efficient, wholeofline risk reduction. In parallel, a sizeable ongoing defect management programme will continue to address emerging condition issues identified through routine maintenance inspections. Recent years have seen an effective reduction in higherconsequence failure modes, such as crossarms (refer section 5.5.2); however, the focus is now shifting toward more challenging and less visible failure mechanisms, including kingbolts, connectors, and LV network components. As ARMM models are further refined, we expect more precisely targeted proactive replacement investment and a corresponding reduction in reactive, defectdriven spend in future versions of this asset management plan.

6.5.3 Distribution (22/11 kV) and LV Lines (continued)

6.5.3.1. Key Threats and Treatment Plans

Known Threats	Treatment Plans
Distribution and LV Conductor	
• Vegetation encroachments • Transient faults • Joint and connector failures • Small diameter conductors (Copper and Swan conductors) • Old vs. new build standards • Lines clashing • Private property encroachment and low lines • Deterioration in asset health • Adverse weather conditions (cyclones and severe storms)	• Vegetation risk is controlled with a continuous vegetation programme, using LiDAR technology and regular inspections to identify high-risk areas. • Accessories for conductors, including binders, connectors, clamps, and related components, are inspected through UAV and acoustic surveys. An inspection schedule and a corrective action plan have been established to address identified defects and reduce the likelihood of failures. • We created a risk model to identify high-risk conductors, such as those with small diameters, and have a plan to replace them to lower risk. • We have introduced a new standard for constructing overhead lines using 2.4 m cross arms in a delta structure, which replaces the previous standard to reduce the risk of line clashes. In addition, we have plans to rebuild high-risk structures supporting long spans that could present clashing hazards. • We replace overhead lines with increased capacity during replacement projects to accommodate future growth. • We acknowledge deficiencies in LV data and are addressing these issues through our regular inspections to update records and correct defects, thereby minimising failures. • Inspections, including LiDAR surveys, help us identify private property encroachments and line clearance risks. We address these issues through our defects programme to minimise public safety risks. • Fault passage indicators have been installed on our distribution lines to facilitate rapid fault detection and restoration, thereby improving overall network performance.
Poles	
• Vehicle accidents • Condition due to age and type • Location of poles • Unstable ground conditions causing lean • Regulatory requirements (red and yellow tags) • Foundations and stay wire failures • Network performance • Adverse weather conditions (cyclones and severe storms)	• Poles are at risk of leaning due to their location and unstable ground conditions. These issues are addressed by relocating the poles or installing a retaining wall when detected to prevent the risk of falling. • Safety-in-design principles are applied during the design stage, considering exposure (location, proximity to roads, public areas, and critical customers), susceptibility (material type, age, decay, loading, and environmental factors such as wind and corrosion), and consequence of failure (safety, service interruption, and network criticality).

Table 6.9 Key threats and treatment plans for our distribution and LV lines assets

6.5.3 Distribution (22/11 kV) and LV Lines (continued)

6.5.3.1. Key Threats and Treatment Plans (continued)

Known Threats	Treatment Plans
Crossarms	
• Crossarm age and condition causing failures • King bolt failures • Insulator failures • Binder wire failures due to poor workmanship and undersized material. • Old vs new build standards • Specific type of insulator failures • Material quality of crossarms and other overhead dressings • Jumper wire failures • Average crossarm asset information quality • Adverse weather conditions (cyclones and severe storms)	• Overhead pole top components, such as insulators, connectors, crossarms, king bolts, and associated accessories, are assessed using walking patrols, UAV surveys, and acoustic evaluations to determine asset condition. A structured inspection schedule and corrective action plan have been established to address identified defects and mitigate failure risks. • We have standardised our new insulators across the network by increasing their height and creepage distance to mitigate risks associated with wildlife and vegetation debris. They are also a polymer design that is more resistant to corrosion. • Failure of legacy porcelain insulators is an issue notably impacting customers. Aside from sizeable proactive replacement programmes, we deploy acoustic testing technologies and are adjusting our electrical protection configurations to limit the impact to our customers. • We perform routine network quality assessments to ensure both construction and supply meet established quality standards, thereby minimising potential quality risks. • We recognise that the data regarding our crossarm fleet contains inaccuracies; however, we are actively addressing this issue by conducting scheduled inspections to enhance our data integrity. We are exploring using AI-based image recognition tools to improve this. • Jumper failures are usually a result of outdated standards and poor workmanship. New standards and regular quality assessments now help address this problem. • We ran a bespoke analysis across our UAV information and identified a reasonable number of previously poorly installed binder wires on our backbone HV network. We have revised our binder wire standard to make installations less prone to human error and are replacing undersized binder wires as part of our defect remediation programme to reduce future issues. • King bolt failures associated with wooden arms remain an issue. These are very hard to identify visually. We are considering proactive replacement programmes on critical network sections.
Private Service Lines	
• Poor data • Failures due to age and condition • Improper demarcation issues • Lack of customer support concerns • Network performance • Adverse weather conditions (cyclones and hurricanes)	• We have implemented a programme to assume ownership of HV private lines. Where ownership is not feasible, we are devising strategies to demarcate these areas with dedicated fuses, aiming to minimise unnecessary network outages and improve overall performance. • We are working with customers to update our records and actively manage risks from these lines. Their condition poses safety concerns for both customers and workers, so we are improving our data to address these risks more effectively.

Table 6.9 Key threats and treatment plans for our distribution and LV lines assets (continued)

6.5.3 Distribution (22/11 kV) and LV Lines (continued)

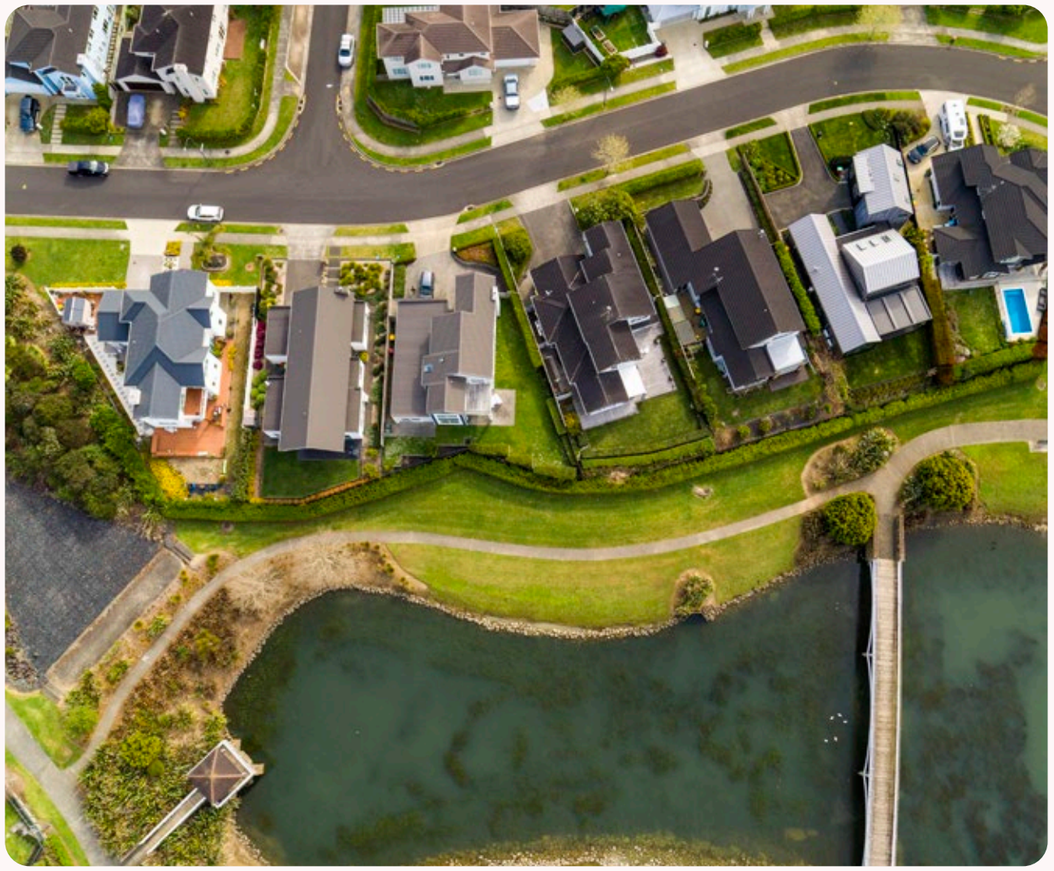
6.5.3.2. Maintenance Activities

The following inspections apply to Distribution and LV Lines:

Activity	Type	Frequency
Distribution and LV Lines		
Detailed Pole and Line Condition Assessment	Inspection	Five yearly
UAV Inspections	Inspection	As required
LiDAR	Inspection	Three yearly
Acoustic Survey	Inspection	As required

Table 6.10 Our inspection and maintenance cycles for our distribution and LV lines assets

Sub-division in Karaka Lakes



6.5.3 Distribution (22/11 kV) and LV Lines (continued)

6.5.3.3. Asset Health Forecast

Within our ARMM model, we can report on the health of our 11 kV and 22 kV distribution conductors across a ten-year period, along with recommended interventions for this planning cycle. These are reported on a risk framework.

The figure illustrates both our present risk levels and inherent risks (if no action is taken), as well as the residual risk expected after intervention. Our overhead conductor replacement program represents these interventions, aimed at lowering existing risks. Although the potential consequences associated with these assets do not change, their overall health improves through this proactive replacement initiative. Looking ahead, we plan to develop similar risk assessment models for our other distribution assets.

Asset Health is reported from 5 (good) to 1 (poor).

Criticality is split into four bands, by quartile, from C1 (most critical) to C4 (least critical).

Figure 6.9 Distribution conductor risk matrix

Asset Quantities – Current Year

Criticality Level	AHI5	AHI4	AHI3	AHI2	AHI1
C4	290,874	110,588	19,320	30,750	3,409
C3	439,957	133,430	26,654	35,503	1,975
C2	175,052	42,594	6,719	7,644	934
C1	38,113	6,609	1,296	485	955

Asset Quantities (AHI at Future Year) – Pre-Intervention

Criticality Level	AHI5	AHI4	AHI3	AHI2	AHI1
C4	225,176	130,726	33,001	24,619	41,419
C3	326,109	197,793	39,826	34,230	39,561
C2	143,467	64,109	7,160	11,511	6,696
C1	29,012	14,111	1,296	1,192	1,847

Asset Quantities (AHI at Future Year) – Post-Intervention

Criticality Level	AHI5	AHI4	AHI3	AHI2	AHI1
C4	274,626	130,726	31,678	14,136	3,775
C3	377,512	197,793	39,122	17,030	6,062
C2	151,779	64,109	6,838	8,526	1,691
C1	31,777	14,111	1,296		274

6.5.4 Distribution and LV Cables

Distribution and low-voltage cables typically demonstrate high reliability and require minimal maintenance. Additionally, as outlined in section 5.3.4, our underground network is relatively young, having been largely installed within the last 30 years corresponding with the conversion to 22 kV which began in the mid-1990s, or from growth around our urban centres.

Consequently, for now our strategy for managing these assets consists of repairing or replacing them upon failure. The network no longer contains any first-generation XLPE cables, which were associated with specific type-related issues and have exhibited premature failures on multiple networks due to water treeing.

Investment in distribution and LV cables over the planning period is limited, with a small allowance set aside to address emerging condition issues, as no significant asset replacement is forecast within the 10-year horizon.

We recognise that as this asset population ages, increased condition monitoring and asset health modelling capability will need to be developed in the longer term.

6.5.4.1. Key Threats and Treatment Plans

Known Threats	Treatment Plans
Distribution and LV Cables	
• Terminations and joint failures • Third-party damage causing cable strikes and outages due to excavations or drillings. • Network performance • Overloading of circuits due to growth	• Underground distribution cables are typically not inspected or tested due to their maintenance-free nature. Cable terminations and pole risers are checked during overhead line surveys, with repairs made as needed. Ground-mounted transformers and switchgear cable terminations are hard to inspect because equipment outages are required, but thermal imaging and partial discharge detection help identify faults in these areas. • Third parties operating in proximity to these assets must obtain a close approach permit. Where necessary, suitable standovers are implemented to mitigate associated risks. • We are installing higher-capacity cables to reduce overloading risk and support future growth.

Table 6.11 Key threats and treatment plans for our distribution and LV cables assets

6.5.4.2. Maintenance Activities

Distribution and LV Cables are not routinely inspected or tested at this time due to their maintenance-free nature installed below ground out of view.

6.5.5 LV Service Pillars and Pits

Public safety is the primary concern associated with this asset class. These assets are widely distributed throughout communities and often located adjacent to customer properties. Positioned near ground level, they are accessible to the general public, including children and pets, and are often exposed to potential deterioration from environmental factors and human interaction.

Nevertheless, these assets play a vital role in ensuring the safe operation of our low-voltage networks, and house live electrical components that pose significant risks if not adequately secured. Accordingly, safety forms the cornerstone of the maintenance programme for LV Service Pillars and Pits, with particular focus on securing units and preventing unauthorised access to live components.

Replacement of these assets is condition-based, using information from our maintenance inspections.

6.5.5.1. Key Threats and Treatment Plans

Known Threats	Treatment Plans
Pillars and Pits	
• Poor data issues • Vehicle collisions • Public safety concerns • Location of pillars • Overheating issues • Third-party damage issues • Space constraints in new developments • Floodings	• We inspect every five years to assess condition, nearby vegetation, and access, and use thermographic scans to check for component overheating, a common failure cause. • We have enhanced our design and installation protocols by positioning pillars in safe locations to minimise the risk of vehicle collisions and associated hazards. Where necessary, pits are installed in areas identified as unsafe to further ensure protection. • We acknowledge that our LV data related to pillars is currently inadequate, but we are making progress as we gather additional information through routine inspections. However, we still do not know the age of some of our fleet. • We are replacing asbestos pillars and mushroom pillars to improve safety for workers and the public. We have replaced the majority of these from our urban areas and prioritise further replacements if any further are found.

Table 6.12 Key threats and treatment plans for our LV service pillars and pits assets

6.5.5.2. Maintenance Activities

LV service pillars and pits inspection cycles are:

Activity	Type	Frequency
LV Service Pillars and Pits		
LV Service Pillars, Link Boxes and Pits	Inspection	Five yearly

Table 6.13 Our inspection and maintenance cycles for our LV service pillars and pits assets

6.5.6 Distribution Substations and Transformers

Public safety is a fundamental consideration in the maintenance programme for transformers and ground-mounted substations, with particular emphasis placed on securing units and preventing public access to live components. Environmental protection also remains a priority, including measures to prevent oil leaks resulting from corrosion or damage to tanks.

Certain equipment types, notably early kiosk-type substations, have limited operating space and exposed live parts, necessitating outages to facilitate safe working conditions. Although the safety risks around these are managed by our operating procedures, where appropriate, these units are replaced with modern alternatives.

Transformers typically require minimal routine servicing and are generally low maintenance; therefore, inspections serve as the primary basis for the maintenance programme, with corrective actions implemented as needed.

In some areas of the network, especially those within 10 km of the coastline, transformer service life may be reduced by up to 10 years compared to other locations due to increased tank and fitting corrosion.

Investment in distribution substations and transformers is planned throughout the 10 year period and is primarily driven by asset age and condition. Higher levels of investment are forecast in the first three years of the planning period, targeted at older design kiosk substations that present increased condition, safety, and reliability risk. Beyond this initial uplift, renewal activity continues at a steady level, reflecting normal age and condition based replacement of substations and transformers to maintain network performance and manage risk over the long term.

Our ARMM models are presently being extended to include overhead transformers, which will enable reporting of asset health and determination of our proactive replacement programmes for this population. Ground mounted transformers will follow.

6.5.6 Distribution Substations and Transformers (continued)

6.5.6.1. Key Threats and Treatment Plans

Known Threats	Treatment Plans
Overhead and Ground Mount Transformers	
• Vehicle Collisions • Undetermined internal failures • Oil leak failures • Old vs new standards • Network growth • Corrosion due to location (coastal areas) needing replacement earlier than expected. • Tap changer failures • Flooding risk • Corrosion and graffiti issues • Network performance • Public and worker safety issues • Lightning arrestor failures • Insufficient space for installations • Adverse weather conditions (cyclones and severe storms)	• Overhead distribution transformers are inspected every five years. Poles and defects like oil leaks, corrosion, or faulty tap changers are replaced as part of our maintenance plan to reduce risk of failures. • Obsolete overhead transformers are also replaced as needed to comply with current standards. • Vehicle collisions are managed by installing transformers away from intersections and by increasing driver awareness in the community. • Flooding risks are evaluated during design, and ground mount transformers are installed on higher ground where needed. • Ground mount transformers are inspected yearly, with issues like corrosion and leaks addressed through proactive maintenance. Tap changers are also maintained and checked as part of the inspection plan. • Transformer earth grids are tested and maintained every five years to ensure public and worker safety. • Each year, we proactively replace Kiosk substations that present safety risks to the public and workers. • We are enhancing our testing procedures as part of our asset recovery process to better establish the reasons for reported transformer internal failures.

Table 6.14 Key threats and treatment plans for our distribution transformer assets

6.5.6 Distribution Substations and Transformers (continued)

6.5.6.2. Maintenance Activities

The inspection and maintenance schedules for our distribution substations and transformers are as follows:

Activity	Type	Frequency
Distribution Substations & Transformers		
Transformer Inspection (Pole Mounted)	Inspection	Five yearly
Auto Transformer Inspection (Pole Mounted)	Inspection	Annual
Auto Transformer Inspection (Ground Mounted)	Inspection	Annual
Transformer Inspection (Ground Mounted)	Inspection	Annual
Transformer Earth Grid Test	Routine Test	Five yearly

Table 6.15 Our inspection and maintenance cycles for our distribution substations and transformers

6.5.7 Distribution Switchgear

Distribution switchgear must remain serviceable, free of defects, and consistently safe for operation. As a critical element in ensuring both the safe and efficient functioning of the network and facilitating equipment isolation, it requires careful attention. These units are typically situated in publicly accessible areas, making safety the primary focus during inspection and maintenance activities.

The adoption of low-maintenance Ring Main Units (RMUs) has proved advantageous, requiring only minimal ongoing maintenance beyond regular safety inspections.

Investment in distribution switchgear over the planning period is largely driven by asset age and condition, with earlier programmes having successfully removed legacy populations of problematic air-break switchgear from the network. While most remaining assets are performing as expected, multiple emerging issues have been identified with a specific design of overhead gas switch, resulting in a higher-than-expected volume of replacements occurring well before nominal service life; longer-term solutions to address these issues are currently being worked through. Overhead fuse investment is primarily condition-based and linked to the defect management programme, with known issues relating to associated connectors proactively addressed and replaced alongside other planned works where practicable. The majority of ground-mounted switchgear units are relatively young, generally less than 40 years old, and aside from a small number of early condition-driven replacements, most renewal activity for these assets is forecast toward the latter part of the planning period.

6.5.7 Distribution Switchgear (continued)

6.5.7.1. Key Threats and Treatment Plans

Known Threats	Treatment Plans
Overhead and Ground Mount switchgear	
• Vehicle collisions • Gas leaks • Poor quality from specific manufacturer • New technologies • Network performance • Locations • Operation • Short lifespan for protection relays • Space limitations for installations • EDO and isolator failures • Adverse weather conditions (cyclones and severe storms)	• Vehicle collisions are managed by installing transformers away from intersections and by increasing driver awareness in the community. • We are replacing overhead switches where they display quality problems. • As part of our automation programme, we are upgrading from outdated switches to modern replacements. • We use UAV inspections alongside regular on-foot assessments to monitor the condition of our overhead switches and plan replacements, helping to minimise failures. • Our ground mount switchgear assets are inspected every two years and maintained every six years to ensure proper operation. • Issues like low gas levels require replacement as part of our replacement plan. • For ground-mounted switchgears equipped with automation, protection relays are replaced every 15 years due to their shorter lifespan. • Switchgear earth grids are tested and maintained every five years to ensure public and worker safety. • We have implemented a proactive plan to replace aging dropout fuses and isolators exhibiting condition issues as part of our defects remedial programme.

Table 6.16 Key threats and treatment plans for our distribution switchgear assets

6.5.7.2. Maintenance Activities

The maintenance schedules for our switches are as follows:

Activity	Type	Frequency
Overhead Switchgear		
Air Break Switch Inspection	Inspection	Annual
Air Break Switch UAV and Thermal	Inspection	Five yearly
Air Break Switch Maintenance	Maintenance	Five yearly
Recloser/Vacuum Switch	Inspection	Five yearly
Gas Switch	Inspection	Five yearly
Overhead Switchgear Earth Bank Test	Routine Test	Five yearly
Ground Mount Switchgear		
Ring Main Unit Inspection	Inspection	Two yearly
Ring Main Unit Maintenance	Routine Maintenance	Six yearly

Table 6.17 Our inspection and maintenance cycles for our distribution switchgear
Note: Isolators / HV fuses are inspected as part of our Detailed Pole and Line Condition Assessment.

6.5.8 Communications

The Communications Network is key to our Network Control Room and ADMS. Without the Communications Network, there would be no automated data for our NOC Team to work with. Because of this, it's critical that the Communications Network is maintained to the highest standards.

The Radio Communications Network and its systems have recently been rebuilt, and allows for remote visibility of key parameters, battery autonomy (when local grid power has been lost), and reporting back to our NOC Team, so they can quickly investigate and react to any potential faults with any site.

Having remote visibility means many maintenance tasks can be completed autonomously, and any faults can be quickly reported – meaning they can be rectified proactively, rather than reactively when the Communications Network fails.

As the majority of the radio communications networks have been recently rebuilt they are in very good condition, resulting in minimal investment requirements over the planning period. One notable exception is the planned replacement of the fibre data centre located near the Pukekohe site, which is approaching end of life and represents the primary communications investment within the period. Investment in fibre assets is otherwise driven by age and condition, with limited intervention required in the near term; however, as these assets continue to age, future AMPs are expected to begin forecasting increased fibre renewal toward the end of the planning horizon.

6.5.8 Communications (continued)

6.5.8.1. Key Threats and Treatment Plans

Known Threats	Treatment Plans
Radio Sites	
• Cybersecurity • Physical security • Radio interference • Loss of power, or battery	• Microwave and Digital UHF Communications use over-the-air (OTA) security measures and encryption to ensure the wireless data and its packets are secure. • Communications Sites are keyed to a separate lock profile, distinct from the standard electricity locks, to limit access to only those that require it. All doors are alarmed to NOC (via pager alerts), including smoke/fire alarms. • All operating frequencies are licensed by MBIE for use by Counties Energy only. Identified interference will be investigated and reported to MBIE via Radio Spectrum Management. • Each communications site has an external generator connection and automatic source changeover, meaning that even individuals without access to the site will be able to restore power via a generator. Most sites have 24-48 hours of backup, which is monitored by NOC.
Remote Terminal Units	
• Cybersecurity • Physical security	• Where possible, all RTUs have their default user credentials removed, and new credentials installed. • All field RTUs are locked inside panels, only accessible to persons holding the relevant HV Switching key.
Fibre Networks	
• Overhead fibre, and over-height loads • Underground fibre strike • Overhead to underground transition points (on poles) • Vermin • Other fibre contractors working within our network	• Typically, fibre is the lowest asset mounted on our poles – meaning any over-height load will strike the fibre network first. We have high-load processes in place which we try and make simple for our customers, and prevent strikes. • Underground fibres contain no metallic jacket or tracer wires, so locating these can be hard. Typically, underground fibres installed within ducts are accompanied by a separate, small copper cable, allowing them to be easily located. Anyone undertaking any excavations should request service plans, which will show the location of our underground fibre network. • Fibre cables that transition from overhead, to underground via an existing pole are at risk to being cut if a vehicle were to hit/damage that pole. These locations are now investigated to ensure transitions are installed on poles in low risk areas, and only one cable will be transitioned per site. • Mice and rats nest within our fibre pits, and in trees (where our fibre cables could run through). Vermin damage to fibre cables could easily degrade or disconnect many links in very quick succession. Where possible, our vegetation teams will trim trees away from our fibre network. • Fibre pits shall be named legibly with "Counties Energy" or previously "Counties Power", and the pit number. Any fibre contractors shall contact the Communications Network Team prior to requesting access to the fibre network.

Table 6.18 Key threats and treatment plans for our communications assets

6.5.8 Communications (continued)

6.5.8.2. Maintenance Activities

The inspection and maintenance schedules for our communication assets are as follows:

Activity	Type	Frequency
Radio Communications		
Radio Repeater Station	Inspection	Six monthly
Remote Communication Equipment	Inspection	Annual
Fibre Pit Inspection	Inspection	Annual

Table 6.19 Our inspection and maintenance cycles for our communications assets
Note: Overhead fibre attachments to the pole are inspected as part of our Detailed Pole and Line Condition Assessment.

6.5.9 Other Network Assets

6.5.9.1. Key Threats and Treatment Plans

Known Threats	Treatment Plans
Capacitor Banks and Voltage Regulators	
• Corrosion, which compromises the external integrity of equipment • Extended lead times for procurement • Adverse weather conditions (cyclones and severe storms)	• We perform annual inspections on these assets, and maintenance of voltage regulators is conducted on a three-year cycle to ensure they remain free of defects. • Our critical spares inventory is maintained at adequate levels to ensure prompt response to any faults or emergencies.
Protection Relays	
• Short lifespan • Insufficient electromechanical or static relays • Performance and reliability problems with a specific relay model	• We have replacement plans for protection relays as they reach end-of-life as well as replaced during a major substation upgrade projects to mitigate this risk. • We maintain sufficient spare parts to address potential faults as they arise. Additionally, we have implemented a proactive strategy to replace a particular relay model that has been identified as posing a potential risk. • We perform routine testing on our relays every three years to verify that they operate according to requirements.
Load Control Equipment	
• Long procurement time frames • Short lifespan for controllers	• We ensure the availability of adequate spare parts to promptly resolve any issues that may occur. Furthermore, we have established a proactive asset replacement strategy to address equipment reaching the end of its service life.

Table 6.20 Key threats and treatment plans for our other assets

6.5.9 Other Network Assets (continued)

6.5.9.2. Maintenance Activities

The inspection and maintenance schedules for our other network assets are as follows:

Activity	Type	Frequency
Capacitor Bank		
Capacitor Bank	Inspection	Annual
Voltage Regulators		
Voltage Regulator Inspection	Inspection	Annual
Voltage Regulator Maintenance	Routine Maintenance	Three yearly
Load Control		
Ripple Injection Plant Inspection	Inspection	Six monthly
Ripple Injection Plant Maintenance	Routine Maintenance	Annual
Earth Grid	Inspection	Three yearly
Protection Relays		
Protection Relay Testing	Routine Testing	Three yearly

Table 6.21 Our inspection and maintenance cycles for our other assets

07
Our Detailed Plan

7.1 About This Chapter

This chapter outlines the details of our upgrade, replacement and investment plans for our network and associated assets over the next decade.

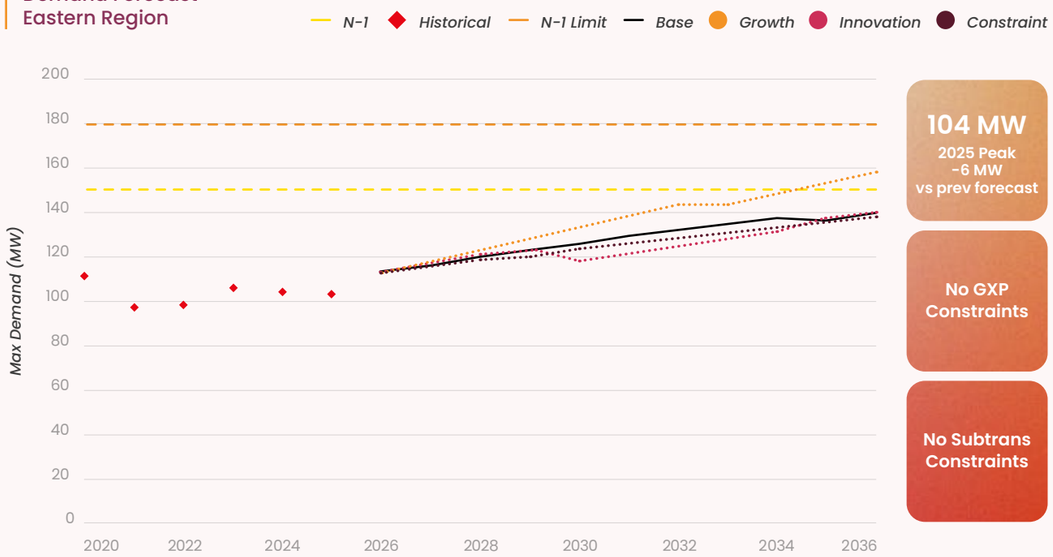
It breaks down the network into regions and asset types, provides an overview of the forecasted growth in demand, the expected remediations and renewals required, and the asset investments and projects planned.

7.2 Eastern Region

The Eastern Region of our network is supplied from Transpower's Bombay Grid Exit Point and encompasses areas served by the Ōpaheke, Pōkeno, Pukekohe, Tuakau and Barber Road Zone Substations.
Its subtransmission network comprises a 110 kV ring from Bombay feeding Pōkeno, Pukekohe, and Tuakau; and two 110 kV lines to Ōpaheke and Barber Road.

The expected demand forecast for the Eastern Region is shown below.

Figure 7.1
Demand Forecast
Eastern Region



Zone Substation	Firm Capacity	2025 Actual	2026	2027	2028	2029	2030	2031 -2036	2037 - 2041
Ōpaheke	40	32	36	38	40	41	43	46 - 51	53 - 58
Pōkeno	40	12	16	16	17	18	18	19 - 21	21 - 23
Pukekohe	60	39	40	41	42	43	44	45 - 49	50 - 57
Tuakau	40	13	14	14	14	14	14	15 - 15	16 - 16
Barber Road	40	12	12	13	13	13	13	14 - 14	15 - 16
Bombay GXP	150	104	114	117	120	124	127	130 - 140	143 - 157

Table 7.1 Capacity by Zone Substation in MVA as per Base Scenario

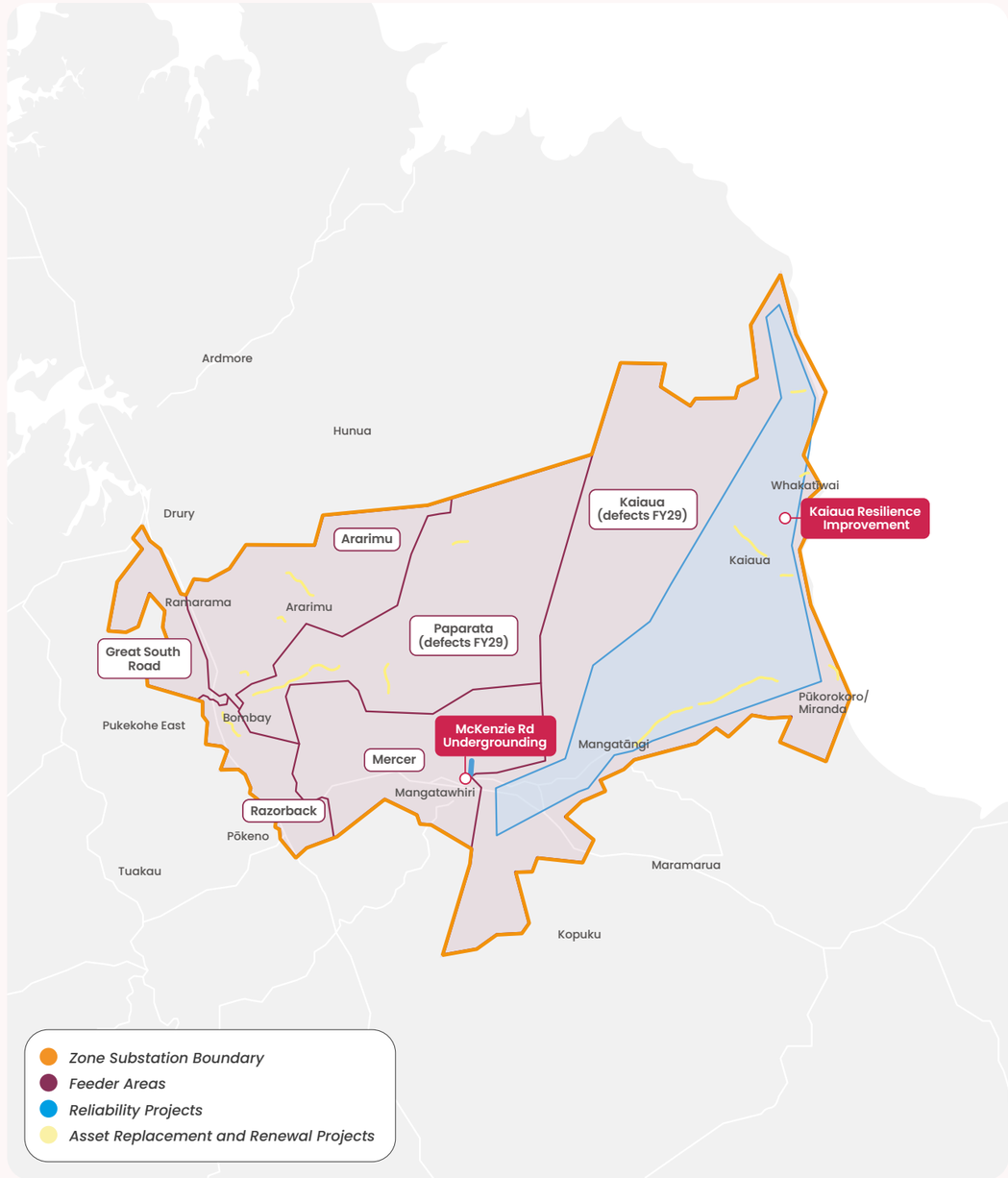
Indicates load nearing or exceeding firm capacity
Indicates expected intervention timeframe

Details on zone substation constraints are discussed in the following sections.

7.2 Eastern Region (continued)

7.2.1 Barber Road Supply Area

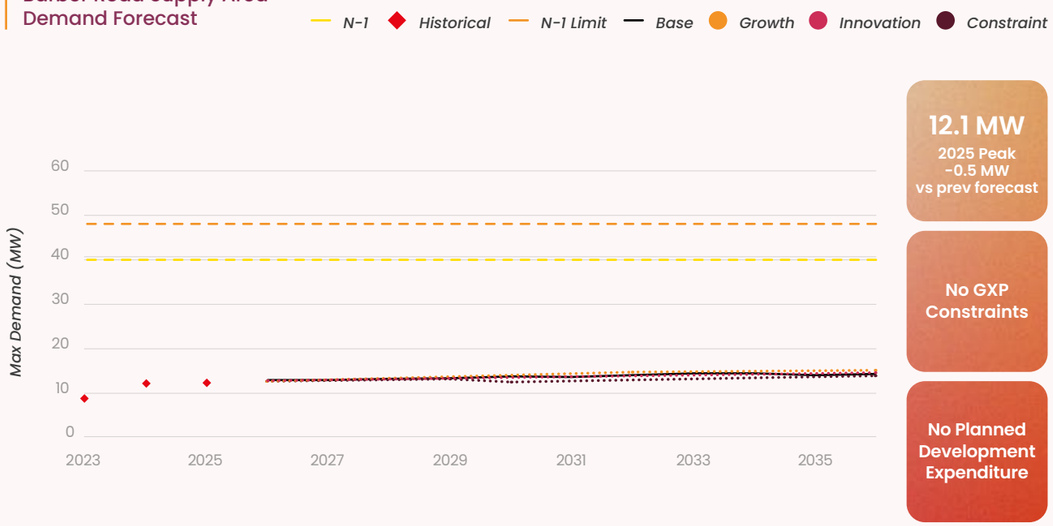
Figure 7.2
Map of Barber Road
Supply Area



7.2.1 Barber Road Supply Area (continued)

The demand forecast for the Barber Road Supply Area is shown below.

Figure 7.3
Barber Road Supply Area
Demand Forecast



Zone Substation and Feeders	Firm Capacity	2025 Actual	2026	2027	2028	2029	2030	2031 -2036	2037 - 2041
Ararimu	13.7	2.8	2.8	2.9	2.9	2.9	2.9	3 - 3.2	3.2 - 3.4
Great South Rd	13.7	2.0	2.0	2.1	2.1	2.2	2.2	2.3 - 2.4	2.5 - 2.7
Kaiaua	11.4	2.5	2.6	2.6	2.7	2.7	2.7	2.8 - 2.8	2.9 - 3.1
Mercer	13.7	1.6	1.6	1.7	1.7	1.7	1.7	1.8 - 1.9	1.9 - 2
Paparata	6.9	1.3	1.3	1.4	1.4	1.4	1.4	1.5 - 1.5	1.6 - 1.7
Razorback	11.1	3.1	3.2	3.3	3.4	3.4	3.5	3.6 - 3.7	3.8 - 4.1
Barber Road SS	40.0	12	12	13	13	13	13	14 - 14	15 - 16

Table 7.2 Capacity for Barber Road Zone in MVA

7.2.1 Barber Road Supply Area (continued)

Zone Substation Auxiliary Battery Banks and Chargers

The auxiliary battery banks on the network will be fully replaced at least once during the planning period, as their expected operational life is eight years out of a 10-year design life. DC battery bank chargers will be replaced upon reaching their 20-year service life. The Barber Road DC battery bank replacement is set for FY30.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Barber Rd DC Battery Bank Replacement	-	-	-	30	-	-	-	-	-	-

Table 7.3 Capex for Barber Road Battery Bank

Overhead High Voltage Conductor Renewal Programme

Over the 10-year planning horizon, we intend to replace the HV overhead conductors within the Barber Road Substation area. These specific sections have been identified as high risk according to our ARMM model.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Aley Road	-	-	-	-	-	-	-	849	-	-
East Coast Road	-	-	-	-	-	-	-	463	-	-
Fausett Road	-	-	-	527	-	-	-	-	-	-
Miranda Road	-	-	-	-	-	-	1,113	-	-	-
Miranda Road	-	-	-	-	-	-	-	-	-	1,792
Moumoukai Road	-	-	-	-	-	-	554	-	-	-
Paparata Road	-	-	-	-	-	-	1,504	-	-	-
Paparata Road	-	-	-	-	-	-	-	1,845	-	-
Portsmouth Road	-	-	-	-	-	593	-	-	-	-
Pukekereru Lane	-	-	497	-	-	-	-	-	-	-
Rangipo Road	-	-	321	-	-	-	-	-	-	-
Rata Road	-	-	264	-	-	-	-	-	-	-
Razorback Road	-	-	-	-	-	1,010	-	-	-	-

Table 7.4 Capex for Barber Road Overhead Conductors

7.2.1 Barber Road Supply Area (continued)

Capex: Asset replacement and renewal (continued)

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Steel Road	-	-	-	-	-	-	-	-	1,303	-
Te Ahu Road	-	-	-	-	-	-	-	143	-	-
Toft Road	-	-	1,292	-	-	-	-	-	-	-
Wootten Road	-	-	-	389	-	-	-	-	-	-

Table 7.4 Capex for Barber Road Overhead Conductors (continued)

Overhead Defect Remedial Programme

In FY28, we will inspect two feeders from Barber Road Substation and based on that inspection, plan any necessary repairs for FY29. Budgets are set by the feeder condition and classification. Any urgent high-risk issues found during inspection will be fixed within three months using corrective maintenance funds.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Kaiaua Feeder Defects	-	-	1,000	-	-	-	-	-	-	-
Paparata Feeder Defects	-	-	1,000	-	-	-	-	-	-	-

Table 7.5 Capex for Barber Road Defect Programme

Kaiaua Feeder Resilience Improvement

In a recent review of fault data from FY24/FY25 and SAIDI statistics, some customers on our Kaiaua feeder have been experiencing an extended period of outages due to network faults. There are approximately 956 customers on this feeder. Counties Energy's neighbouring EDBs (Vector and WEL Networks) have backfeed functionality, although only to a limited extent. The goal of this programme is to create a potential secondary feed to help improve the power quality for these rural customers.

Capex: Quality of supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Kaiaua Feeder Resilience Improvement	-	990	-	-	-	-	-	-	-	-

Table 7.6 Capex for Kaiaua Feeder

7.2.1 Barber Road Supply Area (continued)

Reliability – Feeder Undergrounding

Our Kaiaua and Mercer feeders on McKenzie Road are supplied by the same pole structures for approximately nine spans. This has raised multiple operational and safety concerns. Since both feeders are built on the same pole structures, it is challenging to identify the overhead circuits. If a fault arises on one of these pole structures, we will have to isolate both feeders to resolve the fault. This project is to convert the nine spans of the Kaiaua feeder to an underground circuit as this will eliminate operational and safety issues but also avoid the need to isolate both feeders in a fault situation.

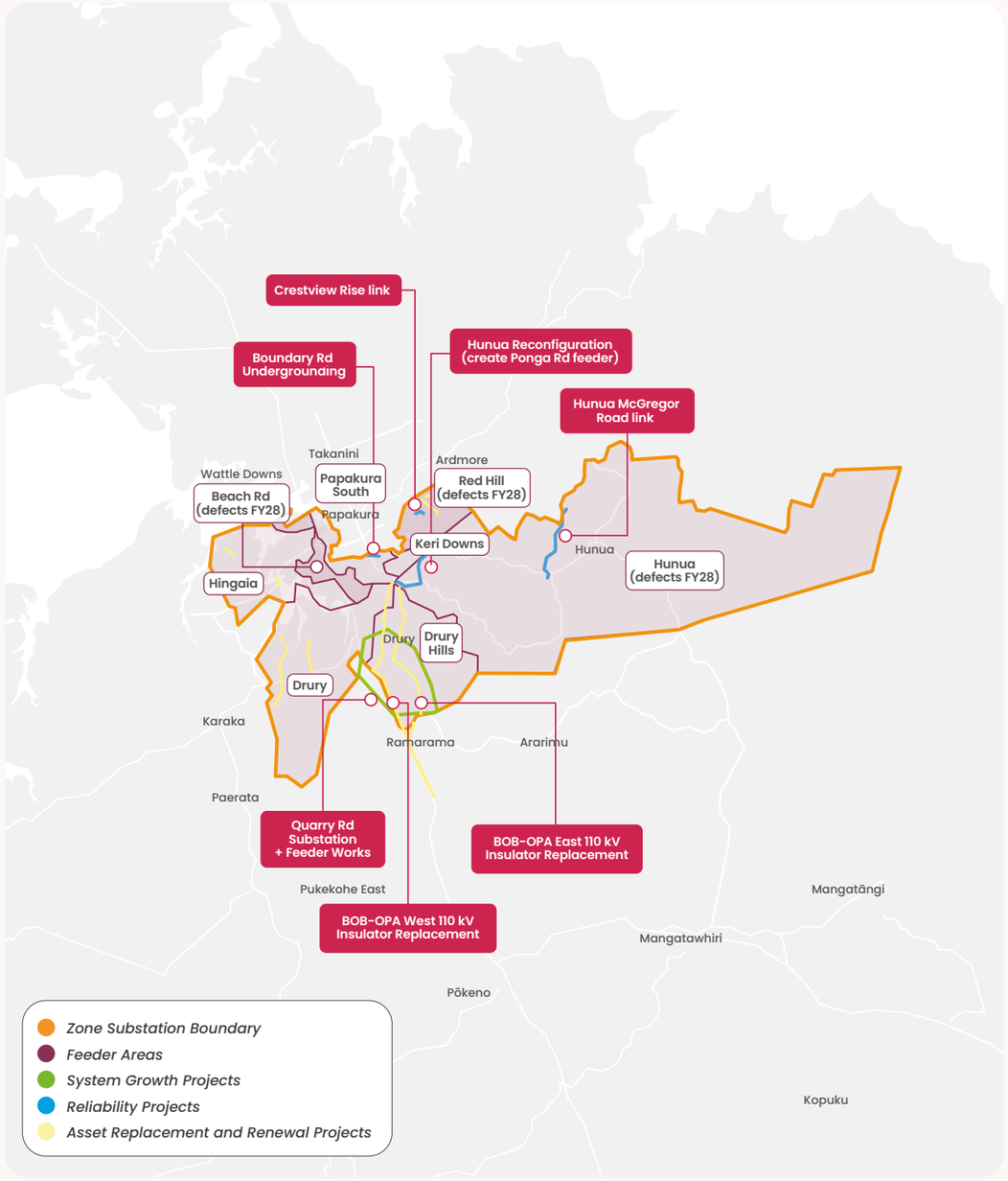
Capex: Quality of supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Kaiaua Feeder - McKenzie Road Undergrounding	-	337	-	-	-	-	-	-	-	-

Table 7.7 Capex for McKenzie Road Undergrounding

7.2.2 Ōpaheke Supply Area

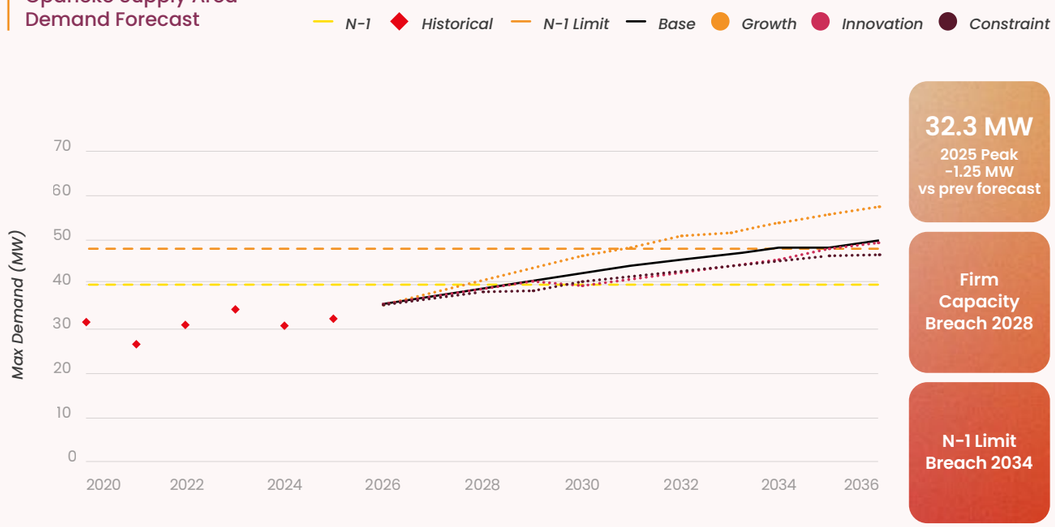
Figure 7.4
Map of Ōpaheke Supply Area



7.2.2 Ōpaheke Supply Area (continued)

The demand forecast for the Ōpaheke Supply Area is shown below.

Figure 7.5
Ōpaheke Supply Area Demand Forecast



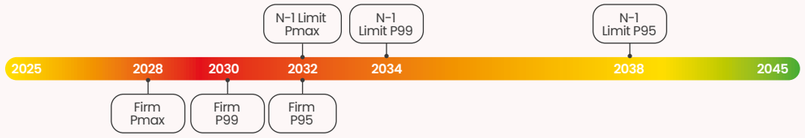
Zone Substation and Feeders	Firm Capacity (MVA)	2025 Actual	2026	2027	2028	2029	2030	2031 -2036	2037 - 2041
Beach Road	13.7	4.4	4.9	5.1	5.4	5.7	5.9	6.2 - 6.6	6.7 - 7.3
Drury	13.7	4.4	5.4	5.9	6.4	6.9	7.7	8.2 - 10.8	11.3 - 14.1
Drury Hills	13.7	6.5	7.3	7.9	8.5	9.2	9.8	10.5 - 12.6	12.9 - 13.8
Hingaia	11.1	3.8	4.7	5.1	5.5	5.8	6.1	6.4 - 6.8	6.9 - 7.5
Hunua	11.1	4.4	4.5	4.5	4.6	4.6	4.7	4.8 - 5	5 - 5.3
Keri Downs	11.4	3.3	3.4	3.4	3.4	3.5	3.5	3.6 - 3.7	3.8 - 4
Papakura South	11.1	5.1	5.6	5.9	6.1	6.2	6.4	6.7 - 7.1	7.3 - 8
Red Hill	13.7	4.2	4.4	4.5	4.6	4.6	4.7	4.8 - 4.9	5 - 5.3
Ōpaheke Substation	40.0	32	36	38	40	41	43	46 - 51	53 - 58

Table 7.8 Capacity for Opaheke Zone in MVA

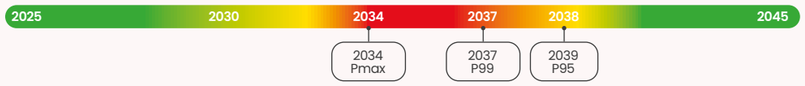
Indicates load nearing or exceeding firm capacity
Indicates expected intervention timeframe

7.2.2 Ōpaheke Supply Area (continued)

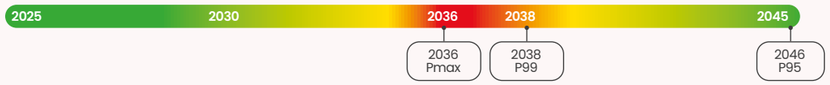
Firm Rating Constraint



Drury Feeder Constraint



Drury Hills Feeder Constraint



Issue description

Our Ōpaheke Zone 110/22 kV Substation has two 40 MVA transformers with a firm capacity of 40 MVA and an N-1 limit of 48 MVA. The area is experiencing significant residential and commercial growth. The commercial development has to date primarily impacted daytime loads and has had only slight impact on the transformer peaks, which are typically during winter evenings. Residential growth continues to impact winter peaks.

System modelling indicates the firm rating of the substation will be exceeded within the planning period. As these transformers can handle short-term overloading and given that this is an N-1 security risk rather than an asset loading issue, the N-1 limit figure is used for planning purposes. The N-1 limit is expected to be exceeded during the period of 2032-2038.

In addition, the Drury Feeder will breach thermal ratings in the period of 2034-2039, while the Drury Hills Feeder will do so in the period of 2036-2046.

Options to address issue:

The following options are in consideration for the substation firm rating constraint:

- Upgrade the existing power transformers from 40 MVA to 60 MVA.
- Install a third power transformer.
- Establish a new substation and redistribute load.
- Shift load onto Barber Road (adjacent substation) during short duration winter peaks.
- Utilise utility scale battery storage solutions to reduce load on the power transformers during N-1 contingent events.
- Utilise demand-side flexibility to reduce load on the power transformers during N-1 contingent events.

The following options are in consideration for the Drury and Drury Hills feeder constraints:

- Shift load onto adjacent feeders during short duration winter peaks.
- Establish a new substation and redistribute load onto new feeders.
- Utilise demand-side flexibility to manage load within thermal limits.

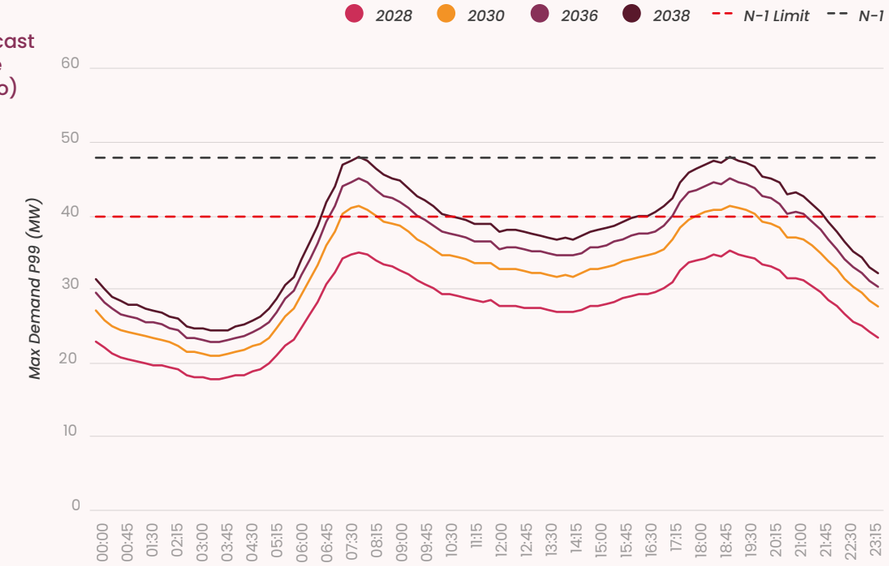
7.2.2 Ōpaheke Supply Area (continued)

Solution selected for the Asset Management Plan

The preferred solution selected for AMP planning purposes is to establish a new substation in the south Drury region (Quarry Road Zone Substation). However, due to the uncertainty in timing, and the duration of N-1 security breaches, alternative options such as utility scale storage solutions or demand-side flexibility from above could become viable.

We will monitor the levels of energy shift required to manage within N-1 limits. The plots below show the expected demand profiles for the zone substation until 2038, which indicate that the Ōpaheke Zone Substation power transformers are likely to be operated until then.

Figure 7.6 Demand Forecast Ōpaheke Zone (Base Scenario)



The requirements for this project will be further defined over the next five years, taking into account actual growth rates. Ultimately, in time a new zone substation will be required, and as such, we are working closely with the developers in Drury to future proof underground cable routes in advance of the need date.

7.2.2 Ōpaheke Supply Area (continued)

Capex: System Growth

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Quarry Road Feeders								1,854	1,154	3,291
Quarry Road Integration										150
Quarry Road Substation Construction	50	50	50	50	50	50	500	500	3,000	5,500
Quarry Road Subtransmission Betterment	1,627	500								

Table 7.9 Investment for Quarry Road

110kV Bus

A 110kV customer connection will necessitate a 110kV bus at Ōpaheke, planned for delivery in FY27 and FY28.

Capex: System Growth

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Ōpaheke 110kV Bus[2]	3,700	500	-	-	-	-	-	-	-	-

Table 7.10 Capex for Ōpaheke 110kV Bus

Zone Substation

The Ōpaheke switchboard replacement project began in FY26 and will continue with funding allocated for FY27 and FY28. If the project finishes in FY27, the funds set aside for FY28 could be redirected elsewhere. Additional funding has been provided to build a firewall for the east transformer, ensuring compliance with industry standards and to reduce the risk of a transformer failure impacting our switchroom building. To address earthquake risks, our substation building underwent seismic strengthening in FY26 as part of broader efforts to improve structural resilience during the switchboard replacement.

Capex: System Growth

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Ōpaheke Substation Renewal	2,650	185	-	-	-	-	-	-	-	-
Ōpaheke East Transformer Fire wall	-	220	-	-	-	-	-	-	-	-

Table 7.11 Capex for Ōpaheke Switchboard

2. Half of the expenditure associated with this line is included under Customer Connection in Table 7.72 and Schedule 11a, due to the customer component involved.

7.2.2 Ōpaheke Supply Area (continued)

Zone Substation Auxiliary Battery Banks and Chargers

Our auxiliary battery banks, with an anticipated operational life of eight years (representing 80% of their designed lifespan of 10 years), will undergo complete replacement at least once within this planning period. Given that DC battery bank chargers have a projected service life of 20 years, they will be replaced as they reach their end-of-life threshold. The Ōpaheke DC battery bank is scheduled for replacement in FY36.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Ōpaheke DC Battery Bank Replacement	-	-	-	-	-	-	-	-	-	30

Table 7.12 Capex for Ōpaheke DC Battery

Ōpaheke Microwave Link

Ōpaheke currently connects to our fibre network, but we have planned to add a microwave link to Barber Road for backup and improved resiliency. We will also need to replace the existing communications pole as the existing pole is unsuitable to support a microwave transmitter; this is scheduled for FY27.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Ōpaheke Microwave Link	175	-	-	-	-	-	-	-	-	-

Table 7.13 Capex for Ōpaheke Microwave Link

Subtransmission

Within this 10-year planning period, funding has been allocated to replace 110 kV insulators on the Bombay to Ōpaheke East line in FY34 and the Bombay to Ōpaheke West line in FY35.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
BOB-OPA East 110 kV Insulator Replacement	-	-	-	-	-	-	-	1,400	-	-
BOB-OPA West 110 kV Insulator Replacement	-	-	-	-	-	-	-	-	1,400	-

Table 7.14 Capex for Bombay to Ōpaheke Insulators

7.2.2 Ōpaheke Supply Area (continued)

Overhead High Voltage Conductor Renewal Programme

Over the 10 years, we intend to replace overhead conductors within the Ōpaheke Substation area. These specific sections have been identified as high risk according to our ARMM model.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Bycroft Road	-	-	-	-	-	-	-	-	665	-
Fitzgerald Road	-	-	-	-	-	-	-	-	-	733
Hingaia Road	-	-	-	-	-	-	-	-	318	-
Kaipara Road	-	-	-	-	-	-	-	-	-	1,048
Oira Road	-	-	742	-	-	-	-	-	-	-
Whangapouri Road	-	1,037	-	-	-	-	-	-	-	-

Table 7.15 Capex for Ōpaheke Overhead Conductors

Overhead Defect Remedial Programme

In FY27, we intend to inspect three feeders, after which we will schedule any required remedial work to address any identified defects for FY28. Indicative budgets have been allocated based on the condition and classification of each feeder. Any high-risk defects requiring urgent attention identified during inspection will be addressed within three months, utilising funds from our corrective maintenance plan.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Beach Road Feeder Defects	-	50	-	-	-	-	-	-	-	-
Hunua Feeder Defects	-	1,000	-	-	-	-	-	-	-	-
Red Hill Feeder Defects	-	500	-	-	-	-	-	-	-	-

Table 7.16 Capex for Ōpaheke Defect Programme

7.2.2 Ōpaheke Supply Area (continued)

East Line Earthing Remedial Works

A minor project is included in FY27 to modify the earthing arrangements where the Bombay-Ōpaheke (East) line meets our Ōpaheke substation. This was identified during the recently completed upgrade works on this line and will improve the overall performance of the high-voltage earthing in this network area.

Capex: Other reliability, safety and environment

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Ōpaheke East Line Earthing Remedial Works	35	-	-	-	-	-	-	-	-	-

Table 7.17 Capex for Ōpaheke Remedial Works

Reliability – Feeder Projects

1) Hingaia new recloser

The Hingaia feeder is primarily an underground network but includes a 2.6 km overhead section along Linwood Road, Karaka, serving approximately 100 customers. This overhead segment is supplied from a Ring Main Unit and transitions back to an underground network before connecting to another Ring Main Unit on Karaka North Road. As the feeder is classified as urban, the protection settings on the protection equipment have no auto-reclosing function, meaning any fault on the overhead section results in a complete outage for customers downstream of the Towai Road Ring Main Unit, leading onto Linwood Road, Karaka.

2) Hunua McGregor Road link

The Hunua feeder is primarily a 22 kV overhead network, with a small 11 kV segment supplied from John Hill Road via an autotransformer serving over 200 customers. In July 2025, a fault on the autotransformer caused a prolonged outage, highlighting some reliability concerns for this section. The Hunua McGregor Road 11/22 kV link has been added to the Asset Management Plan to provide a backfeed supply, ensuring faster restoration during faults.

3) Hunua reconfiguration (create Ponga Road feeder)

A significant replacement project was completed on the Red Hill feeder in FY24, which saw a large proportion of the feeder replaced with a new underground network. Part of this work included the installation of a section of spare ducts, with the intention of being able to split the Red Hill feeder in the future once the Ōpaheke Substation had the ability to do so. This project was presented in our previous Asset Management Plans as “New Feeder to Offload Red Hill Feeder”. During the preparation of the 2024 Asset Management Plan Update, it was identified that the Broken Bridge Road Link on the Hunua feeder needed to be brought forward. This presented the opportunity for the same ducts to be used instead to split the Hunua feeder. Although Hunua supplies roughly half the customers compared to Red Hill, it is over four times the length and includes a much larger proportion of overhead lines, with a lot of this in densely vegetated areas. This is now planned for FY30.

4) Red Hill – Crestview Rise Link

A subdivision within our Red Hill feeder developed in the early 2000s serves over 400 customers from four distribution transformers but has limited backup supply options if a fault were to occur on the main supply cable. This limited configuration poses a significant SAIDI risk, as a single fault could interrupt supply to all customers for a reasonably long duration. To mitigate this, a backfeed supply will be established, improving reliability and providing alternative restoration paths during outages.

7.2.2 Ōpaheke Supply Area (continued)

Capex: Quality of supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Hingaia Feeder Reliability Improvement	124	-	-	-	-	-	-	-	-	-
Hunua Feeder McGregor Road Link	607	-	-	-	-	-	-	-	-	-
Hunua Feeder Create Ponga Road Feeder	-	-	-	1,027	-	-	-	-	-	-
Red Hill Feeder Crest View Rise Link	-	990	-	-	-	-	-	-	-	-

Table 7.18 Capex for Ōpaheke Reliability – Feeder Projects

Reliability - Feeder Undergrounding

Boundary Road in Papakura is supplied by an overhead 22 kV network, despite most of the Papakura South feeder being an underground network. This project will convert eight spans of the residential section to an underground network, eliminating routine maintenance requirements and reducing potential safety risks associated with overhead assets. The change will enhance our network reliability and improve public safety.

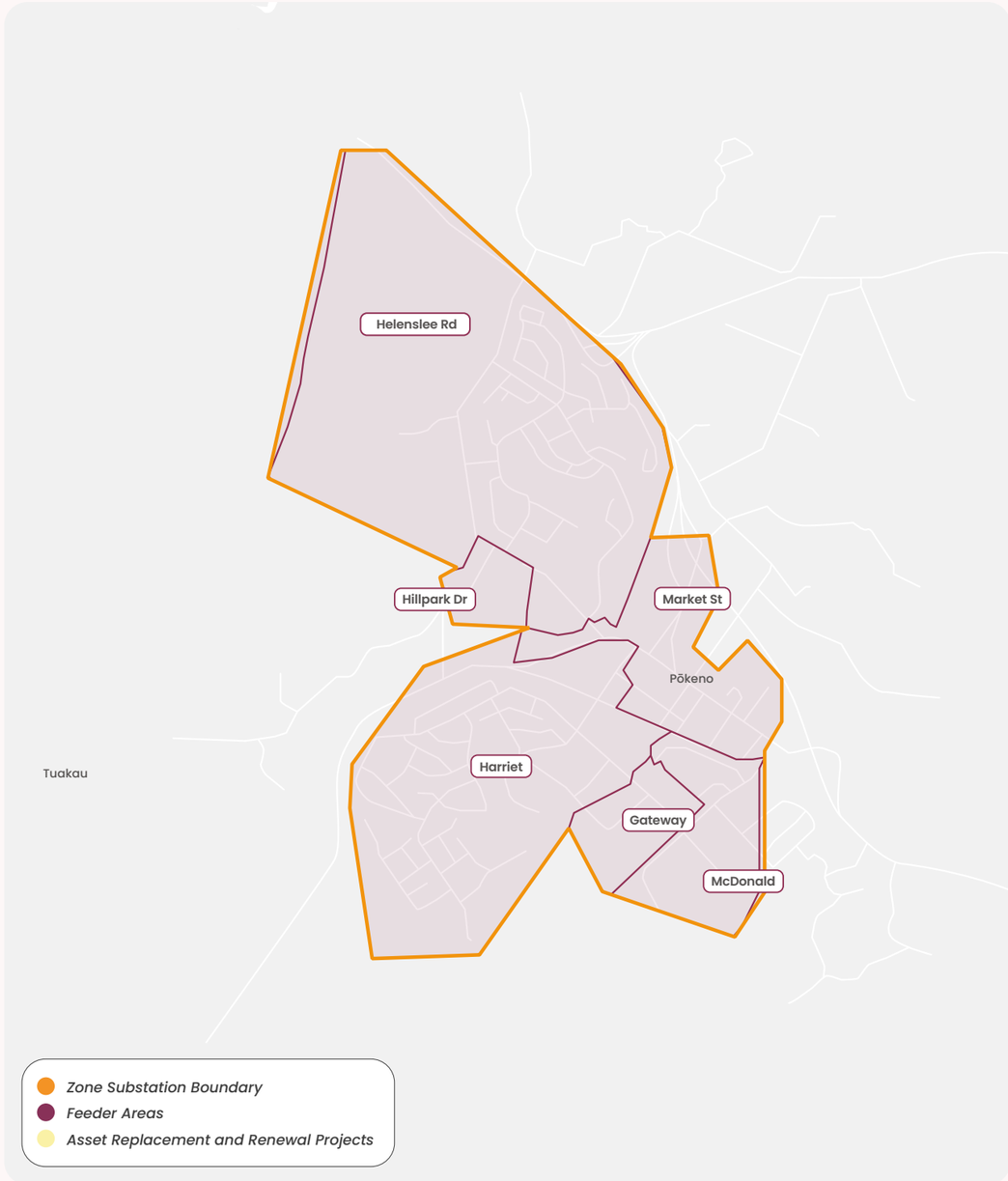
Capex: Quality of Supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Papakura South Feeder - Boundary Road Undergrounding	-	-	-	-	-	1,158	-	-	-	-

Table 7.19 Capex for Boundary Road Undergrounding

7.2.3 Pōkeno Supply Area

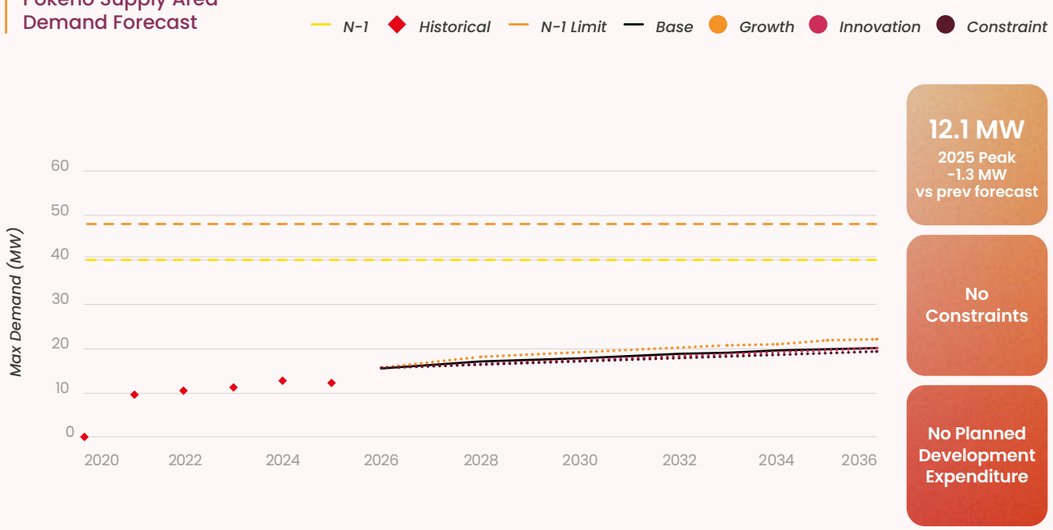
Figure 7.7
Map of Pōkeno Supply Area



7.2.3 Pōkeno Supply Area (continued)

The demand forecast for the Pōkeno Supply Area is shown below.

Figure 7.8
Pokeno Supply Area
Demand Forecast



Zone Substation	Firm Capacity (MVA)	2025 Actual	2026	2027	2028	2029	2030	2031 -2036	2037 - 2041
Gateway	15.0	3.8	3.8	4.2	4.6	4.7	4.7	4.8 - 5	5.1 - 5.4
Harriet	13.7	2.3	2.6	2.6	2.7	2.7	2.7	2.8 - 3	3 - 3.2
Helenslee Road	13.7	2.0	2.2	2.2	2.3	2.4	2.5	2.6 - 2.7	2.8 – 3.0
Hillpark Drive	13.7	0.5	0.6	0.7	0.8	1.0	1.2	1.4 - 2.5	2.7 - 3.7
Huia Road	13.7	0.0	0.0	0.0	0.0	0.0	0.0	0 - 0	0 - 0
McDonald Road	13.7	3.8	3.9	3.9	4.1	4.3	4.3	4.4 - 4.6	4.6 - 4.9
Market Street	13.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9 - 1	1.0 - 1.1
WWTP 4*	16.9	3.7	3.7	3.7	3.8	3.8	3.8	3.9 - 4.1	4.2 - 4.4
Pōkeno Substation	40.0	12	16	16	17	18	18	19 - 21	21 - 23

Table 7.20 Capacity for Pokeno Zone in MVA

**Watercare Water Treatment Plant*

7.2.3 Pōkeno Supply Area (continued)

Zone Substation Auxiliary Battery Banks and Chargers

Our auxiliary battery banks, with an anticipated operational life of eight years (representing 80% of their designed lifespan of 10 years), will undergo complete replacement at least once within this planning period. Given that DC battery bank chargers have a projected service life of 20 years, they will be replaced as they reach their end-of-life threshold. The Pōkeno DC battery bank is scheduled for replacement in FY29.

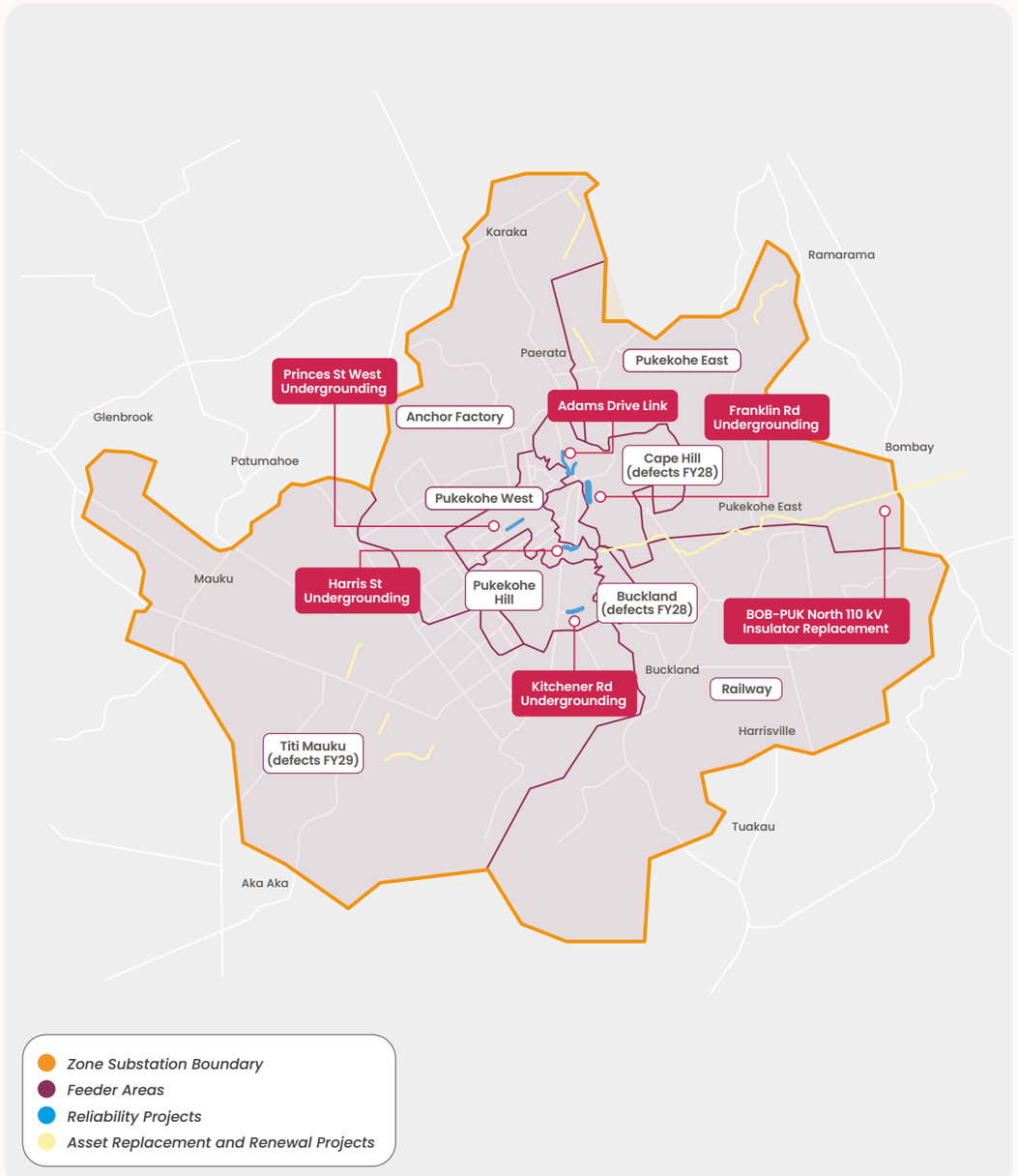
Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Pōkeno DC Battery Bank Replacement	-	-	30	-	-	-	-	-	-	-

Table 7.21 Capex for Pokeno DC Battery

7.2.4 Pukekohe Supply Area

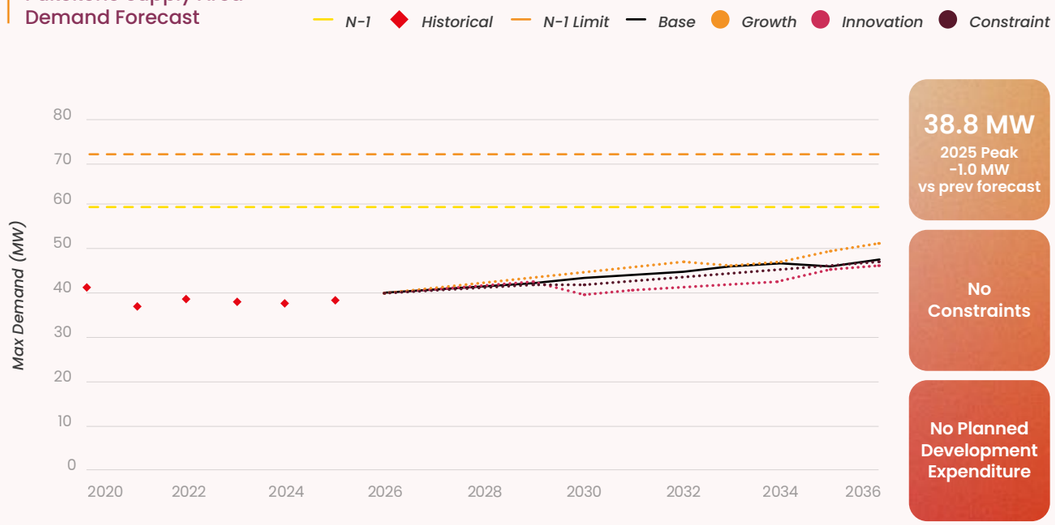
Figure 7.9
Map of Pukekohe Supply Area



7.2.4 Pukekohe Supply Area (continued)

The demand forecast for the Pukekohe Supply Area is shown below.

Figure 7.10
Pukekohe Supply Area Demand Forecast



Zone Substation	Firm Capacity (MVA)	2025 Actual	2026	2027	2028	2029	2030	2031 -2036	2037 - 2041
Anchor Factory	13.7	4.6	5.0	5.2	5.4	5.7	6.0	6.3 - 7.9	8.3 - 10
Buckland	13.7	3.2	3.2	3.3	3.3	3.4	3.4	3.5 - 4	4.2 - 5.2
Cape Hill	13.7	8.0	8.5	8.7	8.9	9.1	9.2	9.4 - 9.8	9.9 - 10.9
Pukekohe East	13.7	2.4	2.6	2.8	2.9	3.0	3.1	3.2 - 3.8	4.1 - 5.3
Pukekohe Hill	13.7	6.7	6.8	7.0	7.1	7.1	7.2	7.4 - 7.6	7.7 - 8.3
Pukekohe Town	13.7	4.5	4.6	4.7	4.8	4.8	4.9	5 - 5	5.1 - 5.5
Pukekohe West	13.7	6.7	7.0	7.1	7.3	7.4	7.5	7.7 - 8.1	8.3 - 9.2
Railway	11.1	3.0	3.1	3.1	3.2	3.2	3.3	3.3 - 3.5	3.6 - 4.1
Titi Mauku	11.1	3.9	3.9	4.0	4.0	4.1	4.1	4.2 - 4.3	4.4 - 4.7
Pukekohe Substation	60.0	39	40	41	42	43	44	45 - 49	50 - 57

Table 7.22 Capacity for Pukekohe Zone in MVA

Indicates load nearing or exceeding firm capacity
Indicates expected intervention timeframe

7.2.4 Pukekohe Supply Area (continued)

Zone Substation

Zone Substations Building

Pukekohe Substation was constructed in the 1990s before the introduction of the latest national seismic construction standards and is now classified as earthquake prone. We plan to upgrade this to remediate it to current seismic standards during the switchboard replacement project from FY33 to FY36.

22 kV Switchgear

A budget of $10 million has been allocated for the replacement of our 22 kV switchboard during FY33–36, as it is nearing the end of its anticipated service life and spare parts are unavailable due to discontinued support from the manufacturer.

Load Control Plant

Our load control plant at Pukekohe Substation is scheduled for replacement in FY35 as it nears the end of its 40-year expected lifespan.

Auxiliary Battery Banks and Chargers

Auxiliary battery banks will be fully replaced at least once in eight years, as they last about 80% of their ten-year design life. DC battery bank chargers will be replaced after twenty years when they reach end-of-life. Our Pukekohe DC battery bank is due for replacement in FY31.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Pukekohe 22 kV Switchboard Replacement	-	-	-	-	-	-	500	3,000	5,500	1,000
Pukekohe Load Control Controller Renewal	-	-	-	-	-	-	-	-	450	-
Pukekohe DC Battery Bank Replacement	-	-	-	-	30	-	-	-	-	-

Table 7.23 Capex for Pukekohe DC Battery, Load Control and Switchboard

Subtransmission

The insulators on our two 110 kV lines supplying the Pukekohe Zone Substation from Bombay GXP have reached the end of their 30-year expected lifespan. Evidence indicates that flashovers have occurred at several locations. The Bombay–Pukekohe 110 kV South line was reinsulated in FY26, while the North line is scheduled for reinsulating in FY27 with an estimated cost of $1.4 million.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
BOB-PUK North 110 kV Insulator Replacement	1,400	-	-	-	-	-	-	-	-	-

Table 7.24 Capex for Pukekohe Insulators

7.2.4 Pukekohe Supply Area (continued)

Overhead High Voltage Conductor Renewal Programme

Over the 10 years, we intend to replace overhead conductors within the Pukekohe substation area. These specific sections have been identified as high risk according to our ARMM model.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Fulton Road	-	-	501	-	-	-	-	-	-	-
Kern Road	-	-	782	-	-	-	-	-	-	-
Morgan Road	-	-	-	-	-	-	-	-	133	-
Rogers Road	-	-	-	-	-	745	-	-	-	-
Sedgebrook Road	-	-	-	169	-	-	-	-	-	-
Settlement Road	-	-	-	864	-	-	-	-	-	-
Sim Road phase 1	-	-	806	-	-	-	-	-	-	-
Sim Road phase 2	-	562	-	-	-	-	-	-	-	-

Table 7.25 Capex for Pukekohe Conductors

Overhead Defect Remedial Programme

We plan to inspect two feeders in FY27 and one in FY28, then based on those investigations schedule any necessary remedial work for FY28 and FY29. Budgets are allocated according to each feeder's condition and classification. High-risk defects found during inspections will be fixed within three months using our corrective maintenance budget.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Buckland Feeder Defects	-	400	-	-	-	-	-	-	-	-
Cape Hill Feeder Defects	-	300	-	-	-	-	-	-	-	-
Titi Mauku Feeder Defects	-	-	1,000	-	-	-	-	-	-	-

Table 7.26 Capex for Pukekohe Defect Programme

7.2.4 Pukekohe Supply Area (continued)

Glasgow Road Data Centre Replacement

We operate a data centre at our Glasgow Road site, which supports our fibre network for the communication needs of Counties Energy and our fibre customers. The building services are nearing end-of-life, and the location has a low-to-moderate risk of flooding. We plan to move to a smaller, more suitable, purpose-built facility in FY28, pending discussions with fibre customers about scope and timing.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Glasgow Road Data Centre Replacement	-	2,000	-	-	-	-	-	-	-	-

Table 7.27 Capex for Glasgow Road Data Centre

Reliability – Feeder Projects

1) Adams Drive Link

There is a section of our 22 kV network in Adams Drive that supplies around 100 customers, mostly commercial. This section of the network previously had a connection to the eastern side of the railway line, but this connection had to be removed in 2023 during the Kiwirail railway electrification upgrade. This vulnerability was highlighted in September 2024 when a vehicle impacted one of our high-voltage switching unit on Paerata Road, causing customers in the area to be without supply. Although temporary connections were made, a permanent link would have been preferable and enabled a faster restoration. This project to install a second link to the area has been added for FY27. It also enables approximately 400 metres of high-voltage lines to be removed from Paerata Road.

Capex: Quality of supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Cape Hill Feeder - Adams Drive Feeder Link	144	-	-	-	-	-	-	-	-	-

Table 7.28 Capex for Adams Drive Permanent Link

7.2.4 Pukekohe Supply Area (continued)

Reliability - Feeder Undergrounding

1) Franklin Road

Most of Franklin Road's electricity infrastructure is underground, but about 400 metres of overhead lines remain at the northern end, where notable trees line both sides. With roughly 3,000 customers relying on these lines, we are planning to move these lines underground, reducing outages caused by the nearby vegetation, whilst also reducing the ongoing trimming required to the notable trees.

2) Kitchener Road

Kitchener Road on the Pukekohe Hill feeder is primarily an overhead 22 kV network, with an approximately 300-metre section of line passing close to a number of notable trees in the vicinity of Pukekohe Hospital., on which over 1200 customers rely. To improve reliability, this project will underground five spans currently exposed to vegetation interference, which has caused outages in the past. Converting these spans to underground will significantly reduce fault risk, enhance our network performance and reduce the ongoing trimming required to the notable trees.

3) Princes Street West

Approximately 600 customers, including a large section of the growing Belmont subdivision, are served by an overhead 22 kV network along Princess Street West, Pukekohe. While most of the surrounding network is underground, a few overhead spans remain. This project will convert these remaining spans to an underground network on Princess Street West, removing HV conductors and poles to improve reliability and eliminate potential safety risks.

4) Harris Street

The overhead 22 kV network along Harris Street, Pukekohe, is the main backbone of our Pukekohe West feeder, supplying over 3000 customers. This project will underground four spans near Pukekohe Intermediate School which presently have a line of notable trees growing all around the lines. This project will reduce outage risks from vegetation interference, eliminating potential public safety hazards and will reduce the ongoing trimming required to the notable trees.

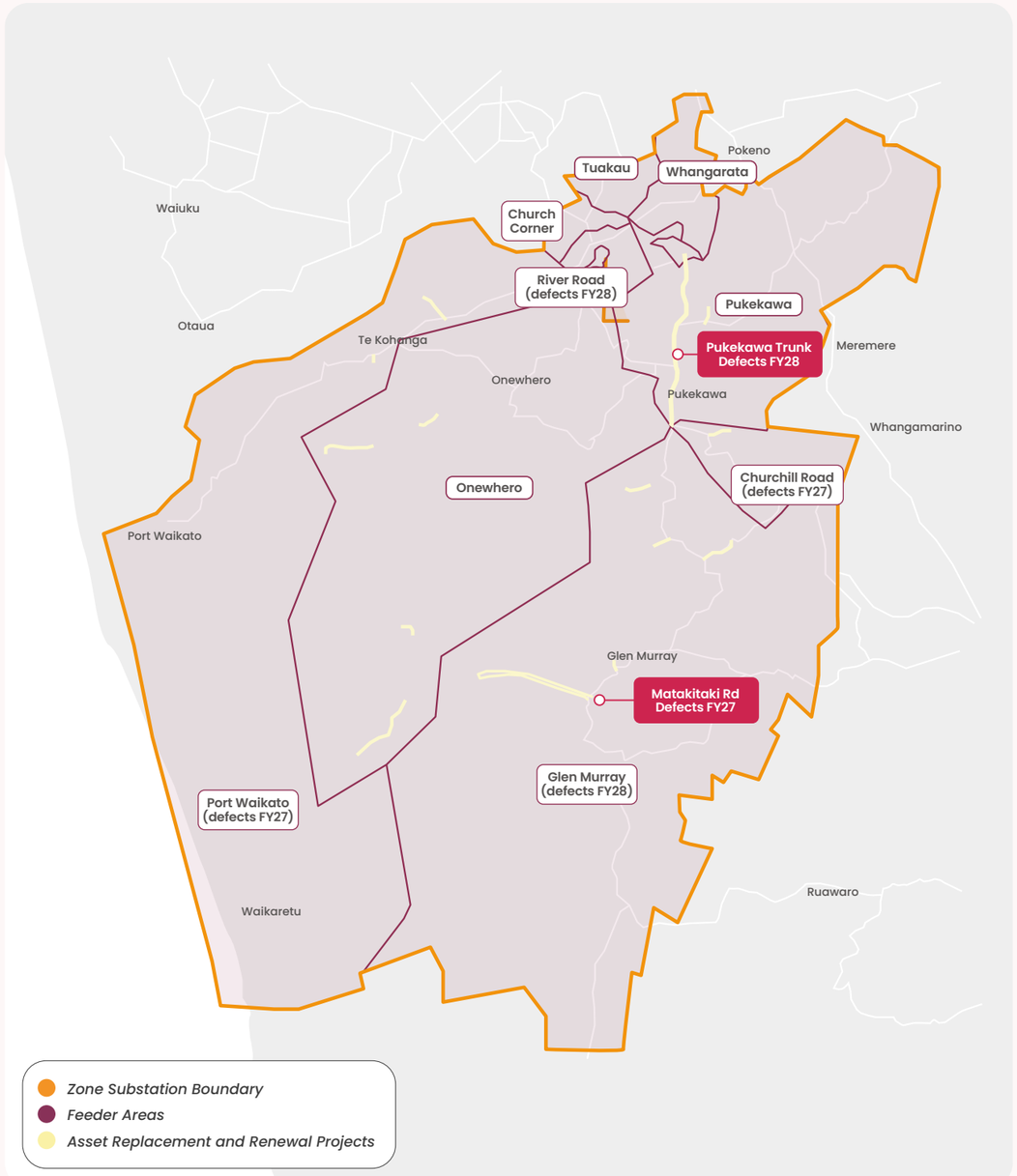
Capex: Quality of supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Cape Hill Feeder – Franklin Road Undergrounding	-	-	-	465	-	-	-	-	-	-
Pukekohe Hill Feeder - Kitchener Road Undergrounding	-	1,122	-	-	-	-	-	-	-	-
Pukekohe West Feeder – Princes Street West Undergrounding	-	-	-	-	815	-	-	-	-	-
Pukekohe West Feeder – Harris Street Undergrounding	-	-	386	-	-	-	-	-	-	-

Table 7.29 Capex for Pukekohe Reliability - Feeder Undergrounding

7.2.5 Tuakau Supply Area

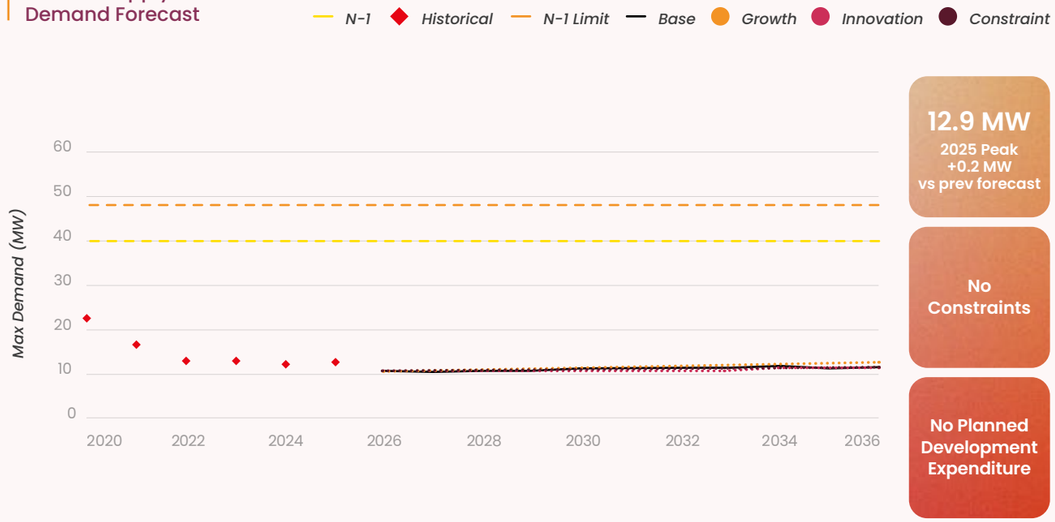
Figure 7.11
Map of Tuakau Supply Area



7.2.5 Tuakau Supply Area (continued)

The demand forecast for the Tuakau Supply Area is shown below (including the network supplied from the Pukekawa Switching Station).

Figure 7.12
Tuakau Supply Area Demand Forecast



7.2.5 Tuakau Supply Area (continued)

Zone Substation and Feeders	Firm Capacity (MVA)	2025 Actual	2026	2027	2028	2029	2030	2031 -2036	2037 - 2041
Church Corner	11.1	3.4	3.5	3.6	3.7	3.7	3.8	3.9 - 4.1	4.1 - 4.4
Port Waikato	11.1	1.0	1.0	1.1	1.1	1.1	1.1	1.2 - 1.2	1.2 - 1.3
River Road	11.1	0.8	0.8	0.8	0.8	0.8	0.8	0.9 - 0.9	0.9 - 1
Tuakau Feeder	8.6	2.0	2.1	2.1	2.1	2.2	2.2	2.3 - 2.3	2.4 - 2.6
Whangarata	11.1	0.6	0.6	0.6	0.6	0.6	0.6	0.7 - 0.7	0.7 - 0.8
WWTP 1*	13.7	1.9	1.9	2.0	2.0	2.0	2.0	2.1 - 2.2	2.2 - 2.4
WWTP 2*	13.7	2.5	2.5	2.5	2.6	2.6	2.6	2.7 - 2.8	2.9 - 3
WWTP 3*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 - 0	0 - 0
Hitchen	16.9	0.0	0.0	0.0	0.0	0.0	0.0	0 - 0	0 - 0
Pukekawa Trunk	11.4	8.7	8.7	8.8	8.8	8.8	8.9	8.9 - 9.1	9.1 - 9.4
Pukekawa	9.4	2.7	2.7	2.8	2.8	2.8	2.9	2.9 - 3	3 - 3.2
Churchill Road	11.1	6.9	7.0	7.0	7.0	7.0	7.0	7 - 7	7 - 7.1
Glen Murray	3.6	1.0	1.0	1.0	1.0	1.1	1.1	1.1 - 1.1	1.1 - 1.2
Onewhero	8.4	1.7	1.8	1.8	1.9	1.9	1.9	2 - 2	2.1 - 2.3
Tuakau Zone Substation	40.0	13	14	14	14	14	14	15 - 15	16 - 16

Table 7.30 Capacity for Tuakau Zone in MVA

**Watercare Water Treatment Plant*

7.2.5 Tuakau Supply Area (continued)

Zone Substation

Load Control Plant

Our load control plant at Tuakau substation is scheduled for replacement in FY35 as it nears the end of its 40-year expected lifespan.

Auxiliary Battery Banks and Chargers

Our auxiliary battery banks, expected to last eight years (80% of their 10-year lifespan), will be fully replaced at least once during the planning period. The DC battery bank chargers have a 20-year service life, and will be replaced as they expire. The Tuakau DC battery bank is set for replacement in FY31, and its charger in FY35. The Pukekawa Switching Station DC battery bank is set for replacement in FY32, and its charger in FY34.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Tuakau Load Control Controller Renewal	-	-	-	-	-	-	-	-	250	-
Tuakau DC Battery Bank Replacement	-	-	-	-	30	-	-	-	-	-
Tuakau DC Battery Charger Replacement	-	-	-	-	-	-	-	-	60	-
Pukekawa DC Battery Bank Replacement	-	-	-	-	-	30	-	-	-	-
Pukekawa DC Battery Charger Replacement	-	-	-	-	-	-	-	60	-	-

Table 7.31 Capex for Tuakau DC Battery and Load Control

7.2.5 Tuakau Supply Area (continued)

Overhead High Voltage Conductor Renewal Programme

Over the 10 years, we intend to replace overhead conductors within the Tuakau substation area. These specific sections have been identified as high risk according to our ARMM model.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Baker Road	-	-	-	-	1,310	-	-	-	-	-
Brewster Road	-	-	-	-	-	-	781	-	-	-
Fleming Road	-	354	-	-	-	-	-	-	-	-
Hull Road	-	-	-	482	-	-	-	-	-	-
Highway 22/ McCutchan Road	-	-	-	-	256	-	-	-	-	-
Klondyke Road	-	-	-	1,139	-	-	-	-	-	-
Klondyke Road	-	-	-	522	-	-	-	-	-	-
Off Tuakau Bridge Port Waikato - Private Land	-	-	-	-	862	-	-	-	-	-
Otuiti Road	-	-	-	-	-	-	-	-	-	928
Punga Punga Road	-	-	-	-	-	-	-	607	-	-
Wairamarama Onewhero Road	-	-	-	-	-	451	-	-	-	-

Table 7.32 Capex for Tuakau Overhead Conductors

Overhead Defect Remedial Programme

In FY26 and FY27, we intend to inspect three feeders from Tuakau Substation, plus the Trunk line to the Pukekawa Switching Station, and three more feeders fed from there. After these inspections, we will schedule any required remedial work to address any identified defects in FY27 and FY28. Indicative budgets have been allocated based on the condition and classification of each feeder. Any high-risk defects requiring urgent attention identified during inspection will be addressed within three months, utilising funds from our corrective maintenance plan.

An additional defect project has been added for Matakitaki Road in Glen Murray a year earlier than the rest of the feeder. This is as a result of feedback from our field teams during a storm event in August 2025.

7.2.5 Tuakau Supply Area (continued)

Overhead Defect Remedial Programme (continued)

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Port Waikato Feeder Defects	1,200	-	-	-	-	-	-	-	-	-
River Road Feeder Defects	-	500	-	-	-	-	-	-	-	-
Watercare Feeder (WCP3) Defects	-	250	-	-	-	-	-	-	-	-
Church Hill Road Feeder Defects	400	-	-	-	-	-	-	-	-	-
Glen Murray Feeder Defects	-	1,000	-	-	-	-	-	-	-	-
Matakitaki Road, Glen Murray Defects	250	-	-	-	-	-	-	-	-	-
Onewhero Feeder Defects	1,150	-	-	-	-	-	-	-	-	-
Pukekawa Trunk Feeder Defects	-	300	-	-	-	-	-	-	-	-

Table 7.33 Capex for Tuakau Defect Programme

Reliability – Feeder Undergrounding

As part of the undergrounding programme, we have analysed potential causes of faults in this section of the Pukekawa feeder, which could be either vegetation debris or bird strikes. As the rural areas are usually overhead built to the 22 kV standard, reclosers on the feeder take care of any temporary faults, however, constant faults lead to a lockout on the recloser.

This requires a fault worker to attend the site to inspect before re-livening. In most cases, the fault is caused by vegetation debris or bird strikes so undergrounding a few spans that are constantly affected will ensure no vegetation debris clashes with the overhead lines and customers don't experience constant outages.

Capex: Quality of supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Pukekawa Feeder – Clark and Denize Road Undergrounding	-	151	-	-	-	-	-	-	-	-

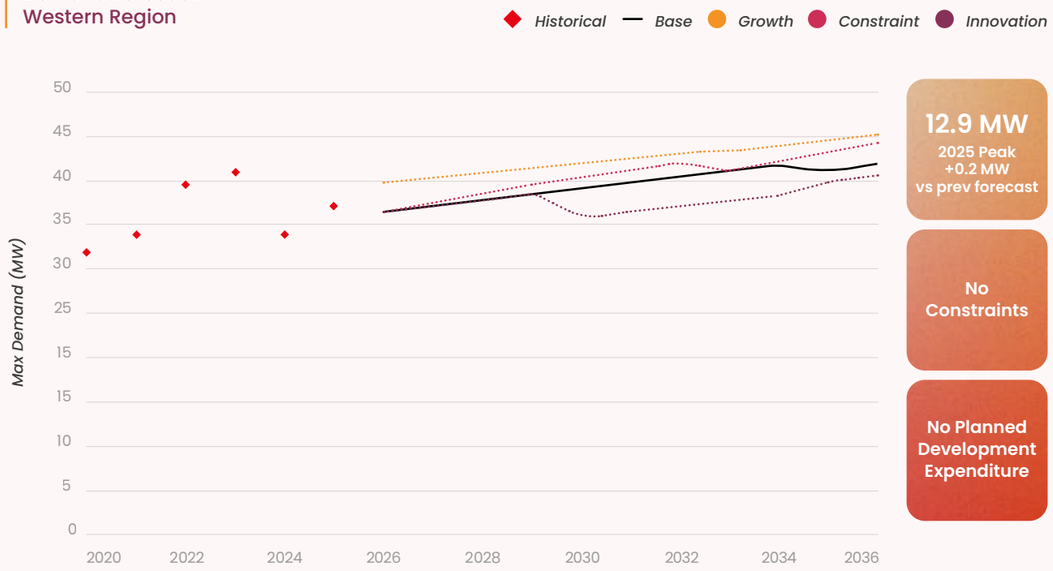
Table 7.34 Capex for Clark & Denize Road Undergrounding

7.3 Western Region

The Western Region is supplied from Transpower's Glenbrook GXP and encompasses areas served by the Karaka, Maioro, and Waiuku Zone Substations, as well as a 33 kV point of supply at Storey Road. Our subtransmission network in this region includes two 33 kV lines from Glenbrook GXP to Waiuku, one 33 kV line from Waiuku to Storey Road Pump Station and Maioro, and two 33 kV lines from Glenbrook GXP to Karaka.

The demand forecast for the Western Region is shown below.

Figure 7.13
Demand Forecast
Western Region



Zone Substation	Firm Capacity	2025 Actual	2026	2027	2028	2029	2030	2031 –2036	2037 - 2041
Karaka	20.0	13	14	14	14	15	15	16 - 17	17 - 19
Maioro	9.4	9	9	9	9	9	9	10 - 10	10 - 11
Waiuku	20.0	17	17	18	18	18	19	20 - 20	20 - 22
New Zealand Steel (Storey Rd)	15.0	1	1	1	1	1	1	2 - 2	2 - 2
Glenbrook GXP	140.0	37	37	37	38	39	39	40 - 43	43 - 47

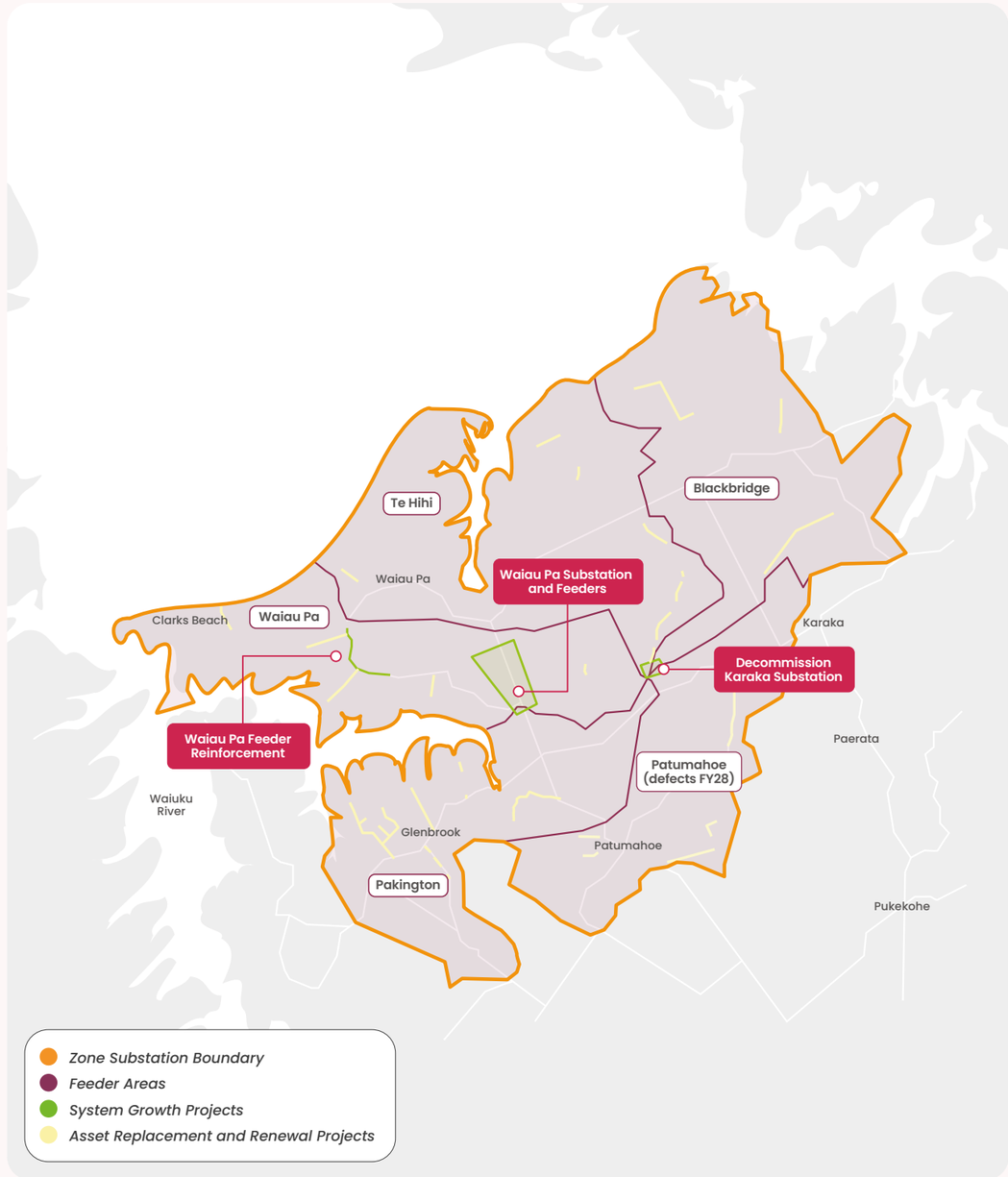
Table 7.35 Capacity for Western Region in MVA

Indicates load nearing or exceeding firm capacity
Indicates expected intervention timeframe

7.3 Western Region (continued)

7.3.1 Karaka Supply Area

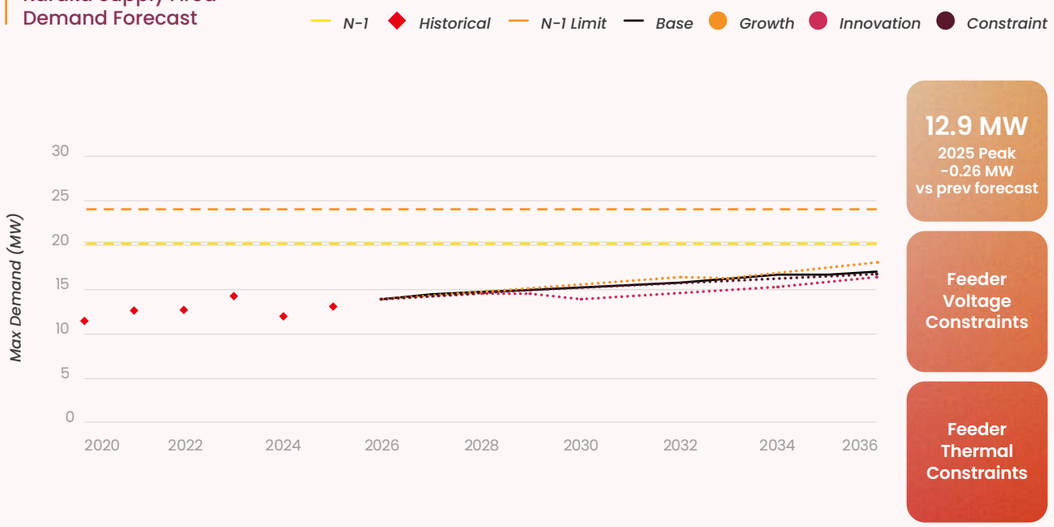
Figure 7.14
Map of Karaka
Supply Area



7.3.1 Karaka Supply Area (continued)

The demand forecast for the Karaka Supply Area is shown below.

Figure 7.15
Karaka Supply Area
Demand Forecast



Zone Substation and Feeders	Firm Capacity (MVA)	2025 Actual	2026	2027	2028	2029	2030	2031 -2036	2037 - 2041
Blackbridge	5.5	1.6	1.9	2.1	2.2	2.3	2.3	2.5 - 2.7	2.8 - 3.1
Pakington	5.5	2.3	2.3	2.3	2.4	2.4	2.4	2.5 - 2.6	2.6 - 2.8
Patumahoe	6.5	2.8	2.9	2.9	2.9	3.0	3.0	3.1 - 3.2	3.2 - 3.5
Te Hihi	3.3	2.4	2.5	2.5	2.5	2.5	2.6	2.6 - 2.7	2.7 - 2.9
Waiau Pa	5.5	4.4	4.7	4.7	4.8	4.9	5.0	5.1 - 5.9	6.2 - 7.1
Karaka Substation	20.0	13	14	14	14	15	15	16 - 17	17 - 19

Table 7.36 Capacity for Karaka Zone in MVA

Indicates load nearing or exceeding firm capacity
Indicates expected intervention timeframe

7.3.1 Karaka Supply Area (continued)

Waiau Pa Feeder Constraint Management

Issue description

Our Waiau Pa Feeder is a rural 11 kV feeder that supplies the Waiau Pa and Clarks Beach settlements and provides backup support to Glenbrook Beach. System modelling indicates the 11 kV voltage in this area will be breaching lower limits during winter peaks from 2029 onwards.

Options to address issue:

- Seasonal manual offline re-tapping of our distribution transformers in the areas with voltage issues to maintain customer experience within acceptable limits.
- Using LV analytics and data from smart meters to manage voltage delivered to our network supply points using zone substation voltage regulation.
- Utilising flexibility from distributed energy resources to manage peaks and voltage.
- Reconductor the segment of Grasshopper conductor that is a primary driver for this constraint, and an upgrade of the existing voltage regulator.

Solution selected for the Asset Management Plan

The preferred solution selected for the AMP is to reconductor the segment of Grasshopper conductor in FY33 and upgrade the existing voltage regulator in FY35. However, with the upcoming availability of low-voltage power quality data, we will get a more granular view of voltage performance on the feeder. This may make some of the alternative options above more viable. As such, the requirements for this project will be further defined in the next five years before the ultimate solution is selected.

Capex: System Growth

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Waiau Pa Feeder Reinforcement	-	-	-	-	-	-	941	-	500	-

Table 7.37 Capex for Waiua Pa Reinforcement

7.3.1 Karaka Supply Area (continued)

New Waiau Pa Zone Substation

Issue description

Our Karaka Zone Substation has been identified as an "Earthquake Prone" facility and has its assets reaching end-of-life in 2031 as detailed in 5.3.2. While the peak demand on the zone substation is within operational limits for the planning period, the firm rating is forecast to be at 80% in year 12.

Options to address issue:

- Rebuild Karaka Zone Substation, in its current location purely based on the renewal driver.
- Establish a new Waiau Pa Zone Substation, at a location more central to the load centres for the supply area.
- Replace selected assets at the Karaka Zone Substation, with an aim to defer its replacement until load growth drives the establishment of the Waiau Pa Zone Substation.

Solution selected for the Asset Management Plan

The solution selected for the AMP is to establish the new Waiau Pa Zone Substation and decommission the Karaka Zone Substation ahead of the renewal driver. With the forecast growth in the Clarks Beach and Glenbrook Beach areas, the opportunity presented by the renewal driver for Karaka Zone Substation will be used to deliver a new Waiau Pa Zone Substation at a location closer to the load centre. This new location also offers an opportunity to offload the Waiuku Zone Substation, particularly for loads in the Glenbrook area.

Capex: System Growth

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Waiau Pa Zone Substation	300	3,000	6,800	-	-	-	-	-	-	-
Waiau Pa Subtransmission	-	500	2,400	-	-	-	-	-	-	-
Waiau Pa Feeders	-	-	2,651	2,749	-	-	-	-	-	-
Decommission Karaka Substation	-	-	-	-	500	-	-	-	-	-

Table 7.38 Capex for New Waiua Pa Substation

7.3.1 Karaka Supply Area (continued)

Overhead High Voltage Conductor Renewal Programme

Over the 10 years, we intend to replace overhead conductors within the Karaka Substation area. These specific sections have been identified as high risk according to our ARMM model.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Batty Road	-	-	-	-	-	-	-	-	1,737	-
Bowker Road	-	-	-	-	-	-	-	-	357	-
Brian Wood Lane	-	-	166	-	-	-	-	-	-	-
Conroy Road	527	-	-	-	-	-	-	-	-	-
Costello Road	-	-	-	-	-	-	-	-	353	-
Dyke Road	-	-	-	-	589	-	-	-	-	-
Gearon Road	-	-	-	-	-	-	-	-	-	850
Harkness Road	-	320	-	-	-	-	-	-	-	-
Hunter Road	-	-	-	-	-	-	441	-	-	-
Hunter Road and Gallagher Road	1,172	-	-	-	-	-	-	-	-	-
Klipsch Road	-	384	-	-	-	-	-	-	-	-
Laing Road and Bryant Road	-	-	-	-	-	1,052	-	-	-	-
Off Charles and Lewis Road	-	-	-	-	-	-	1,129	-	-	-
Off Clarks Beach Road	-	-	-	-	-	-	-	-	347	-
Off Seagrove Road	-	-	-	-	-	-	-	-	278	-
Ostrich Road	-	-	1,009	-	-	-	-	-	-	-
Pakington Lane	-	-	-	-	-	-	-	-	237	-
Pearson and Patullo Roads	-	-	-	-	-	-	-	999	-	-
Percy Millen Drive	-	561	-	-	-	-	-	-	-	-
Reid and Gilmore Roads	686	-	-	-	-	-	-	-	-	-

Table 7.39 Capex for Karaka Ovehead Conductors

7.3.1 Karaka Supply Area (continued)

Capex: Asset replacement and renewal (continued)

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Saddleton Road	623	-	-	-	-	-	-	-	-	-
Taylor Road	-	-	-	-	-	215	-	-	-	-
Whatapaka Road	-	343	-	-	-	-	-	-	-	-
Whitecliffs Drive	290	-	-	-	-	-	-	-	-	-
Wymer Road	-	-	-	-	-	-	752	-	-	-

Table 7.39 Capex for Karaka Oveheard Conductors (continued)

Overhead Defect Remedial Programme

We plan to inspect one feeder in FY26 in the Karaka Substation area and then schedule any necessary remedial work for FY28. Budgets are allocated according to each feeder's condition and classification. High-risk defects found during inspections will be fixed within three months using our corrective maintenance budget.

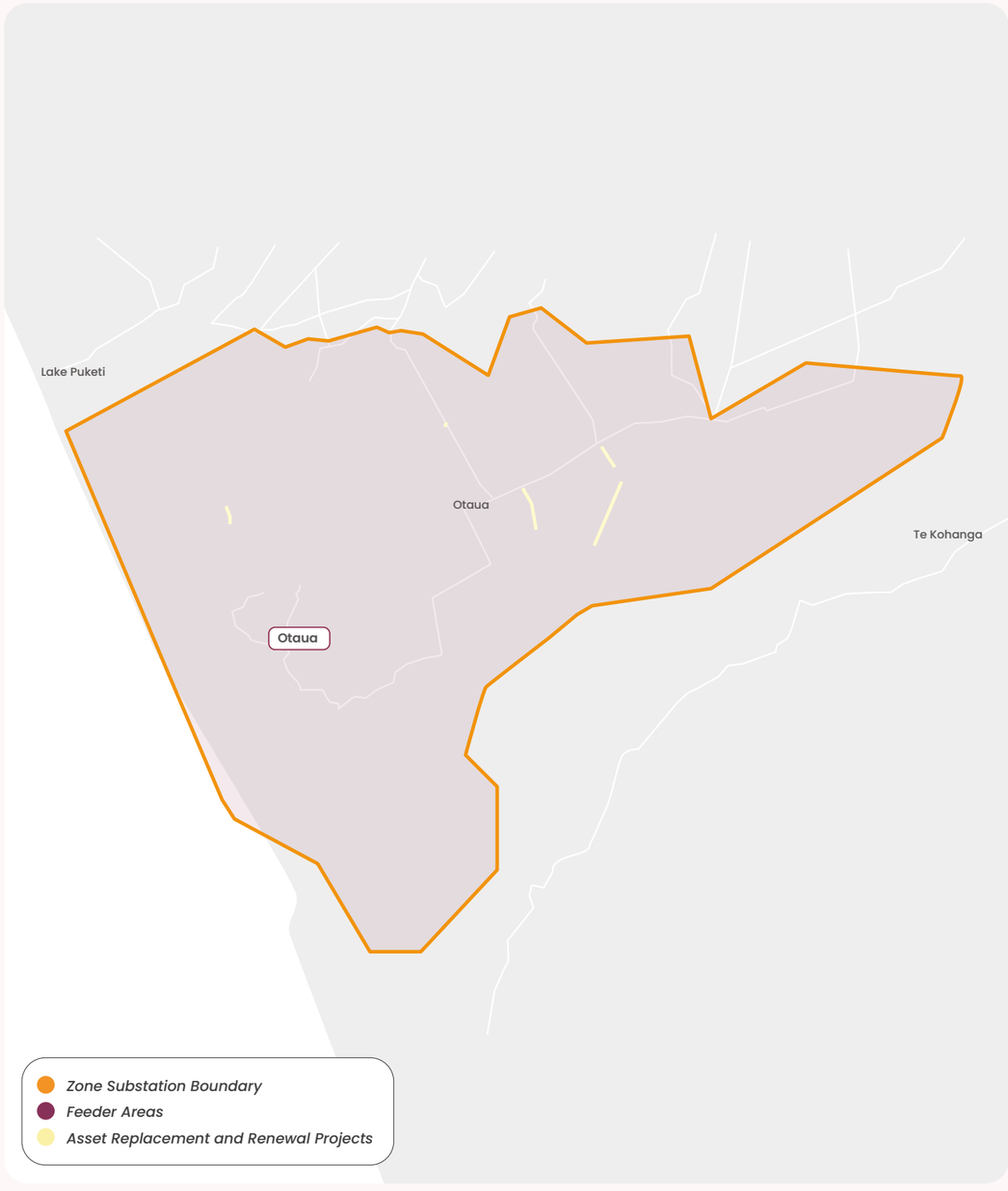
Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Patumahoe Feeder Defects	-	500	-	-	-	-	-	-	-	-

Table 7.40 Capex for Karaka Defect Programme

7.3.2 Maioro Supply Area

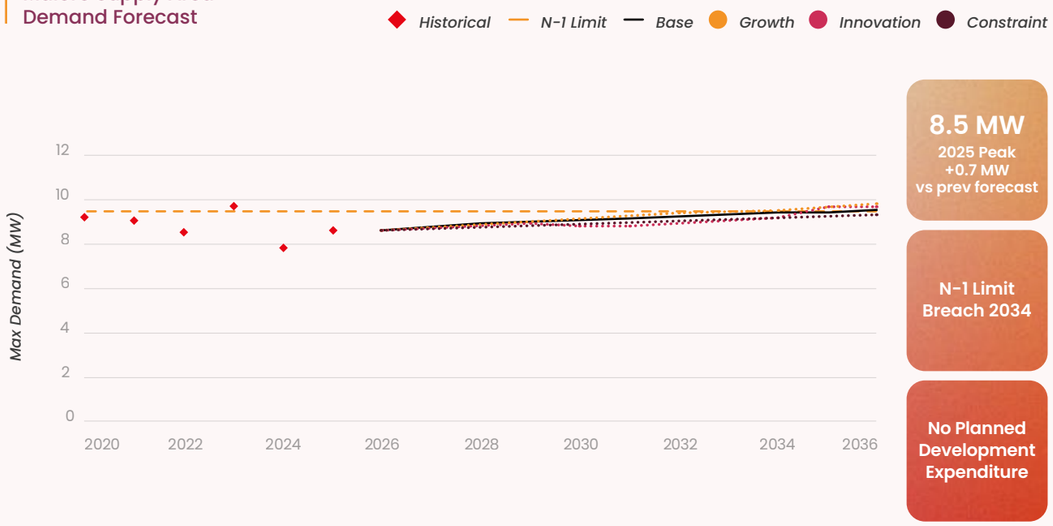
Figure 7.16
Map of Maioro Supply Area



7.3.2 Maioro Supply Area (continued)

The demand forecast for the Maioro Supply Area is shown below.

Figure 7.17
Maioro Supply Area
Demand Forecast



Zone Substation and Feeders	Firm Capacity	2025 Actual	2026	2027	2028	2029	2030	2031 -2036	2037 - 2041
Otaua	3.2	1.5	1.5	1.5	1.5	1.6	1.6	1.7 - 1.6	1.7 - 1.8
Pump Station	5.7	2.4	2.4	2.4	2.5	2.5	2.5	2.6 - 2.7	2.7 - 2.9
Mine Site	5.7	2.7	2.8	2.8	2.8	2.9	2.9	3 - 3.1	3.1 - 3.3
Future Mine Site	5.7	2.5	2.5	2.6	2.6	2.6	2.6	2.7 - 2.8	2.9 - 3
Maioro Substation	9.4	8.5	8.6	8.7	8.8	8.9	9.0	9.1 - 9.5	9.6 - 10.2

Table 7.41 Capacity for Maioro Zone in MVA

Indicates load nearing or exceeding firm capacity
Indicates expected intervention timeframe

Most of the electricity demand at this substation is associated with a single large customer, New Zealand Steel, which operates an iron sands mining facility in the area. Overall demand in the Maioro supply area is expected to remain relatively stable over the next 10 years, and future investment needs will continue to be considered in the context of customer requirements and broader network flexibility.

7.3.2 Maioro Supply Area (continued)

Zone Substation

Zone Substation Building

Our Maioro Substation including most of the contained plant, was constructed in the mid-1960s and is approaching 60 years old. The building is identified as an "Earthquake Prone" building with a very low seismic rating. The switchboard and associated control equipment is end-of-life, one of the last remaining of its type in New Zealand with very few spares left to keep it operational. It is also our last remaining site using oil-filled circuit breaker units, which present higher risks to our operators as the consequences of failure are much higher than more modern designs.

Maioro exists primarily to provide supply to a large industrial customer, with a small share of the capacity supplying the local Otaua area via a single 11 kV feeder.

We plan to address the risks at Maioro via the Maioro switchboard replacement project. The exact solution and timing will be dependent on an agreement being reached with the connected large industrial customer. Detailed design is anticipated to commence in early FY27, with construction scheduled for completion in FY28. One option under consideration involves utilising the ring main unit currently supplying the Ōpaheke Substation on a temporary basis, once the 22 kV switchboard replacement project has been completed. This would see the switchboard and all associated control equipment relocated to these outdoor rated units, enabling the demolition of the existing building.

Power Transformers

The two power transformers at our Maioro Substation, plus the outdoor 33 kV switchyard, are all approaching 60 years old. These are forecast to reach end-of-life within the planning period. A project is planned for FY32 to replace these, with the exact scope dependent on discussions with a key industrial customer that is supplied from the site.

Auxiliary Battery Banks and Chargers

Our auxiliary battery banks, expected to last eight years (80% of their 10-year lifespan), will be fully replaced at least once during the planning period. The DC battery bank chargers, with a 20-year service life, will be replaced as they expire. The Maioro DC battery bank is set for replacement in FY35.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Maioro Substation Rebuild[3]	150	3,000	-	-	-	-	-	-	-	-
Maioro DC Battery Bank Replacement	-	-	-	-	-	-	-	-	30	-
Maioro Transformer Replacement[3]	-	-	-	-	-	2,500	-	-	-	-

Table 7.42 Capex for Maioro DC Battery

3. The expenditure associated with this line is included under Consumer Connection in Table 7.72 and Schedule 11a, due to the consumer component involved.

7.3.2 Maioro Supply Area (continued)

Overhead High Voltage Conductor Renewal Programme

We plan to inspect one feeder in FY27 in the Maioro Substation area and then schedule any necessary remedial work for FY29. Budgets are allocated according to each feeder's condition and classification. High-risk defects found during inspections will be fixed within three months using our corrective maintenance budget.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Otaua Feeder Defects	-	-	1,000	-	-	-	-	-	-	-

Table 7.43 Capex for Otaua Feeder Defects

Overhead Conductor Renewal Programme

Over the 10 years, we intend to replace overhead conductors within the Maioro Substation area. These specific sections have been identified as high risk according to our ARMM model.

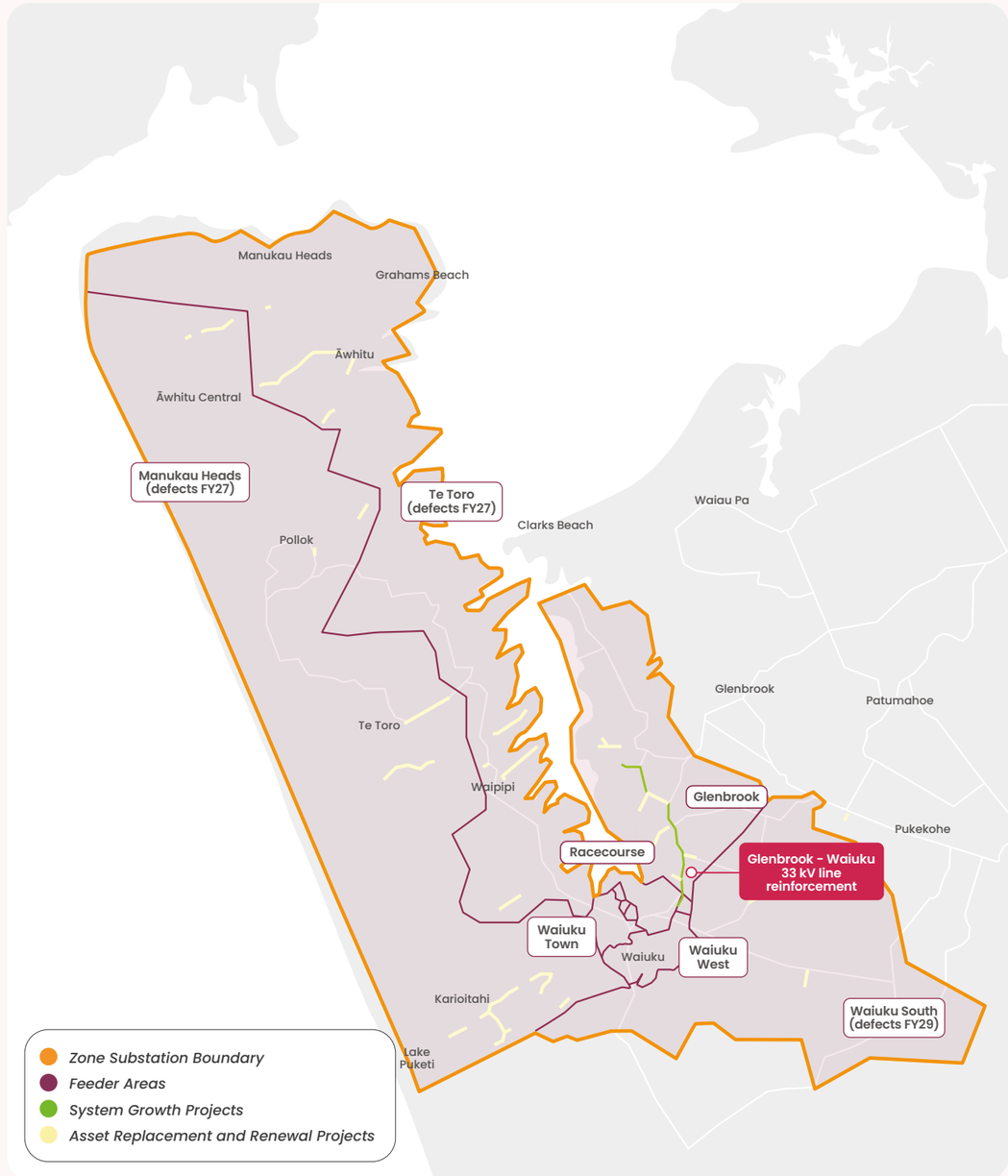
Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Bird Road	-	-	-	-	-	-	-	758	-	-
Crouch Road	-	-	-	-	-	671	-	-	-	-
Harris Road	-	-	-	-	-	-	581	-	-	-
Neil Road	-	-	-	-	-	564	-	-	-	-

Table 7.44 Capex for Maioro Overhead Conductors

7.3.3 Waiuku Supply Area

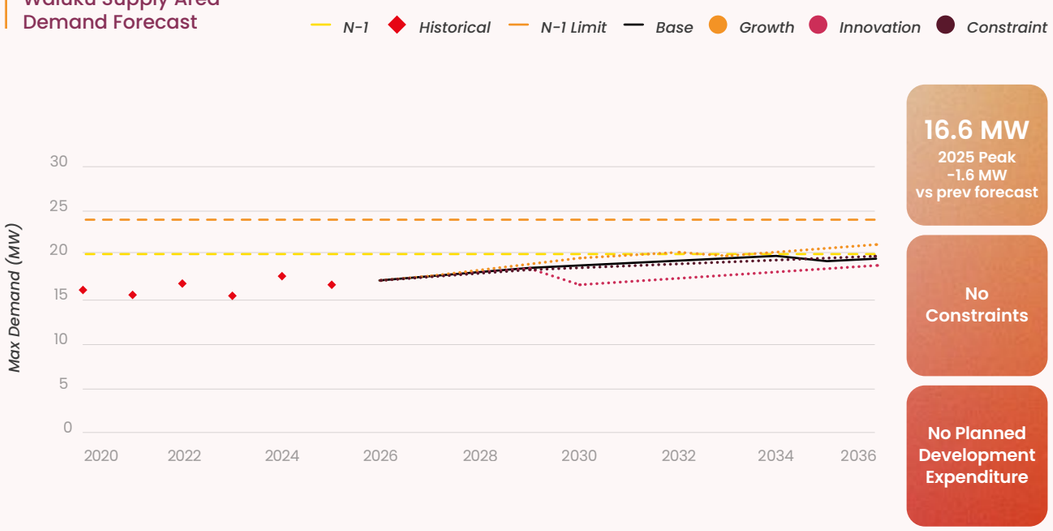
Figure 7.18
Map of Waiuku Supply Area



7.3.3 Waiuku Supply Area (continued)

The demand forecast for the Waiuku Supply Area is shown below.

Figure 7.19
Waiuku Supply Area
Demand Forecast



Zone Substation and Feeders	Firm Capacity	2025 Actual	2026	2027	2028	2029	2030	2031 -2036	2037 - 2041
Glenbrook	5.5	1.6	1.7	1.8	2.0	2.2	2.3	2.4 - 2.7	2.8 - 3.1
Manukau Heads	3.7	2.0	2.0	2.0	2.1	2.1	2.1	2.2 - 2.2	2.2 - 2.4
Racecourse	6.9	2.7	2.8	3.0	3.1	3.2	3.2	3.3 - 3.4	3.5 - 3.7
Te Toro	4.2	1.9	2.0	2.0	2.0	2.1	2.1	2.2 - 2.1	2.2 - 2.3
Waiuku South	5.5	1.9	1.9	1.9	2.0	2.0	2.0	2.1 - 2.1	2.1 - 2.3
Waiuku Town	6.9	3.6	3.6	3.7	3.7	3.8	3.9	4 - 4	4.1 - 4.4
Waiuku West	5.5	3.4	3.4	3.5	3.5	3.6	3.6	3.7 - 3.9	3.9 - 4.2
Waiuku Substation	20.0	16.6	17.1	17.5	18.0	18.5	18.8	19.1 - 19.7	20 - 21.5

Table 7.45 Capacity for Waiuku in MVA

Indicates load nearing or exceeding firm capacity
Indicates expected intervention timeframe

7.3.3 Waiuku Supply Area (continued)

Glenbrook – Waiuku 33 kV East Line Thermal Constraint

Issue description

Our Waiuku Substation is supplied by two 33kV subtransmission from Glenbrook GXP, which also supply the Maioro Zone Substation and a 33 kV connection at Storey Road. These lines are designed for N-1 security levels. Two distributed generators (one wind, one solar) are connected to the downstream distribution network, reducing load on these lines when they are generating.

The peak load (ignoring local distributed generation) in 2025 exceeded the steady state rating of the smaller of the two subtransmissions for a single 15-minute period. Over time, the load will continue to grow until it exceeds the cyclic rating, and there is a risk that local distributed generation is unavailable at the time of winter peaks.

Options to address issue:

- Continue to operate the line in its current cyclic rating level, i.e. do nothing.
- Expand security criteria to allow for more substantial distributed generation and/or negotiate with the local generators to avoid maintenance during winter peaks.
- Line reconductoring.
- Targeted investment at constrained spans with taller poles, retensioning and/or undergrounding of underbuilt LV.
- Localised flexibility solutions during winter peak.

Solution selected for the Asset Management Plan

The proposed solution for AMP planning purposes is targeted investment at constrained spans. This constraint will be monitored over time, with an aim to driving the network harder and employing flexible solutions where possible.

This portion of our network is significantly impacted by a single industrial customer with changing usage patterns. We will be monitoring the net impact on demand over time.

Capex: System Growth

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Glenbrook - Waiuku 33 kV line reinforcement	-	-	800	-	-	-	-	-	-	-

Table 7.46 Capex for Waiuku Line Reinforcement

7.3.3 Waiuku Supply Area (continued)

Zone Substation Auxiliary Battery Banks and Chargers

The auxiliary battery banks, with an anticipated operational life of eight years (representing 80% of their designed lifespan of 10 years), will undergo complete replacement at least once within this planning period. Given that DC battery bank chargers have a projected service life of 20 years, they will be replaced as they reach their end-of-life threshold. The Waiuku DC battery bank is scheduled for replacement in FY28, and again in FY36.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Waiuku DC Battery Bank Replacement	-	30	-	-	-	-	-	-	-	30

Table 7.47 Capex for Waiuku Battery Bank

Overhead High Voltage Conductor Renewal Programme

Over the 10 years, we intend to replace overhead conductors within the Waiuku Substation area. These specific sections have been identified as high risk according to our ARMM model.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Aka Aka Stream Road	-	-	227	-	-	-	-	-	-	-
Baldhill Road	-	-	-	-	-	-	-	306	-	-
Dickey Road	-	-	-	-	260	-	-	-	-	-
Āwhitu Road	245	-	-	-	-	-	-	-	-	-
Āwhitu Road	1,002	-	-	-	-	-	-	-	-	-
Āwhitu Road	-	-	-	-	508	-	-	-	-	-
Baldhill Road	-	-	-	-	-	-	-	-	-	233
Baldhill Road	-	-	-	-	-	-	-	-	672	-
Beach Road and Ronald Avenue	-	-	-	-	-	458	-	-	-	-
Binns and Coe Roads	-	-	-	-	689	-	-	-	-	-
Boiler Gully Road	-	-	-	821	-	-	-	-	-	-
Boiler Gully Road	-	-	-	-	-	269	-	-	-	-

Table 7.48 Capex for Waiuku Overhead Conductors

7.3.3 Waiuku Supply Area (continued)

Capex: Asset replacement and renewal (continued)

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Brookside Road and Higgins Road	-	-	-	-	-	-	-	781	-	-
Butchers Bridge Road	-	-	-	-	-	-	-	-	260	-
Cameron Road	-	-	-	-	-	-	-	220	-	-
Cooper Road	-	-	-	353	-	-	-	-	-	-
Craig Road	-	-	-	-	131	-	-	-	-	-
Gleeson Road	-	-	-	-	-	-	-	-	-	1,323
Gordon Road	-	-	-	974	-	-	-	-	-	-
Grahams Beach Road	-	-	-	-	949	-	-	-	-	-
Karioitahi and Honey Roads	-	-	-	-	470	-	-	-	-	-
Karioitahi Road	-	278	-	-	-	-	-	-	-	-
Kariotahi Road	-	-	-	-	1,069	-	-	-	-	-
Kauri Road-Colbeck Road-Āwhitu Central Road	-	2,229	-	-	-	-	-	-	-	-
McPike Road	-	215	-	-	-	-	-	-	-	-
Mission Bush Road (4E79#-5E02#) and Williams Road	-	-	916	-	-	-	-	-	-	-
Off Karaka North Road (Seabreeze Way)-Private Land -	-	-	-	376	-	-	-	-	-	-
Off Pollok Wharf Road (Cemetery and Given Road)	-	-	-	445	-	-	-	-	-	-
Pukeoware Road	359	-	-	-	-	-	-	-	-	-
Tahurangatira Road	-	-	-	-	-	419	-	-	-	-
Waipipi Wharf Road and Furniss Road	1,267	-	-	-	-	-	-	-	-	-
Waitangi Falls	-	442	-	-	-	-	-	-	-	-

Table 7.48 Capex for Waiuku Overhead Conductors (continued)

7.3 Western Region (continued)

7.3.3 Waiuku Supply Area (continued)

Overhead Defect Remedial Programme

In FY26 and FY28, we intend to inspect three feeders from Waiuku Substation, after which we will schedule any necessary remedial work to address any identified defects in FY27 and FY29. Indicative budgets have been allocated based on the condition and classification of each feeder. Any high-risk defects requiring urgent attention identified during inspection will be addressed within three months, utilising funds from our corrective maintenance plan.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Manukau Heads Feeder Defects	1,850	-	-	-	-	-	-	-	-	-
Te Toro Feeder Defects	1,750	-	-	-	-	-	-	-	-	-
Waiuku South Feeder Defects	-	-	1,000	-	-	-	-	-	-	-

Table 7.49 Capex for Waiuku Defect Programme

Distribution Voltage Regulator – Controller Renewal

The voltage regulator controllers for Manukau Heads and Te Toro feeders at our Waiuku Substation are approaching end-of-life. The Manukau Heads controller [VR05] will be replaced in FY30, and the Te Toro controller [VR02] in FY35.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Distribution Regulator Controller Renewal [VR05]	-	-		65	-	-	-	-	-	-
Distribution Regulator Controller Renewal [VR02]	-	-	-	-	-	-	-	-	65	-

Table 7.50 Capex for Waiuku Voltage Regulators

7.4 Network-Wide

7.4.1 Subtransmission

We carry out corrective maintenance on overhead subtransmission lines whenever defects are identified through rapid inspections or routine detailed condition assessments. This work may involve replacing insulators, crossarms, possum guards, stay wires, and other minor components. An annual budget of $20,000 has been allocated to address these issues across the entire subtransmission network.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Subtransmission Renewal	20	20	20	20	20	20	20	20	20	20

Table 7.51 Capex for Network Wide Subtransmission

Zone Substations

A budget of $1 million, has been allocated in FY34 for the replacement of our strategic spare transformer to support our 33/11 kV power transformer fleet. This measure is intended to enhance network reliability and resilience during emergencies, as it represents a critical asset for the 33 kV network.

A $50,000 annual budget is allocated for minor defect repairs found during routine inspections at zone substations.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Procure Strategic Spare 33/11 kV Transformer	-	-	-	-	-	-	-	1,000	-	-
Zone Substation Renewal	50	50	50	50	50	50	50	50	50	50

Table 7.52 Capex for Spare Transformer & Substations Repairs

Load Control Plant (Glenbrook GXP)

An estimated budget of $700,000 has been allocated for FY36 to replace the Glenbrook 33 kV outdoor load control facility, which provides load control to all our zone substations in the Western Region.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Glenbrook Load Control Plant Replacement	-	-	-	-	-	-	-	-	-	700

Table 7.53 Capex for Glenbrook Load Control

7.4.2 Distribution

LV Rehabilitation

The LV rehabilitation budget is allocated to replace end-of-life overhead LV lines with underground cables in both urban and semi-urban locations, as part of our ongoing undergrounding initiative. Annually, approximately one kilometre of line, at a cost of $300,000, is designated for these projects. However, due to incomplete LV network data, project selection and commencement are undertaken following routine inspections and detailed condition assessments.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
LV Rehabilitation	300	300	300	300	300	300	300	300	300	300

Table 7.54 Capex for LV Rehabilitation

Private Service Lines

A $500,000 annual budget funds private service line ownership projects. These involve acquiring customer-owned HV service lines or installing isolation devices to meet our network standards, enhancing safety for workers and customers and improving network reliability.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
HV Service Line Project	500	500	500	500	500	500	500	500	500	500

Table 7.55 Capex for HV Service Lines Acquisition

HV Rehabilitation

Our HV rehabilitation budget supports the replacement of end-of-life overhead high-voltage lines with underground cables in both urban and semi-urban environments, consistent with our ongoing undergrounding strategy. An annual allocation of $244,000 is dedicated to these initiatives, which are generally executed in conjunction with LV rehabilitation projects. Typically, approximately one kilometre of high-voltage lines is transitioned underground each year, complete with the installation of a ring main unit and transformer.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
HV Rehabilitation	244	244	244	244	244	244	244	244	244	244

Table 7.56 Capex for HV Rehabilitation

7.4.2 Distribution (continued)

Overhead Corrective Maintenance

We have set aside an allowance of $1 million, per year to remedy high-priority (urgent) defects that are identified as part of regular maintenance inspections. These can include tagged poles, or other important concerns that have to be addressed sooner than the associated feeder defect remediation project – which typically follows 6-12 months after our maintenance inspections.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Overhead Corrective Maintenance Plan (urgent defects)	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000

Table 7.57 Capex for Urgent Overhead Defects

Pillar Renewals

Each year, $246,000 is set aside for corrective maintenance on pillars to address minor issues like loose lids, overheated connections, and alignment or positioning problems such as leaning. Vehicle collisions are common and can often result in the need to fully replace damaged pillars, depending on the severity. These problems are discovered during our routine inspections, and the quantity of issues remains high due to ongoing risks. Additionally, several asbestos pillars in the network are showing signs of age-related deterioration. Alongside regular inspections, we've also established a proactive policy to replace mushroom pillars whenever they undergo any work.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Pillar Renewal	246	246	246	246	246	246	246	246	246	246

Table 7.58 Capex for Pillar Renewal

Underground Cable Renewal

We allocate $349,000 annually to renew approximately one kilometre of underground cable whenever we identify issues related to age, damage, or condition.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Underground Cable Renewal	349	349	349	349	349	349	349	349	349	349

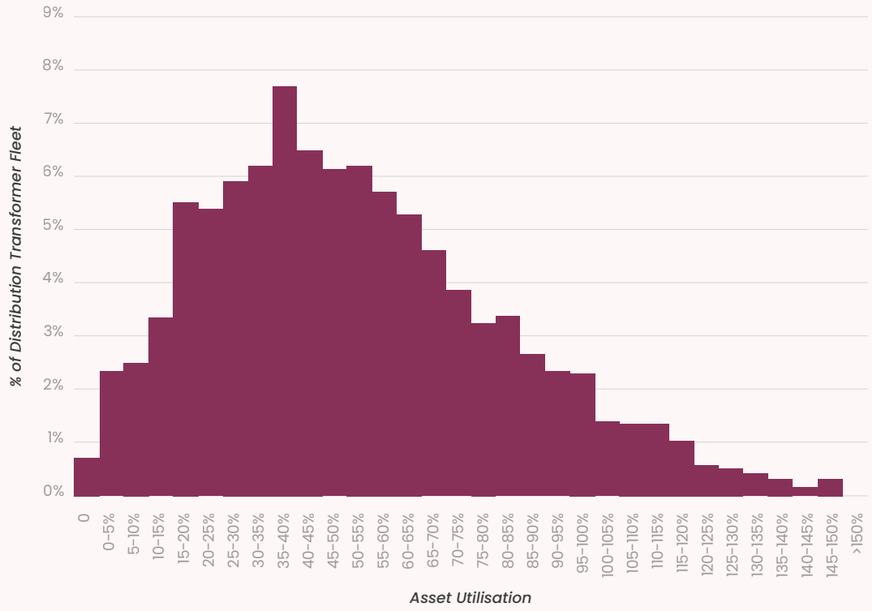
Table 7.59 Capex for Underground Cable Renewal

7.4.2 Distribution (continued)

Distribution Transformer Intervention (Growth)

Historically, growth-driven investment on distribution transformers has been reliant on maximum demand indicators (MDIs). However, with the availability of smart metering data, we now have a more granular view of asset utilisation and load duration for these transformers. The below plot shows the asset utilisation for our existing fleet.

Figure 7.20 Distribution Transformer Utilisation



One of the key risk factors that will impact our distribution transformers is the additional load from transport electrification. To determine this impact, we applied the EV charging scenarios (discussed in 6.4.4.2.3).

7.4.2 Distribution (continued)

One of the key risk factors that will impact our distribution transformers is the additional load from transport electrification. To determine this impact, we applied the EV charging scenarios (discussed in 6.4.4.2.3) developed for feeders and zone substations to distribution transformers.

Existing peak demand was taken from low-voltage metering data, and customer segmentation outputs from the work done in conjunction with the ENA was used to assign different growth and uptake rates to each distribution transformer. These were used to forecast the impact of EVs, distributed generation and organic growth rates per transformer.

The results were broadly in line with our expectations. Our network is dominated by small overhead transformers in rural areas and large ground mounted units in suburban areas. The underground network is, in general, younger than the overhead network, due to extensive development in the last decade. The underground network was designed based on a higher ADMD as the likelihood of widespread electric vehicle use became more probable.

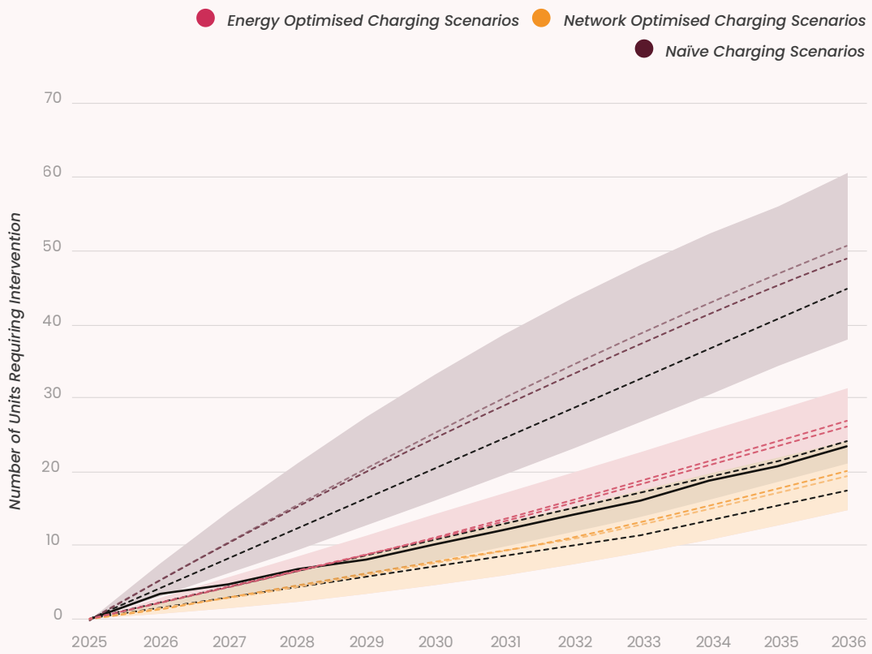
In the base scenario, 13.1% of our distribution transformer fleet is forecast to require intervention in the next 20 years. This is almost exclusively small overhead transformers for the first 10 years, with ground mount units beginning to appear at the end of the forecast.

This number varied between 91% and 120% of the base scenario with varying electric vehicle uptake rates, and between 77% and 166% of the base scenario with varying charging behaviour models.

In the worst-case scenario – "Naïve" charging behaviour, uninhibited by price or capacity signals and rapid EV uptake based on the Climate Change Commission's high carbon costs model – 26% of distribution transformers will require intervention over the next 20 years. While in the best-case scenario – network optimised charging behaviour and slow EV uptake – 9.2% will still require intervention over the next 20 years.

7.4.2 Distribution (continued)

Figure 7.21 Distribution Transformer Forecast Scenarios



For the purpose of AMP planning, the scenario shown with a solid black line above has been used for CAPEX forecasting purposes.

Capex: System Growth

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Distribution Transformer Intervention	91	128	182	219	274	328	383	438	511	565

Table 7.60 Capex for Distribution Transformer Intervention

7.4.2 Distribution (continued)

Distribution Transformer Renewal

Overhead

A yearly budget of $180,000 has been set aside annually to replace at least five overhead units found to have issues during routine inspections. The most common faults requiring transformer replacement include oil leaks, aging, corrosion, and physical damage. With our new overhead transformer standard, some transformers are also replaced during reconductoring projects to meet updated build requirements.

Ground Mounted

Transformers are replaced when they are either in suboptimal condition or require increased capacity. To mitigate seismic risks and improve maintenance efficiency, outdated substation kiosks will be upgraded to pad-mount transformers. From FY27 to FY29, two of our kiosk buildings and one ground-mount unit will be replaced each year, with an allocated annual budget of $321,000. Subsequently, two ground-mount units will be replaced annually, with a projected budget of $155,000 per year.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Overhead Distribution Transformer Renewal	180	180	180	180	180	180	180	180	180	180
Ground Mount Distribution Transformer Renewal	321	321	321	155	155	155	155	155	155	155

Table 7.61 Capex for Transformer Replacement

7.4.2 Distribution (continued)

Distribution Switchgear Renewal

Overhead

We are continuing to upgrade our air break switches, focusing on replacing a particular manufacturer's models with newer gas switches. While most overhead switches were replaced during the Automation programme, we discovered some older gas switches with issues, such as low gas levels, which we are now proactively replacing as they are identified. Our budget allows for the replacement of around eight switches each year, with an annual allocation of $424,000.

Ground Mounted

Budgets have been allocated to replace ring main units on our network that show signs of wear, including low gas levels. Our goal is to replace at least three units each year from FY27 to FY32, with an annual budget of $443,000. In subsequent years, as the fleet ages, we plan to increase replacements to eight units per year at a cost of $738,000.

Ring Main Protection Renewal

The RMU's circuit breaker function needs numerical protection relays with a 15-year lifespan. We've budgeted $2.2 million over 10 years to replace relays reaching end-of-life.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
RMU Renewal	443	443	443	443	443	443	738	738	738	738
Overhead Switchgear Renewal	424	424	424	424	424	424	424	424	424	424
Ringmain Protection Renewal [FY27 VIP35x20)]	70	105	125	125	300	300	300	300	300	300

Table 7.62 Capex for Ringmain Units and Overhead Switchgear Replacement

Capitalised Maintenance

This is an allowance within our capital budgets for the replacement costs associated with fixing faults on our network, for which we have set aside $19.92 million over the planning period. Corresponding with our asset management strategies, the annual spend is forecast to reduce by just under 20% by year 5 when compared to year 1, after which the spend profile is expected to remain flat.

Capex: Asset replacement and renewal

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Capitalised Maintenance	2,318	2,202	2,092	1,987	1,888	1,888	1,888	1,888	1,888	1,888

Table 7.63 Capex for Maintenance

7.4.2 Distribution (continued)

Vegetation Management

Our vegetation programme is designed to be a proactive, risk-based approach, informed by our network criticality models and information obtained from network-wide LiDAR surveys. We initially set up a five-year programme in 2021 from our first LiDAR survey, and refreshed the programme in 2023 once the data from our second LiDAR survey became available.

In line with our Vegetation strategy (set out in section 4.8.8), our plan consists of annual surveys on all of our subtransmission circuits and risk-based inspections on the remainder of our distribution network. Recent years have seen us investing strongly and undertaking a lot of permanent tree removals for the long-term benefit of the network. As these trees will no longer require ongoing maintenance, it is forecast that our spend will decrease over the first four years of the planning period. This will be reviewed again in 2027 when we undertake our third LiDAR survey.

Opex: Vegetation Management

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Vegetation Management	3,233	3,139	3,139	2,982	2,833	2,833	2,833	2,833	2,833	2,833

Table 7.64 Opex for Vegetation Management

Automation Rebuild

The automation rebuild programme was first included in our 2022 Asset Management Plan. When the previous SCADA radio network was identified in 2020 as approaching end-of-life, this presented an opportunity to consider whether our existing deployment of automation was fit for purpose. Analysis completed in 2021 indicated that instead of replacing just the radio communication equipment in all existing locations, a greater overall benefit to network reliability could be achieved by considering sites strategically on a network-wide basis. Our then recently developed Network Criticality Model enabled this analysis. This approach eventuated in existing automation capability removed from some sites on feeders with an existing high penetration of automation, replaced with new additional sites on feeders that had less.

This became a three-year programme, scheduled for delivery between FY24 and FY26. Although mostly delivered to schedule, material availability and local planning constraints for a handful of sites have meant a small tail of work remains to be delivered in FY27.

Capex: Quality of Supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Automation Rebuild	751	-	-	-	-	-	-	-	-	-

Table 7.65 Capex for Automation Rebuild

7.4.2 Distribution (continued)

Network Tie Point Visibility

Counties Energy has three tie points to our neighbouring EDBs. These connections are mutually beneficial as they enable both networks to back up each other as required. However, at all three locations, Counties Energy does not own the connecting switchgear. This not only means operational control sits with our neighbouring networks, but the visibility of the status of these devices to our Network Operations Centre (NOC) is limited. We are working with our neighbours to improve this, and an allowance has been included for FY27 and FY29 to fund the required works.

Capex: Quality of Supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Network Tie Point Visibility	80	-	50	-	-	-	-	-	-	-

Table 7.66 Capex for Network Tie Point Visibility

Fault Passage Indicators

The fault passage indicators (FPI) programme has been added to the Asset Management Plan covering both overhead and underground networks. This programme will assist our Network Control Operations (NOC) in operating during a fault situation and enhance network visibility on fault paths.

Capex: Quality of Supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Fault Passage Indicator – Ground Mounted Units	306	-	-	-	-	-	-	-	-	-
Fault Passage Indicator – Overhead Mounted Units	294	-	-	-	-	-	-	-	-	-

Table 7.67 Capex for Fault Passage Indicators

7.4.2 Distribution (continued)

Long Span Remediation

Our regular fault review processes identified a pattern of both “auto-reclose” and “no cause found” events that often corresponded with gusty wind conditions. Further investigation found it is likely we have some long rural spans, often found across gully crossings, where the installation may be susceptible to clashing lines during severe wind conditions. Starting in FY24, we leveraged information from our latest LiDAR survey, undertaken in early 2023, to identify long spans at risk of line clash. An allowance was added for a five-year programme from FY26 to FY30 to complete site works as required, of which the last four years remain in the planning period.

Capex: Quality of Supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Long Span Remediation Programme	595	595	595	595	-	-	-	-	-	-

Table 7.68 Capex for Long Span Remediation

Network Reliability Improvement

Our regular fault review processes have also occasionally identified other site-specific issues that can lead to transient faults, such as bird strikes or line clashing due to local conditions at specific locations. These are often fixed with relatively simple site works, such as fitting larger cross-arms or fitting additional insulators. A small annual allowance has been added for each year in the planning period to complete these minor improvements as they are identified. This increases in the last four years of the planning period to allow for emerging network concerns that may arise.

Capex: Quality of Supply

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Network Reliability Improvement	155	155	155	155	155	155	755	755	755	755

Table 7.69 Capex for Network Reliability Improvement

7.4.2 Distribution (continued)

Safety Compliance

A provision of $108,000 per year is planned for all years in the planning period, except for FY27 which is reduced slightly to allow for the Ōpaheke East Line Earthing Remedial Works (refer 7.2.2). This is an allowance for minor network projects required to drive better safety outcomes. Past examples of such projects include increasing overhead line heights above access roads to industrial sites or relocating assets in high-risk vehicle areas.

Capex: Other Reliability, Safety and Environment

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Safety Compliance	73	108	108	108	108	108	108	108	108	108

Table 7.70 Capex for Safety Compliance

Spur Line Protection Enhancements

We have some long rural spur lines on our network which can stretch for several kilometres and are often protected only by high-voltage fuses. These fuses do not offer reclosing functionality and are not as sensitive to certain types of downstream line faults compared to the newer, smarter protection devices which are now available on the market. This means customers connected to these long spur lines can experience a higher-than-average number of weak power events. We have set aside an allowance of $200,000 per year over three years (FY29-FY31) to investigate and install smarter options for these longer lines, aiming to reduce the impact on our customers from outages caused by transient faults, as well as aiming to improve safety outcomes by having protection that can better detect a wider range of line fault types.

Capex: Other Reliability, Safety and Environment

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Spur Line Protection Enhancements	-	-	200	200	200	-	-	-	-	-

Table 7.71 Capex for Spur Line Enhancements

Voltage Management

A provision of $379,000 per year is planned for all years in the planning period. This is an allowance for minor network projects required as a result of our power quality strategy (refer to section 4.8.5).

Capex: Other Reliability, Safety and Environment

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Voltage Management	379	379	379	379	379	379	379	379	379	379

Table 7.72 Capex for Voltage Management

7.5 Capital Expenditure Programme

7.5.1 Capital Expenditure Summary

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Consumer Connection	15,150	14,000	10,000	10,000	10,000	12,500	10,000	10,000	10,000	10,000
System Growth	4,468	4,628	13,083	3,218	524	578	2,024	2,992	5,365	9,707
Asset Replacement and Renewal	23,462	20,343	18,845	18,179	18,751	17,576	18,749	23,825	25,810	20,062
Asset Relocations	411	411	411	411	411	411	411	411	411	411
Reliability, Safety and Environment	3,543	3,836	4,094	2,928	1,657	1,800	1,242	1,242	1,242	1,242
Expenditure on Non-Network Assets	7,081	5,485	5,485	5,485	5,485	5,485	5,485	5,485	5,485	5,485

Table 7.73 Network Capital Expenditure by Disclosure Category

7.5.2 System Growth Capital Expenditure Breakdown

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Eastern Region										
Ōpaheke Substation Supply Area[4]	3,700	500								
Pōkeno Substation Supply Area	50									
Quarry Road Substation Supply Area	1,677	550	50	50	50	50	500	2,354	4,154	8,941
Tuakau Substation Supply Area	300									
Network Wide										
Distribution Transformer Intervention & Innovation	291	328	382	419	474	528	583	638	711	765
Western Region										
Waiau Pa Substation Supply Area	300	3,500	11,851	2,749			941		500	
Waiuku Substation Supply Area			800							

Table 7.74 System Growth Capital Expenditure

4. Half of the expenditure associated with this line is included under Consumer Connection in Table 7.5.1 and Schedule 11a, due to the consumer component involved.

7.5.3 Asset Replacement and Renewal Capital Expenditure Breakdown

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Subtransmission										
Subtransmission Insulator Replacement	1,400							1,400	1,400	
Subtransmission Renewal	20	20	20	20	20	20	20	20	20	20
Zone Substations										
Karaka Substation Rebuild					500					
Maioro Substation Rebuild[5]	150	3,000								
Ōpaheke Renewal	2,650	405								
Pukekohe Substation Rebuild							500	3,000	5,500	1,000
Strategic Subtransmission Spares								1,000		
Zone Substation Renewal	50	50	50	50	50	50	50	50	50	50
Distribution and LV lines										
Capitalised Maintenance	2,318	2,202	2,092	1,987	1,888	1,888	1,888	1,888	1,888	1,888
LV Rehabilitation	300	300	300	300	300	300	300	300	300	300
Overhead High Voltage Conductor Renewal Programme	6,171	6,723	7,521	7,061	7,092	6,447	6,855	6,971	6,661	6,908
Overhead Corrective Maintenance Plan	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Overhead Defects Remedial Programme	6,600	4,800	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Private Service Lines	500	500	500	500	500	500	500	500	500	500
Distribution and LV Cables										
HV Rehabilitation	244	244	244	244	244	244	244	244	244	244

Table 7.75 Asset Renewal and Replacement Capital Expenditure

5. The expenditure associated with this line is included under Consumer Connection in Table 7.72 and Schedule 11a, due to the consumer component involved.

7.5.3 Asset Replacement and Renewal Capital Expenditure Breakdown (continued)

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Distribution and LV Cables										
Pillar Renewal	246	246	246	246	246	246	246	246	246	246
Underground Cable Renewal	349	349	349	349	349	349	349	349	349	349
Distribution Substations and Transformers										
Ground Mount Transformer Renewal	321	321	321	155	155	155	155	155	155	155
Pole Mount Transformer Renewal	180	180	180	180	180	180	180	180	180	180
Voltage Regulator Renewal				65					65	
Distribution Switchgear										
Distribution RMU Renewal	443	443	443	443	443	443	738	738	738	738
Overhead Switchgear Renewal	424	424	424	424	424	424	424	424	424	424
Ringmain Protection Renewal	70	105	125	125	300	300	300	300	300	300
Other Network Assets										
Load Control Plant Renewal									700	700
Radio/Fibre Communications Replacement	175	2,000								
Substation DC Battery Bank System Replacement		30	30	30	60	30		60	90	60

Table 7.75 Asset Renewal and Replacement Capital Expenditure (continued)

7.5 Capital Expenditure Programme (continued)

7.5.4 Reliability Safety and Environment Capital Expenditure Breakdown

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Quality of Supply										
Automation Rebuild	751									
Fault Passage Indicators	601									
Feeder Projects	955	990	393	1,027						
Feeder Undergrounding		1,610	386	465	815	1,158				
Long Spans	595	595	595	595						
Network Reliability Improvement	155	155	155	155	155	155	755	755	755	755
Voltage Management										
Power Quality Compliance	379	379	379	379	379	379	379	379	379	379
Safety Compliance										
Protection Enhancements			200	200	200					
Safety compliance	109	108	108	108	108	108	108	108	108	108
Other Reliability, Safety & Environment										
Radio/Fibre Communications Replacement			1,878							

Table 7.76 Reliability, Safety and Environment Capital Expenditure

7.5.5 Non-Network Capital Expenditure Breakdown

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Digital	4,928	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,191
Plant & Vehicles	98	412	412	412	412	412	412	412	412	412
Property	2,056	882	882	882	882	882	882	882	882	882

Table 7.77 Non-Network Capital Expenditure

7.6 Operational Expenditure Programme

Investment ($ 000s)	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36
Service Interruptions and Emergencies										
Faults	3,150	3,197	3,245	3,294	3,343	3,393	3,444	3,496	3,548	3,602
Network Operational Control	300	300	300	300	300	300	300	300	300	300
Vegetation Management	3,233	3,139	3,139	2,982	2,833	2,833	2,833	2,833	2,833	2,833
Routine and Corrective Maintenance and Inspection										
Subtransmission	75	81	75	75	75	75	81	75	67	67
Zone Substations	573	645	573	573	573	573	573	573	573	573
Distribution and LV Lines	528	554	204	565	204	204	565	204	204	204
Distribution and LV Cables	112	117	122	177	183	188	194	200	207	214
Distribution Substations and Transformers	392	409	427	445	464	484	505	527	549	573
Distribution Switchgear	226	234	242	251	260	269	279	289	300	311
Other Assets	323	251	263	263	263	263	263	263	263	263
Public Safety Services	355	362	369	377	384	392	400	408	416	424
Network Operational Control	300	300	300	300	300	300	300	300	300	300
Asset replacement and renewal										
Subtransmission	2	2	2	2	2	2	2	2	2	2
Zone Substations	29	29	29	29	29	29	29	29	29	29
Distribution and LV Lines	303	303	268	304	18	18	54	18	18	18
Distribution and LV Cables	77	78	79	80	82	83	84	85	86	88
Distribution Substations and Transformers	96	159	283	286	290	294	398	402	407	411
Distribution Switchgears	52	53	55	56	58	60	62	64	66	68
Other Assets	16	16	16	16	16	16	16	16	16	16
Network Operational Control	300	300	300	300	300	300	300	300	300	300

Table 7.78 Network Operating Expenditure by Disclosure Category

7.6 Operational Expenditure Programme (continued)

This forecast reflects the expected cost of operating, inspecting, maintaining and repairing the assets that make up the network, and has been prepared to align with the planned capital programme and service outcomes over the planning period.

All forecasts have been adjusted for inflation and other key cost drivers. Routine inspections are forecast bottom up based on asset maintenance requirements and include some of our advanced inspection methods such as LiDAR. Some asset populations, such as cables, substations and transformers are forecast to grow in line with network and ICP growth, while others are assumed to remain relatively stable. Asset replacement and renewal forecasts combine historical trends with specific project forecasts initiated in response to the threats and treatments outlined in Section 6.5. Fault-related costs are largely based on historical levels with a small growth factor relating to the growing asset population rather than an expected increase in fault rates. Vegetation expenditure reflects current investment levels, with a forecast reduction from the middle of the planning period consistent with the vegetation strategy.

7.7 Project List

The following projects are planned for the first five years of the planning period. Where projects are considered material, reference is given to the section in which they are discussed. Projects that are part of routine ongoing programmes such as conductor replacement and defect works are omitted for clarity.

Project	Scope	Status	Reference
Ōpaheke Microwave Link	Establish improved communications to our Ōpaheke site	Planned for FY27	7.2.2
Maioro Substation	Replace end of life assets at Maioro Substation	Ongoing multi-year project, planned for completion in FY28.	7.3.2
Community Resilience Improvements	Resilience improvement project for strategic feeder	Ongoing multi-year project, planned for completion in FY28.	8.4.3
Automation Rebuild Programme	Deploy a variety of automation solutions across the network to improve reliability	Ongoing multi-year project, planned for completion in FY27	7.4.2
Kiwirail Opaheke	Counties Energy works related to the Kiwirail Southern Power Feed project	Ongoing multi-year project, planned for completion in FY28	7.2.2
Bombay – Pukekohe North Insulator Replacement	Replacement of end of life asset	Planned for FY27	7.2.4
Ōpaheke Substation Renewal	Replacement of 22kV switchboard.	Ongoing multi-year project, planned for completion in FY28	7.2.2
Quarry Road Substation	Establish new substation at Quarry Road, to address load constraints at Opeheke.	Ongoing long term project. Commissioning planned for 2038	7.2.2
Waiau Pa Substation	Establish a new substation to replace the end of life Karaka Substation, and to address load growth in the Western region.	Commissioning planned for FY29	7.3.1
Fault Passage Indicator Rollout	Deploy new equipment on the network to improve reliability	Ongoing multi-year project, planned for completion in FY27	7.4.2
Hingaia Reliability Improvement	Minor network modification to improve reliability	Planned for FY27	7.2.2
Cape Hill Feeder Adams Drive Link	Minor network modification to improve reliability	Planned for FY27	7.2.4

7.7 Project List (continued)

Project	Scope	Status	Reference
Hunua Feeder McGregor Road Link	Minor network modification to improve reliability	Planned for FY27	7.2.2
Ōpaheke East Transformer Fire Wall	Construction of a firewall between switchroom and transformer	Planned for FY28	7.2.2
Glasgow Road Data Centre Replacement	Replacement of end of life building.	Planned for FY28	7.2.4
Kaiaua Feeder Resilience Improvements	Resilience improvement project for strategic feeder	Planned for FY28	7.2.1
Pukekohe Hill Feeder Reliability Improvement	Strategic undergrounding to improve network reliability	Planned for FY28	7.2.4
Pukekawa Feeder Reliability Improvement	Strategic undergrounding to improve network reliability	Planned for FY28	7.2.5
Kaiaua Feeder Reliability Improvement	Strategic reconfiguration to improve network reliability	Planned for FY28	7.2.1
33kV Glenbrook – Waiuku East Line Upgrade	Targeted investment at constrained spans to relieve network constraint	Planned for FY29	7.3.3
Pukekohe West Reliability	Strategic undergrounding to improve network reliability	Planned for FY29	7.2.4
Red Hill Feeder Cresta Rise Link	Strategic reconfiguration to improve network reliability	Planned for FY29	7.2.2
VR05 Voltage Regulator Controller Renewal	Replacement of end of life asset	Planned for FY30	7.3.3
Cape Hill Feeder Reliability Improvement	Minor network modification to improve reliability	Planned for FY30	7.2.4
Hunua Feeder Reconfiguration	Minor network modification to improve reliability	Planned for FY30	7.2.2
Decommission Karaka Substation	Remove electrical assets from site and make suitable for sale or storage, once Waiau Pa substation livened.	Planned for FY31	7.3.1
Pukekohe West Feeder Reliability Improvement	Strategic undergrounding to improve network reliability	Planned for FY31	7.2.4

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08

Transforming to be Future Ready

8.1 About This Chapter

This chapter goes into more detail on the macro factors that are going to influence the operating environment for Counties Energy over the next decade, and the way in which we are transforming ourselves to be future-ready.

8.2 Current State

Counties Energy is undergoing a period of rapid transformation, shaped by four critical industry forces: Decarbonisation, Digitalisation, Decentralisation, and Democratisation (the "4Ds"). Each of these drivers is redefining our operational and strategic priorities:

- **Decarbonisation:** A strong commitment to reducing carbon emissions is influencing all facets of our business, aligning with New Zealand's national targets and supporting the decarbonisation of process heat and transport.
- **Digitalisation:** Technological advancements are enabling new ways to monitor, manage, and optimise our energy flows. Digital platforms are vital for real-time insights, improved customer engagement, and network resilience.
- **Decentralisation:** The integration of distributed energy resources such as solar, wind, and battery storage is resulting in multi-directional energy flows, requiring innovative approaches to our network management.
- **Democratisation:** Customers now expect sustainable, flexible energy solutions and greater transparency, driving increased demand for tailored services and market participation.

Key challenges for us include the ongoing evolution of technology in the sector (digitalisation, electrification of transport, distributed energy resources), rising customer expectations for digital engagement and flexibility, legacy systems requiring modernisation, and the increasing complexity of integrating technologies like IoT, advanced metering, and battery storage. Cybersecurity threats, regulatory changes, decarbonisation pressures, and workforce attraction, retention, and upskilling also remain critical concerns. Collectively, these factors are catalysing our ongoing shift from being a traditional Distribution Network Operator (DNO) to a Distribution System Operator (DSO), positioning the business as an orchestrator of a smarter, more sustainable energy future.

8.2 Current State (continued)

Figure 8.1 Our Five Technology Pillars

Establishing the right practices, processes and capabilities to keep Counties Energy's technology secure, fit-for-purpose and scalable to meet our future ambitions.

Counties Energy's transformation to be future ready is driven by our commitment to deliver value and resilience through five strategic pillars: Our Customers, Smarter Networks, Business Excellence, Innovation, and Digital Foundations. These pillars serve as the foundation for how we address the evolving challenges in the energy sector, including technological advancements, rising customer expectations, system modernisation, cybersecurity, and workforce capability. By aligning our delivery approach to these pillars, we are positioning the business for our ongoing transition from a traditional Distribution Network Operator (DNO) to a Distribution System Operator (DSO).

- **Our Customers:** We are prioritising customer-centric workforce planning by recruiting, training, and retaining more staff skilled in digital communication and service delivery. Our focus includes building the capability for 24/7 customer engagement, digital support, effective feedback mechanisms, and advanced outage management. Additionally, we are developing commercial models for electric vehicle (EV) demand management, which necessitates new forms of expertise and industry partnerships.
- **Smarter Networks:** Our teams are upskilling in advanced network operations, SCADA, IoT devices, and real-time analytics, ensuring we can operate a modern and resilient network. We are strengthening our technical and digital competencies across the workforce, and enhancing cybersecurity awareness and protocols for both field and control centre roles.
- **Business Excellence:** We are embedding a culture of continuous improvement and automation within all our business support teams. Initiatives in diversity, equity, inclusion, and belonging (DEIB) are key to building a high-performing, resilient workforce. Leadership development and operational excellence are promoted through targeted training and process reviews.

- **Innovation:** Attracting talent with expertise in innovation management, agile delivery, and emerging energy technologies is central to our strategy. We are building structured frameworks for systematic innovation, including processes for idea capture and piloting new projects, while strengthening partnerships with technology providers, research institutions and other forward thinking electricity distribution businesses.

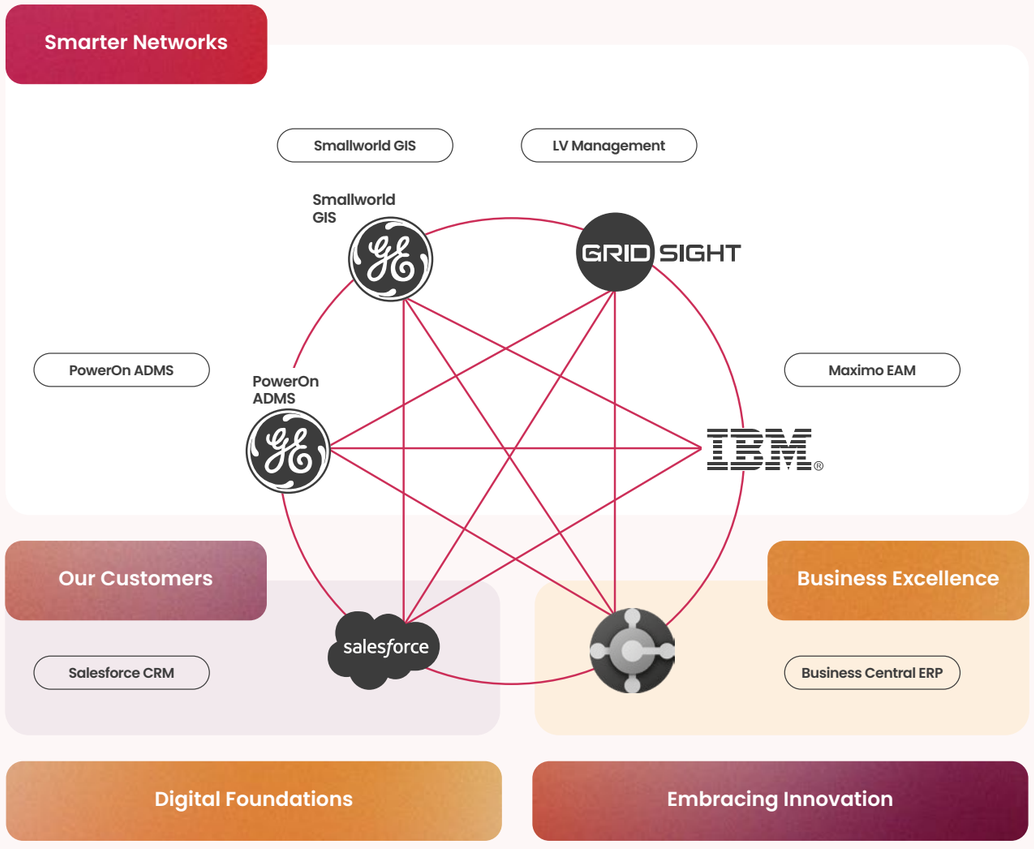
- **Digital Foundations:** We are expanding digital, data, and cybersecurity capabilities throughout the organisation. This includes resourcing digital transformation projects by recruiting project managers, system architects, and data analysts. Over the past two years, Counties Energy has made substantial investments in cybersecurity, resulting in a significant uplift in our overall capability. As we continue with our three-year cybersecurity roadmap, these investments have enabled us to strengthen our defences, enhance staff awareness, and adopt industry-leading technologies and practices. Ongoing training in new digital tools and security best practices is provided for all staff, ensuring our workforce is equipped to operate securely and efficiently in an increasingly digital environment.

These five pillars collectively enable Counties Energy to navigate sector-wide challenges — such as technology evolution, customer expectations, legacy system modernisation, and regulatory pressures — and to deliver a future-ready, customer-focused, and digitally-enabled energy network.

8.2 Current State (continued)

The Big Six Applications: Foundational Systems of Record

Figure 8.2 Overview of the Foundation Systems of Record



Counties Energy has identified six core applications that will serve as the backbone for our operational, customer, and business management processes. Each system plays a pivotal role within one of three strategic pillars: Networks, Customers, and Business Excellence. Together, these applications underpin our digital transformation and support the company's shift towards a smarter and more resilient energy future.

- **Smallworld GIS (Networks Pillar):** This Geographic Information System manages the network topology, field asset ratings, asset nameplate data, and planned network designs. It is essential for overseeing and maintaining the integrity of our network infrastructure, enabling detailed mapping and real-time visibility of the grid.

- **PowerOn ADMS (Networks Pillar):** The Advanced Distribution Management System (ADMS) facilitates high-voltage network management, monitoring of network state and topology, and supports field asset ratings. This system is critical for real-time control, situational awareness, and safe, efficient network operations.

- **Maximo EAM (Networks Pillar):** Serving as the Enterprise Asset Management (EAM) platform, Maximo manages field asset ratings, planned maintenance, inspection data, fault records, and the asset risk matrix. This ensures the reliability and longevity of our network assets through systematic maintenance and risk management.

- **INDI (Customers Pillar):** INDI is the primary system for managing customer activity, outage reports, notifications, vegetation cut and trim schedules, and new connection requests. It supports streamlined customer engagement and efficient service delivery.

  Going forward, INDI will progressively cede customer-facing capabilities to Salesforce and LV network-focused capabilities to Gridsight, aligning each function with platforms better suited to customer engagement and network intelligence respectively.

- **Salesforce CRM (Customers Pillar):** Salesforce is used for comprehensive customer relationship management, including handling customer data, issuing notifications, and managing connection processes. This enhances our customer experience and supports proactive communication.

- **Business Central ERP (Business Excellence Pillar):** This Enterprise Resource Planning system oversees financial data, asset valuation, warehousing, purchase orders, and goods receipt. It is vital for financial stewardship and effective resource allocation across the business.

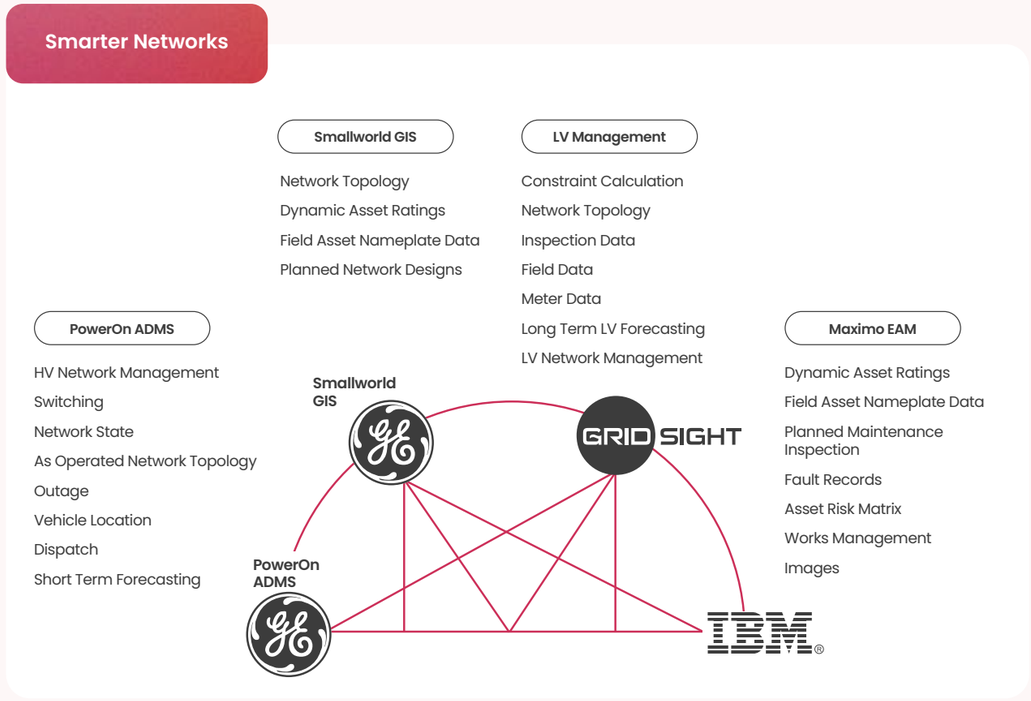
8.2.1 Strategic Workforce and Organisational Capability

To meet evolving industry demands, Counties Energy is pursuing a customer-centric workforce strategy, focusing on recruiting, training, and retaining more talent skilled in digital communication, service delivery, and 24/7 engagement. There is a strong emphasis on strengthening our expertise in electric vehicle (EV) demand management and developing new commercial models in partnership with industry players.

Workforce upskilling is targeted at advanced network operations, including SCADA, IoT, and real-time analytics, alongside enhanced cybersecurity awareness for all our field and control centre roles. We are embedding continuous improvement and automation competencies across our business support teams and fostering leadership development. Innovation management skills, agile delivery, and partnerships with technology providers, research institutions and other forward thinking EDBs, are prioritised to drive systematic innovation. Digital transformation projects are resourced with project managers, system architects, and data analysts, supported by ongoing training in digital tools and security best practices.

8.2.2 Smarter Networks

Figure 8.3
Overview of Smarter Networks



8.2.2 Smarter Networks (continued)

Smarter Networks encompasses all aspects of our operational planning and maintenance relating to the electrical network. This includes the management and optimisation of our network performance, proactive identification and resolution of faults, and the deployment of advanced technologies to support safe and efficient operations. Whether it involves the integration of new grid assets, upgrades to existing infrastructure, or the implementation of predictive maintenance strategies, Smarter Networks serves as the foundation for ensuring the reliability, safety, and adaptability of all electrical systems within our network.

The Smarter Networks initiative is driving the deployment of our advanced SCADA and IoT solutions for real-time network control and monitoring. Community-scale battery storage pilots are underway to enhance reliability and flexibility, while continuous improvements in our network communications supports operational excellence.

A comprehensive five-year programme is focused on integrating SCADA and IoT systems with GE ADMS. This includes:

- Switch Order Management System.
- Outage Management Systems (OMS).
- Distributed Power Flow (DPF) modules.
- Fault Location, Isolation, and Service Restoration (FLISR) solutions.

These upgrades are designed to deliver better real-time control, improve outage and switch order management, and strengthen our automation and reliability.

The rollout of the Maximo asset management system is a foundational step in enhancing our asset lifecycle management, scheduling, maintenance, and resource allocation. Integration with ISO compliance frameworks and the adoption of Asset Risk Management Methodology (ARMM) will enable enhanced risk-based management and align asset practices with industry standards. Ongoing innovation is embedded through agile pilots, rapid learning cycles, and partnerships with technology providers and research institutions.

To advance our Smarter Networks initiative, we are actively trialling the deployment of drones for both routine inspections and reactive scanning of our network assets. These early-stage pilots are designed to explore the transformative potential of drones in enhancing asset visibility, reducing manual inspection times, and improving safety.

The trials are closely focused on capturing high-quality, actionable data from drone operations, laying the foundation for scalable adoption and integration with our digital asset management systems. As we progress, insights gained from these trials will inform the development of improved processes and data pipelines, ensuring that the quality and reliability of incoming data support better future analytics, predictive maintenance, and strategic decision-making. This approach positions us to leverage innovative technology for smarter, more resilient networks, driving tangible value for the organisation and our customers.

8.2 Current State (continued)

8.2.2 Smarter Networks (continued)

Five-Minute Metering Technology

Counties Energy is rolling out improved metering capabilities across our network, collecting smart meter data every five minutes and updating internal systems every 15 minutes. This gives customers up-to-date information about their energy use and helps them manage consumption more accurately. The new metering supports precise billing, detailed energy tracking, and a faster response to network issues, making our network smarter and more efficient.

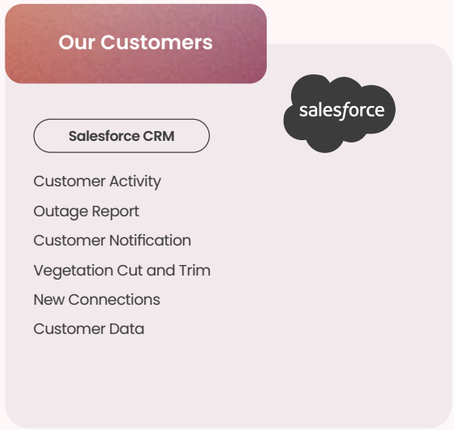
Most benefits come from the prevention and avoidance of problems, such as fewer complaints and equipment failures, rather than direct savings. This is similar to the value of preventative measures in areas like cybersecurity and safety, where avoiding issues is less costly than fixing them later. As more low-carbon technologies connect to the network, understanding and managing power quality becomes even more important, and the risk of missing issues may outweigh the cost of monitoring.

Counties Energy's existing smart meter system is already delivering value with half-hour outage data, and moving to five-minute intervals will further improve our productivity and customer service with little extra cost.

In parallel with the smart meter advancements, Counties Energy is making significant investments in LV Analytics as part of a broader transformation in network planning. By deepening our capabilities in this space, we are reshaping how our planning teams operate to unlock even greater value from network data. As part of this shift, Gridsight will be elevated to become one of our Big Six strategic tools for LV network analysis, providing enhanced insights and decision support. While INDI has delivered substantial value and proven to be a highly successful asset, the move towards richer datasets and advanced data science will see INDI transition to a second-tier application within Counties Energy's ecosystem. This evolving toolset ensures that our planning function remains at the forefront of innovation and data-driven strategy.

8.2.3 Our Customers

Figure 8.4
Overview of Our Customers



Our customer strategy encompasses every facet of customer interaction, from initial contact through ongoing support and engagement. This includes managing service requests, handling inquiries, resolving issues, and facilitating access to essential information. By adopting a holistic approach, Counties Energy ensures that each touchpoint — whether digital or face-to-face — delivers value and addresses the evolving needs of all customer segments.

We are committed to continuous improvement by integrating customer feedback into our processes, enhancing transparency, and leveraging advanced digital tools to create a seamless, efficient, and responsive customer experience. This comprehensive coverage supports a unified journey for all our residential, commercial, and industrial clients, fostering trust and satisfaction across the network.

Counties Energy is committed to enhancing digital engagement and self-service for all our customer segments, ensuring data privacy and security in every interaction. We are building 24/7 support capabilities for outages, incidents, and planned works, leveraging data insights to proactively address customer needs and preferences.

Continuous improvement of customer-facing processes is also prioritised, with a focus on integrating feedback into process redesign and business system upgrades. These efforts aim to streamline our customer interactions, make services more accessible, and deliver measurable benefits.

Customer Focus: Salesforce Rollout and CRM Strategy

As part of our commitment to delivering a superior customer experience, we are embarking on the strategic rollout of Salesforce as our central Customer Relationship Management (CRM) platform. This initiative is foundational to our vision of enabling a seamless self-service environment for all customer segments, ensuring that interactions are intuitive, efficient, and transparent.

Market Analysis of Customer Segments

The transition began with a comprehensive market analysis to identify and understand the diverse needs and preferences of our customer base. By categorising customer types and mapping their unique requirements, we can tailor self-service solutions that are both relevant and accessible. This data-driven approach ensures that our CRM and digital channels align with the expectations of residential, commercial, and industrial customers alike.

8.2.3 Our Customers (continued)

Process Deep Dive for Self-Service Enablement

Building on the insights from our market analysis, we are conducting a thorough review of internal processes that underpin customer interactions. This review seeks to streamline workflows, eliminate friction points, and identify opportunities for automation. By reengineering these processes, we are laying the groundwork for customers to independently manage their accounts, access services, and resolve issues through a unified digital interface.

Enhanced Visibility and Online Payment Options

With Salesforce as the backbone of our customer engagement strategy, we are introducing enhanced visibility into service status, transaction history, and account management. Customers will benefit from real-time updates and a transparent view of their interactions with us. Additionally, the platform has the capability to support secure online payment options, simplifying billing and providing greater flexibility for customers to manage their financial commitments online.

Building on the Outage Hub Foundation

These advancements build upon the successful implementation of the Outage Hub, which transformed the outage journey by providing customers with timely updates and self-service reporting capabilities. Leveraging this foundation, the Salesforce rollout extends our digital reach, supporting a fully integrated and responsive self-service ecosystem across all touchpoints. This forward-looking approach positions us to continuously evolve our customer offerings and deliver best-in-class service experiences.

8.2.4 Business Excellence

Figure 8.5
Overview of Business Excellence

Business Excellence encompasses all the key supporting functions across the organisation, including Finance, Human Resources (HR), Legal, and Property. These areas operate in alignment to drive operational effectiveness, risk management, and continuous improvement throughout our business. By streamlining support processes and consolidating platforms, we reduce complexity and enhance collaboration across teams. Our commitment to risk management, compliance, and quality assurance ensures that our business operations remain robust and responsive to evolving standards and regulations.

Performance measurement and ongoing improvement are embedded in all our business support systems, allowing us to identify opportunities for optimisation and innovation. Vendor resilience is strengthened through collaborative partnerships, while automation and artificial intelligence (AI) are being adopted for process optimisation and cost savings. Data governance is standardised, supported by robust access controls and auditing procedures. Innovation is accelerated through rapid prototyping, pilot initiatives, and structured frameworks for business transformation.

Recent upgrades, such as the transition from Navision to Business Central, further modernise our core business systems and reduce technical debt, preparing the organisation for future cloud migration and greater operational agility. Through these initiatives, Business Excellence supports the delivery of high-quality services and underpins our broader goals of digital transformation and operational excellence.

8.2.4 Business Excellence (continued)

Navision to Business Central Programme

As part of our commitment to business excellence, we have recently completed an upgrade from Navision to an on-premises version of Business Central. This transition marks a significant step forward in modernising our core business systems. Our legacy Navision environment contains a considerable amount of customisation, which represents technical debt and limits our agility.

To address this, we have launched a targeted programme to systematically remove unnecessary customisations and streamline our processes. This initiative is essential preparation for our future migration to the Microsoft 365 (M365) cloud version of Business Central. The programme will encompass critical business functions including ICP Management, Billing, and Jobbing (capital works), ensuring that each area is optimised for efficiency and future scalability.

By reducing this technical debt, we are positioning ourselves to fully leverage the advanced capabilities and integration potential of the Microsoft 365 platform, supporting our broader goals of digital transformation and operational excellence.

8.3 Digital Foundations

Digital Foundations covers all our supporting digital technology, including the full spectrum of IT and OT networking, hypervisors, compute resources, Active Directory, cloud services, and base computing infrastructure. This foundational layer ensures that every aspect of our digital environment is resilient, scalable, and aligned with modern best practices. By integrating core technologies across both IT and OT, we create a connected ecosystem that underpins business operations, supports innovation, and drives digital transformation.

8.3.1 Infrastructure

A robust digital infrastructure underpins all operations, with substantial investments in core platforms, cloud adoption, and integrated systems to ensure both scalability and interoperability. Our IT environment is a hybrid model, combining on-premises Nutanix infrastructure with Amazon Web Services (AWS) cloud. This approach enables IT to leverage the flexibility and agility of AWS, supporting the deployment of modern, containerised applications and facilitating rapid adaptation to changing business needs. The cloud's elastic resources empower our digital teams to scale workloads efficiently, support innovation, and quickly respond to emerging challenges.

In contrast, our Operational Technology (OT) environment is based on a mix of VMware virtualisation and bare-metal servers. This architecture provides a stable and reliable core, essential for maintaining the integrity and continuous operation of our critical industrial control systems. By keeping OT systems on dedicated, robust infrastructure, we ensure greater operational continuity and mitigate risks associated with downtime or system disruptions.

Upgrading and consolidating our business platforms supports streamlined and flexible operations across both IT and OT environments. The strategic use of AWS in IT fosters a dynamic, future-ready ecosystem, while the stability of VMware and bare-metal infrastructure in OT guarantees reliability where it matters most. Major investments in cybersecurity, data protection, and cloud solutions further reinforce this dual approach, ensuring Counties Energy remains secure, compliant, and prepared for future growth.

Network Segmentation and Modernisation

As part of our Digital Foundations strategy, we are advancing network segmentation to support both security and operational efficiency. The IT network is undergoing micro-segmentation, leveraging modern security architectures to isolate workloads, minimise attack surfaces, and enable granular policy enforcement. This approach enhances our ability to contain potential threats and ensures that critical IT assets are protected within tightly controlled zones.

In contrast, our Operational Technology (OT) environment continues to adhere to macro-segmentation principles as outlined in the Purdue model. This structured approach maintains clear separation between OT layers, supporting the integrity and reliability of industrial control systems while aligning with industry best practices. By modernising network segmentation across both IT and OT, we strike a balance between agility, security, and operational continuity, ensuring our digital infrastructure is robust and future ready.

8.3 Digital Foundations (continued)

8.3.2 Cybersecurity

The cybersecurity strategy is grounded in Zero Trust principles and Data Loss Prevention (DLP), with proactive security frameworks and measures to protect digital assets and ensure regulatory compliance. Leading cybersecurity and resilience measures are embedded across all IT and OT environments, with ongoing uplift in digital literacy and capability for all staff.

8.3.3 AI & Data

Counties Energy is integrating six major business applications into Snowflake*, establishing data quality pipelines, and promoting data democratisation across teams. The Data Governance Council oversees data management, quality, standardisation, and stewardship, setting policies and monitoring compliance.

By providing teams with self-service access to big data, we empower staff at all levels to independently extract insights, perform analyses, and make informed decisions without unnecessary bottlenecks. This shift accelerates innovation, encourages cross-functional collaboration, and ensures that data-driven decision-making becomes embedded in everyday business processes.

These data sources and information gleaned from field devices, smart meters, and field crew (e.g. imagery from inspections or meter data) are key to enabling innovation practices at Counties Energy.

Currently, data quality remains a significant challenge, with issues stemming from legacy systems, inconsistent data standards, and manual handling across disparate platforms. To address this, Counties Energy is methodically implementing Data Quality (DQ) pipelines within Snowflake. These pipelines automate the cleansing, transformation, and validation of data as it moves from source systems into the central data platform. Over time, this systematic approach is expected to significantly improve the reliability, accuracy, and timeliness of data available to our teams, reducing errors and rework while enabling more robust analytics and reporting.

The Data Governance Council plays a central role in this transformation by overseeing all aspects of our data management, quality, standardisation, and stewardship. By establishing clear policies, enforcing consistent data definitions, and monitoring compliance, the Council ensures that the move towards data democratisation is underpinned by strong governance. This holistic approach allows us to balance agility and accessibility with the necessary controls to safeguard data integrity and support regulatory compliance.

*Snowflake is a cloud-native data platform designed for storing, processing, and analysing large datasets.

8.3 Digital Foundations (continued)

8.3.3 AI & Data (continued)

We are preparing for a multi-agent AI environment, developing digital architecture, integration frameworks, and governance protocols to support advanced analytics, automation, and intelligent decision-making. Centralised data repositories and modern data models enable seamless integration, while analytics capability uplift supports business optimisation and innovation.

Building on this, we are actively progressing towards a fully end-to-end agentic model, or agentic mesh, where autonomous agents collaborate across the business ecosystem to drive continuous optimisation and innovation. This vision goes beyond simple automation, embracing a decentralised architecture where intelligent agents interact, learn, and make decisions independently, yet cohesively, across multiple domains. Such an agentic mesh not only enables more dynamic and adaptive business processes but also positions us to respond rapidly to emerging challenges and opportunities.

To realise this future-ready architecture, a robust foundation of automation and integration is essential. By automating routine workflows and integrating disparate systems, we can eliminate silos and reduce manual intervention, paving the way for scalable, decentralised intelligence. Integration frameworks and APIs (Application Programming Interfaces) are being designed with flexibility and interoperability at their core, supporting seamless agent-to-agent communication and orchestration. This approach ensures that as AI capabilities proliferate and become more distributed, we remain agile, resilient, and prepared to harness the full potential of multi-agent systems.

Ultimately, the transition towards a decentralised agentic mesh will empower us with a prolific, adaptive digital infrastructure — one that is not only scalable and secure, but also capable of supporting the complex, interconnected AI environments that will define future-leading enterprises.

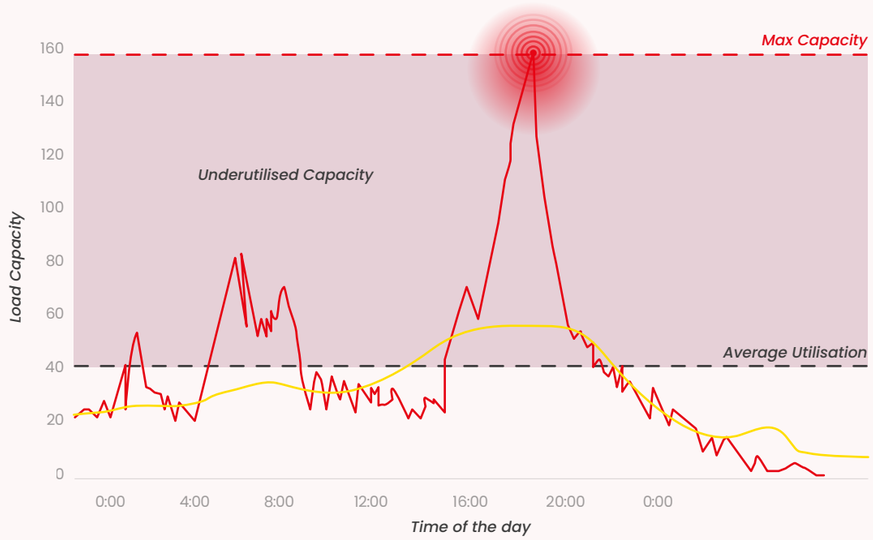
8.4 Alternative Network Investment

8.4.1 Introduction

Counties Energy is actively investigating and deploying Non-Wire Alternatives (NWAs) to increase our existing network utilisation/productivity which drives price stability as the Franklin region electrifies. The conventional approach to network investment — i.e. reinforcing feeders, uprating transformers, building new substations — is increasingly challenged by cost, lead times, environmental constraints, and uncertainty.

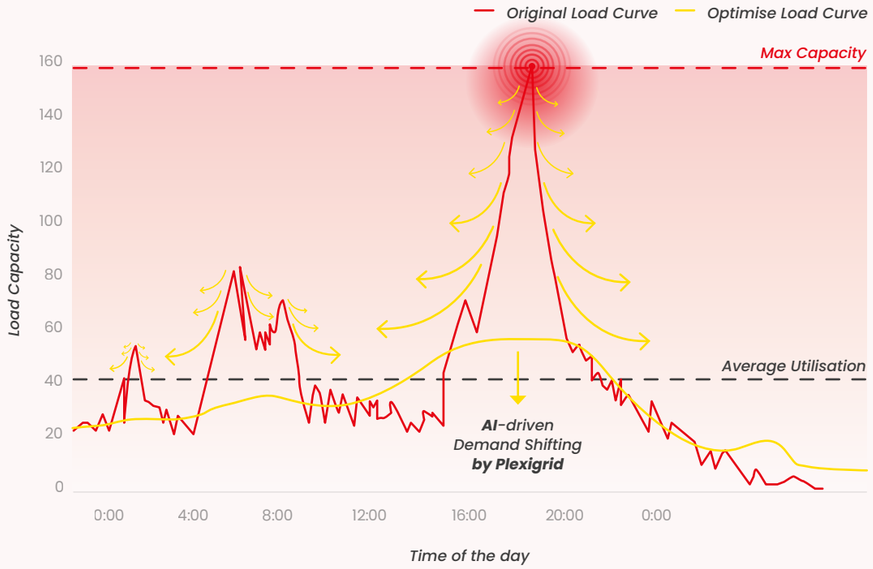
To maintain affordability, resilience, and alignment with decarbonisation goals, Distribution System Operators (DSOs) must explore NWAs (e.g. flexible demand, storage, active network control, market-based flexibility) as complements or alternatives to “poles and wires”. The strategic rationale is to unlock optionality, defer or avoid high-cost reinforcement, and better align investment with dynamic needs and customer value.

Figure 8.6 Electricity Demand Throughout the Day (kW) – Underutilised Capacity



8.4.1 Introduction (continued)

Figure 8.7 Electricity Demand Throughout the Day (kW) – AI Driven Demand Shifting



This direction is supported by the two regulatory bodies for the sector, Electricity Authority (EA) and the Commerce Commission (ComCom). Examples of this support are shown through EA's consultations over the past year. To highlight a few: streamlining the customer connection, introducing flexible connections, payment for solar PV injection, increasing export limits to 10kW, improving network visibility and the Decentralisation Green Paper by the EA.

Counties Energy is one of a handful of EDBs that are a part of the EA's Power Innovation Pathway (PiP) that shares insights about its NWA – particularly its developments in the DSO space. The ComCom has also incentivised price regulated EDBs to increase their participation in NWA initiatives through the introduction of the Innovation, and Non-Traditional Solutions Allowance (INSTA) scheme. Counties Energy has received direct support from EECA to undertake a Demand Flexibility pilot in the Karaka Harbourside region to prove the value of a decentralised and fully electrified cluster of our network. EECA is also supporting four similar projects with other EDBs nationally to demonstrate the value of Demand Flexibility.

8.4.1 Introduction (continued)

The regulatory environment is being driven by both consumer trends as well as government commitment to the Climate Accords. The consumer trends that are most relevant to Counties Energy are:

- **Increasing electrification** — transport (EVs), heating, and other end uses are shifting demand from fossil fuels to electricity, pushing peak loads and changing load profiles.
- **Decarbonisation imperatives** — goals to reach net zero emissions drive growth in renewable energy, distributed energy resources (DER), and zero-carbon loads. Incentives, grants and zero interest loans being offered by government to expedite the transition are also influencing customer behaviour.
- **Demand growth and volatility** — in many regions, rapid population and economic growth (especially peri-urban areas) also place upward pressure on network capacity.
- **Customer technology uptake** — more customers adopt behind-the-meter solar, batteries, smart thermostats, EV chargers, and flexibility-enabling devices. These changes require both demand shaping and active management.
- **Two-way flows and non-coincident peaks** — increasing DER injection and variable net load also requires more dynamic network control.

Solar panels being installed on a Counties Energy warehouse.

8.4.2 Alternative Investment (NWA) Approach Overview

Counties Energy is working towards improving our alternative investment (NWA) approach. Our approach is to apply a structured and evidence-based process to identify network needs where non-traditional investment may deliver greater overall value. The process begins with screening projects during early planning stages to determine whether flexibility, distributed resources, or other non-network options can address localised constraints more efficiently than traditional reinforcement. Key selection criteria include the nature of demand growth (temporary or enduring), the availability and maturity of flexibility services, comparative cost-effectiveness, implementation lead times, and the potential for customer or community participation.

Projects that meet the screening thresholds will progress to detailed evaluation, incorporating financial modelling, risk assessment, and technical feasibility studies. These determine whether a flexibility-based solution can achieve equivalent network outcomes, reliability, and safety performance at lower lifecycle cost. This structured approach aligns with international best practice.

Figure 8.8 Alternative Investment Approach

Counties Energy recognises there is a spectrum of non-traditional investment options that can complement or replace conventional reinforcement, depending on the network need and local context. These include:

- **Flexible Connections:** Dynamic or time-bound connections that vary export or import capacity based on network conditions, enabling faster, lower-cost connections for distributed generation or large loads.
- **Flexible Imports and Exports:** Customer or aggregator-driven flexibility services where demand or generation adjusts in response to signals that alleviate constraints or shift load profiles. This includes market-based or third-party solutions, contracted flexibility services delivered by aggregators, retailers, or customers via bilateral arrangements or emerging local flexibility markets.
- **Energy Storage and Management Solutions:** Network, community, or customer-level storage systems used to balance supply and demand, enhance power quality, and improve reliability.
- **Network Operational Flexibility:** Advanced automation, voltage optimisation, or reconfiguration techniques that increase utilisation of existing assets and defer upgrades. Each NWA option presents distinct value opportunities, ranging from capacity deferral and carbon reduction to increased resilience and improved network utilisation/productivity.

8.4.2 Alternative Investment (NWA) Approach Overview (continued)

Counties Energy faces two immediate challenges to its NWA options:

1. **"Need" identification** is difficult and requires enhanced planning and forecasting tools as well as good data. We are in the process of developing these tools such as five-minute and power quality inclusive smart metering data, LV analytics tools, MV and LV congestion modelling tools.
2. **Procurement of Flexibility** is a key challenge for Counties Energy given the low visibility and relatively low uptake of Distributed Energy Resources (DERs) so far, as well as the low visibility and maturity of Flexibility Services Providers (FSPs). Strategies to bridge the current gap include early engagement with customers, aggregators and FSPs, acting as the default FSP and deploying assets where relevant, as well as accessing NZTA data for visibility on EV registration data by postcode to understand where EV Charging might be located.

Alternative investments can deliver significant benefits for both the network and consumers. We aspire to achieve the following benefits provided by NWAs:

- **Deferral of major capex:** Flexibility options can provide cost-effective solutions that defer or avoid major capital expenditure, improve utilisation of existing assets, and enable more efficient management of peak demand.
- **Reduced environmental impacts:** Flexibility options utilise an existing asset in a smarter way, that avoids increasing general consumption.
- **Increased opportunities for community engagement and customer participation:** NWAs allow consumers to participate in the energy transition as active players offering their assets as flexible resources, which gives them the power to make choices about their energy consumption.

Experience from leading DSOs from around the world, especially Australia and UK, provides valuable insights for embedding flexibility into our investment decision-making. Our view is that flexibility must be treated as a core planning consideration, not a last resort. Robust procurement, verification, and governance processes are essential to ensure flexibility delivers sustained and measurable value. The timing of consideration is crucial; flexibility identified early in the planning cycle offers greater optionality and avoids overcommitment to traditional reinforcement. Transparency and trust between the DSO, customers, and service providers underpin scalable participation.

8.4.3 Our NWA Projects and Roadmap

The Counties Energy DSO team is delivering a variety of NWA pilot projects to grow capability and awareness of NWA solutions. The capability being built by the NWA projects strategically targets areas of our DSO team's roles and responsibilities:

- **Customer Enablement & Operations:** Educating customers by bringing them on the journey of flexibility, including benefits to them and to the grid.
- **Whole-system Orchestration:** Connecting customer DERs - FSPs - DSOs & DNOs - TSOs & TNOs to the full electricity market unlocks value-stacking potential and co-ordination of flexibility.
- **Connections and Capacity Management:** Using flexibility to provide cheaper and faster alternatives for customers to connect and maintain their electrical connection.
- **Asset and Operations Management:** Actively orchestrating flexibility to better operate and maintain assets in the network, thereby strengthening its resilience.
- **Flexibility Services and Commercial Operations:** Considering flexibility as part of our pricing and commercial frameworks to unlock and deliver value to our customers and community.
- **Digital Enablement and Operations:** To achieve all the above capabilities requires capability growth in our digital tools, systems, processes, infrastructure, automation, and data.

A list of the NWA pilot projects in order of progress is summarised in the next table. The table includes a brief description of each pilot project, its status, impact, and a tie back to the capability area of development being focused on. Figure 8.9 provides a high-level view of the DSO Transition Programme.

8.4.3 Our NWA Projects and Roadmap (continued)

Project Name	Description	Status	Impact	Capability Area
Mercer Berm Battery	Trialling a Flexible Connection using Second Life Nissan Leaf Batteries and Public EV Charging at Mercer in collaboration with EECA	Completed, with the model transitioned to BAU	1. Fill a gap in the national Public EV Charging network 2. Operate Public EV Charging infrastructure within limited network capacity and leverage on-site batteries on site to reduce peak demand	Connections & Capacity Management
Eneida Distribution Transformer Mapping Algorithms	A trial to test whether using detailed and high-frequency smart meter data can allow Counties Energy to map its LV network with confidence	Completed and transitioned to BAU	1. Enables Counties Energy to validate field capture data against algorithm-derived data to assess whether confidence can be established within algorithm-based LV connectivity mapping 2. Once successful, Counties Energy can map its LV network using algorithms and high-frequency smart meter data in order to better plan, operate and enable flexibility on its network, avoiding costly manual mapping	Asset and Operations Management
Karaka Harbourside SIQ Smart Meter Trial	Upgrading smart meter capability to provide more data points that are useful for operating and planning the network	Completed	1. Collecting consumption and Power Quality data from smart meters at a high frequency that allows for near-real-time decision-making in operational platforms like ADMS and DERMS 2. The granular and more detailed data set allows Counties Energy to reduce assumptions and develop a data driven decision-making framework towards network reinforcement	Asset and Operations Management
Enabling Hot Water Flexibility using Smart Meters	Unlocking hot water flexibility opportunities using existing smart meters technology	In progress	1. Providing energy retailers with access to Hot Water Cylinder load and allowing them to trade energy and provide customers with cost-competitive offers 2. Providing Counties Energy with access to Hot Water Cylinders, allowing us to defer large capital expenditure projects and free capacity during emergencies through targeted demand orchestration	Whole System Orchestration

Table 8.1 NWA Pilot Projects Underway

8.4.3 Our NWA Projects and Roadmap (continued)

Project Name	Description	Status	Impact	Capability Area
Harbourside Flex	Unlocking New Zealand's first decarbonised smart subdivision by subsidising (through EECA support) the deployment of smart-internet connected technologies and connecting these technologies with DSO platforms	In progress	1. Generating between 1-2MW of flexible demand that can be used to optimise customer energy 2. Allows access to this flexibility for use to defer large capital expenditure projects and free capacity during emergencies 3. Providing energy retailers and aggregators with access to this flexibility for electricity market trading 4. Creating a New Zealand first peer-to-peer (P2P) energy trading network using community storage technology 5. Demonstrating use of real-time Dynamic Operating Envelopes and Flexible Connections 6. Generating insights on the use of smart-internet connected technologies deployed at scale	Whole System Orchestration Customer Enablement & Operations
HQ Solar PV	Deploy ~1MWp of Solar PV on Counties Energy buildings at HQ	In progress	1. Reduce operating costs for Counties Energy by offsetting its energy needs through renewable solar generation 2. Use excess solar generation to trade and generate more renewable energy in the electricity market and gift to energy hardship customers 3. Support adjacent decarbonisation objectives that would increase the electricity demand at the HQ site (i.e. electrifying the light vehicle fleet and associated EV Charging requirement)	Whole System Orchestration
Multiple Trading Relationship (P2P) using HQ Battery Trial	Trialling peer-to-peer (P2P) trading using a Second Life Nissan Leaf Battery in combination with HQ excess generated Solar PV	In progress	1. Capturing excess solar PV generation with an on-site second life battery to increase self-consumption of generated renewable energy 2. Gifting generated energy to a consortium of energy hardship customers within the Counties Energy network by exporting stored renewable energy from the batteries at peak energy price periods 3. Working with the regulator (EA) and energy retailers to deliver this solution	Flexibility Services and Commercial Operations

Table 8.1 NWA Pilot Projects Underway (continued)

8.4.3 Our NWA Projects and Roadmap (continued)

Project Name	Description	Status	Impact	Capability Area
GrideX DER Gateway	Creating a DER communication gateway to aggregate and access all different types of flexibility available across the Counties Energy network	In progress	1. Creating a scalable software platform that connects different DERs owned by Counties Energy and its customers (via aggregators) with our DERMS platform to orchestrate energy across the network using DOEs, enabling the offset of major capital expenditure projects through NWAs 2. Making the flexibility available to aggregators and energy retailers to offer more cost-competitive electricity offers to their customers 3. Leveraging an open-standards and interoperable communications protocol approach to create this connection with flexibility (e.g. CSIP AUS IEEE 2030.5, OCPP, ISO etc.)	Whole System Orchestration
Plexigrid DERMS	Deploying Counties Energy's Distributed Energy Resource Management Platform (DERMS) to orchestrate flexibility using near-real-time network insights	In progress	1. Creates DOEs that Counties Energy can issue to aggregators, DERs and customers to operate flexibility assets within network limits 2. Creates a more informed capital and operational expenditure approach using NWAs 3. Tracks and forecasts flexibility assets use, and planned to better operate and plan the network	Whole System Orchestration
DSO & TSO Integration Pilot	Creating a framework for co-ordinating the operation and planning of flexibility between distribution networks and transmission networks	In progress	1. Creating a standardised approach using open standards based interoperable communications protocols to orchestrate, request and observe aggregated flexibility	Whole System Orchestration
Enabling Commercial & Industrial Flexible Connections	Creating a new type of BAU connections process that allows the customer to bring flexibility to the table for a connection request	In progress	1. Drives down cost and time to connect for customers 2. Allows customers to invest in firm capacity connections when they have more certainty around their decarbonised energy needs 3. Presents the opportunity to customers to use the flexibility to drive down their operational costs through smart use of their energy during off-peak and shoulder periods	Connections & Capacity Management
Electricity Authority Power Innovation Pathway (PiP)	Sharing learnings from flexibility trials to inform regulation	In progress	1. Provides us with a dedicated direct engagement channel with a key regulator to discuss barriers to innovation and flexibility in the New Zealand environment	Customer Enablement & Operations

Table 8.1 NWA Pilot Projects Underway (continued)

8.4.3 Our NWA Projects and Roadmap (continued)

Project Name	Description	Status	Impact	Capability Area
Commercial Framework and Modelling of Flexibility Services	Creating and testing commercial flexibility frameworks to validate the value of flexibility in the Counties Energy network	In progress	1. Allows Counties Energy to pay a fair compensation to those that offer flexibility that results in the deferral of major capital expenditure using NWA solutions	Flexibility Services and Commercial Operations
Vehicle-to-Grid (V2G) Trials	Unlocking NZs biggest (mobile) battery using Vehicle-to-Grid technology	In progress	1. Testing and validating opportunities to use V2G as an abundantly available flexible resource to defer large infrastructure as the transport sector in New Zealand decarbonises	Whole System Orchestration
Counties Energy's Flexibility Marketplace	Creating a space where Counties Energy can tender for flexibility with aggregators and customers	Planned	1. Setting up an open transparent and fair flexibility tendering marketplace 2. Creates a space for Counties Energy to publish upcoming constraints and projects and get fast feedback on available flexibility 3. Provides Flexibility Services Providers (FSPs) an opportunity to tender for NWAs and assess value	Flexibility Services and Commercial Operations

Table 8.1 NWA Pilot Projects Underway (continued)

These initiatives focus on building capacity and capability to enable Counties Energy to utilise NWAs when addressing future network constraints. Based on the base scenario load forecast, these initiatives do not materially impact forecast peak demand or contribute to addressing constraints within the planning period, though this will be refreshed over time.

Measuring Success

Counties Energy measures innovation success by balancing technical performance, customer value, commercial viability, and strategic alignment. Success requires solutions to operate safely and reliably, meet regulatory and engineering standards, improve customer experience through faster, more flexible or more resilient access to energy, and deliver cost-effective outcomes. Environmental benefits, such as reduced waste and lower emissions, also contribute to the definition of success.

Decision-making for Innovation

Innovation decisions follow a structured, iterative approach grounded in Counties Energy's test–learn–trial–pilot framework. New ideas proceed only when early assessments show manageable risk, strong safety controls, and a clear problem or opportunity aligned with strategic goals. Decisions to advance an innovation to the next stage are based on demonstrated technical feasibility, compliance readiness, customer and community benefit, and the potential to scale safely and efficiently. Cross functional evaluation - including engineering, safety, commercial, and planning teams - ensures decisions are robust and multidimensional.

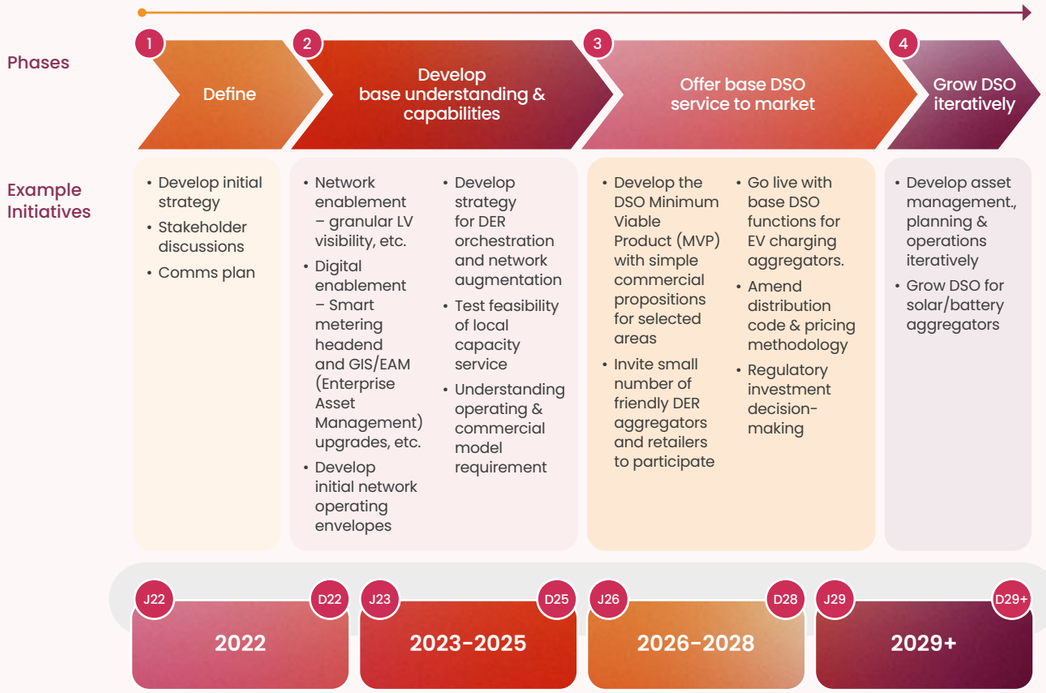
8.4.3 Our NWA Projects and Roadmap (continued)

Adopting, Scaling, or Discontinuing Practices

Counties Energy commercially adopts an innovation once we have proven real world performance, established repeatable processes, delivered measurable value, and shown we can meaningfully support the company's long-term transition toward a more flexible, customer-centric energy system.

Innovations are discontinued when risks outweigh benefits, when solutions underperform or become uneconomic, or when they no longer align with evolving customer needs or strategic direction. This discipline ensures that only innovations delivering genuine operational, customer, and strategic value progress to full adoption.

Figure 8.9
High Level View of the DSO Transition Programme



8.4.4 Distribution System Operator (DSO) Working with the Distribution Network Operator (DNO)

Counties Energy's transition toward a Distribution System Operator (DSO) model directly supports and enhances the core responsibilities of the Distribution Network Operator (DNO). As the DSO develops and validates new NWA capabilities through structured pilots and trials, these solutions provide the DNO with proven tools, processes, and operational approaches that can be deployed at scale to meet emerging network needs.

The DSO and DNO functions are mutually reinforcing. The DNO continues to plan, operate, and maintain our physical network, ensuring safety, reliability, and compliance. The DSO complements this by orchestrating flexibility services, enhancing visibility of customer energy resources, and introducing new operational levers to manage constraints in real time. This relationship is critical to delivering a future-ready, cost-effective network that supports the region's electrification and decarbonisation pathways.

To manage the evolving requirements of the modern distribution system, Counties Energy operates a dual-track delivery model:

- The DSO track focuses on innovation, trials, and capability development in areas such as flexibility procurement, DER integration, dynamic operating envelopes, distributed automation, and market-based coordination with retailers, aggregators, and customers.
- The DNO track focuses on continuous improvement of planning, asset management, field delivery, traditional investment assessment, and enduring operational processes.

As pilot projects mature, the DSO formally hands over validated capability modules to the DNO for incorporation into business-as-usual (BAU) workflows. This ensures innovations are embedded into standard planning and operational practice rather than remaining isolated or experimental.

Each NWA project completed by the DSO provides the DNO with:

1. **Proven technical capability:** Demonstrated performance of flexible connections, DER orchestration, high-resolution visibility, local optimisation, and automation tools. Evidence that flexibility can reliably mitigate or defer specific types of constraints.
2. **Operational confidence:** Clear understanding of the use cases, operational boundaries, and performance characteristics. Tested procedures, safety requirements, customer communication pathways, and fallback actions.
3. **Commercial and governance frameworks:** Contracting structures for flexibility, including pricing or incentive mechanisms. Verification, settlement, and compliance processes.
4. **Blueprints for BAU implementation:** Documented workflows, interface requirements, and system dependencies (e.g., ADMS/DERMS integration). Asset planning decision rules that incorporate flexibility on equal footing with traditional investment.

8.4.4 Distribution System Operator (DSO) Working with the Distribution Network Operator (DNO) (continued)

This structured handover allows the DNO to systematically incorporate NWA approaches into network planning and operations, scaling them across substations, feeders, or geographic regions as required.

As the Asset Management Plan is updated annually, new insights from our DSO-led pilots shape both medium- and long-term investment decisions. Over time:

- Traditional reinforcements in the AMP may evolve to include hybrid solutions, where NWAs complement conventional upgrades.
- Some listed major projects may incorporate NWA-first assessments, where flexibility provides early-stage optionality and reduces scope or timing of physical reinforcement.
- Priority projects may transition fully from traditional CAPEX to flexibility-led deferral, where DER-based capacity relief is proven feasible and cost-effective.
- Network risk assessments will increasingly reflect the DSO's enhanced visibility and dynamic modelling of LV and MV networks.

This dynamic planning approach ensures that Counties Energy makes balanced, evidence-based investment decisions that optimise lifecycle value for customers while maintaining resilience and affordability.

Collaboration between the DSO and DNO also strengthens Counties Energy's ability to operate within a broader whole-of-system model. As coordination with aggregators, retailers, Transpower (TSO), and other market participants increases, the DNO benefits from:

- Improved situational awareness through high-frequency data and digital tools.
- Access to local flexibility that can be stacked with national market signals.
- Enhanced resilience, especially during peak periods, outages, or supply scarcity events.
- Better alignment between distribution and transmission planning, enabled by shared standards and interoperability developed in DSO–TSO projects.

This integrated model ensures that as the region electrifies, Counties Energy remains well positioned to manage uncertainty, minimise costs, and deliver greater value to customers and communities.

09
Our Performance

9.1 About This Chapter

This chapter provides an overview of the Counties Energy performance against targets, including our delivery capabilities, expenditure performance, and performance to plan.

9.2 Capability to Deliver the Plan

Deliverability has been carefully considered in the development of this plan and is underpinned by cross functional review, resource and workload planning, debt management, and detailed analysis against our historical investment levels.

9.2.1 Cross Functional Review & Resource Balancing

The plan has been developed collaboratively by our engineering, operational, and delivery teams to ensure it is practical, achievable, and aligned with available resourcing. The programme has been structured by work type and skill requirements, enabling targeted review and validation by subject matter experts across the organisation.

Where appropriate, work has been deliberately phased across financial years to create a balanced and sustainable long-term workload. This approach reduces delivery risk, supports workforce stability, and ensures our programme can be delivered efficiently without unnecessary volatility in resourcing.

9.2.2 Debt Profiling

The forecast debt requirements associated with this plan have been tested across a range of interest rate and broader economic scenarios. This provides assurance that our proposed investment programme is financially prudent, supportable, and sustainable over the long term.

9.2.3 Analysis Against Previous Years

The Franklin region has experienced significant growth over the past decade, resulting in an elevated capital expenditure profile. Between 2020 and 2024, average annual capital expenditure was $66.9 million (in constant dollar terms), with a peak of $70.9 million in 2022. This peak reflected the convergence of high substation investment, elevated customer-driven activity, and the one-off rebuild of the Counties Energy office building.

In contrast, total capital expenditure is forecast to exceed $50 million per annum only twice in the 10-year planning period. This reduction primarily reflects two ongoing trends:

- **the completion of major investment programmes, including our Eastern Network Renewal programme (encompassing Barber Road substation) and the establishment or reconstruction of substations at Pōkeno, Waiuku, and Tuakau; and**
- **a general easing in the exceptionally high level of property development observed in the early 2020s.**

As a result, forecast expenditure across our forward programme is materially lower than historical peak levels, providing a high degree of confidence in the plan's overall deliverability.

9.3 Expenditure Performance against Past Plans

Assessing performance against previous plans is a part of our continual improvement in asset management and overall business performance.

This chapter provides an assessment of our performance against the last complete financial year (FY25) as well as comparing against the forecast performance of the current financial year at the time of writing.

Our financial year runs from 1 April to 31 March, which aligns with the regulatory year. Network performance and other service levels are compared against previous targets in section 4.10.

9.3.1 FY25 Performance to Plan

The plan has been developed collaboratively by our engineering, operational, and delivery teams to ensure it is practical, achievable, and aligned with available resourcing. The programme has been structured by work type and skill requirements, enabling targeted review and validation by subject matter experts across the organisation.

Where appropriate, work has been deliberately phased across financial years to create a balanced and sustainable long-term workload. This approach reduces delivery risk, supports workforce stability, and ensures our programme can be delivered efficiently without unnecessary volatility in resourcing.

9.3.1.1. Capital Expenditure FY25

Disclosure Category	Target ($000s)	Actual ($000s)	Variance	Reason for variance
Consumer connection	11,000	15,968	+45%	Higher than anticipated customer development volumes
System growth	5,621	1,529	-73%	Deferral of network investment to align with lower-than-expected increase in peak demand
Asset replacement and renewal	26,844	26,336	-2%	
Asset relocations	295	44	-85%	Lower than anticipated customer demand
Reliability, safety and environment	9,532	6,935	-27%	Slower than planned delivery of reliability programme
Non-network	6,202	7,056	+14%	Phasing of land acquisition work

Table 9.1 Capital Expenditure Performance FY25

9.3.1 FY25 Performance to Plan (continued)

9.3.1.2. Operational Expenditure FY25

Disclosure Category	Target ($000s)	Actual ($000s)	Variance	Reason for variance
Service interruptions and emergencies	3,078	3,260	6%	
Vegetation management	3,125	3,190	2%	
Routine and corrective maintenance and inspection	2,736	1,565	-43%	Delivery efficiencies and rephasing of non-urgent work to FY26
Asset replacement and renewal	1,033	1,073	4%	
System operations and network support	4,585	3,668	-20%	Combination of staff vacancies, lower consultancy costs and other savings
Business support	12,924	12,459	-4%	

Table 9.2 Operational Expenditure Performance FY25

9.3.1.3. Project Performance FY25 Plan Against Actual Asset Replacement

Project	Scope	Budget ($000s)	Status
Barber Road Substation	New 110kV/22kV substation to replace existing 33kV/11kV assets	1,950	Completed in FY26
Bombay - Ramarama Tower Line Refurbishment	Refurbish 110kV towers and conductor	1,690	Completed in FY26
Glenbrook Station Road Copper Replacement	Replacement of aging & poor condition conductor based on ARMM model	1,823	Completed in FY25
Grierson Place LV Rehabilitation	Replacement of aging & poor condition conductor	210	Completed in FY25
Karaka Substation Differential Communications Reinstatement	New protection fibre and updated protection scheme	1,900	Completed in FY25
Maioro Substation Rebuild	Replace or refurbish aging 33kV/11kV assets	600	Ongoing multi-year project, progressing to plan
Mercer RMU Replacement (Rollover)	Replacement of aging & poor condition asset	180	Completed in FY25
Ōpaheke Substation Renewal	Replacement of 22kV switchboard and associated auxiliary systems	1,164	Ongoing multi-year project, progressing to plan
Ōpaheke Subtransmission Transformer Refurbishment	Mid-life refurbishment of substation transformer	700	Completed in FY25

Table 9.3 Asset Replacement Project Performance FY25

9.3.1 FY25 Performance to Plan (continued)

9.3.1.3. Project Performance FY25 Plan Against Actual Asset Replacement (continued)

Project	Scope	Budget ($000s)	Status
Operational Technology Communications Network and Infrastructure Upgrade	Replacement of end-of-life asset	700	Ongoing multi-year project, progressing to plan
Portsmouth Road Swan Replacement	Replacement of aging & poor condition conductor based on ARMM model	2,168	Reprioritised at business case stage and deferred
Substation Seismic Strengthening	Building reinforcement programme	350	Ongoing multi-year project, progressing to plan
Tuakau Relay Replacement	Substation protection replacement and upgrade	350	Completed in FY25
Tuhimata Road Copper Replacement	Replacement of aging & poor condition conductor based on ARMM model	1,400	Completed in FY25
Woodleigh Road Conductor Replacement	Replacement of aging & poor condition conductor based on ARMM model	2,503	Completed in FY25

Table 9.3 Asset Replacement Project Performance FY25 (continued)

9.3.1.4. Growth

Project	Scope	Budget ($000s)	Status
Glenbrook - Waiuku 33kV Line Upgrade	Review cyclical rating of 33kV line, upgrade where necessary	200	Ongoing multi-year project, progressing to plan
Drury Feeder Reconfiguration	Connect two spurs of network to improve overall capacity	159	Completed in FY25
Hunua Reconfiguration	Connect two spurs of network to improve overall capacity	660	Completed in FY25
Network Battery Redeployment	Redeploy battery energy storage system	50	Ongoing multi-year project. Subject to performance of other similar pilots and trials in this space.
Ōpaheke 110kV Bus	Establish outdoor 110kV switchyard	1,628	Ongoing multi-year project, progressing to plan
Pōkeno Transformer Cables & Bay Controller Communications Aggregator	Civil structural enabling works on cables stand and communications scheme upgrade	300	Ongoing multi-year project, progressing to plan
Quarry Road Substation	Establish new 110kV to 22kV substation.	2,498	Ongoing multi-year project, deferred in line with slower than anticipated growth in network peak demand.

Table 9.4 Growth Project Performance FY25

9.3.1 FY25 Performance to Plan (continued)

9.3.1.4. Growth (continued)

Project	Scope	Budget ($000s)	Status
Manukau Heads Voltage Regulator Controller	Review voltage regulator settings and upgrade controller	100	Ongoing multi-year project, progressing to plan
Glenbrook Beach Voltage Regulator	Establish new voltage regulator	25	Cancelled due to change of customer requirements

Table 9.4 Growth Project Performance FY25 (continued)

9.3.1.5. Reliability

Project	Scope	Budget ($000s)	Status
Automation Rebuild	Deploy a variety of automation solutions across the network to improve reliability	5,477	Ongoing multi-year project, progressing to plan
Baker Road Autotransformer	Replacement of end-of-life assets & creating a link between feeders	206	To be completed in FY26
Church Corner Network Reliability Improvement	Minor network modification to improve reliability	416	Completed in FY26
Fault Passage Indicator Deployment	Deploy new equipment on the network to improve reliability	583	Ongoing multi-year project, progressing to plan
Network Isolation Point Improvement	Deploy new equipment on the network to improve reliability	1,253	Multi-year project completed in FY26
New Reclosers (Glen Murray & Onewhero)	Minor network modification to improve reliability	300	Completed in FY26
Pukekohe West Reliability	Minor network modification to improve reliability	269	Scheduled for FY29
Vector SCADA Visibility	Automation and communication to improve operability of network during backfeed scenario.	50	Scheduled for FY27
Recloser Air Gap	Deploy new equipment on the network to improve reliability	89	Completed in FY26
Swing Link Permanent Solution	Deploy new equipment on the network to improve reliability	189	Completed in FY26

Table 9.5 Reliability Project Performance FY25

9.3.2 FY26 Forecast Performance to Plan

9.3.2.1. Capital Expenditure FY26

Disclosure Category	Target ($000s)	Actual ($000s)	Variance	Reason for variance
Consumer connection	11,000	12,800	+16%	Higher than anticipated customer development volumes
System growth	1,426	1,542	+8%	
Asset replacement and renewal	24,060	24,498	+2%	
Asset relocations	384	84	-78%	Lower than anticipated customer demand
Reliability, safety and environment	7,267	5,623	-23%	Slower than planned delivery of reliability programme
Non-network	9,955	7,133	-10%	Slower than forecast delivery of software projects

Table 9.6 Capital Expenditure Forecast Performance FY26

9.3.2.2. Operational Expenditure FY26

Disclosure Category	Target ($000s)	Actual ($000s)	Variance	Reason for variance
Service interruptions and emergencies	3,313	3,313	-	
Vegetation management	3,219	3,219	-	
Routine and corrective maintenance and inspection	2,576	2,446	-5%	Delivery efficiencies and lower than expected costs
Asset replacement and renewal	852	852	-	
System operations and network support	4,234	4,240	-	
Business support	15,221	14,297	-6%	Lower than expected software costs due to project timing

Table 9.7 Operational Expenditure Forecast Performance FY26

9.3.2 FY26 Forecast Performance to Plan (continued)

9.3.2.3. Forecast Project Performance FY26 Plan Against Actual Asset Replacement

Project	Scope	Budget ($000s)	Status
Bombay – Pukekohe North 110kV Insulator Replacement	Replacement of end-of-life asset	850	In progress expected to finish FY26
Bombay - Ramarama Tower Line Refurbishment	Refurbish 110kV towers and conductor	850	Completed in FY26
Maioro Substation Rebuild	Replacement of end-of-life asset	100	Ongoing multi-year project
Barber Road Substation	New 110kV/22kV substation to replace existing 33kV/11kV assets	300	Completed in FY26
Ōpaheke Substation Renewal	Replacement of 22kV switchboard and associated auxiliary systems	3,350	Ongoing multi-year project, progressing to plan
Substation Seismic Strengthening	Building reinforcement programme	650	In progress expected to finish FY26
Tuakau Power Transformer Control Box Replacement	Replacement of end-of-life asset	200	In progress expected to finish FY26
Parsons Road Conductor Replacement	Replacement of end-of-life conductor	649	In progress expected to finish FY26
Stan Wright Road Conductor Replacement	Replacement of end-of-life conductor	657	In progress expected to finish FY26
Hamilton Road Conductor Replacement	Replacement of end-of-life conductor	1,575	Completed FY26
Buckland Road Conductor Replacement	Replacement of end-of-life conductor	1,640	In progress expected to finish FY26
Roulston and Graham Street Conductor Replacement	Replacement of end-of-life conductor	675	In progress expected to finish FY26
Ōpaheke Load Control Controller Renewal	Replacement of end-of-life asset	250	In progress expected to finish FY26

Table 9.8 Asset Replacement Project Performance FY26

9.3.2 FY26 Forecast Performance to Plan (continued)

9.3.2.4. Growth

Project	Scope	Budget ($000s)	Status
Glenbrook - Waiuku 33kV Line Upgrade	Review cyclical rating of 33kV line, upgrade where necessary	200	On hold due to customer demand reduction
Quarry Road Substation	Establish new 110kV to 22kV substation	500	Ongoing multi-year project, deferred in line with slower than anticipated growth in network peak demand
Network Battery Redeployment	Redeploy battery energy storage system	350	Ongoing multi-year project. Subject to performance of other similar pilots and trials in this space
Pōkeno Transformer Cable Resilience	Civil structural enabling works on cables stand	250	Forecast to complete in FY26
Waiau Pa Substation	Establish new 33kV to 11kV substation	100	Ongoing multi-year project, progressing to plan

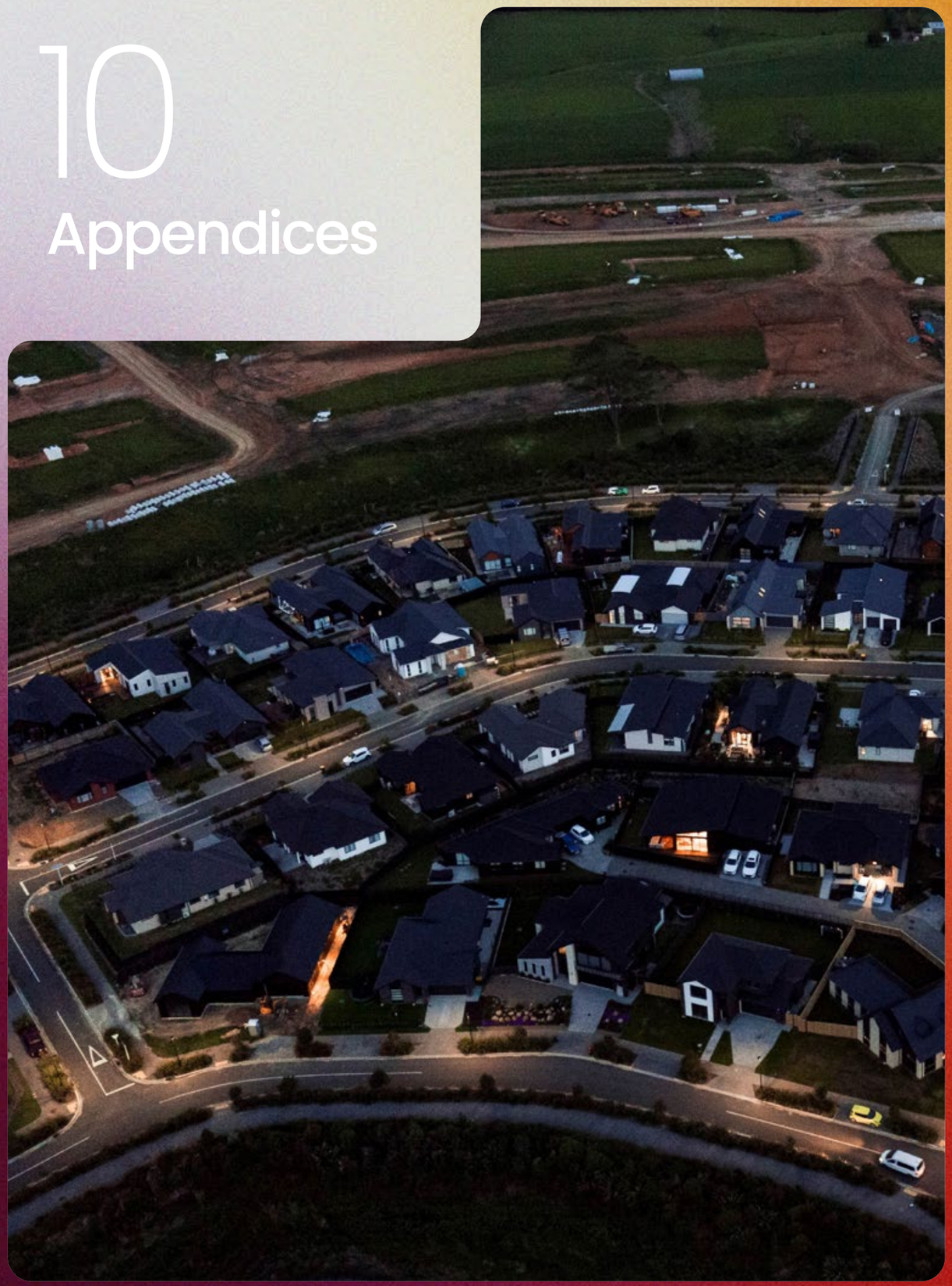
Table 9.9 Growth Project Performance FY26

9.3.2.5. Reliability

Project	Scope	Budget ($000s)	Status
Network Isolation Point Improvement	Targeted rollout of additional equipment to improve isolation	429	Multi-year project completed in FY26
Cape Hill Feeder Link	Network configuration change to improve network reliability	279	To be completed in FY26
Automation Rebuild	Targeted rollout of automation equipment to improve network reliability	3,467	Ongoing multi-year project, progressing to plan
Red Hill New Recloser	Targeted rollout of automation equipment to improve network reliability	92	Completed in FY26
Automation Rebuild - Quarry Road Feeders	Targeted rollout of automation equipment to improve network reliability	716	Ongoing – to be completed in FY26
Fault Passage Indicator Deployment	Targeted rollout of automation equipment to improve network reliability	584	Ongoing multi-year project, progressing to plan
Automation Rebuild - Paerata Rise	Targeted rollout of automation equipment to improve network reliability	448	Scheduled for FY26
Vector SCADA Visibility	Automation and communication to improve operability of network during backfeed scenario	50	Scheduled for FY27

Table 9.10 Reliability Project Performance FY26

10 Appendices



Appendix A

10.1 Regulatory Schedules

Schedule 11a: Report on Forecast Capital Expenditure

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34	31 Mar 35	31 Mar 36
11a(i): Expenditure on Assets Forecast											$000 (in nominal dollars)
Consumer connection	12,800	15,150	14,420	10,609	10,927	11,255	14,491	11,941	12,299	12,668	13,048
System growth	1,542	4,468	4,766	13,880	3,516	589	670	2,417	3,679	6,796	12,665
Asset replacement and renewal	24,498	23,462	20,953	19,993	19,865	21,105	20,375	22,387	29,301	32,695	26,176
Asset relocations	84	411	423	436	449	462	476	490	505	520	536
Reliability, safety and environment:											
Quality of supply	5,120	3,056	3,449	1,621	2,449	1,091	1,522	901	928	956	984
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	503	488	502	2,722	751	773	565	582	599	617	636
Total reliability, safety and environment	5,623	3,543	3,951	4,343	3,200	1,865	2,087	1,483	1,527	1,573	1,620
Expenditure on network assets	44,547	47,034	44,514	49,261	37,957	35,276	38,099	38,717	47,311	54,251	54,045
Expenditure on non-network assets	7,133	7,081	5,595	5,707	5,821	5,937	6,056	6,177	6,301	6,427	6,555
Expenditure on assets	51,680	54,115	50,109	54,968	43,778	41,213	44,155	44,895	53,612	60,678	60,600
plus Cost of financing	227	165	171	207	155	139	163	161	190	212	205
less Value of capital contributions	13,050	15,000	14,420	10,609	10,927	11,255	14,491	11,941	12,299	12,668	13,048
plus Value of vested assets											
Capital expenditure forecast	38,857	39,280	35,859	44,565	33,005	30,098	29,827	33,115	41,504	48,222	47,758
Assets commissioned	38,857	39,280	35,859	44,565	33,005	30,098	29,827	33,115	41,504	48,222	47,758

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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 11a: Report on Forecast Capital Expenditure (continued)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34	31 Mar 35	31 Mar 36
											$000 (in constant prices)
Consumer connection	12,800	15,150	14,000	10,000	10,000	10,000	12,500	10,000	10,000	10,000	10,000
System growth	1,542	4,468	4,628	13,083	3,218	524	578	2,024	2,992	5,365	9,707
Asset replacement and renewal	24,498	23,462	20,343	18,845	18,179	18,751	17,576	18,749	23,825	25,810	20,062
Asset relocations	84	411	411	411	411	411	411	411	411	411	411
Reliability, safety and environment:											
Quality of supply	5,120	3,056	3,349	1,528	2,241	970	1,313	755	755	755	755
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	503	488	487	2,566	687	687	487	487	487	487	487
Total reliability, safety and environment	5,623	3,543	3,836	4,094	2,928	1,657	1,800	1,242	1,242	1,242	1,242
Expenditure on network assets	44,547	47,034	43,217	46,433	34,736	31,342	32,865	32,425	38,469	42,826	41,421
Expenditure on non-network assets	7,133	7,081	5,485	5,485	5,485	5,485	5,485	5,485	5,485	5,485	5,485
Expenditure on assets	51,680	54,115	48,702	51,918	40,221	36,827	38,350	37,911	43,954	48,312	46,906
Subcomponents of expenditure on assets (where known)											
Energy efficiency and demand-side management, reduction of energy losses											
Overhead to underground conversion											
Research and development											

10.1 Appendix A – Regulatory Schedules (continued)

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 11a: Report on Forecast Capital Expenditure (continued)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34	31 Mar 35	31 Mar 36
Difference between nominal and constant price forecasts											$000 (in constant prices)
Consumer connection	-	-	420	609	927	1,255	1,991	1,941	2,299	2,668	3,048
System growth	-	(0)	139	797	298	66	92	393	688	1,431	2,958
Asset replacement and renewal	-	(0)	610	1,148	1,686	2,353	2,799	3,638	5,477	6,885	6,114
Asset relocations	-	(0)	12	25	38	52	65	80	94	110	125
Reliability, safety and environment:											
Quality of supply	-	0	101	93	208	122	209	146	173	201	230
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	0	15	156	64	86	78	95	112	130	148
Total reliability, safety and environment	-	0	115	249	271	208	287	241	285	331	378
Expenditure on network assets	-	0	1,297	2,828	3,221	3,934	5,234	6,292	8,843	11,425	12,624
Expenditure on non-network assets	-	-	110	222	336	452	571	692	816	942	1,070
Expenditure on assets	-	0	1,406	3,049	3,557	4,386	5,805	6,984	9,658	12,366	13,694

Schedule 11a: Report on Forecast Capital Expenditure (continued)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
11a(ii): Consumer Connection						$000 (in constant prices)
Consumer types defined by EDB						
Urban residential	6,400	5,500	5,500	5,000	5,000	5,000
Urban commercial	2,560	6,350	5,200	2,000	2,000	2,000
Rural residential	2,176	1,870	1,870	1,700	1,700	1,700
Rural commercial	1,664	1,430	1,430	1,300	1,300	1,300
Consumer connection expenditure	12,800	15,150	14,000	10,000	10,000	10,000
less Capital contributions funding consumer connection	13,050	15,150	14,000	10,000	10,000	10,000
Capital contributions funding consumer connection	(250)	-	-	-	-	-

11a(iii): System Growth						$000 (in constant prices)
Subtransmission	1,311	1,627	1,000	3,200	-	-
Zone substations	169	2,550	3,300	6,850	50	50
Distribution and LV lines	15	200	200	2,851	2,949	200
Distribution and LV cables		-	-	-	-	-
Distribution substations and transformers	47	91	128	182	219	274
Distribution switchgear						
Other network assets						
System growth expenditure	1,542	4,468	4,628	13,083	3,218	524
less Capital contributions funding system growth						
System growth expenditure	1,542	4,468	4,628	13,083	3,218	524

Schedule 11a: Report on Forecast Capital Expenditure (continued)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
11a(iv): Asset Replacement and Renewal						$000 (in constant prices)
Subtransmission	1,278	1,420	20	20	20	20
Zone substations	3,940	2,700	455	50	50	550
Distribution and LV lines	15,210	16,889	15,525	16,412	15,848	15,780
Distribution and LV cables	118	840	840	840	840	840
Distribution substations and transformers	270	502	502	502	400	335
Distribution switchgear	610	937	972	992	992	1,167
Other network assets	3,072	175	2,030	30	30	60
Asset replacement and renewal expenditure	24,498	23,462	20,343	18,845	18,179	18,751
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	24,498	23,462	20,343	18,845	18,179	18,751

11a(v): Asset Relocations						$000 (in constant prices)
Project or programme						
Asset Relocations	84	411	411	411	411	411
All other project or programmes - asset relocations						
Asset relocations expenditure	84	411	411	411	411	411
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	84	411	411	411	411	411

Schedule 11a: Report on Forecast Capital Expenditure (continued)

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
11a(vi): Quality of Supply						**$000 (in constant prices)**
Project or programme						
Reliability Programme	5,120	3,056	3,349	1,528	2,241	970
All other projects or programmes - quality of supply						
Quality of supply expenditure	5,120	3,056	3,349	1,528	2,241	970
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	5,120	3,056	3,349	1,528	2,241	970

11a(vii): Legislative and Regulatory						**$000 (in constant prices)**
Project or programme						
Nil						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
11a(viii): Other Reliability, Safety and Environment						**$000 (in constant prices)**
Project or programme						
Voltage Management	330	379	379	379	379	379
Safety Compliance	173	109	108	308	308	308
Other		-	-	1,879	-	-
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	503	488	487	2,566	687	687
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	503	488	487	2,566	687	687

11a(ix): Non-Network Assets						**$000 (in constant prices)**
Routine expenditure						
Project or programme						
Property	1,379	2,056	882	882	882	882
Digital	5,344	4,928	4,191	4,191	4,191	4,191
Plant & Vehicles	410	98	412	412	412	412
All other projects or programmes - routine expenditure						
Routine expenditure	7,133	7,081	5,485	5,485	5,485	5,485
Atypical expenditure						
Project or programme						
All other projects or programmes - routine expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	7,133	7,081	5,485	5,485	5,485	5,485

Schedule 11b: Report on Forecast Operational Expenditure

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34	31 Mar 35	31 Mar 36
Operational Expenditure Forecast												**$000 (in nominal dollars)**
Service interruptions and emergencies		3,313	3,450	3,602	3,761	3,927	4,100	4,282	4,471	4,668	4,875	5,091
Vegetation management		3,219	3,233	3,233	3,330	3,258	3,188	3,284	3,382	3,484	3,588	3,696
Routine and corrective maintenance and inspection		2,446	2,885	3,043	2,732	3,306	3,046	3,187	3,773	3,492	3,646	3,821
Asset replacement and renewal		852	875	969	1,095	1,174	895	930	1,129	1,127	1,170	1,216
Network Opex		9,830	10,443	10,847	10,918	11,665	11,229	11,681	12,754	12,771	13,280	13,823
System operations and network support		4,240	4,147	4,242	4,348	4,457	4,568	4,682	4,799	4,919	5,042	5,169
Business support		14,297	15,720	16,115	16,547	16,990	17,446	17,914	18,394	18,887	19,393	19,913
Non-network solutions provided by a related party or third party	*Not required before DY2025*											
Non-network opex		18,538	19,867	20,967	22,167	23,436	24,777	26,195	27,694	29,279	30,954	32,726
Operational expenditure		28,368	30,310	31,814	33,085	35,101	36,006	37,876	40,448	42,050	44,234	46,549

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10-year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11b) as a specific value rather than ranges. If EDBs wish to provide any supporting information about these values, this may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 11b: Report on Forecast Operational Expenditure (continued)

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34	31 Mar 35	31 Mar 36
Operational Expenditure Forecast												$000 (in constant prices)
Service interruptions and emergencies		3,313	3,450	3,497	3,545	3,594	3,643	3,693	3,744	3,796	3,848	3,902
Vegetation management		3,219	3,233	3,139	3,139	2,982	2,833	2,833	2,833	2,833	2,833	2,833
Routine and corrective maintenance and inspection		2,446	2,885	2,954	2,575	3,025	2,706	2,749	3,160	2,839	2,878	2,928
Asset replacement and renewal		852	875	941	1,032	1,075	795	802	945	916	924	932
Network Opex		9,830	10,443	10,531	10,291	10,675	9,977	10,077	10,682	10,384	10,483	10,594
System operations and network support		4,240	4,147	4,242	4,348	4,457	4,568	4,682	4,799	4,919	5,042	5,169
Business support		14,297	15,720	16,115	16,547	16,990	17,446	17,914	18,394	18,887	19,393	19,913
Non-network solutions provided by a related party or third party	*Not required before DY2025*											
Non-network opex		18,538	19,867	20,357	20,895	21,447	22,014	22,596	23,193	23,806	24,436	25,082
Operational expenditure		28,368	30,310	30,887	31,186	32,122	31,991	32,672	33,875	34,190	34,919	35,676

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34	31 Mar 35	31 Mar 36
Subcomponents of operational expenditure (where known)											$000 (in constant prices)
Energy efficiency and demand-side management, reduction of energy losses											
Direct billing*											
Research and Development											
Insurance	750	825	874	927	982	1,041	1,104	1,170	1,240	1,315	1,394

** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 11b: Report on Forecast Operational Expenditure (continued)

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33	31 Mar 34	31 Mar 35	31 Mar 36
Difference between nominal and real forecasts												$000 (in constant prices)
Service interruptions and emergencies		-	-	105	216	333	457	588	727	873	1,027	1,189
Vegetation management		-	-	94	191	276	356	451	550	651	756	863
Routine and corrective maintenance and inspection		-	-	89	157	281	340	438	613	653	768	892
Asset replacement and renewal		-	-	28	63	100	100	128	183	211	246	284
Network Opex		-	-	316	627	990	1,252	1,605	2,073	2,387	2,797	3,229
System operations and network support		-	-	127	265	413	573	746	931	1,131	1,345	1,575
Business support		-	-	483	1,008	1,575	2,190	2,853	3,569	4,342	5,174	6,069
Non-network solutions provided by a related party or third party	*Not required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
Non-network opex		-	-	611	1,272	1,989	2,763	3,599	4,501	5,472	6,519	7,644
Operational expenditure		-	-	927	1,899	2,979	4,015	5,204	6,574	7,859	9,315	10,873

Commentary on options and considerations made in the assessment of forecast expenditure

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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 12a:
Report on Asset Condition

Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade) H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
All	Overhead Line	Concrete poles / steel structure	No.	7.92%	0.29%	0.87%	54.28%	35.01%	1.64%	3	4.83%
All	Overhead Line	Wood poles	No.	12.58%	-	-	73.84%	10.93%	2.65%	3	9.60%
All	Overhead Line	Other pole types	No.	20.75%	-	-	1.89%	7.55%	69.81%	3	17.24%
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	9.55%	63.39%	24.55%	2.51%	-	3	-
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	37.72%	62.28%	-	3	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	1.89%	2.21%	95.90%	-	3	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (oil pressurised)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (gas pressurised)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	100.00%	-	4	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (oil pressurised)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (gas Pressurised)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	N/A	-
HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	N/A	-
HV	Zone Substation Buildings	Zone substations up to 66kV	No.	25.00%	25.00%	25.00%	25.00%	-	-	3	50.00%
HV	Zone Substation Buildings	Zone substations 110kV+	No.	-	-	20.00%	60.00%	20.00%	-	3	-
HV	Zone Substation Switchgear	22/33kV CB (indoor)	No.	-	-	-	-	-	-	N/A	-
HV	Zone Substation Switchgear	22/33kV CB (outdoor)	No.	-	-	-	100.00%	-	-	3	33.33%
HV	Zone Substation Switchgear	33kV Switch (ground mounted)	No.	-	-	-	-	-	-	N/A	-
HV	Zone Substation Switchgear	33kV Switch (pole mounted)	No.		55.55%	-	5.56%	38.89%	-	3	33.33%
HV	Zone Substation Switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
HV	Zone Substation Switchgear	50/66/110kV CB (indoor)	No.	-	-	-	100.00%	-	-	N/A	-
HV	Zone Substation Switchgear	50/66/110kV CB (outdoor)	No.	-	-	-	83.33%	16.67%	-	3	-
HV	Zone Substation Switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	6.12%	8.16%	12.24%	60.20%	13.27%	-	3	25.51%
HV	Zone Substation Switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-

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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 12a:
Report on Asset Condition (continued)

Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade)							
				H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	17.65%	17.65%	23.53%	41.18%	-	3	11.76%
HV	Distribution Line	Distribution OH Open Wire Conductor	km	5.56%	1.26%	2.48%	50.73%	37.51%	2.46%	3	6.64%
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	N/A	-
HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.11%	0.12%	8.44%	21.21%	69.18%	0.94%	3	1.20%
HV	Distribution Cable	Distribution UG PILC	km	-	0.58%	26.02%	65.91%	7.49%	-	3	-
HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	49.82%	50.06%	0.12%	4	-
HV	Distribution Switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	11.90%	7.14%	47.62%	33.33%	-	3	11.90%
HV	Distribution Switchgear	3.3/6.6/11/22kV CB (indoor)	No.	-	-	-	-	-	-	N/A	-
HV	Distribution Switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	12.16%	18.91%	10.69%	28.04%	29.12%	1.08%	3	7.44%
HV	Distribution Switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	-	N/A	-
HV	Distribution Switchgear	3.3/6.6/11/22kV RMU	No.	0.60%	1.60%	8.62%	40.48%	48.50%	0.20%	3	2.00%
HV	Distribution Transformer	Pole Mounted Transformer	No.	3.31%	12.07%	30.95%	37.39%	16.16%	0.13%	3	3.13%
HV	Distribution Transformer	Ground Mounted Transformer	No.	0.45%	4.54%	30.79%	42.05%	21.34%	0.82%	3	1.36%
HV	Distribution Transformer	Voltage regulators	No.	-	-	-	26.67%	73.33%	-	4	-
HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.63%	4.07%	30.86%	42.26%	21.36%	0.81%	4	1.36%
LV	LV Line	LV OH Conductor	km	0.01%	0.38%	0.91%	8.22%	6.43%	84.04%	2	3.73%
LV	LV Cable	LV UG Cable	km	1.05%	0.38%	11.99%	21.52%	49.70%	15.35%	2	0.20%
LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	0.49%	4.57%	89.39%	5.56%	3	-
LV	Connections	OH/UG consumer service connections	No.	3.60%	0.98%	11.24%	18.22%	47.42%	18.54%	2	2.05%
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	9.14%	1.08%	8.60%	50.54%	30.65%	-	3	21.51%
All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	100.00%	-	4	-
All	Capacitor Banks	Capacitors including controls	No.	-	-	64.71%	23.53%	11.76%	-	3	-
All	Load Control	Centralised plant	Lot	-	-	66.67%	16.67%	16.67%	-	3	-
All	Load Control	Relays	No.	64.35%	17.43%	14.70%	3.49%	0.03%	-	3	-
All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 12b:
Report on Forecast Capacity

12b(i): System Growth – Zone Substations

		Not Required after DY2024	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*	*Not Required after DY2024*
Existing Zone Substations	**Current peak load (MVA)**	**Installed firm Capacity (MVA)**	**Security of Supply Classification (type)**	**Transfer Capacity (MVA)**	**Utilisation of Installed Firm Capacity (%)**	**Installed Firm Capacity +5 years (MVA)**	**Utilisation of Installed Firm Capacity +5 years (%)**
Barber Road	12				-		
Ōpaheke	32				-		
Pōkeno	12				-		
Pukekohe	39				-		
Tuakau	13				-		
Karaka	12				-		
Maioro	9				-		
Waiuku	17				-		

Not Required after DY2024	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*							
Installed Firm Capacity Constraint +5 years (cause)	**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)**							
	Winter	40	N-1	No constraint	28	Winter	27	N-1							
	Winter	40	N-1	No constraint	8	Winter	17	N-1							
	Summer	40	N-1	No constraint	28	Summer	22	N-1							
	Winter	60	N-1	No constraint	21	Winter	16	N-1							
	Winter	40	N-1	No constraint	27	Winter	26	N-1							
	Winter	20	N-1	No constraint	8	Winter	5	N-1							
	Summer	9	N	No constraint	0	Summer	-	N							
	Winter	20	N-1	No constraint	3	Winter	11	N-1							

Schedule 12b:
Report on Forecast Capacity (continued)

12b(i): System Growth – Zone Substations

	Not Required before DY2025	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	
Existing Zone Substations	**Peak load period +10 yrs**	**Min. available capacity +10 yrs (MVA)**	**Max. available capacity +10 yrs (MVA)**	**Security of supply classification +10 yrs (type)**	**Forecast constraint type**	**Year of any forecast constraint**	**Constraint primary cause**	**Constraint solution type**	**Constraint solution progress**	**Temporary constraint solution remaining lifespan**	**Explanation**
Barber Road	Winter	26	26	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
Ōpaheke	Winter	3	14	N-1	Security	3	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Transformer upgrade to be followed by establishment of an additional zone substation
Pōkeno	Summer	18	21	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
Pukekohe	Winter	10	14	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
Tuakau	Winter	25	25	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
Karaka	Winter	3	3	N-1	No constraint	10+	Not applicable	Not required	Not applicable	Not applicable	
Maioro	Summer	-1	0	N	Capacity	9	Zone substation transformer	Undecided	Planning stage	Not applicable	Ongoing commercial discussions with the large customer supplied from this substation
Waiuku	Winter	9	11	N-1	Security	9	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Constraint will be managed by using cyclic ratings and flexibility as required in the short term, followed by a network upgrade. For the purpose of this schedule, the security constraint in Year 9 is assumed as resolved for the +10 "Available Capacity" figures.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 12c:
Report on Forecast
Network Demand

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
12c(i): Consumer Connections						Number of Connections
Number of ICPs connected during year by consumer type						
Standard domestic	822	937	930	935	890	858
Low user domestic	101	-	-	-	-	-
Mass market business	5	5	5	5	5	5
Time of use business	12	15	18	20	20	20
Distributed streetlights						
Connections total	940	957	953	960	915	883
Distributed generation						
Number of connections made in year	297	298	299	301	302	304
Capacity of distributed generation installed in year (MVA)	2	5	4	5	2	2

12c(ii): System Demand

Maximum coincident system demand (MW)						
GXP demand	133	142	145	149	153	156
plus Distributed generation output at HV and above	8	9	9	9	9	9
Maximum coincident system demand	141	151	154	158	162	165
less Net transfers to (from) other EDBs at HV and above						
Demand on system for supply to consumers' connection points	141	151	154	158	162	165

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.

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
12c(ii): System Demand						
Electricity volumes carried (GWh)						
Electricity supplied from GXPs	649	649	649	663	678	692
less Electricity exports to GXPs	-	-	-	-	-	-
plus Electricity supplied from distributed generation	69	83	98	98.5	99	101
less Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
Electricity entering system for supply to ICPs	718	732	747	761.5	777	793
less Total energy delivered to ICPs	689	703	717	731	746	761
Losses	29	29	30	31	31	32
Load factor	58%	55%	55%	55%	55%	55%
Loss ratio	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%

Schedule 12d:
Report on Forecast
Interruptions and Duration

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
SAIDI						
Class B (planned interruptions on the network)	161.3	159.2	149.0	192.4	148.2	143.0
Class C (unplanned interruptions on the network)	100.6	95.1	90.0	85.2	82.1	82.1
SAIFI						
Class B (planned interruptions on the network)	0.61	0.50	0.48	0.59	0.47	0.46
Class C (unplanned interruptions on the network)	1.65	1.55	1.46	1.39	1.33	1.33

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.

Schedule 13c:
Report on Asset Management Maturity

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	Asset management policy is in place, and was developed under consultation with senior managers and communicated with wider staff, refreshed to align with updated Corporate strategy.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	Counties Energy continues to demonstrate proactive and constructive asset-management practices, evidenced by new stakeholder engagement in updating the Asset Management Policy and strong cross-team communication behaviours that reflect a commitment to continuous improvement and organisational alignment.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	Counties Energy continues to demonstrate strong stewardship of its network assets, underpinned by deep organisational knowledge, experienced engineering ownership, and proactive condition monitoring practices. Our teams leverage decades of expertise to inform investment decisions and ensure that high-risk assets are responsibly managed. At the same time, we acknowledge opportunities to strengthen our asset management framework — particularly in refining asset classes and lifecycle strategies, formalising accountabilities, and improving the visibility and security of technical information.		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.

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Counties Energy treats its AMP as a genuine strategic planning tool, supported by a 20-year horizon, detailed feeder and back-feed modelling, and stronger justification for each proposed project through the use of asset-health methodologies such as ARRM. These practices enhance transparency and support more robust investment planning. However, uncertainties remain around the long-term economic modelling of customer-driven capital works and the future impact on the RAB.		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 optimise costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	Counties Energy is strengthening its financial and network planning discipline by tracking project expenditure mid-year, avoiding unnecessary investment, and using smart-meter insights to pinpoint where load is genuinely increasing. This more granular view has improved growth forecasting and supports better-targeted investment decisions. Economic evaluation and assessment of localised growth and risk are being further developed.		Plans will be ineffective unless they are communicated to all, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Counties Energy advances its investment planning by progressing named projects once their business cases are approved, with AMP inclusion providing early visibility before detailed development begins. The organisation is actively improving its estimating practices, resulting in reduced scope changes and tighter cost variations. Continuous improvement initiatives in this area will further strengthen forward planning.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	"What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)"	4	Counties Energy is strengthening the alignment between growth projects and asset renewals, recognising situations where aging assets may need replacement just a few years before planned growth works. The 2025 AMPCAMP provided a more detailed and structured approach to aligning projects, with teams coming better prepared with modelling and clear requirements. For example, while old switchgear at one substation was due for renewal, it was already known that a new substation would be required within five years. The outcome was to bring the growth project forward and determine appropriate contingency measures to keep the at-risk assets operating safely in the meantime.		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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset Management Maturity

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	A well-established business continuity framework is maintained, supported by annual drills and recent specialist reviews tested scenarios. A structured storm-response plan exists, including predefined switching contingencies for substation loss, while operational teams hold multiple response pathways for managing significant disruptions. Together, these measures strengthen organisational resilience and ensure preparedness for a range of high-impact events.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Counties Energy has established clear structures, documented scopes, and defined responsibilities that support effective delivery of its asset management plans, with strong coordination between Design and Delivery and increasing senior-level ownership through the developing SAMP. Opportunities exist in asset management capability, data stewardship and processes to further strengthen asset and project delivery.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Counties Energy benefits from strong capability across its design and delivery teams, supported by committed people who consistently step up to meet operational needs. Looking ahead, there is an opportunity to strengthen resilience by broadening support for key specialist roles — such as underground/substation engineering, communications, and GIS — and by allocating dedicated resource for improvement, documentation, and training activities. Enhancing capacity in these areas will help ensure that the organisation's solid delivery foundations are matched by equally robust support structures that enable continuous improvement and sustainable growth.		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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset Management Maturity (continued)

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Counties Energy's leadership has strengthened awareness of asset management expectations across teams, demonstrated through tangible improvements such as shorter outage durations, better return-to-service compliance, and more accurate planning practices that compare actual effort against estimates. Teams also receive clear guidance on quality and cost-efficiency, reflecting the organisation's customer-owned ethos. Enhancing the consistency and timeliness of resolving minor non-conformances will help maintain the strong performance momentum already building across teams.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	Counties Energy maintains strong working relationships with its contracting partners, supported by long-standing engagement, clear master service agreements, and thorough onboarding processes that embed safety and operational expectations. These established partnerships, along with effective verification systems and tendering activities, contribute to reliable delivery across outsourced workstreams.		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 could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	Counties Energy continues to strengthen capability in the field through frequent audits by operational managers, which reinforce safe work practices, technical quality and consistent documentation. Teams are supported by improving guidance, better work quality, and a focused effort to reduce high-impact defects, contributing to more efficient delivery. To build on this progress, the organisation has an opportunity to accelerate the adoption and effective use of new systems, improve access to information for field staff, establish a consistent approach to process and information management, and introduce stronger change-management support so teams are confident in both their processes and the tools that enable them.		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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	Counties Energy benefits from bespoke training, a well-structured graduate programme that rotates new engineers through key operational areas, and the use of registered training organisations to support fault and electrical training. These initiatives help build practical knowledge early and reinforce field-ready skills.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organisation 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	Counties Energy maintains strong links to recognised industry bodies, drawing on guidance and professional resources from the Asset Management Council of Australia, as well as material from EEA and CIGRE to inform its practices. The organisation also benefits from having several personnel accredited through WPiAM and the Institute of Asset Management, supporting a lift in asset-management professionalism and alignment with global good practice.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. Organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	Counties Energy maintains several core information systems that support communication and visibility of asset management data, with GIS serving as the authoritative record for network assets, Business Central holding the asset register for fleet and fixed assets, and system architecture information available when required. To further strengthen information access and consistency, the organisation has an opportunity to improve the completeness and adoption of standard reporting, enhance awareness of available reports, and rationalise duplicate versions to ensure staff and service providers can confidently rely on a single, accurate source of truth.		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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset Management Maturity (continued)

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	Counties Energy has established core documentation that supports the Asset Management System, including a developing project management framework, robust technical-change sign-off processes, and ongoing efforts within Operations to strengthen procedure documentation. The organisation is also prioritising its documentation workload based on risk, with the Quality team maintaining ownership of standards. To further enhance this foundation, Counties Energy has an opportunity to broaden the availability and clarity of procedural guidance, strengthen standards for risk and asset-management practices, and formalise documentation for technical change and master-data processes.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	Counties Energy has established a growing asset-information environment supported by key systems such as INDI, Business Central and GIS, with data increasingly consolidated through Snowflake to enable consistent reporting and improved visibility. Governance is strengthened through the Data Council, which meets regularly under a defined charter and has begun to streamline reporting and insights.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	Counties Energy maintains a structured approach to managing asset information and has a clear understanding of data quality. High-voltage data is reliable, while low-voltage data is an area for improvement. There is an opportunity to better coordinate access-window scheduling, improve visibility of outage-related constraints, and enhance data-quality reporting so it reflects both completeness and accuracy, further strengthening decision-making across the Asset Management System.		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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Counties Energy has access to useful inspection and condition information, enabling informed decisions on asset replacement. Inspection data is well-used, and rollout of Maximo will further enhance data-capture capability and strengthen accuracy and traceability.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/ or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	Counties Energy is strengthening its risk-management practices, with asset engineers developing asset-specific risk models, completing selected FMEAs, and applying structured defect-risk assessments using a consequence-likelihood-criticality matrix. A risk model for Maximo is underway.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	The organisation is strengthening how it uses risk assessment outcomes to guide resources, training, and competency development across construction, maintenance, emergency response, and other operational tasks. A draft Risk Management Standard aligned with IEC 31010 and a multi-disciplinary new-equipment approval process provide a solid foundation. Recent reviews have highlighted opportunities to improve staff understanding of risk processes and enhance project data collection, and these insights are helping shape more consistent training, clearer processes, and better integration of asset information into systems like Maximo.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how are requirements incorporated into the asset management system?	3	Counties Energy's legal teams advise on contract terms and conditions plus community issues such as land management.		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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset Management Maturity (continued)

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	The organisation has well-defined processes to support asset creation, acquisition, and enhancement, with clear workflows for both routine and complex projects. Routine projects benefit from strong standards, documentation, and coordinated stakeholder involvement, while complex projects begin with thorough feasibility studies to determine asset needs. Project approval includes safety, environmental, and training considerations. Enhancing engineering-controlled specifications and responsibilities further strengthens consistency and will support integration of assets across the network.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. T hey need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. procurement.	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	The organisation has strong processes for maintaining and inspecting assets, with effective scheduling, clear prioritisation, and close coordination between Delivery and Asset Planning. Vegetation, inspections, and defect work are managed efficiently through internal teams and contractors, with ongoing projects relating to customer-owned lines supporting consistent, safe and well-governed maintenance activities.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business.	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	The organisation monitors asset performance through established measures such as SAIDI/SAIFI, fault trends, dashboard reporting, and routine inspection cycles for distribution assets, transformers, switchgear, and substations. These insights drive future work based on risk, supported by existing data captured for distribution assets. Digitalising substation condition data, strengthening documentation, and enhancing the use of LV condition information will further optimise insights.		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 contractors 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).

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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?	3	The organisation has clear processes for managing and investigating asset-related failures and incidents, capturing fault details and repair status efficiently. Regular control-room reviews help identify recurring issues, and there is a strong focus on reducing SAIDI, ensuring customer-critical events are prioritised. Building on this, expanding analysis of wider fault trends — including frequent, short-duration HV faults — will further enhance proactive mitigation and strengthen overall network resilience.		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.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The organisation benefits from targeted field audits led by an experienced quality assessor, providing valuable insights and feeding into continuous improvement. Moving toward a more coordinated, scheduled audit programme across teams would help strengthen consistency and shared learning across the asset management system.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments.	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Steady improvement has been achieved across multiple areas as people chip away at small tasks. An example is the improvement of construction drawings which have more information etc. Improvement driven by emails and local discussions. Working groups are stood up for complex or extensive improvements.		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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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?	3	The organisation supports continual improvement through a wide range of governance groups, quality reports, registers and project review processes that help track issues and drive better asset, data and design outcomes. While the tools and information exist across the company, making improvement insights easier to surface and consolidate will further strengthen decision-making and whole-of-life asset performance.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/ team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	The organisation actively engages with emerging asset management technologies and industry groups, supported by staff with recognised AM qualifications, ensuring new practices and tools are continuously identified and assessed for their potential benefit.		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.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	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.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	"The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	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.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	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.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	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.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	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.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	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.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	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.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	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.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	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.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	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.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	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.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	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.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen."
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?	The organisation has not established documentation that describes the main elements of the asset management system.	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.	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.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not established documentation that describes the main elements of the asset management system.	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.	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.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation has not considered what asset management information is required.	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.	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.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	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.	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.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	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.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	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.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	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.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	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 activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/ incomplete).	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.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have process(es)/ procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	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.	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.	The organisation has 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, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

10.1 Appendix A – Regulatory Schedules (continued)

Schedule 13c:
Report on Asset
Management Maturity (continued)

Question No	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	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.	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.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	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.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	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.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	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.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	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.	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.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

10.1 Appendix A – Regulatory Schedules (continued)

10.1 Appendix A – Regulatory Schedules (continued)

10.1.1 Schedule 14a: Mandatory Explanatory Notes on Forecast Information

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

- 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)

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

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

The difference between nominal and constant prices reflects inflation of 3% per annum.

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

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

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

The difference between nominal and constant prices reflects inflation of 3% per annum.

Appendix B

10.2 Assessment Against Information Disclosure Requirements

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses			Ref within AMP
Contents of the AMP			
3	The AMP must include the following-		
3.1	A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;		
3.2	Details of the background and objectives of the EDB's asset management and planning processes;		1.1
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. The purpose statement must also include a statement of the objectives of the asset management and planning processes;	1.1
	3.3.2	states the corporate mission or vision as it relates to asset management;	2.3
	3.3.3	identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB;**	1.1
	3.3.4	states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and	1.1
	3.3.5	includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	1.1
The purpose statement should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest.			
	Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed;		1.1
Good asset management practice recognises the greater accuracy of short-to- medium term planning, and will allow for this in the AMP. The asset management planning information for the second 5 years of the AMP planning period need not be presented in the same detail as the first 5 years.			
3.5	The date that it was approved by the directors;		
3.6	A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-		3.4
	3.6.1	how the interests of stakeholders are identified	3.4
	3.6.2	what these interests are;	3.4
	3.6.3	how these interests are accommodated in asset management practices; and	3.4
	3.6.4	how conflicting interests are managed;	3.7
3.7	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-		
	3.7.1	governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to **directors;**	3.3
	3.7.2	executive—an indication of how the in-house asset management and planning organisation is structured; and	3.3

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses			Ref within AMP
Contents of the AMP (continued)			
	3.7.3	field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	3.3
3.8	All significant assumptions-		
	3.8.1	quantified where possible;	2.6
	3.8.2	clearly identified in a manner that makes their significance understandable to interested persons, including-	
	3.8.3	a description of changes proposed where the information is not based on the EDB's existing business;	2.6
	3.8.4	the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	2.6
	3.8.5	the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b;	2.6
3.9	A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;		2.6
3.10	An overview of asset management strategy and delivery;		1.1; 1.2; 4.8
To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify- • *how the asset management strategy is consistent with the EDB's other strategy and policies;* • *how the asset strategy takes into account the life cycle of the assets;* • *the link between the asset management strategy and the AMP; and* • *processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.*			
3.11	An overview of systems and information management data;		5.6; 8.3
	3.11.1	To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe-	
	(a)	the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;	4.9
	(b)	the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;	4.9
	(c)	the systems and controls to ensure the quality and accuracy of asset management information;	4.9
	(d)	the extent to which these systems, processes and controls are integrated;	4.9
	(e)	how asset management data informs the models that an EDB develops and uses to assess asset health; and	4.9
	(f)	how the outputs of these models are used in developing capital expenditure projections.	4.9

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses		Ref within AMP
Contents of the AMP (continued)		
	A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data;	8.3
Discussion of the limitations of asset management data is intended to enhance the transparency of the AMP and identify gaps in the asset management system.		
3.13	A description of the processes used within the EDB for-	
3.13.1	managing routine asset inspections and network maintenance;	6.4
3.13.2	planning and implementing network development projects; and	6.3
3.13.3	measuring network performance;	6.3; 6.4
	An overview of asset management documentation, controls and review processes.	4.4
To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-		
i.	*identify the documentation that describes the key components of the asset management system and the links between the key components;*	
ii.	*describe the processes developed around documentation, control and review of key components of the asset management system;*	
iii.	*where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;*	
iv.	*where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and*	
v.	*audit or review procedures undertaken in respect of the asset management system.*	
	An overview of communication and participation processes;	3.10
To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-		
i.	*communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants; and*	
ii.	*demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.*	
	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	1.6
	The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	Yes

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses		Ref within AMP
Assets covered		
4	The AMP must provide details of the assets covered, and non-network solutions including-	
	a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	1.3
4.1.1	the region(s) covered;	1.3
4.1.2	identification of large consumers that have a significant impact on network operations or asset management priorities;	6.4
4.1.3	description of the load characteristics for different parts of the network;	5.2; 7.2; 7.3
4.1.4	peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	6.4
4.2	a description of the network configuration, including-	
4.2.1	identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	6.4
4.2.2	a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	5.2; 6.4; 7.2; 7.3
4.2.3	a description of the distribution system, including the extent to which it is underground;	5.2
4.2.4	a brief description of the network's distribution substation arrangements;	5.2
4.2.5	a description of the low voltage network including the extent to which it is underground;	5.2
4.2.6	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and	5.3
4.2.7	a quantification of the contribution each non-network solution makes towards solving a network risk or constraint, and a description of the extent to which those non-network solutions are provided by a related party or third party.	8.4
To help clarify the network descriptions, network maps and a single line diagram of the subtransmission network should be made available to interested persons. These may be provided in the AMP or, alternatively, made available upon request with a statement to this effect made in the AMP.		
4.3	If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses		Ref within AMP
Network assets by category		
The AMP must describe the network assets by providing the following information for each asset category-		
4.4.1	voltage levels;	5.3
4.4.2	description and quantity of assets;	5.3
4.4.3	age profiles; and	5.3
4.4.4	a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.+	5.3
The asset categories discussed in clause 4.4 should include at least the following-		
4.5.1	the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	5.3; 5.6
4.5.2	assets owned by the EDB but installed at bulk electricity supply points owned by others;	5.3
4.5.3	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	5.6
4.5.4	other generation plant owned by the EDB.	N/A
Service Levels		
5	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	4.10
6	Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	4.10
7	Performance indicators for which targets have been defined in clause 5 should also include-	
	Consumer oriented indicators that preferably differentiate between different consumer types; and	4.10
	Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	4.10
8	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	4.10
9	Targets should be compared to historic values where available to provide context and scale to the reader.	4.10
10	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	N/A

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses		Ref within AMP
Service Levels (continued)		
Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.		
Network Development Planning		
11	AMPs must provide a detailed description of network development plans, including—	
11.1	A description of the planning criteria and assumptions for network development;	6.4
11.2	Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	6.4
11.3	A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	6.4
11.4	The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	N/A
11.4.1	the categories of assets and designs that are standardised; and	6.4
11.4.2	the approach used to identify standard designs;	6.4
11.5	A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	6.4
The energy efficient operation of the network could be promoted, for example, though network design strategies, demand side management strategies and asset purchasing strategies.		
11.6	A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network;	6.4
The criteria described should relate to the EDB's philosophy in managing planning risks.		
11.7	A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision;	6.3; 6.4
11.8	Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	6.4; 7.2; 7.3
11.8.1	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	6.4
11.8.2	provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/ developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	7.2; 7.3
11.8.3	identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	7.2; 7.3
11.8.4	discuss the impact on the load forecasts of any anticipated levels of non-network solutions in a network;	6.4; 8.4

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses		Ref within AMP
Network Development Planning (continued)		
11.9	Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	6.4
11.9.1	the reasons for choosing a selected option for projects where decisions have been made;	7.2; 7.3
11.9.2	the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and	7.2; 7.3
11.9.3	consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	6.4
11.10	A description and identification of the network development programme including non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	5.6, 7.2, 7.3, 7.4,7.5
11.10.1	a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	Throughout Chapter 7
11.10.2	a summary description of the programmes and projects planned for the following four years (where known); and	Throughout Chapter 7
11.10.3	an overview of the material projects being considered for the remainder of the AMP planning period;	Throughout Chapter 7
	For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next five years, alternative options should be discussed, including a detailed description of the investigations undertaken in respect of the potential for non-network solutions to be more cost effective than network augmentations and vice versa. This should specify if any third parties were approached in relation to non-network solutions, and if so, whether those third parties are related parties. For the purposes of disclosing the information described in clause 11.10.3, an EDB is not required to include commercially sensitive or confidential information.	
11.11	A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated; and	3.1; 4.8; 6.4
11.12	A description of the EDB's policies on non-network solutions, including-	6.4
11.12.1	economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation;	8.4
11.12.2	the potential for non-network solutions to address network problems or constraints; and	8.4
11.12.3	how information on current and forecast constraints (both load and injection) is shared with potential providers of non network solutions. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2 of Attachment A.	6.4

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses		Ref within AMP
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;	6.4
12.2	Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	6.4; 6.5
12.2.1	the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	6.5
12.2.2	any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	6.4; 6.5
12.2.3	budgets for maintenance activities broken down by asset category for the AMP planning period;	7.6
12.3	Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	
12.3.1	the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	6.4
12.3.2	a description of innovations that have deferred asset replacements;	6.4
12.3.3	a description of the projects currently underway or planned for the next 12 months;	Throughout Chapter 7
12.3.4	a summary of the projects planned for the following four years (where known); and	Throughout Chapter 7
12.3.5	an overview of other work being considered for the remainder of the AMP planning period; and	Throughout Chapter 7
12.4	The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	Throughout Chapter 7
12.5	Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of	6.4; 4.8
12.5.1	the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	6.4
12.5.2	the rationale for using the approach for each asset category	6.4
12.6	Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance.	4.8.8
12.7	The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB	8.4

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses		Ref within AMP
Non-Network Development, Maintenance and Renewal		
13	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including-	
13.1	a description of **non-network assets;**	5.6
13.2	development, maintenance and renewal policies that cover them;	5.6
13.3	a description of material capital expenditure projects (where known) planned for the next five years; and	5.6
13.4	a description of material maintenance and renewal projects (where known) planned for the next five years.	N/A
Risk Management		
14	**AMPs** must provide details of risk policies, assessment, and mitigation, including—	
14.1	Methods, details and conclusions of risk analysis;	4.11
14.2	Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	4.11
14.3	A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	4.11
14.4	Details of emergency response and contingency plans.	4.11
Asset risk management forms a component of an EDB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.		
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; referring to the most recent disclosures made under clause Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances; • commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction • or other problems experienced; and • commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.	9
15.2	An evaluation and comparison of actual service level performance against targeted performance; • in particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances.	4

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses		Ref within AMP
Evaluation of performance (continued)		
	An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	4.7
	An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	4.7
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; and	9.2
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP.	9.2
Requirements to provide qualitative information in narrative form		
17	AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
	Notice of planned and unplanned interruptions	
17.1	a description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned interruptions and unplanned interruptions;	3.9
	Voltage quality and constraints	
17.2	a description of the EDB's practices for:	
17.2.1	monitoring voltage, including:	4.8
(a)	the EDB's practices for monitoring voltage quality on its low voltage network	4.8
(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;	4.8
(c)	how the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder;	4.8
(d)	how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and	4.8
(e)	any plans for improvements to any of the practices outlined at clauses (a)-(d) above;	4.8
17.2.2	monitoring load and injection constraints, including:	
(a)	any challenges, and progress, towards collecting or procuring data required to inform the EDB of current and forecast constraints on its low voltage network, including historical consumption data; and	2.5; 4.9; 8.2
(b)	any analysis and modelling (including any assumptions and limitations) the EDB undertakes, or intends to undertake, with the data described in clause 17.2.2(a).	2.5; 4.9; 8.2

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses			Ref within AMP
Customer service practices			
There may be a degree of overlap between the information required under this clause and the information required in respect of customer charters under clause 2.5.3. For the avoidance of doubt, if there is overlap, EDBs should disclose the information in both places.			
17.3	a description of the EDB's customer service practices, including:		
17.3.1	the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services;		3.6; 3.9; 3.10; 3.11; 3.14; 4.8; 4.10.
17.3.2	the EDB's approach to planning and managing customer complaint resolution;		3.8
	Practices for connecting new consumers and altering existing connections		
17.4	a description of the EDB's practices for connecting consumers, including:		3.14
17.4.1	the EDB's approach to planning and management of-		
	(a)	connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and	3.14
	(b)	alterations to existing connections (offtake and injection connections);	3.14
17.4.2	how the EDB is seeking to minimise the cost to consumers of new or altered connections;		3.14
17.4.3	the EDB's approach to planning and managing communication with consumers about new or altered connections; and		3.14
17.4.4	commonly encountered delays and potential timeframes for different connections.		3.14
17.4.5	the EDB's approach to sharing information on current and forecast constraints (both load and injection) with potential new consumers. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2(a) of Attachment A.		3.14
New connections likely to have a significant impact on network operations or asset management priorities			
The following requirements focus on the EDB's capability and risk management regarding demand, generation, or storage capacity that the EDB considers are likely to have a significant impact on its network operations or asset management priorities. The EDB may consider voltage, network location, or other factors in making this assessment.			
17.5	A description of the following:		
17.5.1	how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including:		6.4; 7.2; 7.3
	(a)	how the EDB measures the scale and impact of new demand, generation, or storage capacity;	6.4; 7.2; 7.3
	(b)	how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account;	6.4; 7.2; 7.3

10.2 Appendix B – Assessment Against Information Disclosure Requirements (continued)

Appendix A Clauses			Ref within AMP
Customer service practices (continued)			
	(c)	how the EDB takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and	6.4; 7.2; 7.3
17.5.2	how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;		6.4
Innovation practices			
17.6	a description of the following:		
17.6.1	any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials;		8.2
17.6.2	the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;		8.0-8.4
17.6.3	how the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices;		8.4
17.6.4	how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and		8.4
17.6.5	the types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information.		8.3; 8.4
For the purpose of disclosing the information required under clauses 17.6.1- 17.6.5 above, an EDB is not required to include commercially sensitive or confidential information.			

Appendix C

10.3 Schedule 17. Certificate of year-beginning disclosure

10.3 Appendix C – Schedule 17 Certificate for Year-beginning Disclosures

We, Keith Watson and Hamish Stevens, being directors of Counties Energy Limited, certify that, having made all reasonable enquiry, to the best of our knowledge:

a. The following attached information of Counties Energy 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. Noting Appendix A Clause 15.1 is at risk of compliance due to limited articulation of mapping to previous projects, and Appendix A Clause 15.2 for service level targets that cannot be compared due to limited granularity in the 2023 AMP.

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, 11c, 12a 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Counties Energy Limited's corporate vision and strategy and are documented in retained records.

RKH Watson
(Director)

HW Stevens
(Director)

Certified this 25th Day of March 2026

Appendix D

10.4 Glossary of Terms

10.4 Appendix D – Glossary of Terms

Term	Description
A	Ampere – Unit of electrical current flow, or rate of flow of electrons
AAAC	All Aluminium Alloy Conductor
AAC	All Aluminium Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
ADMD	After Diversity Maximum Demand
ADMS	Advanced Distribution Management System
AI	Artificial Intelligence
AMMAT	Asset Management Maturity Assessment Tool
AMO	Asset Management Objectives
AMP	Asset Management Plan
AMP	Asset Management Policy
AMS	Asset Management System
APIs	Application Programming Interfaces
ARMM	Asset Risk Management Modelling
AUP(OP)	Auckland Unitary Plan (Operative in Part)
BAU	Business as usual
Bus	Busbar – A common connection point between multiple circuits and equipment.
Bushing	An electrical component that insulates a high-voltage conductor passing through a metal enclosure
CAIDI	Customer Average Interruption Duration Index – The average total duration of interruption per interrupted customer.
CAMA	Certified Asset Management Assessor
Capacity	The greatest amount of load a circuit can carry
Capex	Capital Expenditure
CB	Circuit Breaker
CCOO	Chief Customer & Operations Officer
CDEM	Civil Defence and Emergency Management
CELID	Customers Experiencing Long Interruption Durations
CEMI	Customers Experiencing Multiple Interruptions

10.4 Appendix D – Glossary of Terms (continued)

Term	Description
CER	Consumer Energy Resources
CNDO	Chief Network & Digital Officer
Conductor	'Wire' that carries the electricity and includes overhead lines which can be covered (insulated) or bare (not insulated), and underground cables which are insulated.
CRM	Customer Relationship Management
CT	Current Transformer
CVM	Customer Value Management model
CX	Customer Experience
DDO	Drop-out Fuse Switch or Disconnector/Isolator
DDP4	Default Price-Quality Paths 2024
Demand	The amount or energy sought by the consumers
DERMS	Distributed Energy Resource Management System
DERs	Distributed Energy Resources
DG	Distributed Generation
Disconnector	Also known as a disconnecting switch, isolator, or drop-out
Distribution Line	[Ref NZECP 34] Means works that are owned by Counties Energy used for the conveyance of electricity to one or more electrical installations.
DMS	Distribution Management Systems
DNO	Distribution Network Operator
DOE	Dynamic Operating Envelope
DPP	Default Price-Quality Path (Commerce Commission)
DQ	Data Quality
DSO	Distribution System Operator
EA	Electricity Authority
EAM	Enterprise Asset Management
Earth-fault	A circuit conductor unintentionally grounded
Easement	An easement is a right given to another person or entity to access upon land that person or entity does not own.
EDB	Electricity Distribution Business
EIEP5	Electricity Information Exchange Protocol

10.4 Appendix D – Glossary of Terms (continued)

Term	Description
ENA	Electricity Networks Association
Energy Retailer	An electrical energy supplier who has a User Supply Agreement with Counties Energy.
ERP	Enterprise Resource Planning
EV	Electric Vehicle
FAQs	Frequently Asked Questions
Fault	A physical condition that causes a device, component or network element to fail to perform in the required manner and includes third-party actions impacting the network.
Feeder	A physical grouping of conductors that originate from a district/zone substation circuit breaker.
FIEAust	Fellow of Engineers Australia
FISEAM	Fellow of the International Society of Engineering Asset Management
Fixed Asset	A purchase normally over $1,000 with an intended life cycle of at least over one year.
Flashover	A disruptive discharge around or over the surface of an insulator
FLISR	Fault Location, Isolation and Service Restoration
FMEA	Failure Mode & Effects Analysis
FMECA	Failure Mode, Effects & Criticality Analysis
FULSS	(Auckland) Future Urban Land Supply Strategy
FY	Financial Year, e.g. FY2026 is Financial Year 2026 which covers 1 April 2025 to 31 March 2026.
GFMAM	Global Forum on Maintenance and Asset Management
GIS	The Geographic Information System used for electronic mapping of the network.
GPD	Group Peak Demand
GWh	Giga-watt Hour
GXP	Grid Exit Point – The point at which Counties Energy equipment is deemed to connect to the Transpower Grid System.
Harmonics	Distortion of the sine wave which represents ideal AC power. Usually by super imposed higher frequencies.
HECA	High Energy Control Assessment
HEMS	Home Energy Management System
HILP	High Impact, Low Probability
HV	High Voltage – Any voltage exceeding 1000 V AC or 1500 V DC but usually pertaining to the 11 kV or 33 kV distribution system.
ICAM	Incident Cause Analysis Methodology

10.4 Appendix D – Glossary of Terms (continued)

Term	Description
ICP	Installation Control Point – A number that uniquely identifies each connection to an electrical lines network that is recorded in a national registry.
ID	Information Disclosure
IL4	Importance Level 4
INDI	Infrastructure and Network Data Interface
Injection Plant	Injects a signal onto 50Hz network, for controlling ripple relays
JSA	Job Safety Analysis
JSEA	Job Safety & Environmental Analysis
Kiosk	A small structure, often open on one or more sides
KPIs	Key Performance Indicators
kV	Kilo-volt
LiDAR	Light Detection and Ranging — A pulsed laser measurement technology
Lines	The LV and HV network of overhead and underground electricity conductors and cables and their associated equipment such as insulators, poles, crossarms, etc.
Load Break Switch	A switch that can be operated under load
LTI	Lost Time Injury
LTIFR	Lost Time Injury Frequency Rate
LTISR	Lost Time Injury Severity Rate
LV	Low Voltage – Any voltage exceeding 32 V AC or 115 V DC but not exceeding 1000 V AC or 1500 V DC.
MAIFI	Momentary Average Interruption Frequency Index
Maximum Demand	The highest value of the power or apparent power taken within the account period, such as, month or year.
MBIE	Ministry of Business, Innovation and Employment
MEP	Metering Equipment Provider
MfE	Ministry for the Environment
MVA	Mega-Volt-Ampere
MW	Mega-Watt
N-1 security	A load is said to have n-1 security if, for the loss of any one item of equipment, supply to that load is not interrupted or can be restored in the time taken to switch to alternate supplies.
NAV	ERP and accounting software package; version used in Counties Energy is Microsoft Dynamics NAV R2 2009.
NOC	Network Operation Centre

10.4 Appendix D – Glossary of Terms (continued)

Term	Description
NWA	Non-Wires Alternative
NZ CSSIE	New Zealand Control Systems Security Information Exchange
NZECP	New Zealand Electrical Code of Practice (A series of Publications)
OHSMS	Occupational Health and Safety Management System
Opex	Operating Expenditure
Outage	An interruption to the electricity supply
Overcurrent	Current in excess of the rated current of a conductor
Overhead	Above ground, pole-mounted conductor
Pillar (LV)	A plastic ground-mounted enclosure, usually found on a property's boundary containing the fuses for a service supply.
PRP	Parallel Redundancy Protocol
PSCP	Pre-Stressed Concrete Pole
PSMS	Public Safety Management System
PV	Photo-Voltaic — The conversion of light into electricity
Recloser	A piece of equipment on the distribution network work which automatically trips when a fault is detected (typically a tree touching the line) and recloses after a set time (minutes).
Reliability	The ability of an item to perform a required function under stated conditions for a stated period of time.
Residual Risk	The remaining level of risk after risk treatment measures has been taken
Risk	Probability (likelihood) and consequences, positive or negative, of an event. In some situations, risk is a deviation from the expected.
Risk Management	AS/NZS 4360 defines risk management as a term applied to a logical and systematic method of identifying, analysing, evaluating, treating, monitoring and communicating risk associated with any activity, function or process in a way that enables maximisation of benefits or minimisation of losses or detrimental effects.
RMA	Resource Management Act
RMMAT	Resilience Management Maturity Assessment Tool
RMU	Ring Main Unit
RTU	Remote Terminal Unit – Communications device used for relaying data from the field.
SAIDI	System Average Interruption Duration Index – The average total duration of interruption per connected customer.
SAIFI	System Average Interruption Frequency Index – The average number of interruptions per connected customers.
SANS	SysAdmin, Audit, Network and Security

10.4 Appendix D – Glossary of Terms (continued)

Term	Description
SCADA	Counties Energy's computerised Supervisory Control and Data Acquisition System, being the primary tool for monitoring and controlling access, and switching operations for Counties Energy's Network.
SF6	Sulphur hexafluoride – A gas used as an insulator in some switchgear
SIF	Significant Injuries and Fatalities
Smallworld	GIS-based system for mapping of the network
SMS	Short Message Service
SP	Service Provider
Stakeholder	People and organisations who may affect, be affected by, or perceive themselves to be affected by a decision or activity.
Standard	The document that prescribes the requirements with which the product or service has to conform. The criteria for acceptable levels of safety performance/behaviours set by Counties Energy, industry codes or relevant legislation.
Substation	An electrical facility where the voltage of incoming and outgoing circuits is changed and controlled.
Supplier	An organisation that provides a service or product to the customer
TOU	Time of Use pricing structure
Transpower	The national grid operator
TRIFR	Total Recordable Injury Frequency Rate
TRWG	Tree Regulations Working Group
UAVs	Unmanned Aerial Vehicle
UDL	Utilities Disputes Limited
UG	Underground
User	Any person or organisation using the Distribution System but excluding Transpower. It includes all customers, embedded generators, and where appropriate, Electricity Retailers acting on behalf of their customers.
Vegetation	Any trees or other plants threatening the Counties Energy Networks overhead lines.
VoLL	Value of Lost Load
Voltage Regulator	An electrical regulator device designed to automatically maintain a constant voltage level.
WPiAM	World Partners in Asset Management
XLPE	Cross-linked Polyethylene – A type of cable insulation
Zone Substation	Includes HV substations, switching stations, voltage regulators, ground-mounted HV switchgear, large industrial/commercial distribution substations, ripple control plant, and associated protection and controls.

Appendix E

10.6 List of Tables and Figures

10.6 Appendix E – List of Tables and Figures

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