

vector

2026—2036

electricity asset management plan

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SECTION 01

Introduction

1 – Introduction -

1.1 Asset management planning in a dynamic environment

Vector's 2026 Asset Management Plan (AMP) builds on the priorities we've set in recent years, including:

- maintaining and improving resilience and reliability for our customers
- building the network our customers will need in future as our region grows
- supporting decarbonisation and electrification of the economy
- making sure every dollar we spend produces the best value possible for our customers.

Through delivering on these priorities, we'll fulfil our role in enabling our customers, city and region to thrive.

Looking ahead, big trends like population growth, electrification, and climate change mean we need to build and reinforce the electricity distribution network significantly and quickly to keep it strong and reliable. At the same time, we want to enable efficient use of the network, where power use is less concentrated in peak periods, to help moderate the costs of network investment. Some investment decisions will take time as we understand the scale and timing of future needs. Factors like data centres, EV charging, and solar or battery systems can change demand patterns quickly, and regulatory and market changes may also affect how and when electricity is used, for example solar or EV uptake, or popular off-peak electricity plans.

Our approach focuses on flexibility, innovation, and efficiency. We choose options that avoid unnecessary costs and keep us agile. These principles guide the investment forecasts in this AMP.

In our last full AMP published in 2024, we highlighted ways to make our lines charges as affordable as possible by using existing infrastructure better and giving customers more choice about when they use power to reduce congestion. We've already applied this approach for some large customers with tailored, flexible connections. To extend these benefits to more customers, including households, we want to work with others to further develop the necessary technology, markets, and, in the case of EV charging, potentially regulation. We're committed to leading this work and our updated network roadmap shows how we're making this happen.

The infographic on the following page presents our 10-year capex forecast needs, broken down by the primary reasons for each category of expenditure. This visual summary helps to illustrate how our planned investments align with our strategic priorities and anticipated regional growth.

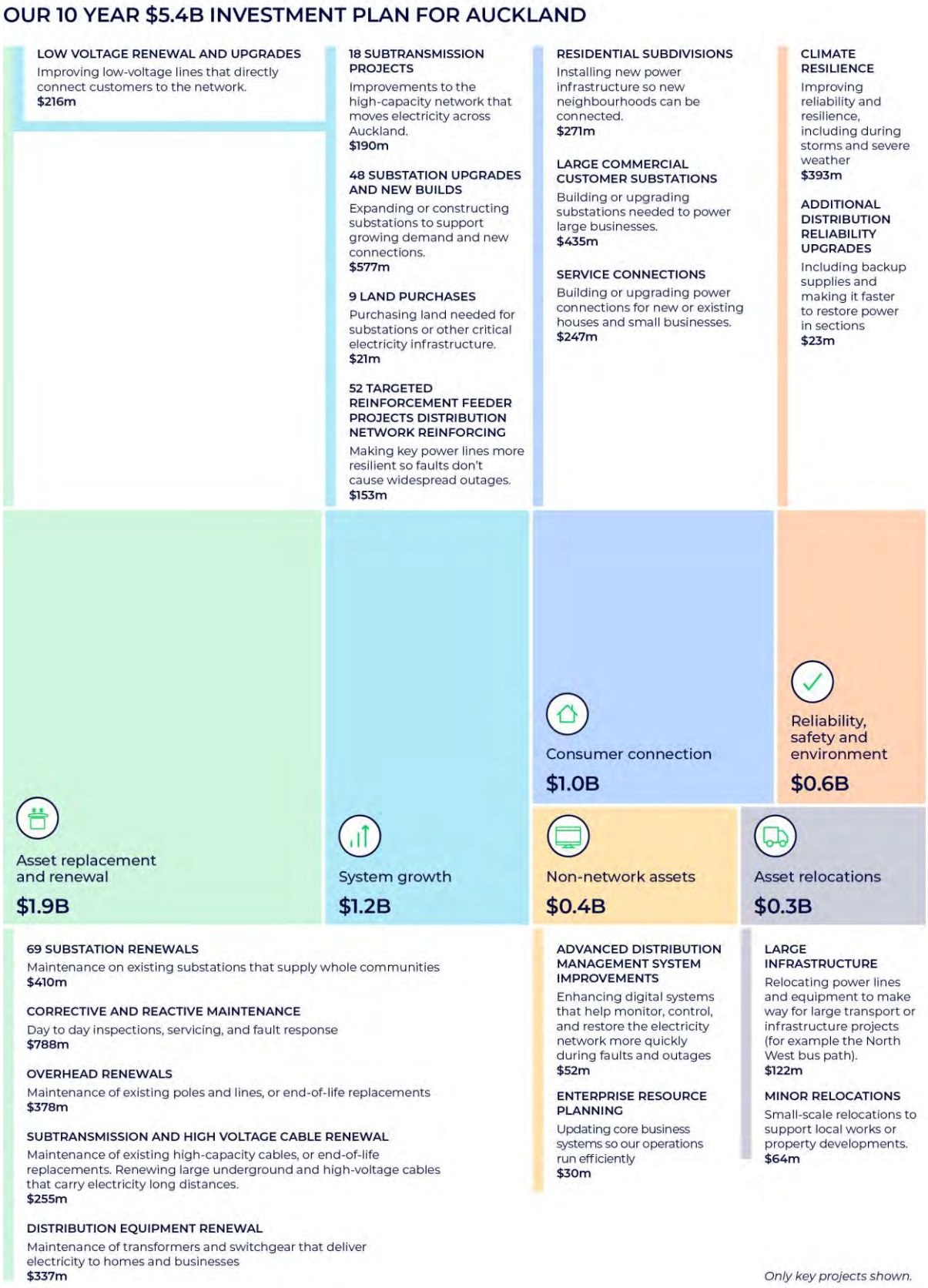


FIGURE 1-1: AMP 26 CAPEX FORECAST OF NEARLY $5.4B INVESTMENT IN THE NEXT 10 YEARS

1.2 The potential for change

While this AMP shows our current view of the investments needed to deliver for our customers, there are multiple areas where we may face ongoing, significant uncertainty over the scale and timing of investment need. In some cases, we may need to adjust our investment forecasts above what has already been approved under the current DPP4. We outline some of these significant uncertainties here, because where additional investment is needed, we may apply to the Commerce Commission for additional revenue to enable this under a reopener process.

1.2.1 ELECTRICITY AUTHORITY (EA) CHANGES TO CONTRIBUTIONS AND CONNECTION PROCESSES

[1]The Electricity Authority has recently introduced new regulations for connection charges which impacts capital contributions disclosed in AMP26. There are three new requirements that apply to applications for new connections and upgrades to existing connections from 1 April 2026:

- Connection enhancement cost allocation – distributors must set connection prices with reference to a 'minimum scheme' and any enhancement costs are paid by whichever party required them. The 'minimum scheme' is determined by the distributor with reference to their connection and operating standards. In addition, the customer may request consideration of a lower-cost flexible connection;
- Pioneer schemes – distributors must develop and publish a policy for establishing 'pioneer schemes'. Pioneer schemes look to ensure the applicant who funded a network extension receives rebates from those who follow and utilise the same network;
- Connection charge reconciliation – distributors must prepare a reconciliation that breaks down their quoted connection charge into incremental cost, incremental revenue and network cost components. This aims to improve transparency of how costs are allocated to new connections. To undertake such reconciliation, an EDB must publish capacity charge rates at five different tiers of the network where an EDB applies a system growth/capacity charge.

Starting from 1 April 2027, a further requirement applies to connection applications. If a distributor decides to assign upstream capacity costs to applicants, they must use published rates that reflect capacity usage as it occurs, rather than at the time of construction. This timeline gives distributors the opportunity to test capacity costing (used in charge reconciliations) during the period to 31 March 2027, before applying it when setting charges from 1 April 2027.

Currently, Vector charges upstream capacity costs to connection applicants via a system growth charge, also known as a development contribution. In AMP26, covering 1 April 2026 to 31 March 2027, we've assumed our existing system growth charge approach for all customer categories. For periods after 31 March 2027, AMP26 uses, as a default, the capacity rates recently determined by Vector under the Electricity Authority's regulated approach. This is on the basis that such rates reflect the best information available at the time of preparing AMP26. Readers of the AMP should however be aware that Vector (1) intends to test the data used and the approach for its recently published capacity rates during 1 April 2026 to 31 March 2027, (2) to better understand customer impacts and (3) continue to engage with the EA on its proposed further customer connection reforms that intend to oblige EDBs to target a balance point when determining individual customer contribution levels. It is anticipated that all these factors will shape our future capacity charging practices and ultimately our contribution recovery levels. Therefore, the capital contributions disclosed in AMP26 may materially change when disclosed again in AMP27.

1.2.2 COORDINATION ON BIG AUCKLAND INFRASTRUCTURE

Other infrastructure projects across Auckland are also influencing our electricity network planning and investment decisions. For example, Chorus's decision to retire the copper telecommunications network means that Vector will need to take responsibility for maintaining poles that will continue to carry our electricity assets, requiring additional coordination and investment. Major transport projects such as the East West Link, the proposed second harbour crossing, and Te Ara Hauāuru (Northwest Busway) will all impact both existing assets and future network requirements. We are actively engaging with the planners and delivery agencies behind these projects to ensure our network can adapt efficiently, manage risks, and maximise opportunities for shared infrastructure and reduced disruption to customers. However, these projects are also subject to complex planning processes across a range of stakeholders, which adds further uncertainty to our asset management planning.

1.2.3 TREE REGULATIONS

The 2023 Auckland floods and Cyclone Gabrielle were extreme events which prompted a review of future resilience expenditure for the electricity network. We're continuing our investment into projects that will improve the network resilience to climate change, where the investments deliver the most value to our customers. Trees are a particular concern as they cause the majority of outages during storms. Vegetation management regulations have long been outdated, and we welcome long over-due reform in this area. In April 2025 amendments to the Electricity (Hazards from Trees) Regulations 2003 were announced. While these changes will help lower the risk to power lines from trees, and so lead to fewer outages for customers, the costs will ultimately be borne by our customers. This is because the regulations still require that we pay for any actions taken to protect the electricity supply where the tree owner declares no interest on a tree, transferring the obligation to us to trim or remove the tree. If we determine that, to secure more customer benefit, more expenditure is required for tree management over and above our current forecasts, we may need to apply to the Commerce Commission for a reopener to secure the reliability and resilience benefits for our customers.

1.2.4 ENVIRONMENTAL PLANNING

This AMP period is subject to significant regulatory change with the repeal and replacement of the Resource Management Act 1991 (RMA). Because we have so many physical assets all over Auckland, we have a high exposure to changing built and natural environments, and uncertainty as we transition from the RMA to the new environmental planning system. Throughout this regulatory transition Auckland remains a highly complex and variable environment, due in part to significant growth in brownfield residential development around the network. As intensification leads to structures being physically closer to our network, we're some specific challenges become more common. These include more complexity around maintaining safe power

[1] A 'first mover' connection is one that provides up-front funding for a network extension that will serve other connections in future.

line clearances during and after construction, as well as ensuring adequate fire separation distances for oil insulated assets. We're also seeing competition between utilities for space to install new assets in transport corridors, particularly where significant routes are designated for future infrastructure construction and upgrades. This results in some exposure of more significant subtransmission and high voltage feeder projects to greater uncertainty, cost and delay.

Vector has been driving for regulatory change that both enables and protects electricity distribution activities under the RMA and pending replacement Acts. Significant progress has been made with the recently gazetted National Policy Statement for Electricity Networks (January 2026) and pending National Environmental Standards for Electricity Network Activities. These national direction instruments recognise the national, regional and local significance of electricity distribution networks and provide regulatory direction through the transition from the RMA to the new planning regime. We anticipate that changes could enable network construction, upgrades and operation, with greater certainty and fewer resource consents as well as protection from the effects of third-party activities that create conflict with safe and efficient network operation.

1.2.5 EV UPTAKE AND IMPACT ON DEMAND FROM CHARGING

While current EV uptake rates don't indicate significant impact from charging requirements, it's possible that the rate could increase dramatically in future. If this happens, and if customer flexibility requirements are not enabled or solely prioritise system-level outcomes, additional investment may be needed to accommodate increased demand clustered around charging times. We will continue monitoring the rate of EV uptake and work towards enabling customer flexibility, but if more investment is needed, we would apply under a reopener process.

1.2.6 CUSTOMERS SUBSTITUTING GAS FOR ELECTRICITY

There is continued uncertainty around the future of natural gas, driven in the near term by significant market uncertainty, scarcity of gas and rising costs, and in the longer term by a lack of a national gas transition plan. In this context there is potential for Government policy to accelerate or decelerate the rate of gas substitution to electricity and as a result provide clarity for infrastructure owners and customers alike. We expect an acceleration in commercial and industrial gas substitution if current government policy remains unchanged. We manage this uncertainty through engaging with customers, doing surveys to understand customer intent, and allowing for the potential impact of this in our scenario-based load forecasting model, but it remains very uncertain.

1.3 2026 AMP highlights

1.3.1 CUSTOMERS AND STAKEHOLDERS

We've made a number of changes that reinforce our commitment to put customers at the heart of what we do. We've created a central customer function which will set the direction for how we engage with our customers and understand their needs and expectations, drive continuous improvements across every interaction, and be guided by making it easy for our customers to interact with us. This central customer function is informed by a robust customer insights capability.

We're working through actions to improve customer experience and communications during storms, driven by our regular process to comprehensively review our performance after each significant event. And we're continuing with specific programmes to improve customer experience in areas that matter to customers, including with ongoing improvements in how we communicate planned and unplanned outages.

Energy retailers remain the primary bill relationship for most customers. They, along with a growing set of energy service providers (for example, flexibility providers, EV charging service providers, and technology platforms), will increasingly shape how customers use electricity, the prices they face, and the service experience they receive. These organisations are important stakeholders and partners for delivering customer outcomes - particularly affordability, reliability, and the safe integration of distributed energy resources - because they directly influence customer behaviour and technology settings "behind-the-meter".

1.3.2 MAKING IT EASY FOR NEW CUSTOMERS TO CONNECT

Vector has undertaken a comprehensive review of the connections process for its customers following feedback and our recognition of how important enabling connections is to Auckland. The purpose of this review was to identify specific areas within the process that could be improved to enhance the overall customer experience. As a result of this assessment, a number of changes were identified and are currently being implemented. These improvements are being rolled out in alignment with the introduction of new EA capital contribution connection process code changes. This coordinated approach ensures that all enhancements are cohesive and support both regulatory compliance and customer satisfaction.

The changes are designed to minimise delays encountered by customers during two critical stages of their connection requests: the application phase and the technical design phase. By streamlining these stages, Vector aims to provide greater transparency, a smoother and more efficient experience for customers seeking new connections or upgrades.

Additionally, the revised process acknowledges that customers are facing increasingly complex challenges, particularly as they consider integrating technologies such as electric vehicle (EV) charging infrastructure and solar power systems. The improvements are tailored to support customers in navigating these complexities and ensuring their connection requirements are met effectively.

1.3.3 SOLAR AND NEW VOLTAGE STANDARDS

The introduction of new voltage standards presents both opportunities and challenges for our network. As these changes may drive increased solar installations, we're working towards planning and operational practices that can accommodate this while maintaining network stability and reliability. The new voltage standards will require updates to our technical specifications and may necessitate targeted investments in network infrastructure, which would be paid for by all our customers. We are engaging with industry stakeholders to ensure a smooth transition and to maximise the benefits of solar integration for all customers. This

includes seeking to learn and share how other networks, for example in Australia, have enabled customers to realise the full value of their investment in rooftop solar, while also keeping network upgrade costs to a minimum, through enabling the flexibility for solar output into the network to be dialled down in periods of network congestion.

1.3.4 INNOVATION AND NON-TRADITIONAL SOLUTIONS ALLOWANCE

We will continue to leverage the funding opportunity provided by the Commission's innovation and non-traditional solutions allowance (INTSA) to seek collaboration with other lines companies and other parts of the wider sector. We'll explore new and innovative solutions to plan and operate the network more efficiently and deliver solutions in the long-term interest of consumers. The funding of these projects is not included in the expenditure forecasts, in line with the guidance from the Commission.

1.3.5 EMBEDDING NEW TOOLS AND AI-POWERED PROCESSES

After launching an AI-powered, aerial inspection regime through the GridAware product, which we partnered with X, the moonshot company, to develop, we're now embedding this into our asset replacement and maintenance processes. Our entire overhead network is inspected using drones or helicopters every 2.5 years, generating more than 1 million high resolution images, thermal scans and LiDAR data. This data is used for us to complete our network inspections, with AI helping us do this faster. This has led to us having access to vastly more information about the conditions of our assets, and we've developed a new maintenance regime to take advantage of this and deliver more effective maintenance investment on behalf of our customers, while ensuring customer privacy.

We're also beginning to use another tool that's been developed out of our partnership with X, the moonshot company: GridPlanning for Distribution. This tool vastly speeds up the time it takes to conduct network studies used to plan for future scenarios, helping us improve internal efficiencies. This is helpful in keeping us to adapt quickly so customers benefit from more choice, smarter energy use, and more affordable costs over time.

1.4 What is in this AMP?

1.4.1 AMP STRUCTURE

SECTION		OBJECTIVES
1.	Introduction	• Provides context to our stakeholders on the key factors that have influenced our asset management planning over this ten-year period as well as the potential for change
2.	Future Network Roadmap	• Details how our future network roadmap supports Vector's Symphony strategy by identifying the initiatives required to respond to evolving economic and societal changes
3.	Network overview	• Outlines our high-level asset populations, key network statistics as well as Vector's geographical area map
4.	Customers and stakeholders	• Outlines our engagement process with stakeholders and customers and the changes we have made to reinforce our commitment to put customers at the heart of what we do
5.	Asset management systems	• Details the framework that supports and enables Vector's asset management
6.	Governance, risk and information management	• Provides an overview of Vector's governance and organisational structure, accountable for delivering effective and fit for purpose asset management planning
7.	Service levels	• Sets out the specific service levels we measure our performance by to ensure we are delivering for our customers and stakeholders
8.	Network maintenance	• Describes the key elements of Vector's approach to the maintenance of our network assets
9.	Customer connections	• Outlines Vector's approach to connecting new customers, managing customer cost and communication, and how we forecast expenditure for these connections
10.	Network growth and security	• Describes the processes Vector has implemented to identify where investment is required on the network to resolve network constraints and meet changes in electricity demand and presents the relevant projects
11.	Reliability, environment, and resilience	• sets out the investment in both asset replacement and asset reinforcement categories with a specific focus on projects for the improvement and bolstering of network reliability and resilience, including managing the impacts of climate change as well as reducing our asset management carbon footprint
12.	Asset replacement and renewal	• Describes how we manage our asset fleets, the factors that influence our asset management strategy, our approach to forecasting and drivers for asset replacement and presents the relevant projects

SECTION	OBJECTIVES
13. Asset relocations	• Describes our approach to relocating assets on behalf of customers, other utilities or requiring authorities and describes typical relocation works, our process for managing these works and how they are funded
14. Non-network assets	• Describes the context for our investment in digital, our major programmes/projects and focus areas
15. Expenditure forecasts	• Presents a summary of the capex and opex forecasts for the electricity distribution network assets over the next 10-year planning period based on the investment proposals outlined in sections 8 to 14
16. Programme delivery	• Gives an overview of the processes used to manage the delivery of our capital and maintenance works programmes and the approach to prioritising works and optimising resources
17. Appendices	• Contains supporting and supplementary information, a compliance table showing how our AMP meets the Commerce Commission's Information Disclosure Requirements as well as the Commerce Commission's Information Disclosure Schedules

1.4.2 AMP PURPOSE STATEMENT

This AMP is intended to provide transparency to our customers, staff and stakeholders over the context in which we make investment decisions and how our asset management and planning processes support Vector's decision-making process.

1.4.3 AMP PLANNING PERIOD

This AMP covers a 10-year planning period, from 1 April 2026 to 31 March 2036. Consistent with information disclosure requirements, a greater level of detail is provided for the first five years of this period. All analysis and section details within this AMP are based on Vector's financial year, which ends on 30 June. Accordingly, tables and charts labelled with "FY" refer to the financial year ending 30 June. Schedules marked with "RY" refer to the regulatory year ending 31 March.

1.4.4 CERTIFICATION DATE

This AMP was certified and approved by our board of directors on 24 March 2026 and publicly disclosed on 31 March 2026.

This Asset Management Plan sets out, as at the date of certification, our view of the investments we believe will deliver the best outcomes for our customers, and which also represent a prudent investment strategy. We note that, particularly given the uncertainty over future electricity demand, we may not follow the investments described here as we update our plans and analysis on how to best deliver for our customers. Each investment we make goes through appropriate governance processes to ensure it is delivering against our strategy.

1.4.5 OVERVIEW OF VECTOR

Vector is an innovative New Zealand energy company, delivering energy and communication services to more than 630,000 residential and commercial customers across New Zealand. Vector has a leading role in creating a new energy future through its Symphony strategy which puts customers at the heart of the energy system. Vector is listed on the New Zealand Stock Exchange with ticker symbol VCT. Our majority shareholder, with voting rights of 75.1%, is Entrust. For further information, visit www.vector.co.nz.

Vector's electricity distribution network is described in Section 3, and our Asset Management Practice is described in Section 5.

1.4.6 VECTOR'S CORPORATE VISION

Vector's corporate vision is to create a new energy future. Vector's Asset Management Policy supports the achievement of strategic objectives aligned with this corporate vision.



SECTION 02

Future Network Roadmap

2 – Future Network Roadmap -

2.1 Societal changes and evolving customer expectations

New Zealand's energy landscape is transforming, influenced by evolving customer expectations, the adoption of new technology, the move away from gas, and the rise of technologies such as rooftop solar, batteries, and electric vehicles (EVs). In Auckland, this transition—along with growth such as increasing data-centre load—is altering demand profiles, driving localised peaks, and making demand across the network less predictable. Recent, and more frequent, severe weather events have sharpened customer expectations around resilience, while customers' growing focus on affordability is shaping the way they engage with electricity. Together, these shifts are prompting increased policy and regulatory action, which is in turn generating further change across the sector.

Vector's Symphony strategy responds to the following major economic and societal changes driving this transformation:

- Evolving customer expectations, technology and choice
- Decarbonisation and electrification
- Affordability and equity
- Severe weather and resilience (incl. cyber)
- Market, regulatory and policy dynamics.

The Future Network Roadmap (FNR) provides a structured framework for developing the capabilities required to respond to these evolving economic and societal challenges, with a focus on achieving the following Symphony outcomes:

- Reliable, resilient and dependable
- Clarity amid uncertainty
- Innovative and future focused
- Enabling customer choice and efficient energy use
- Optimised trade-offs for least cost and efficient expenditure.

Vector's Symphony strategy aims for equitable energy solutions, delivered as affordably as possible, using non-network and demand-side solutions as distributed energy resources grow. We will therefore continue during this AMP period to work towards understanding and unlocking the benefits of load and generation flexibility to improve the effectiveness of operational expenditure and effectiveness of capital deployed by leveraging learnings from customer demand side flexibility pilots, and deploying the expenditure described in our non-network investment forecasts in this AMP.

2.2 Future Network Roadmap

The FNR supports Vector's Symphony strategy by identifying the initiatives needed to build new capabilities. It goes beyond technology, driving a strategic shift in planning, operations, and customer relationships by leveraging technology, data, machine learning, artificial intelligence (AI), as well as global partnerships and engagement. Given the integrated nature of the Symphony strategy, specific initiatives and programmes related to the FNR are discussed across the AMP. The focus of this section is to provide a connected view of how network innovation and transformation laid out in our FNR supports Symphony.

Our FNR has evolved since the publication of the last AMP and is now organised around four key pathways (refer Figure 2.1): efficient network growth; customer demand side flexibility; network operations and resilience; and data-driven asset intelligence.

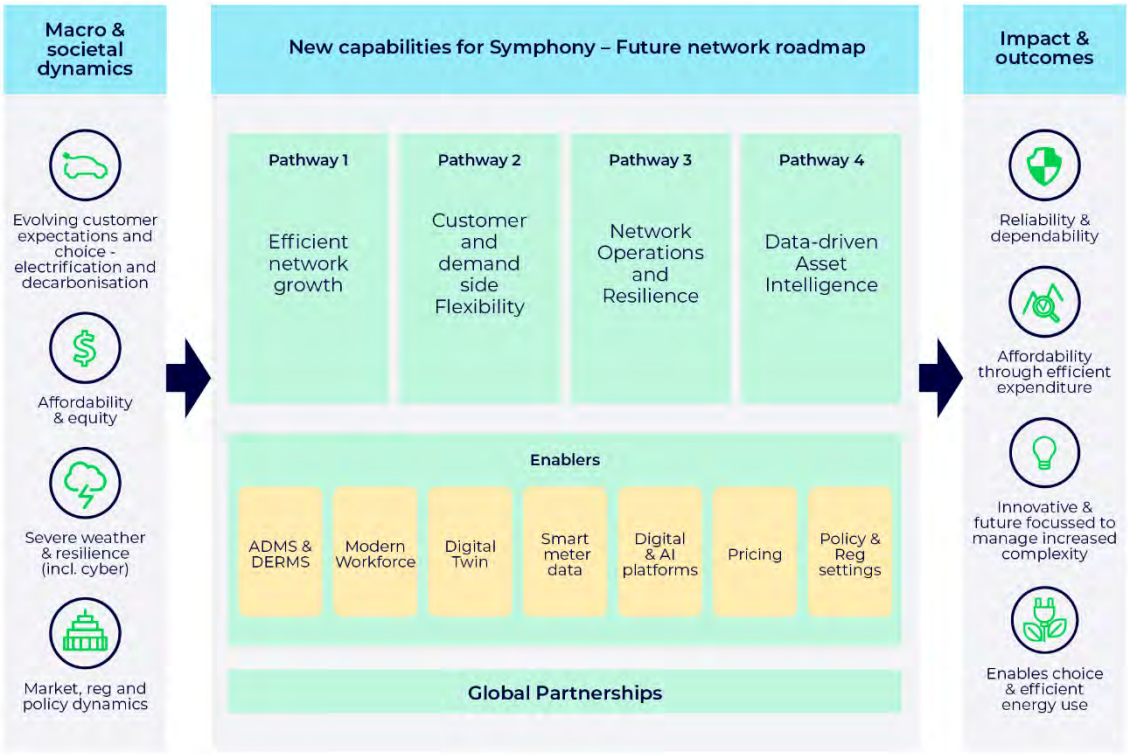


FIGURE 2-1: FNR PATHWAYS

2.3 Pathways of the FNR

2.3.1 PATHWAY 1: EFFICIENT NETWORK GROWTH

Objective - enable downward pressure on network costs under increased complexity by building a more efficient network while meeting customer expectations and forecasted network growth.

We are forecasting significant demand growth over the next decade. The forecast increase in peak demand over this AMP period (refer section 10), informed by Vector's Customer Scenario Model, is driven by large customers' increased demand resulting in increased reinforcement investment, such as data centres, public transport electrification (buses and ferries), as well as organic load growth from continued residential development, fuel switching from gas to electricity, and electric vehicle charging. Additionally, we are forecasting a proliferation of customer-owned distributed energy resources over time. These changes mean that we expect fundamentally different demand patterns, resulting in increased uncertainty and complexity, as well as a need to accelerate the deployment of electricity network infrastructure to respond to customer needs.

Addressing this transformation requires advanced network forecasting tools capable of accommodating dynamic, decentralised energy flows and greater variability in both supply and demand, while ensuring the safe and efficient management of bidirectional power flows. We will continue our focus on non-wires solutions, since our early implementation of network batteries and microgrid have enabled efficient network growth.

Additionally, we are increasing our focus on speeding up construction delivery, in collaboration with our construction partners, and customer service interactions to seek to minimise costs and maximise capital effectiveness for the long-term benefit of consumers.

The FNR enables a more intelligent, data-driven, and probabilistic approach for network planning, using AI and machine learning for predictive, integrated network development, deploying non-network alternatives to support an efficient network build.

Key initiatives:

- Customer scenario model – forecasts the impact of growth, customer behaviour, new technology uptake, and fuel substitution - on Auckland's electricity peak demand
- Development of new AI powered planning tools
- Programme Management Office (PMO) Transformation
- Improve our customer connection processes – focusing on the efficient delivery of projects
- Standby generation to improve network security and provide resilience support.

2.3.2 PATHWAY 2: CUSTOMER AND DEMAND SIDE FLEXIBILITY

Objective - Unlock demand-side flexibility by shaping how customers use electricity to meet their needs, supporting network efficiency while maintaining safety, security and equity.

In this era of increasing demand for electrification, customers are asking for new connection products from Vector to provide them choice and differentiation from the standard 24/7 connection. Our initial trials of electric vehicle charging behaviour, smart hot water control pilots, and agreements with E-bus and charge point operators have demonstrated the benefits that flexible demand connections offer to customers. Section 10.3 and 10.5 describe how we already actively include flexibility into our network planning approach.

The pivotal role that demand-side flexibility can play in building an efficient and reliable network has been emphasised in previous asset management plans (AMPs), along with enabling network modernisation, pricing and regulatory policy to ensure it delivers secure, safe and equitable outcomes in the long-term interest of consumers.

Since the last AMP Vector has firmed up our approach to network flexibility (flexibility) based on learnings from the following:

- Projects, trials, and pilots completed by Vector over the DPP2 and DPP3 regulatory periods.
- Case studies from international jurisdictions including Australia, UK and Europe.
- Published work and case studies by the ENA, EEA and EECA.
- Projects completed by other EDBs and Transpower.
- Global partnerships with world leading companies like Google Tapestry that are dealing with large utilities and system operators across the world.

Retailers and other flexibility providers will play a growing role in the rollout of managed load (for example, managed hot water and managed EV charging). In concert with electricity retailers, we are also developing and deploying new commercial (pricing) mechanisms that support retailers engaging household and business customers to reliably and cost-effectively shift consumption out of peak periods. These initiatives also promote energy-efficient network operation by improving load factor and reducing technical losses through more even loading and voltage management, enabled by increased network visibility and control.

To support this transition in a way that protects network safety and integrity of supply, Vector is progressing the deployment of operational foundations required for effective coordination, including clearer expectations around interoperability, data exchange, and load management practices. Third parties managing consumers' assets must follow good electricity industry practice, operating within the thermal and power-quality limits of the existing network and assisting EDBs in the management of network and grid emergency events. This will be enabled by load management protocols for retailer and non-retailer aggregators, supporting predictable and transparent coordination between Vector and the parties managing customers' load. We will also require connectivity of every device to Vector's distributed energy resource management system (DERMS) – either directly, or indirectly via the third party's DERMS. Provided the necessary protocols, technology, visibility, contractual liabilities are in place, these should create a system where competing, value-stacking retailers aggregators can be orchestrated to manage consumer devices safely and reliably.

Our efforts also focus on industry engagement and leadership to ensure that new technologies and devices must be able to work with existing systems. Essential building blocks for the smart system envisaged are interoperability and connectivity, with standards for "smartness" requiring regulation to ensure certain consumer devices have consistent demand-response and connectivity capabilities.

However, these solutions are clearly still at a nascent stage. It will take time to build confidence within EDBs that consumers' flexible demand will be shifted outside peak periods with sufficient certainty to avoid and/or defer investment, especially when under management of third parties. One of these challenges is to safeguard our customers, our assets and our people against unintended consequences and risks associated with third parties managing customer load and injection across the network. A large number of devices responding en masse to the same external stimuli – such as a fleet of retailer-managed devices turning on in response to low network or wholesale prices, or rooftop solar injecting network-wide on the sunniest days – will erode diversity, and risk creating unintended peaks. To address these risks, and avoid expensive network upgrades, we will implement safeguarding and monitoring technology as an extra layer of protection over and above the operating protocols.

The key objectives of new initiatives of the FNR will be to explore the following emerging challenges and risks associated flexibility:

- Customer participation and trust
- Visibility of low-voltage networks
- Coordination with retailers and aggregators
- Regulatory and incentive alignment
- Simultaneous management of headroom for both injection and import
- Cybersecurity and control risks
- Network and asset safeguarding
- Managing network emergencies
- Potential deterioration of power quality for some customers on the common network

In addition to these mechanisms, as highlighted in previous AMPs and Vector's Future Network Roadmap (FNR), flexibility also requires enabling investment to create new capabilities in low voltage (LV) visibility, digital platforms and network modernisation. The next section provides the latest view of the FNR.

In parallel with these developments, we will continue to engage with regulators and others in the sector to work through some of the complex challenges of realising consumer benefits from flexibility.

Key initiatives:

- Flexible connections for large consumers (Flex Connect)
- Network connection standards including flexible solar exports (>5kVA for residential rooftop solar)

- Cost-reflective, time-of-use lines pricing with targeted, evidence-based peaks
- Contracted out-of-peak load shifting on low-voltage networks (Residential DER tariff), and
- Contracted non-wires alternatives (or "non-traditional solutions") for deferring specific high-voltage investments.
- Actively engaging with retailers and other flex providers to agree load management protocols with mandatory operating limits to avoid emergencies, and processes for managing network emergencies.

2.3.3 PATHWAY 3: NETWORK OPERATIONS AND RESILIENCE

Objective - enable Vector to meet customers' expectations for reliability and resilience through advanced distribution management systems to increase situational awareness.

Symphony acknowledges the growing importance of a resilient and reliable electricity network as customers transition to electric transportation, increase their dependence on digital communication, and reduce reliance on gas. The threats posed by climate risks and natural disasters—including severe storms, droughts— and cyber-attacks, make it essential to build a stronger, safer and more adaptable network.

Investment in advanced monitoring and control technologies—like sensors, automation, and integrated data platforms—is necessary to improve outage response, enhance cybersecurity, and enable efficient recovery and communications during disruptive events. Advanced integrated platforms improve efficiency and situational awareness through advanced standardised and automated processes. Facilitating effective handovers with our Field Services Providers (FSPs) is essential for maintaining operational efficiency and enhancing the customer experience.

Asset hardening is a critical component of enhancing network resilience, involving the reinforcement and strategic upgrade of infrastructure to withstand extreme weather, natural disasters, and emerging security threats. By investing in robust materials, advanced engineering practices, and targeted retrofits, we can minimise the risk of damage and service interruptions during adverse events. This investment is informed by vulnerability and climate risk modelling. This is further complemented by monitoring and automation technologies, ensuring that the network remains dependable and responsive even in challenging conditions. Finally, deploying mobile technology for rapid temporary supply and establishing community hubs further supports swift recovery and minimal disruptions to ongoing service for customers.

We place a strong emphasis on utilising digital platforms and operational insight to help us communicate effectively with customers during periods of severe weather. Vector's ADMS, operational technology platforms, and related digital platforms are key enablers and support network automation and improving outage detection and restoration processes while also helping us adapt to evolving customer needs.

Continuous engagement with regulatory authorities, governmental agencies, and other infrastructure stakeholders is critical to enhancing overall system resilience.

Key initiatives

- Enhancing customer experience of planned and unplanned outages through improved information and systems
- Executing on the advanced distribution management system (ADMS) roadmap
- Asset hardening strategies informed by our Resilience Index
- Advanced operational technology tools for fault location and lines down detection
- Future workforce project to strengthen organisational capability to meet evolving customer needs in a more complex engineering environment.
- Using customer insights to understand customer expectations across the network and inform priorities through initiatives like the "Voice of Customer and customer engagement programmes".

2.3.4 PATHWAY 4: DATA DRIVEN ASSET INTELLIGENCE

Objective - enable predictive and immediate decision-making for asset health and maintenance, ensuring proactive, efficient, and cost-effective network management to deliver on customer expectations for reliability and affordability.

Our asset management approach supporting Symphony is intended to drive innovation and is future-focused. It draws on the transformative capabilities of smart grid technologies and the resulting immediate and predictive insights on asset health and maintenance to deliver customer outcomes and improve operational efficiency.

Central to this approach is the transition to automated inspections, enabled by platforms such as Tapestry GridAware, which leverages artificial intelligence and machine learning to anticipate adverse impacts to asset performance and optimise maintenance schedules. The strategy incorporates modern inspection techniques, including drones and helicopters, to enhance the accuracy and reach of asset assessments. Coupled with condition-based asset replacement models (CBARM) and predictive maintenance, this enables early detection of potential asset failures which will help reduce downtime and improves reliability—outcomes that directly benefit the customer experience.

A robust modern and connected data platform underpins the strategy, allowing for seamless integration of commercial and anonymised/high level customer asset data through a mindset of "Vector 360". This unified data environment supports rapid decision-making and predictive insights on of maintenance asset health. Advanced automation and sectionalisation, hallmarks of smart grid evolution, further support fast and targeted restoration efforts in the event of outages, minimising disruption to customers.

Access to smart meter data is particularly instrumental in driving innovation and efficiency. Combining smart meter data, transformer monitoring and data from network sensors facilitate asset condition assessment and enable the increase of headroom for distributed energy resources by incorporating dynamic ratings—critical for managing load and responding swiftly to changing demand patterns.

Key initiatives

- Implement new maintenance standards following review complimented by standardisation of maintenance practices (and assets) – targeting productivity and efficiency.
- Embedding the use of technology for aerial surveillance, using modern inspection techniques using drones and helicopters.
- Progressing the next stages of our automated inspections strategy.
- Dynamic ratings of assets to maximise use
- Modernisation of Enterprise resource planning (ERP) - enterprise asset management (EAM) systems and Customer Management platforms
- Development of integrated data platform 'Vector360.'
- HV capacity headroom maps
- LV visibility

2.4 Innovation to support the FNR

A key enabler for the FNR is innovation, we believe a commitment to innovative and forward-thinking approaches is key as we navigate the rapid changes redefining the energy sector. By proactively adopting technological advancements, we cultivate a culture focused on continuous improvement and collaboration, ensuring that innovation generates measurable benefits for all stakeholders in the long-term interest of consumers.

Vector has successfully delivered innovation projects in DPP2 and DPP3 that involved new technology, our customers, vendors, and stakeholders like EECA, to seek information, learn, gather data, conduct field test, validate assumptions (or not) and test our hypotheses - to take initiatives through to business case development and operationalisation of the new capability, or to discontinue.

The following are examples of innovation projects undertaken over this period:

- The use of network batteries (BESS) to defer investment by extending asset lives of subtransmission circuits in Glen Innes and Warkworth.
- EV charging pilots in Waiheke and Auckland to improve our understanding of the impact of controlled and uncontrolled charging (using smart chargers) on the after diversity maximum demand.
- Public EV charging trials across Auckland to understand charging profiles to explore opportunities for flexible charging and the faster deployment of charge point operators.
- Smart hot water control to defer reinforcement in the low voltage network.
- Out of peak e-bus charging for electricity bus depots, which has now been fully operationalised.
- Contingency management of e-ferry charging to avoid network congestion, which has now been operationalised.
- The use of high-resolution aerial images and AI to automate the asset inspection process, which has now been operationalised.
- The use of smart meter consumption data to enable visibility of transformer loading on the low voltage network, which has now been operationalised.

These innovation practices are intended to deliver more efficient, data-driven and resilient planning and operation of the network, including through automation, advanced analytics and improved network visibility, as well as deferral or avoidance of traditional network reinforcement where practicable. These outcomes are expected to improve consumer outcomes by maintaining reliability and security of supply and placing downward pressure on long-term network costs through more efficient use of network assets.

The information used to inform or enable these innovation practices includes operational network and asset condition/inspection data, smart meter and low-voltage visibility data, and relevant external information including published research/case studies and weather data. Vector seeks this information through structured trials/pilots, and partner engagements (including vendor and retailer arrangements where relevant) and validates findings through engineering review and operational testing prior to adoption.

Our DPP4 and DPP5 innovation approach (this AMP period) builds on the learnings from these projects and identifies more area to explore through innovation initiatives. Consistent with the network planning options process in Section 10.6, Vector considers planned innovations that improve efficiency such as improved utilisation, extended asset lives and deferral of investment alongside conventional reinforcement when assessing options to address forecast constraints. Vector will utilise the *Innovation and Non-Traditional Solutions Allowance* (INTSA) scheme implemented by the Commerce Commission in 2025 to fund these initiatives, subject to meeting the criteria of the scheme.

INTSA provides exciting opportunities for electricity distribution businesses (EDBs), subject to DPP4, to apply for an additional allowance for projects involving innovative or non-traditional solutions that meet the INTSA criteria. Some of the innovation projects that we will be seeking funding for will be done in collaboration with other electricity distribution businesses and other parts of the wider energy sector.

The introduction of INTSA represents a significant opportunity to scale and advance our innovation portfolio. However, it necessitated a comprehensive transformation of our innovation process from end to end. At the governance level, we have established an Innovation Steering Committee, Working Group, and Project Teams to oversee a stage-gate process for each critical step in the typical INTSA project lifecycle: ideation, prioritisation, scoping, execution, and reporting. Figure 2.2 illustrates this approach.

Vector assesses innovation success against pre-defined criteria aligned to consumer outcomes and network performance, including impacts on reliability and resilience, safety and power quality and demonstrated efficiency benefits. Decisions to commence, scale, embed, or discontinue an innovation practice are based on whether trial evidence demonstrates net consumer benefit, operational feasibility, and acceptable risk including cybersecurity and controllability within defined operating limits.



FIGURE 2-2: INNOVATION APPROACH

Our DPP4 and DPP5 innovation initiatives are based on key aspects of the network of the future that we anticipate will be challenging for the traditional network to cope with, as illustrated in figure 2.3.

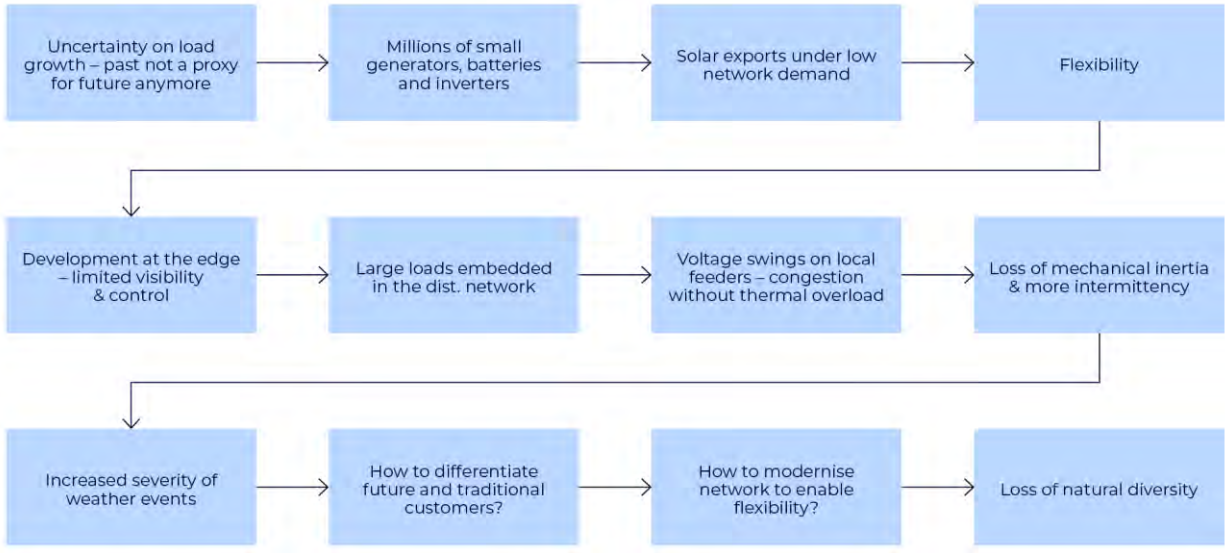


FIGURE 2-3: EMERGING CHALLENGES FOR THE TRADITIONAL NETWORK

The development of our innovation programme for DPP4 and DPP5 is organised into themes that support the pathways of the FNR, as illustrated in figure 2.4.

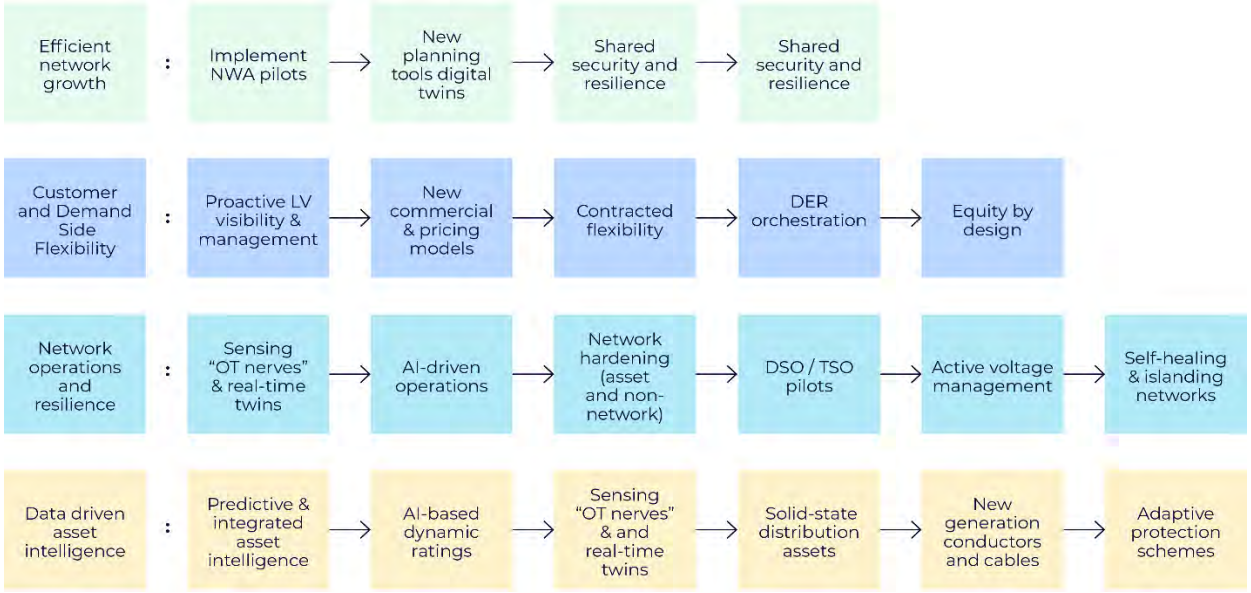


FIGURE 2-4: INNOVATION THEMES

This programme harnesses the expertise at Vector and leverages external expertise and experience from industry and non-industry specific players, for example:

- Deploying digital tools in collaboration with global partners to navigate the transition to a digital energy future such as cyber-physical security solutions, smart meter edge data analytics, a Distributed Energy Resource Management System (DERMS), Advanced Distribution Management System (ADMS), and the Tapestry collaboration with Google's X, the moonshot factory.
- Establishing global alliances and drawing on international expertise to foster innovation and maintain an open perspective.
- Adopting best practices from leading international utilities strengthens our ability to adapt to shifting customer expectations and operational demands, supporting continuous innovation and enhancing affordability.
- Partnering with other distributors, retailers, other organisations, and our own customers to continue innovation projects like DER integration to build the knowledge needed for an efficient and effective transformation of our network.
- Consulting and engaging with stakeholders, vendors and service providers in traditional and non-traditional network technology including behind the meter distributed energy resource technology.

Our candidate project INTSA project list for DPP4, based on our initial assessment, is shown in table 2.1

PROJECT	INNOVATION ASPECTS
LocalFlex platform	New way to publish our non-wired alternative (NWA) opportunities to flex providers.
Mobile dry type substation	Large 30MW dry type mobile substation will be the first of its kind.
Suburb of the future - LV visibility	Total end to end LV visibility testbed in a residential suburb using a low-cost comms.
LV safeguards for charge point flex	Advanced, smart LV circuit breakers to enable localised implementation of dynamic operating envelopes (no DERMS).
AI-prediction of latent asset failure	A PhD project to predict latent asset failures following a major event – combining lab work and AI based ageing models.
CSIP-server for solar uptake	Enable automated approval of residential flexible rooftop solar up to 10kW.
AI based dynamic rating of OH lines	Dynamic ratings - using AI and published weather data.
Autonomous drone mapping tool	Mapping tool to fly long-distance, autonomous drones after a major event.
Suburb of the future - flex orchestration pilot	Large scale DER deployment and orchestration trial in collaboration with EECA, various retailers and other EDBs.

PROJECT	INNOVATION ASPECTS
Predictive and integrated asset intelligence	GridAware 2.0 - first integrated and adaptive maintenance and asset replacement tool linked to real time data.
Tapestry grid planning tool for distribution (GPTD)	Flexible adequacy - automating planning process to identify and value flex solutions (digital twin).
Future feeder – sensor/AI based	Deploy an automated, end-to-end asset health solution for a rural OH feeder.
Vegetation sensors on FSP trucks	LiDAR cameras for real time assessment of vegetation encroachment - combining growth rate forecasting and actual data.

TABLE 2-1: DPP4 CANDIDATE INTSA PROJECTS

Our DPP5 candidate project list is not finalised and will evolve as we progress the projects in DPP4. However, it is also likely to be informed by the rate of deployment and clustering of customer owned DER over the next 4 years. Conceptually, it will focus on the areas shown in figure 2.5.

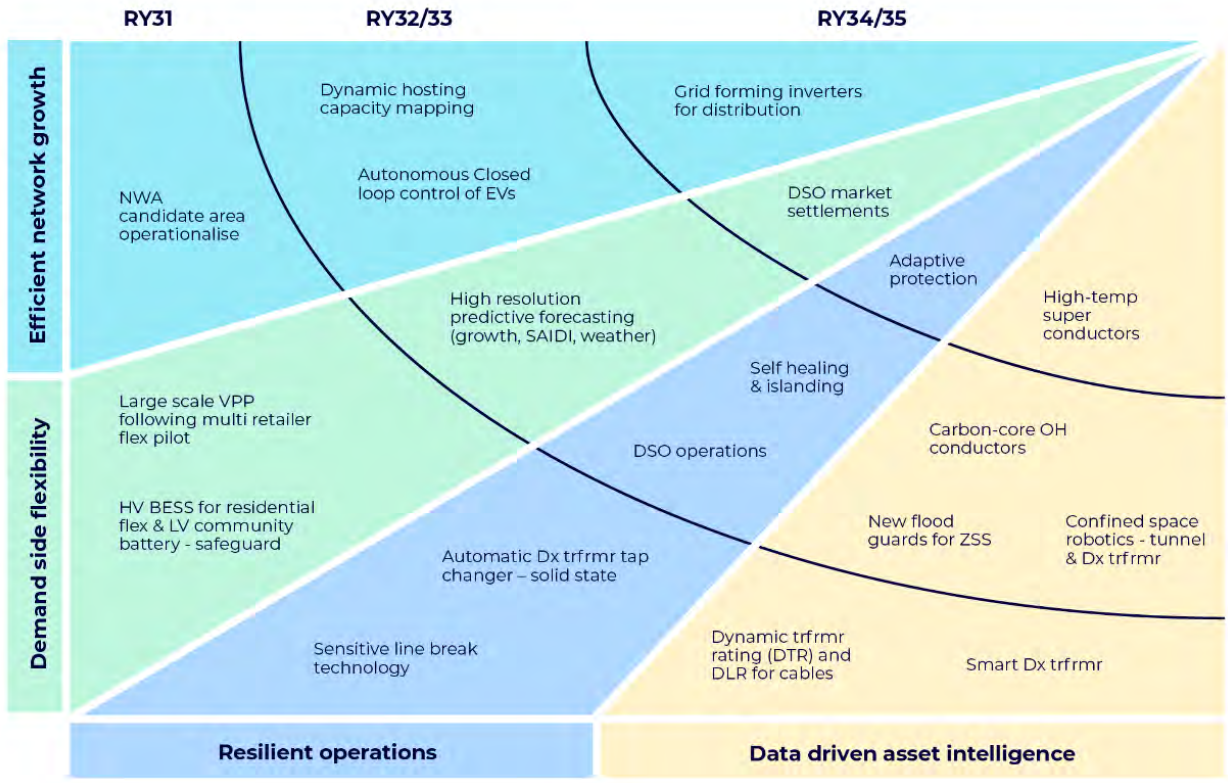


FIGURE 2-5: LIKELY DPP5 INTSA AREAS OF FOCUS



SECTION 03

Network overview

3 – Network overview

3.1 Our network

Vector is the largest distributor of electricity in New Zealand, managing a rapidly expanding energy distribution network across the Auckland region. The Vector network area is centred on the Auckland isthmus, supplying 632,106[2] ICPs between Mangawhai Heads in the north and Papakura in the south, including Waiheke Island in the Hauraki Gulf. Our network is the largest of the electricity distribution businesses in New Zealand in terms of connected customers, peak demand and energy consumption.

We broadly divide our network into two sub-networks, the Auckland and Northern network. The geographical area map in Figure 3-1 shows the entire Vector supply area (both the Northern and Auckland network regions) and the underlying grid exit point (GXP) supply areas. Neighbouring distribution networks operated by Northpower to the North and Counties Energy to the South can be seen in the figure. Table 3-1 provides a summary of the key network statistics of the Auckland and Northern regions as of 31 March 2025. In addition, Vector owns and operates a zone substation, Lichfield, in the South Waikato that supplies a large industrial customer. The Lichfield zone substation is not shown in the figure below.

Large customers that have a significant impact on our network are summarised in appendix 3 but are also referred to in sections 5.3 and 5.4 below.

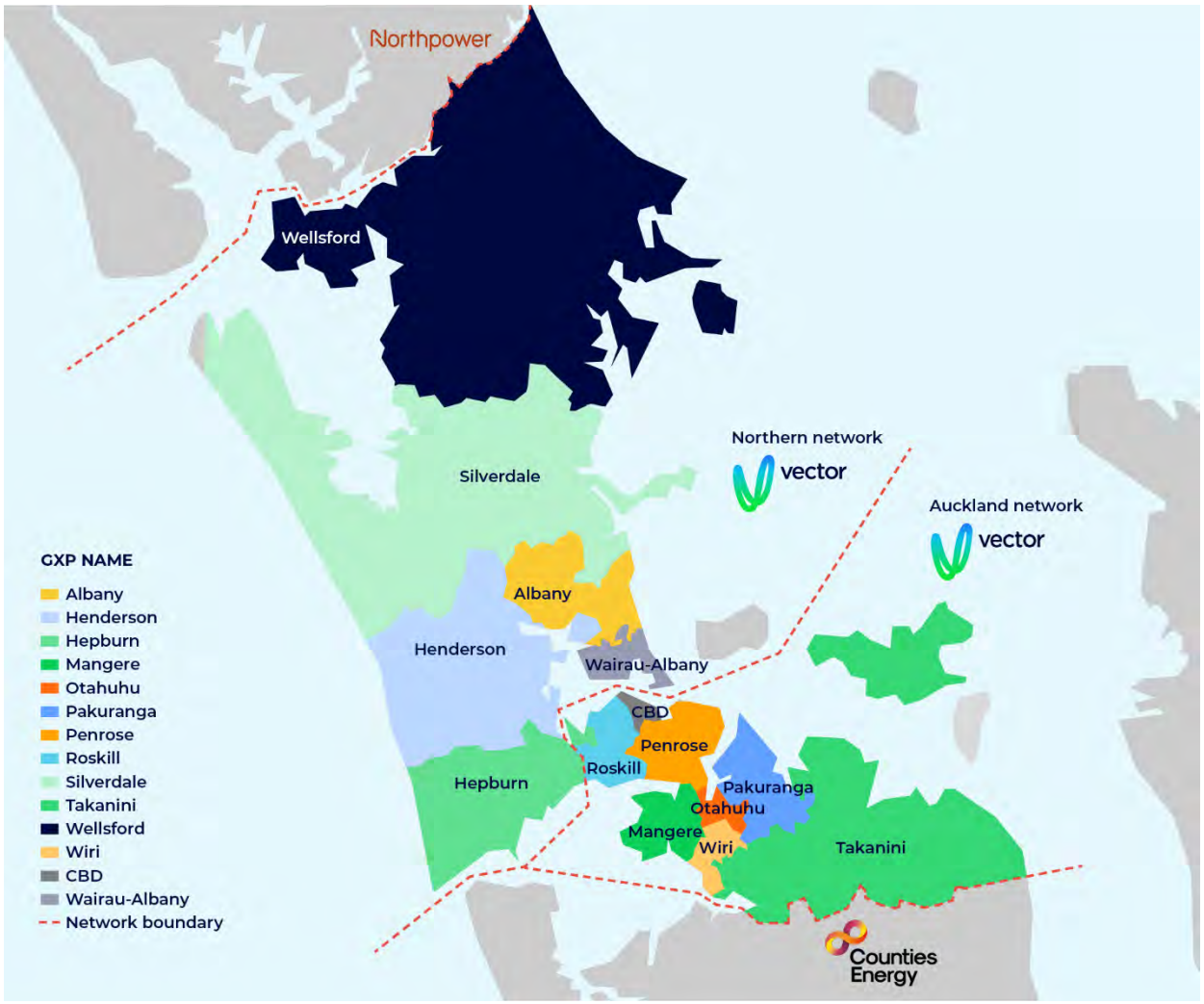


FIGURE 3-1: VECTOR NETWORK GEOGRAPHICAL AREA WITH SUPPLY REGIONS AND GXP AREAS

To help clarify the network descriptions, network maps are available on Vector's Open Data Portal https://data.vector.co.nz/.

A single line diagram of the subtransmission network is also available upon request.

2 Number of electricity connections (2025 Annual Report)

MEASURE	AUCKLAND	NORTHERN	VECTOR TOTAL
Customer Connections[3]	369,916	256,077	625,993
Overhead circuit network length (km)	2,788	5,397	8,185
Underground circuit network length (km)	6,931	4,609	11,540
Grid Exit Points (GXP) (excl. Lichtfield)	8	6	14
Zone substations (zone substation)	58	58	116
Peak Demand (MW)[4]	1,116	695	1,802
Energy throughput (GWh)	5,883	3,173	9,056

TABLE 3-1: KEY NETWORK STATISTICS (YEAR ENDED 31 MARCH 2025)

3.2 Grid exit points

Vector takes supply from the Transpower grid at 110 kV, 33 kV and 22 kV at 15 points of supply[5] known as grid exit points (GXPs). Transpower owns and maintains the GXP equipment but provides current transformers in their switchgear for Vector's protection schemes and power quality measurement. Vector owns the line differential unit protection schemes on the outgoing zone substation supplies. Because unit protection consists of protection relays at the GXP as well as the remote Vector zone substation (ZSS) ends, it makes practical sense for Vector, as distributor, to own the unit protection.

Transpower owns the feeder management relays at the GXPs. The feeder management relays provide backup protection to plant but, as their name implies, they are also used by Transpower to control their circuit breakers. At certain GXPs, most of the subtransmission network switching is required and undertaken by Vector and, under agreement with Transpower, Vector has been enabled to control the subtransmission circuit breakers in GXPs. Where this operational mode has been agreed the communication schemes between Transpower and Vector have been modified to allow this mode of operation by Vector.

3.3 Network configuration

From the grid exit points power is distributed across Auckland to our ZSS via our subtransmission network. The supply is then stepped down through our zone substation transformers and distributed across zone substation supply areas at 11 kV and 22 kV. The supply is stepped down further to 230 V single phase or 400 V three-phase via our overhead and underground distribution transformers and distributed to our customers through our low voltage (LV) network.

We have lines and cables operating in three distinct voltage ranges:

- Subtransmission – predominantly 33 kV but also 22 kV and 110 kV
- Distribution – predominantly 11 kV but also 22 kV
- Low Voltage (LV) – 230 V single phase or 400 V three-phase. Customers use this network to obtain electricity but also to export when excess electricity is generated by customer owned distributed energy resources

We complement our lines and cables with a range of Distributed Energy Resources:

- Two diesel powered emergency generating stations at the far end of two lengthy rural parts of the network (Piha and South Head)
- Seven battery energy supply systems (BESS) are in place across the network ranging in size from 1 MW to 2.5 MW to shave peak demand and provide voltage support. Some can operate in a microgrid configuration and have been specifically designed for that operational mode

3.4 Auckland region

3.4.1 OVERVIEW

Eight GXPs supply 58 zone substations in the Auckland network at connection voltages of 110 kV, 33 kV and 22 kV. The Auckland region can be broken down into three primary zones:

- Central business district (Hobson GXP and Penrose GXP)
- Central Zone (Roskill GXP and Penrose GXP)
- Southern Zone (Mangere, Wiri, Otahuhu, Pakuranga and Takanini GXPs)

The Auckland region consists of residential and commercial developments around the urban areas on the isthmus, concentrated commercial developments in the CBD, industrial developments around Rosebank, Penrose and Wiri areas, and rural residential and farming communities in the eastern rural areas.

3 Average number of customer connections for disclosure year 2025.

4 Peak demand in each network region occurs at different times of the day and therefore the coincident Vector total peak demand will not directly equate to the sum of the two distinct regions.

5 14 GXPs in Auckland and Northern networks combined plus 1 GXP at Lichfield equals a total of 15 GXPs

3.4.2 CENTRAL BUSINESS DISTRICT (PENROSE AND HOBSON GXPS)

The Auckland CBD is supplied from an extensive substation complex in lower Hobson St in the CBD that also contains a 220 kV GXP with 220 kV switchgear and a 220 kV/110 kV interconnecting transformer. The zone substation has 110 kV, 22 kV and 11 kV distribution nodes. The North Auckland and Northern (NAaN) cable from the Transpower Penrose 220 kV node runs through the Hobson GXP 220 kV node and then northwards to Wairau GXP and from there to Albany GXP. Hobson ZSS 110 kV node connects to the 220 kV/110 kV interconnecting transformer via a 110 kV switchboard at Hobson zone substation.

Two 110 kV feeders run in a Vector-owned tunnel from Penrose GXP to a 110 kV switchboard at Liverpool zone substation in the CBD. The Hobson zone substation and Liverpool zone substation 110 kV switchboards are interconnected by two 110 kV cables that provide security of supply to each other. A 110kV circuit connected between Roskill GXP 110kV bus and Liverpool 110kV switchboard provides back up supply to CBD. A 22kV circuit connected between Kingsland substation 22kV switchboard and Liverpool substation 22kV switchboard also provides backup supply to CBD.

Two 110 kV cables run from the Hobson 110 kV board and Liverpool 110 kV board respectively to Quay St zone substation, the 3rd Vector bulk supply substation in the CBD. Between Hobson, Liverpool, and Quay bulk supply substations, they supply eight zone substations. To meet growing demand, the distribution network in the CBD is progressively being upgraded from 11 kV to 22 kV.

3.4.3 CENTRAL ZONE (ROSKILL AND PENROSE GXP)

The central zone is supplied from Roskill and Penrose GXPs. Roskill GXP has a 110 kV node and a 22 kV node. From the Roskill 110 kV node two Vector owned 110 kV underground cables connect to two 110 kV/22 kV transformers at Kingsland zone substation. From the Vector 22 kV node at Kingsland, three zone substations are supplied namely, Chevalier, Kingsland itself and Ponsonby.

The Mt Roskill GXP 22 kV node supplies six zone substations, namely Avondale, Hillsborough, Mt Albert, Sandringham, Balmoral and White Swan as well as the Waterview tunnel. The customer base in these areas is largely residential, with industrial customers in the White Swan area. Kingsland, Mt Albert, and Chevalier are undergoing extensive urbanisation with many high-rise apartments being constructed and planned. A number of areas especially around train stations, have been identified in the Auckland Unitary Plan for high-rise intensification that will further drive load demand. A large tract of land that previously formed part of Te Pukenga (Unitec) will be converted to high density housing.

Penrose GXP has a 33 kV node and 22 kV node. Thirteen zone substations are supplied at 33 kV and two are supplied at 22 kV. The customer base in this area is a mix of residential, commercial, and industrial. The industrial customer base in the Penrose area includes some of Auckland's largest industrial customers. It is Vector's largest planning area by demand.

3.4.4 SOUTHERN ZONE (MANGERE, WIRI, OTAHUHU, PAKURANGA AND TAKANINI GXPS)

Five GXPs cover the Southern zone namely Mangere, Wiri, Otahuhu, Pakuranga and Takanini GXPs. Vector takes supply from the listed GXPs at 33 kV except Otahuhu where the grid supply voltage is 22 kV.

Mangere GXP covers the Mangere township and surrounding residential commercial and industrial areas, extending south to the continuously developing commercial areas surrounding the Auckland airport. This supply area includes large logistics centres.

Pakuranga GXP area covers East Tamaki, Pakuranga and Howick and the growth area of Flat Bush to the south. The customer base in these areas is largely residential, with industrial customers in East Tamaki and Greenmount.

Wiri GXP covers the established areas of Manukau, west to the Wiri commercial area and south to the residential area of Clendon. The customer base in this area is a mix of residential, commercial, and industrial.

Takanini GXP covers the urban areas of Manurewa, Takanini, and Papakura township, extending east to the more remote areas of Clevedon, Maraetai, Beachlands, as well as Waiheke Island. The customer base in this area is a mix of mostly residential, with some light commercial and industrial.

Otahuhu GXP covers the Highbrook commercial and industrial area, and the Otara and Bairds areas. The customer base in this area is mainly industrial with some interspersed residential areas.

3.5 Northern region

3.5.1 OVERVIEW

Our network in the Northern region has 58 zone substations which supply a mix of both urban and rural areas. These zone substations are supplied from six GXPs all at a supply voltage of 33 kV. The Northern region can be broken down into three primary zones:

- Albany and Wairau GXPs
- Henderson and Hepburn GXPs
- Silverdale and Wellsford GXPs

3.5.2 ALBANY AND WAIRAU-ALBANY[6] GXP

Thirteen zone substations are supplied at 33 kV from Albany GXP. The Albany supply area includes Albany, North Harbour, Rosedale, Forest Hill, Browns Bay, the East Coast beach enclaves as well as Torbay and Greenhithe. The customer base in this area is predominantly residential but extensive commercial areas exist in Albany and in the Wairau Valley. Extensive and rapid urban infill developments permitted under the Unitary Plan together with large datacentres, are driving load growth in the Albany supply area.

6 The reason for the use of the term Wairau-Albany GXP is because the Wairau zone substation has a 220 kV/ 33 kV GXP connection via the GXP at Wairau zone substation as well as three 110 kV overhead line supplies from a 110 kV GXP node at Albany GXP

Wairau zone substation is supplied via a 220 kV/ 33 kV interconnecting transformer from the GXP that is co-located at Wairau zone substation. Three Vector 110 kV subtransmission lines from the Albany GXP 110 kV node connect directly to three 110 kV/ 33 kV transformers at Wairau zone substation. The Wairau zone substation supply area includes Wairau Valley, Glenfield, Devonport, Bayswater, Takapuna, Northcote, Birkenhead, and Beach Haven. The customer base in this area is largely residential, but many commercial customers exist in the Wairau Valley, Takapuna, and Highbury areas.

3.5.3 HENDERSON AND HEPBURN GXP

Vector takes supply from the Henderson 33 kV bus via two 220 kV/33 kV transformers. Ten zone substations are supplied from this GXP. The supply area covers Ranui, Swanson, Woodford, Hobsonville including Hobsonville Point, Westgate, Te Atatu, Riverhead, Greenhithe[7] and Simpson Rd. The Henderson area is one of the major growth areas in the Auckland region with major residential greenfields developments at Hobsonville Point as well as in Whenuapai, Riverhead, Kumeu, Westgate and Red Hills to the west. The customer base in the Henderson area is largely residential, but the Westgate commercial area is rapidly expanding with logistics centres and large datacentres. This is driving rapid and extensive load demand.

Vector takes supply from the Hepburn 33 kV bus via three 110 kV/33 kV transformers. Ten zone substations are supplied from this GXP 33 kV node. The Hepburn supply area includes Rosebank, Green Bay, Ranui, Oratia, Glendene, New Lynn, Titirangi extending westward out to the coast including Laingholm and the beach enclaves south of Laingholm. The customer base in this area is largely residential with commercial customers mainly in the Henderson township and industrial customers in Rosebank.

3.5.4 SILVERDALE AND WELLSFORD GXP

Vector takes supply from the Silverdale 33 kV GXP bus via two 220 kV/33 kV interconnecting transformers at this GXP. Eight zone substations are supplied from this 33 kV GXP node. The Silverdale GXP supply area stretches from Albany in the south to Waiwera in the north and stretches west to Helensville and, all the way to the West coast including South Head.

It covers the greater Orewa emerging city area, Silverdale, and Millwater urban areas as well as the area east of SH1 that comprises Whangaparaoa, Stillwater, Red Beach, Manly, Tindalls Beach all the way to Gulf Harbour. The customer base in this area is largely residential, but the Millwater commercial area is rapidly developing and includes new large-scale datacentres, warehouses, and logistics centres. Urban infill permitted under the Unitary Plan is also having an impact on load growth.

The Wellsford area is the most northern in Vector's network. It stretches from Wellsford to Warkworth and includes the townships of Matakana, Sandspit, Omaha, Snells Beach, and Leigh in the east and the Tapora isthmus in the west. In the North the network stretches to Te Arai and Tomarata. Wellsford GXP supplies four zone substations: Wellsford, Warkworth, Big Omaha and Snells Beach via two 110 kV/33 kV transformers. A fifth zone substation at Sandspit was commissioned in late August 2025.

Wellsford and Warkworth zone substations are undergoing refurbishment with complete modernisation of the subtransmission switchgear at Wellsford and installation of an additional subtransmission circuit to Warkworth ZSS to make it ready for the modelled peak demand. The customer base consists of urban customers in the rapidly expanding larger townships of Wellsford, Warkworth and Matakana, as well as beach enclaves such as Omaha and Snells Beach that are both expanding. The Wellsford supply area also includes a large rural part of the network that contains the lengthiest 11 kV overhead distribution circuits in Vector's network. The customer base in this area is largely residential with some commercial customers. Some of the farming customers are extensive operations with high load demands. The Tapora isthmus is equipped with a large-scale battery energy system that can operate in islanded microgrid mode.

3.6 Asset overview

This section provides an overview of the asset portfolio that Vector owns and operates including the overall population of our key assets across the Vector network.

3.6.1 ASSET CLASSES

The asset portfolio owned by Vector is divided into nine asset classes. For each asset class, a strategy document records the asset strategy down to sub-asset class level.

- EEA 100 Subtransmission Switchgear
- EEA 200 Power Transformers
- EEA 300 11 kV – 110 kV Cable Systems
- EEA 400 Overhead Lines
- EEA 500 Distribution Equipment
- EEA 600 Auxiliary Systems
- EEA 700 Infrastructure and Facilities
- EEA 800 Protection and Operational Technology
- EEA 900 Distributed Energy Systems

3.6.2 ASSET POPULATIONS

The table below provides an overview of our asset population across our electricity network for the Auckland and Northern regions combined.

7 Greenhithe is normally supplied from Albany GXP but has a connection to Henderson GXP

ASSET TYPE	POPULATION
Subtransmission Switchgear	
Indoor switches	1,783
Outdoor switches	66
Power Transformers	
Power transformers	232
11 kV – 110 kV Cable Systems	
Subtransmission (km)	643
Distribution (km)	3,998
LV cables (km)	6,898
Overhead Lines	
110kV Subtransmission (km)	27
33Kv Subtransmission (km)	368
Distribution (km)	3,685
LV overhead lines (km)	4,088
Poles	126,438
Distribution Equipment	
Transformers	23,020
Switches	21,260
Infrastructure and Facilities	
Buildings (including customer substation buildings)	216
Protection and Operational Technology	
Protection relays	3,982
Transformer management systems	213
Routers and Ethernet switches	1,463
Automation RTU	763
Generation and Energy Storage	
Utility Battery Energy Storage Systems	7
Emergency generating stations	2

TABLE 3-2: ASSET POPULATION SUMMARY



SECTION 04

Customers and Stakeholders

4 – Customers & Stakeholders –

4.1 Customers

In this Asset Management Plan the term ‘customer’ refers to the people and businesses in the Auckland region supplied across more than 630,000 connection points, all of whom we consider a 'customer'. This extends the definition beyond our contractual relationship with retailers and some large directly billed users with dedicated capacity or non-standard supplies and our connection customers. It is important because, for us to be able to build, operate and maintain a modern, reliable, safe, and affordable network that can support New Zealand’s energy transition, we must first understand the people and organisations who use and rely on electricity and the service we provide.

Customers’ use of electricity is changing rapidly. Transport is electrifying, with increasing uptake of electric vehicles, electric buses and electric ferries creating new, often high-capacity and time-specific demands on the network. At the same time, many customers are becoming producers as well as consumers of electricity, with growing adoption of rooftop solar and other distributed generation (e.g. batteries) altering traditional demand profiles and power flows across the network. The future of gas supply in New Zealand is also uncertain.

Electricity demand is also being reshaped by new and emerging loads, including data centres and increased cooling requirements driven by climate, technology and building design. In parallel, changes in the economy and the way people work (i.e. including more working from home and the growth of home-based businesses) are blurring traditional distinctions between residential and commercial customers. Together, these shifts are changing when, where and how electricity is used, reinforcing the need for to continuously engage with customers and their evolving customer needs.

At the same time customers' expectations are evolving. Customers expect reliability and resilience from their electricity networks. They want our investments in the network and forewarning about how planned outages and capital works impact them. They also want to understand in real time how any unplanned outages are being resolved, and when power is on. This has implications for how we run our maintenance and investment, and how we communicate and engage customers. This chapter sets out how we are evolving to meet these expectations.

Our ambition is that customers trust Vector because we provide reliable energy access, while demonstrating value - delivered in a way that is transparent, responsive, flexible, and future-focussed.

4.2 Energy retailers and service providers

As the energy transition accelerates, the number of parties influencing customer energy outcomes is increasing. Energy retailers remain the primary bill relationship for most customers. They, along with a growing set of energy service providers (for example, flexibility providers, EV charging service providers, and technology platforms, including solar and battery), will increasingly shape how customers use electricity, the prices they face, and the service experience they receive. From Vector’s perspective, these organisations are important delivery partners for customer outcomes - particularly affordability, reliability, and the safe integration of distributed energy resources - because they directly influence customer behaviour and technology take-up, and how that technology may be used to meet customers’ needs.

Vector increasingly engages with retailers and other energy service providers because they are central to customer-facing innovation while we play an enabling role in the development of new products and services. This engagement supports Vector’s focuses on ease of doing business, efficient use of the network and industry coordination, while also ensuring that customer protections, operational requirements, and network constraints are appropriately understood and managed.

4.3 Stakeholders

Vector as a critical infrastructure provider operating in New Zealand’s largest city has a wide range of stakeholders whom we also engage with regularly. Vector employs different structures and resources across the varying stakeholder groups to facilitate strong relationships and while accommodating stakeholder needs.

Stakeholders are wide ranging and include government agencies (both local and central), community-based entities and groups (e.g., business associations, iwi, special interest groups), other utilities and industry groups (including specific industry associations and lobbying groups like MEUG, ERANZ, ENA.). A fuller summary of key stakeholder groups and how Vector engages with them is detailed in section 4.5.3.

4.4 Customer – at the heart

Vector’s Symphony strategy places customers at the centre of the energy system and at the heart of decision-making. This extends beyond customer service to a deeper understanding of customer needs, perceptions, and expectations, and ensuring these inform business priorities and trade-offs.

In mid-2025, Vector launched a refreshed customer strategy and customer experience programme. Later in that year, a centralised customer function was established under a single executive, bringing together customer insights, channels, communications, experience, and continuous improvement. This structure has been augmented through the DPP4 customer engagement uplift with additional capability in customer strategy, experience, and community engagement.

While accountabilities have been clarified, responsibility for customer outcomes sits across the business. This is reflected in the Symphony strategy and the organisational behaviour (internal business values) of “Customer, Customer, Customer”.

4.5 Vector's Engagement Process with Stakeholders and Customers

4.5.1 EVIDENCE AND DATA UNDERPIN OUR APPROACH TO STAKEHOLDER AND CUSTOMER ENGAGEMENT

Vector employs a data-led, evidence-based approach to understanding customers and stakeholders, alongside direct engagement with customers (see 4.5.3). This combines market-level customer perceptions research, our Voice of Customer programme feedback across key journeys, social media insights, and operational and asset performance data. All data is collected and analysed with privacy and security-by-design principles. Looking ahead, we are exploring how advances in analytics and AI-enabled tools can enhance our customer insights.

In September 2025, as part of its refreshed customer strategy and customer experience programme, Vector undertook a market-level customer perceptions study to better understand customer priorities, drivers of trust, and expectations. This, alongside targeted qualitative and quantitative research, informs asset management and planning decisions across the AMP period.

4.5.2 DPP4 INVESTMENT IN CUSTOMER ENGAGEMENT

During the DPP4 reset, Vector received an uplift to support enhanced customer engagement and improved customer outcomes. In the first year, this investment has gone towards bringing in additional customer capability in the business, namely experience in developing customer strategy, enhancing customer experience in business process, change management and community engagement. This capability will underpin initiatives designed to improve customer engagement and experience over the coming AMP period.

4.5.3 WHO HAVE WE ENGAGED WITH OVER THE PREVIOUS AMP PERIOD

There are numerous customers and stakeholders whom Vector engages with. Interested stakeholders are identified drawing on (i) customer and stakeholder research, (ii) engagement feedback and enquiries, (iii) operational / outage and asset performance insights, and (iv) external environment scanning including regulations and policies. This process identifies stakeholders based on their level of interest in, and potential impact from, Vector's network activities and services. Accountability for engagement sits with relevant leaders across the business, reflecting the areas they oversee. Priority stakeholders within each catgory are identified in he stakeholder list and the list is reviewed periodically to ensure it remains current and reflects changes in our operating environment. We are focused on taking increasingly proactive and structured approach to stakeholder engagement over the AMP period. When an AMP is published we consult with key customer and stakeholder groups and use this ongoing engagement to inform future AMPs.

Broadly speaking our stakeholders can be grouped into seven categories. Within these larger catgories there are many sub-groups which can be dynamic in nature over time. The table below provides an overview of each major category and, where appropriate, some examples. It also outlines high level stakeholder interests as we understand them:

	RESIDENTIAL & SMALL BUSINESS	LARGE COMMERCIALS & BUSINESS ASSOCIATIONS	LOCAL GOVERNMENT, GOVT. AGENCIES & REGULATORY BODIES	INFRASTRUCTURE PROVIDERS & LIFELINE UTILITIES	ENERGY RETAILERS & OTHER SERVICE PROVIDERS	COMMUNITY GROUPS, IWI & SPECIAL INTEREST ORGANISATIONS	OWNERS, INVESTORS & WORKERS
Description	All households and small businesses on low voltage connections.	High voltage customers and entities with complex power needs. Includes business and industry associations and lobby groups.	Includes Auckland Council, its various planning bodies and its Council-controlled organisations, Government bodies such as MBIE, Housing New Zeland, Commerce Commission , Electricity Authority, Civil Defence etc.	All infrastrucutre providers including transport whether commercial or government controlled. Includes hospitals and health boards.	Independent electricity retailers as well as large vertically integrated generator / retailers.	Includes Iwi, formal residents groups and emergency services (e.g., Nga Tai Ki Tamaki, Papakura Marae, Waimauku and Auckland Northwest Community Emergency Readiness Network, and organisations with unique insight into the community (e.g., Bike Auckland, Auckland City Centre Residents Group).	Vector is 75.1% owned by the people of Auckland whose ownership is held in trust by Entrust. The remainder is publicly traded on the NZX.

	RESIDENTIAL & SMALL BUSINESS	LARGE COMMERCIALS & BUSINESS ASSOCIATIONS	LOCAL GOVERNMENT, GOVT. AGENCIES & REGULATORY BODIES	INFRASTRUCTURE PROVIDERS & LIFELINE UTILITIES	ENERGY RETAILERS & OTHER SERVICE PROVIDERS	COMMUNITY GROUPS, IWI & SPECIAL INTEREST ORGANISATIONS	OWNERS, INVESTORS & WORKERS
Interests	Reliable and affordable network that meets existing and future needs.		Creating enabling infrastructure; civil defense and emergency management; resilience and reliablity.	Optimise infrastructure life cycle; coordination; disaster response coordination.	Maintain strong relationships and ensure ease of doing business; promote customer service; facilitate development of new products and services; industry development and coordination.	Reliable and affordable network that meets existing and future needs; concise communication and strong engagement and working relationships.	Sustainable & prudent business operations and practices (including financial management); risk management ; strategic planning and implementati on; health and well being of workers; safety of people and community; legal, contractual, ethical and regulatory compliance

TABLE 4-1: VECTOR'S CUSTOMER AND STAKEHOLDER ENGAGEMENT GROUPS AND THEMES

Vector has drawn on its wealth of energy transition and customer research as well as that of third parties both in New Zealand and overseas. We undertook comprehensive customer research specifically for the 2024 AMP. Since then, we have undertaken a range of new research to inform our understanding of customers and their expectations.

Overall we have:

- Carried out a comprehensive evaluation of all customer feedback collected through our continuous Voice of Customer programme established in 2016. This program encompasses:
  - between 2,000 to 6,000 responses collected on an annual basis via our electricity unplanned outages customer survey;
  - more than 3,000 responses collected per year via Vector's electricity unplanned outages customer survey;
  - almost 900 responses collected on an annual basis via our customer complaints and technical enquiries survey;
  - around 150 to 250 responses collected every year from customers for which Vector has delivered new or alterations to their current electricity small connections;
  - around 50 annual responses from customers with completed project connections;
  - around 400 pieces of feedback collected annually from customers after an Outage Centre interaction.
- Reviewed ad-hoc studies carried out by Vector for bespoke business needs over the last several years:
  - over 6,000 responses to our two surveys focused on understanding the impact of time-of-use plans on customers' electricity consumption and customer willingness to shift electricity usage outside peak times.
  - just under 3,000 customer surveys collected after major weather events (e.g., cyclone Dovi, the 2023 Auckland floods and cyclone Tam);
  - 1,847 responses and 10 customer interviews collected via Vector's 2025 resilience customer engagement programme.
  - more than 1,200 responses to a bespoke survey focused on understanding customer preferences when it comes to being informed about electricity faults impacting customers, an area visited frequently or a different location;
  - over 1,200 responses from customers impacted by four major network development projects aiming at informing Vector's customer communication strategy;
  - over 1,000 responses from a representative sample of Auckland residential customers collected via a third party to identify Vector's level of awareness, how customers perceive us and what is important to them when it comes to their electricity distributor.
- Reviewed more than 100 reports released in the public domain by third parties:
  - annual plans and customer engagement reports published by Australian and United Kingdom energy distribution companies (e.g., Ausgrid, Energy Queensland, AU Western Power, Endeavour Energy, Electricity North West, UK Power Networks, UK National Grid;
  - EECA research – https://www.eeca.govt.nz/insights/;
  - Kantar Better Futures reports – https://www.kantarnewzealand.com/latest-thinking/better-futures/;

- ENA customer segmentation report – https://www.ena.org.nz/our-work/publications/document/1577.

4.6 Understanding and responding to customer expectations

As we have described, Vector uses ongoing and bespoke customer research to understand what customers value and where their expectations are changing. In September 2025, a representative market-level residential customer perceptions study indicated that customers place importance on a network that is reliable and dependable, affordable, and future-focused. Ease of dealing with Vector, effective use of technology, responsiveness, advocacy for Auckland's residents and businesses, and innovation were also identified as important attributes, albeit secondary to core reliability and affordability outcomes.

Customer interactions with Vector are generally event-based (e.g. outage) rather than day-to-day. In a typical year, around half of ICPs experience an unplanned outage (excludes major event days), and approximately one-fourth to one-fifth are affected by a planned outage. As a result, customer perceptions are shaped primarily by how effectively Vector performs and communicates at key moments that matter most.

Insights from Vector's customer engagement programme show that, during unplanned outages, customers place greatest value on timely and transparent communications, early indications of likely restoration time, minimising repeat interruptions, and knowing what caused the outage. For planned outages, customers value early notice, clear and consistent updates, and effective management of outage duration. For connections, customers prioritise a streamlined process, clear communication and engagement, and transparency around pricing and network charges.

During normal weather, both residential and SME customers have a strong vested interest to learn about / receive information about power outages impacting their area. Furthermore, SME customers also demonstrate a keen interest to find information about outages in an Auckland location they visit often or somewhere else in Auckland, likely driven by business activity and interests across the Auckland region. Vector is the preferred choice for customers to receive outage information during normal weather, regardless of the impacted Auckland location, followed by their electricity retailer for faults impacting their area or location visited frequently. Customers most want to receive notifications every time the restoration work status changes, especially if the outage is impacting their area or an Auckland location they visit frequently. SME customers are particularly interested to learn information that is business critical and will assist continuity planning.

When customers are impacted by major storms or cyclones, they acknowledge and value the work our field teams do and accept that recovery times will be extended. When reporting a power outage in these conditions, customers want Vector to acknowledge that their power is out and that their request is being processed. Furthermore, they want to receive proactive updates as work is carried out and to be provided with an estimated restoration time as soon as it can be provided so they can plan. This work has been used to inform the development of improvements to our storm response.

These insights help inform how Vector prioritises customer outcomes across network operations, communications, and investment planning, ensuring that effort is focused on the interactions and experiences that most strongly influence trust and confidence.

4.7 Customer experience transformation

4.7.1 USING CUSTOMER INSIGHTS TO INFORM STRATEGY AND CUSTOMER EXPERIENCE

Vector uses customer insights to inform how we design and evolve our approach to customers and communities over the long term. These insights help us understand what matters most to customers - particularly around reliability, affordability, resilience, ease of engagement and communication - and to ensure that our operating model, priorities, and ways of working remain aligned to those expectations.

As part of this, the business has been progressively strengthening its customer capability and governance, including consolidating customer accountabilities to improve clarity, alignment, and consistency of outcomes. This approach supports clearer ownership of customer outcomes across the organisation and enables a more joined-up response to customer needs.

4.7.2 EMBEDDING CUSTOMER FOCUS IN THE BUSINESS

Vector continues to embed a customer-focused mindset across the organisation by setting clear expectations for leaders, strengthening business processes, and building capability. Rather than treating customer activity as a standalone programme, the intent is to increasingly integrate customer considerations into day-to-day decision-making, planning, and delivery. For example, the group's Short Term Incentive programme includes key customer satisfaction metrics, alongside SAIDI and SAIFI.

Into this AMP period we are putting more focus on how our people and delivery partners understand how their roles contribute to customer outcomes and ensuring that customer outcomes are always considered alongside operational, financial, and regulatory requirements.

4.7.3 IMPROVING CUSTOMER EXPERIENCES

Customer insights have highlighted areas within key customer journeys that can be improved. In response, the business is focusing on improving how customers experience:

- **Connections**, including responding to changes in regulatory requirements and undertaking an end-to-end review to identify opportunities for continuous improvement.
- **Outages**, particularly through clearer, timelier, and more transparent communications using channels aligned to customer preferences.
- **Major events**, where expectations, uncertainty, and complexity are heightened, and where empathy and clarity are especially important.

These focus areas recognise that while not all outcomes are within Vector's direct control, how we communicate and engage with customers has a significant influence on trust and confidence. Several changes designed to improve customer experience in these areas will roll out through 2026, with ongoing initiatives planned for the future.

4.7.4 A FOCUS ON CUSTOMER SERVICE

Customer service is a key driver of customer trust and satisfaction, particularly given that most customers interact with Vector only at specific moments, such as outages, new connections, or major network projects. Customers have a strong preference for clear, timely, and proactive communication, especially during unplanned outages, and a growing expectation that information will be delivered proactively by Vector as well as accessible through digital channels.

Vector continues to invest in its customer service and engagement capability to improve the quality and consistency of customer interactions. This includes ongoing enhancements to digital platforms such as Vector's outage centre, which provides information about planned and unplanned outages at scale, and continual review of communication channels to ensure they meet evolving customer preferences. Customers also expect information to be accurate and consistent across channels, with dissatisfaction increasing when they are required to use multiple pathways to obtain the same information.

In 2026 we are focussed on improving our complaints and resolution process and fit for purpose approach for engaging Utility Disputes Limited and resolving customer complaints raised through that process.

Vector provides some critical services for free to residential customers. For example, Vector provides three 'free' non-network call outs per year. This means customers can report a fault and will not be charged, even if the fault is identified as coming from the customer's property (e.g. service line).

For business customers, customer service extends beyond day-to-day interactions. Larger customers value timely delivery of projects, early visibility of planned works, and ongoing dialogue to support their operational and strategic planning. Vector responds to these expectations through expanded engagement with customer and stakeholder groups, the use of Key Account Managers for major customers, and increased publication of information on network performance, investments, and planned works.

Through these efforts, Vector aims to provide a customer service experience that is responsive, informative, and aligned with customer needs, while meeting operational and regulatory requirements.

4.7.5 RELIABILITY AND RESILIENCE FOR CUSTOMERS

Reliability and resilience are consistently identified by customers as critical outcomes, particularly as Auckland grows and faces increasing environmental and operational pressures. Vector's approach to reliability is grounded in established performance measures, with SAIDI and SAIFI playing a central role in driving network operations, compliance obligations, and investment priorities. These measures provide a consistent, system-level view of network performance and form a core part of how Vector plans, operates, and demonstrates accountability for reliability outcomes.

Providing a reliable and efficient network is important to customers and we have in place service standards for customers on our network. The service standards cover the time we take to restore power, the number of interruptions customers may experience, and the power quality customers can expect. These are in place for both residential and business customers. Vector offers service guarantee payments to affected residential and business/commercial customers, if time thresholds are not met when restoring power.

Looking ahead, Vector is exploring additional capability to understand the frequency and duration of interruptions for specific customers, communities, and parts of the network, and meeting regulatory expectations such as reporting on the worst-performing feeders. Customer feedback and engagement provide additional context to this analysis, helping to identify where reliability issues are most persistent or have disproportionate impacts, particularly in areas more exposed to environmental conditions or network constraints.

Customers also indicate a high level of interest in receiving updates about resilience challenges, initiatives or major development projects in their area, especially over email. Vector is responding to this need by communicating in a bespoke manner with customers connected to those parts of the network with resilience challenges, initiatives or development projects. This approach started in 2025.

Increasingly we wish to use these customer insights in conjunction with asset condition information, risk assessments, and operational data to inform capital investment and maintenance planning over time. Improved network visibility and data-driven approaches — including the use of advanced analytics and technologies such as AI-enabled asset inspections — support more targeted identification of emerging risks and prioritisation of interventions. Through an increasingly integrated approach, Vector aims to balance reliability, resilience, and affordability, while ensuring that network performance aligns with both regulatory requirements and customer expectations over the long term.

More information on SAIDI, SAIFI and other service levels is presented in Section 7.

4.7.6 AFFORDABILITY AND VALUE FOR CUSTOMERS

Our focus is on ensuring every dollar we spend produces value for our customers. We recognise the impact that network charges have on household and business costs, and the importance customers place on receiving value for money alongside reliable and resilient network performance.

Overall residential customer awareness of the benefits of managing peak electricity demand is low, however, customers generally have some flexibility in shifting energy use to 10pm or 11pm, especially when it comes to using their dishwasher or doing laundry for benefits such as lower electricity bills, higher use of renewable electricity or increased power reliability.

Around 30% of Vector's residential customers are on time-of-use plans and a further 28% are very interested in these types of plans, mostly driven by the desire to save on electricity bills. TOU customers tend to time shift activities like laundry, space heating, using the dishwasher or EV charging during 9pm to midnight. Cooking, taking showers/baths and entertainment activities show much less time-shifting, likely driven by inconvenience. This behaviour is linked to parts of the Vector network peaking at 9pm.

In this context, Vector's approach to affordability is grounded in operating efficiently, making prudent investment decisions, and ensuring that expenditure delivers clear customer and system benefits. Customer insights help inform how value is perceived, reinforcing the need to balance cost, reliability, and resilience rather than focusing on price in isolation.

The business continues to pursue efficiency opportunities across operations and maintenance, explore the use of advanced analytics, automation, and AI-enabled tools to improve asset visibility, target interventions, and reduce avoidable costs over time. These efficiencies support better utilisation of existing assets and help moderate cost pressures while maintaining service levels.

While distribution prices influence just a quarter of the customers' total electricity bills, customers experience affordability primarily through the bill and communications provided by their retailer. For this reason, Vector sees value in closer coordination with retailers on how pricing changes and time-varying signals support new products and services for customers, and how customers are supported to respond.

Through this approach, Vector seeks to demonstrate value to customers by delivering reliable and resilient outcomes as efficiently as possible, while maintaining transparency and accountability within the regulatory framework.

4.7.7 LOOKING AHEAD

Vector is committed to improving customer experience and deepening our engagement with customers. We are focussed on making improvements now and into the future.

4.8 Working with energy retailers and energy service providers

Retailers are a key interface for customers: they hold the billing relationship, provide customer communications (beyond outage and connection information), and increasingly enable customer participation in new product and technology offerings. In parallel, a growing set of energy service providers (including flexibility providers and technology platforms supporting smart devices) will influence how customers use electricity and how distributed energy resources interact with the network. For Vector, these parties are important partners in delivering customer outcomes - particularly affordability and reliability - because they can influence customer behaviour and technology settings at scale.

Vector's Symphony strategy anticipates that demand-side orchestration and other non-network solutions can materially improve long-term affordability and support an equitable transition as customers deploy distributed energy resources. In this context, retailers and other flexibility providers are expected to play a growing role in the rollout of managed load (for example, managed hot water and managed EV charging). To support this transition in a way that protects network safety and integrity of supply, Vector is progressing the operational and commercial foundations required for effective coordination, including clearer expectations around interoperability, data exchange, and load management practices. This includes developing consistent protocols (including load management protocols) that support predictable and transparent coordination between Vector and retailers managing customers' load on the network.

Vector also sees value in closer retailer collaboration to support new pricing innovation, including time-varying pricing and managed device offers. Over the past 12 months we have engaged deeply with energy retailers' pricing and product innovation teams to understand their direction and how our pricing could evolve to support outcomes that are good for customers, positive for retailers and beneficial for the network. Building on our existing analytical capability, Vector will continue to evolve how we use insights, research, and community engagement to contribute to real outcomes for customers experiencing bill stress. Where appropriate governance settings are in place, this creates opportunities for joint analytics and more targeted interventions - supporting customers to respond to price signals, improve energy literacy, and adopt practical measures that reduce bills without compromising customer needs, health, or safety.

4.9 Energy transition and customers

Customer and stakeholder insights show that support for the energy transition is strongly influenced by affordability, reliability, and resilience considerations. While decarbonisation, network modernisation, and new energy technologies are important to customers, they are consistently considered behind core priorities including reliability affordability and resilience. This highlights the importance of delivering the energy transition in a way that provides clear value to customers and avoids placing undue cost or risk on households and businesses.

Customers expect Vector to play a role in enabling the energy transition, particularly as electrification of transport, heating, and industrial processes continues. At the same time, customers recognise that the transition introduces new uncertainties around capacity, reliability, and cost. Customer insights reinforce the need for Vector to take a balanced approach—supporting new technologies and electrification while maintaining a strong focus on system reliability, resilience to extreme weather, and long-term affordability.

Vector's approach to the energy transition is informed by these insights and focuses on solutions that deliver multiple benefits. This includes prioritising initiatives that support reliability, affordability, and decarbonisation simultaneously, and using demand-side flexibility, network orchestration, and non-traditional solutions to reduce the need for higher-cost network investment over time. Vector also continues to monitor customer uptake of electric vehicles, distributed generation, and storage, incorporating a range of uptake scenarios into long-term network planning to assist the network in supporting future needs. Our approach to modelling future customer demand management network growth is outlined in section 10.

Engagement with customers, industry participants, and government agencies plays an important role in this approach. Larger customers value early engagement and information sharing to support their own decarbonisation planning, while smaller businesses and residential customers seek clearer guidance and confidence that the transition will be affordable and reliable. Through ongoing engagement, data-driven planning, and participation in cross-industry initiatives, Vector seeks to support an orderly and equitable energy transition that aligns with customer expectations and system constraints.

4.10 Managing conflicting interests

With numerous customer segments and stakeholders with diverse interests, it may happen that not all stakeholder interests can be accommodated, or that conflicting interests exist. From an asset management perspective, these are managed by:

- Clearly identifying and analysing any conflicts (existing or potential);
- Seeking an acceptable alternative or commercial solution based on a set of fundamental, consistent and transparent principles;
- Engaging directly with interested groups or more widely if appropriate;
- Effective communication with affected parties to assist them to understand Vector's position, as well as that of other parties or groups that may have different requirements;

In developing solutions where conflicting interests exist, Vector strives to achieve consistency, transparency and fairness.

Conflicts can also arise where customer interests, retailer propositions, and network requirements do not naturally align - for example, where customer-facing incentives encourage behaviour that increases local network peak demand or introduces operational risk. In these situations, Vector will continue to apply consistent, transparent principles to protect system integrity and fairness, while working with affected parties to identify practical alternatives that preserve customer choice.



SECTION 05

Asset management at Vector

5 – Asset management at Vector

This section describes the framework that supports and enables Vector's asset management practice.

Vector's asset management practice is a multi-utility practice that includes electricity, gas and fibre communications assets. Much of the enabling framework applies equally to each of those utility networks, however where a practice at Vector relates specifically to its electricity distribution network it is called out in this section.

5.1 Electricity, gas and fibre strategy

At Vector, we want all our customers to have access to clean, reliable, safe and affordable energy. The electricity, gas and fibre strategy sets the management direction for effective and efficient management of Vector's electricity assets and how it contributes to achieving Vector's vision of "*Creating a new energy future"* . The strategy defines the purpose of the Electricity, Gas and Fibre business to:

Create an affordable, reliable & safe energy system that meets customer needs & efficiently manages network demand.

By collaborating across Vector, the industry and through strategic partnerships we will:

ELECTRICITY, GAS AND FIBRE STRATEGY

1. **Operate safely as one team**
2. **Step change in our service to customers**
3. **Invest in our networks wisely and efficiently**
4. **Modernise, systemise & automate processes**
5. **Enable Auckland's growth & electrification**
6. **Enable the new energy future**

5.2 Asset management policy and principles

Our Asset Management Policy supports our vision of creating a new energy future by setting clear principles (detailed below) to guide the development of Vector's asset management objectives and plans. Our policy principles deliver against all of the element of the electricity, gas and fibre strategy and represent Vector's values, commitments and strategic pillars which apply to all employees and partners (field services providers, contractors and suppliers), involved in the management of Vector's electricity assets.

ASSET MANAGEMENT PRINCIPLES

1. **Safety is our highest priority, and we strive to achieve zero harm to employees, contractors, and the public through the management of our assets over their entire lifecycle.**
2. **We deliver network services at the highest possible level of quality, resilience and availability, and focus on meeting regulatory standards for network reliability and security of supply.**
3. **We strive to optimise the total lifecycle costs of our assets in ensuring the safe, reliable, resilient, efficient, and affordable provision of energy related services.**
4. **We implement a well governed, measurable and auditable asset management system to assure alignment of all standards, processes and activities in delivering network asset management services**
5. **We manage asset and systematic risk effectively through innovative risk models, data, analytics, and market driven insights, and continuously adjust our approaches to manage new and emerging risks such as cybersecurity, privacy, and climate change.**
6. **We manage the impact of our assets on the environment while supporting both Vector and our customers' decarbonisation objectives.**
7. **We utilise broad expertise to best deliver all asset management activities by engaging commercially but collaboratively with our partners to encourage open and clear communication to leverage diversity of thinking and experience**
8. **We have a culture of objective decision making, and continuous improvement where we measure the performance of our network assets and effectiveness of our asset management system and seek to continuously improve our asset management system.**
9. **We ensure the continual development of the asset management capability of the Vector team through effective training, professional development and investment in supporting systems and resources.**

5.3 Asset management objectives

Vector's asset management strategy is aligned with and gives effect to Vector's wider corporate strategies and policies including risk management, safety, sustainability and information governance. The strategy is lifecycle-based, covering the acquisition, operation, maintenance, renewal and retirement of network assets. This AMP translates that strategic intent into objectives, asset class strategies and forecast work programmes for implementation. Delivery of the AMP is managed through defined governance and control processes that monitor and manage cost, risk and network performance during implementation, with outcomes informing continuous improvement.

The above ensures each AMP is realistic and the objectives set out in the plan can be achieved. Furthermore, sections 6.1 and 6.2 provide an overview of Vector's governance and organisational structure, accountable for delivering effective and fit for purpose asset management planning.

Our asset management objectives have been developed in alignment with the principles set out in the Electricity, Gas and Fibre strategy (section 5.1) and our Asset Management Policy (section 5.2). The objectives provide detailed guidance to asset management practitioners enabling appropriate asset management plans and activities to be developed and set and consider our operating environment and represent specific stakeholder requirements. When an AMP is published, we consult with key customer and stakeholder groups and use this ongoing engagement to inform future AMPs.

Vector accommodates stakeholder interests by translating the needs identified through our stakeholder engagement (see section 4) into:

- Asset management objectives (table 5.1);
- Measurable service and performance commitments (including safety, quality and security of supply obligations;
- The planning, prioritisation and delivery processes that govern our asset lifecycle activities.

These interests are embedded in our day-to-day asset management practices through our risk-based investment prioritisation, standards and maintenance regimes, and our governance and review processes for AMP development and delivery. Where stakeholder interests compete, trade-offs are assessed through structured decision-making that considers cost, risk and performance impacts, and outcomes are reflected in investment and maintenance plans and communicated through our engagement channels.

Sections 6–15 details asset management practices for these objectives. Stakeholder feedback shaped the prioritisation, discussed in relevant sections.

FOCUS AREA	OBJECTIVES	AM PRINCIPLES	STRATEGY ELEMENT
Safety, environment and network security	• Prevent harm to workers, contractors and the public through our work practices and assets so far as is reasonably practicable. • Ensure health and 'safety always' is at the forefront of decision making for the business. • Comply with relevant safety and environmental legislation, regulation and planning requirements. • All staff are competent and trained in their applicable roles with the right equipment available to work safely and effectively. • Asset management activities align with environmentally responsible and sustainable behaviours, in line with industry best practice, enabling wider emissions reductions. • Minimise the impact on the environment with regards to our assets and work practices. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change). • Key performance measure: Total recordable injury frequency rate (TRIFR); Asset safety incident measure.	1, 6	1, 6
Customers and stakeholders	• Enable customers' future energy and technology choices. • Provide a high-quality customer service experience across all interactions. • Listen to and learn from our customers to ensure our service offering aligns with customer expectations. • Consider the impact of our operational decisions on customers and minimise the disruption of planned outages and unplanned outage response times. • Ensure the long-term interest of our customers by endeavouring to provide an affordable and equitable network. • Key performance measure: Notified Planned Interruption Accuracy; Average Grade of Service (GOS); Speed of quotes for new connections.	2, 4, 5, 7, 9	2, 3, 4, 5, 6

FOCUS AREA	OBJECTIVES	AM PRINCIPLES	STRATEGY ELEMENT
Network performance and operations	• Comply with regulatory quality standards set out in the DPP4 Determination. • Maintain accurate and comprehensive information management systems to drive continuous improvement of our asset health database and information records and meet regulatory reporting obligations. • Continual improvement of our asset management system and alignment to ISO 55001. • Strive to optimise asset lifecycle performance through increased asset standardisation, clear maintenance regimes and the development of fact-based investment profiling. Utilise clear business case processes, integrate risk management and complete post investment reviews to inform our decision making and analysis. Maintain compliance with Security of Supply standards through risk identification and mitigation. Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. Collaborate with teams throughout Vector to leverage different thinking, skillsets and asset management capabilities. Ensure continuous improvement by reviewing and investigating performance and embedding learnings. • Manage performance of field service providers through effective commercial arrangements and regular review. • Key performance measure: SAIFI; SAIDI; Customer interruptions performance against agreed service standards.	2, 3, 4, 5, 7, 8, 9	3, 4, 5, 6
Future energy network	• Prepare the network for future changes that will be driven by: – technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc. – environment: climate disruption and network resilience – customer: decarbonisation of the economy, electrification of transport, etc – operations: transition to distribution system operator model and whole of system planning • Embed network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third party flex traders and retailers. • Facilitate customer adoption of new technology while ensuring a resilient and efficient network. • Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network. • Develop digital and data platforms to meet changing customer needs and enable the future network in partnership with new entrants to the energy market. • Improve our visibility of, and ability to control, the LV network including management of the information required. • Collaborate with industry, partners, thought leaders and subject matter experts to ensure Vector remains at the leading edge of future energy solutions.	2, 3, 4, 5, 6, 7, 9	2, 3, 4, 5, 6

TABLE 5-1: VECTOR ASSET MANAGEMENT OBJECTIVES

5.4 Asset management system

Vector's Asset Management System turns organisational asset management objectives into business practice and actions. It is managed by Vector and provides a clear line of sight from Vector's vision and strategic objectives to asset management plans.

The framework for our Asset Management System is shown in the diagram below.

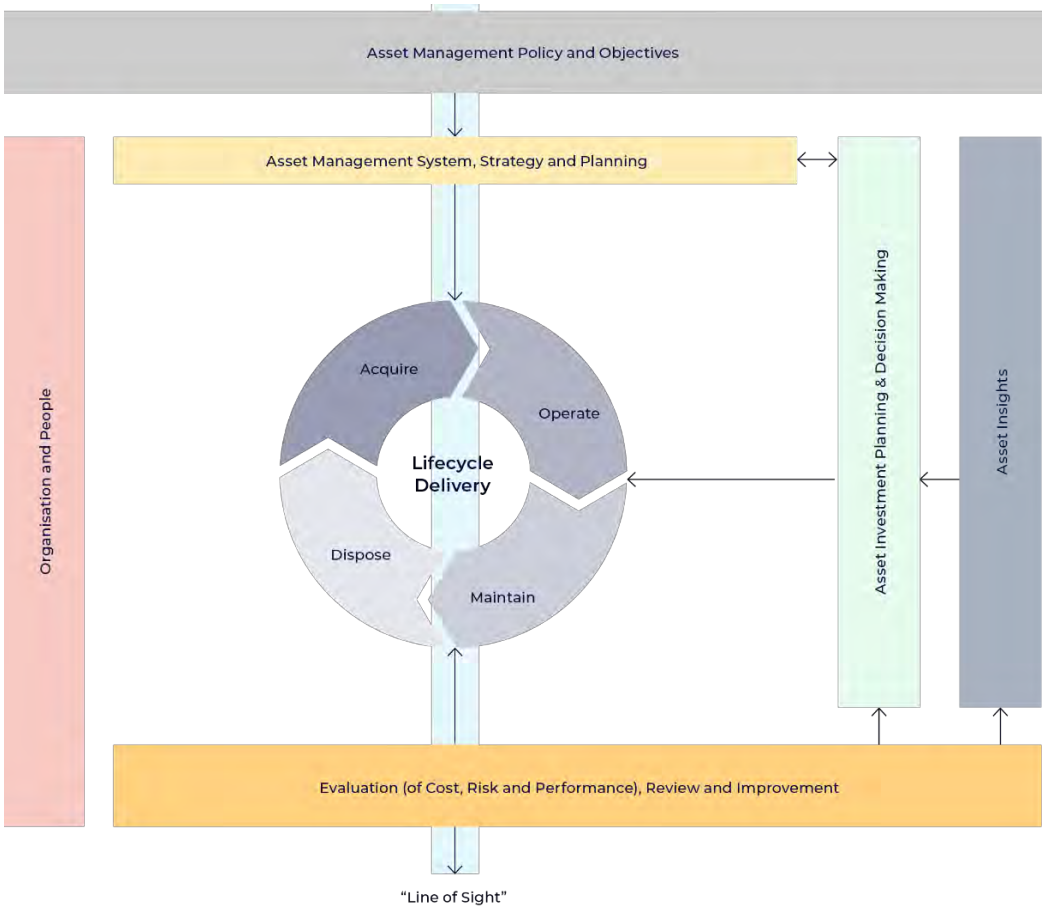


FIGURE 5-1: VECTOR'S ASSET MANAGEMENT SYSTEM FRAMEWORK

Continuous improvements in our practices, with supporting cost, risk and performance monitoring, as well as data-driven reporting, ensure a full "Line of Sight" throughout the asset management governance structure, from Asset Management Objectives to localised asset-level performance. We continuously measure and review progress against Asset Management Objectives to provide assurance and to respond quickly to changes in our operating environment.

Documentation, control and review processes apply to all key components of Vector's asset management system, including delivery programmes, and reviews are undertaken on a scheduled and event-driven basis to ensure documents remain current, compliant and fit for purpose, with review outcomes informing continuous improvement of the asset management system. Sections 16.2 and 16.4 of this AMP describe the governance processes for major capital works and maintenance works delivery. Where findings are identified that influence asset risk, they are actively managed to idnetify and impleemnt treatment plans and documented in the asset startegy for the relevant asset class.

Vector is continually advancing its asset management practices to best position ourselves to achieve its objectives and ultimately its vision of a new energy future. This journey includes alignment of our asset management system to ISO 55001.

5.5 Asset management key documents

Vector uses a hierarchy of document types to govern the asset management system, at the level of detail and focus required for different stakeholders (see Figure 5.2). This hierarchy provides a traceable link between Vector's asset management strategy and delivery and this AMP. Policy and strategies set direction, standards and processes define how that direction is applied.

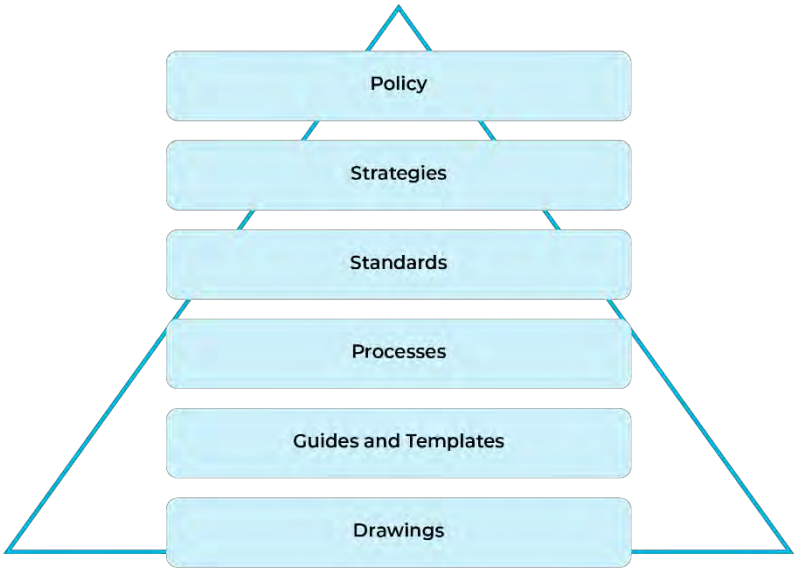


FIGURE 5-2: VECTOR DOCUMENT HIERARCHY

5.5.1 STRATEGIC DOCUMENTS

This table sets out the key strategic documents relating to Vector's asset management framework. Our strategic documents are subject to change control. The change control process obtains feedback and approval of the controlled document and related change impacts prior to publication.

DOCUMENT	ROLE IN ASSET MANAGEMENT PRACTICE
Asset management policy	This policy is Vector's formative asset management document. It defines the principles that guide all aspects of our asset management practice including the development of objectives and plans.
Strategic asset management plan	As part of our working towards alignment with ISO 55001, we are defining the scope and requirements of the Electricity asset management system. The AMP sections 1-7 describe the organisational context, stakeholder needs, asset management scope, system scope and objectives, as such the requirements of a SAMP are fulfilled by sections 1-7 of the AMP.
Asset class strategies	These strategy documents facilitate the annual development of the AMP through formally recording asset strategies at the asset header class level for our different asset classes.
Delegated authority (DA) framework	The delegated authority framework applies to all business activities that have financial or non-financial consequences including contracts and expenses. The delegated authority framework sets out specific approvals for transactions and governs the level of financial commitment that individuals can make on behalf of Vector. All decisions within our asset management practice that require expenditure or involve significant risk will be made under this policy and in accordance with Vector's project approval process.
Risk management policy	This policy provides the overarching risk management intent that Vector strives for. Its purpose is to: a) outline our key risk management objectives and the principles underpinning them, b) Outline the Vector risk appetite baseline c) provide a framework for optimising opportunities and minimising risks, d) demonstrate Vector's understanding and commitment to promoting a culture of risk awareness throughout the organisation, and e) define key risk management roles, responsibilities, accountabilities and reporting requirements.
Electricity maintenance strategy	This strategy outlines the maintenance approach and activities carried out on Vector's electrical network. Maintenance is a key asset management activity that ensures that network assets deliver to Vector's asset management objectives by achieving a high degree of safety, reliability, functional performance and optimised through life cost.

DOCUMENT	ROLE IN ASSET MANAGEMENT PRACTICE
Health and safety policy	This policy sets out Vector's commitments and requirements for health and safety. Vector will conduct its business activities in such a way as to protect the health and safety of all workers, the public and visitors in its work environment.
Sustainability policy	This policy provides Vector's framework for managing environmental, social and governance risks and opportunities. It includes commitments to recognised international agreements and sets out the key principles by which sustainability will be adopted within the business.
Supply chain and procurement policy	This policy provides Vector's framework for building supplier capacity and capability enabling more effective management of network and supply chain risk, realisation of value and assist in achieving Vector's strategy to reduce its carbon footprint
Electricity safety and operating plan	The safety and operating plan has been developed for Vector's electricity network to detail the controls in place to mitigate the risks that have been identified under the hazard and risk assessment processes for minimisation of harm to persons, property, the public and the environment, including emergency response.
Group data and information policy	The purpose of this policy is to govern and guide Vector's key data and information principles and includes everyone's responsibilities regarding data. Data and information refer collectively to all records and documents (both physical and electronic) used to describe and document Vector's business.

TABLE 5-2: VECTOR ASSET MANAGEMENT STRATEGIC DOCUMENTS

5.5.2 STANDARDS

Standards and specifications are an integral part of our asset management framework. These state the levels of service, performance targets, define intervention levels and minimum performance criteria.

The table below lists the major standards that support the procurement, supply, commissioning, operation and maintenance of existing, new or replacement assets. Our technical specifications and engineering and maintenance standards are listed in detail in Appendix 2. These documents are improved under a defined change control process and document revision control process as described in Vector standard USD001 Controlled document management. Change control ensures agreement between the document author, our field service providers and all end users in Vector. Change control obtains internal and if our field service providers are involved, external feedback and approval of the controlled document and related change impacts prior to publication.

ASSET STANDARD	ROLE IN ASSET MANAGEMENT PRACTICE
Planning standards (ENS series)	These standards guide the planning and development of Vector's overall distribution network architecture. They work in conjunction with the Security of Supply Standards (SoSS) service level metric to ensure that the network has sufficient capacity and capability to provide the required service levels, enable customer connections, accommodate growth and allow for the orderly and safe connection of distributed generation. These standards also set requirements that enable the appropriate operation of the network in accordance with the Network Operating Standards.
Maintenance standards (ESM series)	Vector has developed a set of maintenance standards for each major class of asset that detail the failure modes, required inspections, condition monitoring, maintenance and data capture requirements. Where a cyclic maintenance strategy is applied these standards also set out the maximum maintenance cycle frequency.
Network operating standards (EOS series)	These standards define protocols and procedures for operating and controlling Vector's electricity network, including contingency plans. They also inform the minimum requirements for network planning and design practices.
Design and construction standards (ESE and ESS series)	These standards and their accompanying standard design drawings cover the detailed design and installation of Vector's network equipment. They also include the data capture requirements for our asset management systems and plant in Vector's network.
Technical specifications (ENS series)	Technical specifications specify the materials and equipment to be used on the electricity network and the quality and performance requirements with which the materials and equipment must comply.
AS/NZ standards IEC standards	Australian and New Zealand standards as well as International Electrotechnical Commission (IEC) standards are referenced extensively in our standards and scopes of work.

TABLE 5-3: VECTOR STANDARDS

5.5.3 Standardised assets and designs to promote cost-efficiency

Vector uses standardised assets and standard designs as a core mechanism to improve cost-efficiency, consistency, safety, and quality across the electricity network while maintaining required service levels and asset performance. Standardisation reduces design and construction variability, enables efficient procurement and delivery, and supports predictable whole-of-life asset performance.

The use of standardised assets and designs supports cost efficiency by:

- Reducing bespoke engineering effort and design rework for common network applications
- Enabling economies of scale in procurement and inventory management
- Supporting standardised and efficient maintenance regimes to assure asset performance
- Reducing whole-of-life costs through installation, stores holding and maintenance support that is scaled at volume.

These standardised assets and designs are defined through Vector's design and construction standards (ESE and ESS series) and technical specifications (ENS series), and associated standard design drawings, which together define approved equipment types, configurations, installation requirements, and data capture expectations.

Standardisation is applied across Vector's asset base, including:

- Power transformers, switchgear, distribution substations and OT systems are based on standard equipment types, ratings, interfaces, and installation arrangements.
- Zone substations are based on standard layouts, equipment configurations, protection philosophies, earthing arrangements and spatial requirements for indoor and outdoor substations. However, due to local requirements and constraints (e.g. scale, physical space, site orientation, consenting, demand), bespoke designs are required to optimise for construction.
- Distribution substations are based on standard layouts and equipment types facilitating efficient easements and standardised earthing arrangements. Where site specific constraints are encountered standard designs allow a degree of adaptability, and where required, bespoke designs are managed as engineering deviations with specific engineering analysis to assure safety, supportability and asset performance.
- Overhead and underground network components, such as poles, crossarms, conductors, cables, insulators, fittings, and standard construction arrangements for typical network application.
- Investment in digital tools, such as Neara and GridAware, to enable inhouse ability to create bespoke designs inhouse and manage the network more efficiently

Standard designs are developed for repeatable and high-frequency network applications where a consistent solution delivers efficient outcomes without compromising safety or performance. Standard designs are aligned with network planning standards, network operating standards, and maintenance standards to ensure assets can be operated and maintained efficiently over their lifecycle. Feedback from EOC, engineering design consultants, maintenance and delivery teams is incorporated to ensure designs are practical, repeatable, and suitable for construction, operation and maintenance.

Standardisation therefore complements Vector's broader standards framework by translating technical requirements and service level objectives into practical, cost-effective network solutions that can be consistently applied across the network.

5.6 Asset management and asset management maturity

Developing our asset management maturity is a key focus of continuous improvement for Vector. We review our asset management practices using the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT).

At an overall level, our asset management maturity compares well with generally accepted New Zealand electricity asset management practices to ensure the ongoing safe and efficient operation of the electricity network. Our approach has matured progressively with our self-assessment improving year-on-year from an overall AMMAT score of 2.77 in 2019, 2.87 in 2021 and 3.01 in 2023. Our current score of 3.03 reflects the effort made to continuously improve our asset management practice. Note that Vector has taken the approach of not solely using whole numbers in our AMMAT scoring to better reflect the efforts we have made in continually improving our asset management maturity.

Our asset management maturity assessments are reviewed by senior management and used to inform AMP development, investment prioritisation and improvement planning. Where the AMMAT assessment identifies material gaps against relevant asset management objectives and these are not attributable to one-off factors, Vector defines planned improvement initiatives to address those gaps. Progress against maturity improvement actions is monitored as part of Vector's asset management governance framework. Vector has an asset management 2030 initiative to uplift asset management capability progressively to the year 2030 and aim to achieve a target score of three on each AMMAT rating criteria, and to align to ISO 55001 in the longer term. Also note that after each AMP cycle, we do a debrief with internal stakeholders to discuss lessons learnt and identify areas for improvement in the next AMP cycle.

For our latest AMMAT self-assessment, refer to Schedule 13: Report on Asset Management Maturity in the Appendices section (Appendix 12). Set out below is an overview of the primary areas where ongoing improvements in our asset management practise are being implemented.

Vector Electricity has initiated a strategy to uplift the capability of the asset management system by 2030. The intent for *Asset Management 2030* is for a data-driven, ISO-aligned asset management system that delivers faster, defensible investment and maintenance decisions, with clear data ownership and governance, so that by 2030 we can evidence improved reliability, resilience and cost-efficiency across the network.

5.6.1 ASSET MANAGEMENT, ASSET MANAGEMENT STRATEGY AND ASSET MANAGEMENT POLICY

Our asset management policy broadly outlines the principles and requirements for undertaking asset management across the organisation. These strategies and goals then translate the strategic intentions into an asset investment strategy. These are documented in the Asset Management Plan. Technical standards, work practices and equipment specifications support the asset management policies, guiding the capital and operational works programmes.

5.6.2 COST, RISK AND SYSTEM PERFORMANCE

Asset management encompasses all practices associated with considering management strategies as part of the asset lifecycle. The objective is to look at the lowest long-term cost rather than short-term savings only seeking a balance between cost, level of risk and performance of the asset. We utilise a risk-based approach that considers the different failure modes of an asset, its condition, criticality scores, probability of failure, likelihood of consequences and a final risk score (our condition-based asset risk models are described in detail elsewhere).

A combined list of proposed projects and initiatives are then prioritised based on a set of agreed business objectives and values with the constraints of resources taken into consideration. The combined list contains our proposed projects and initiatives, high level cost estimates and estimated risks together with investment prioritisation.

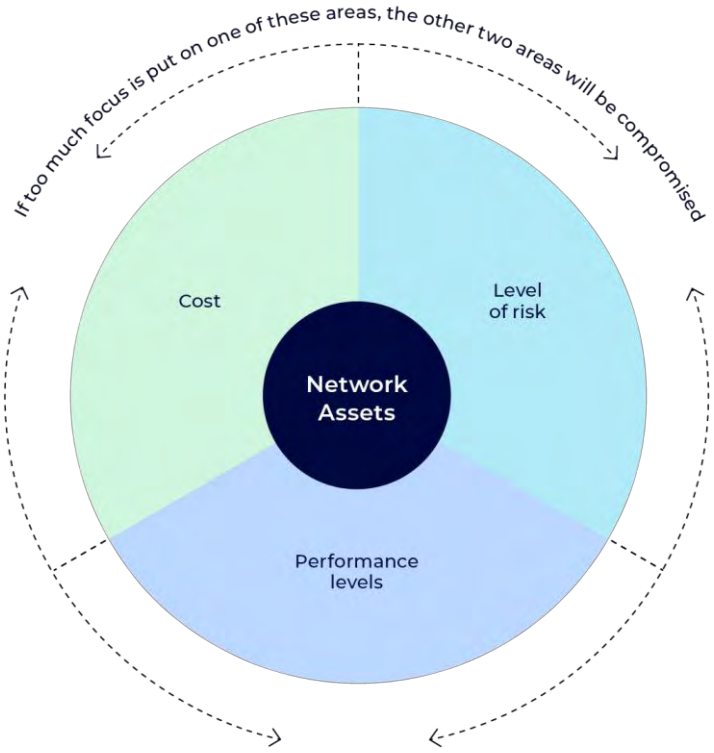


FIGURE 5-3:RELATIONSHIP, COST, RISK AND PERFORMANCE

5.6.2.1 COST

Improvements have been made to our process for creating business cases and justifications for capital projects to arrange capital budgets. A clear business process with stage gates has been compiled that describes the actions that need to be completed prior to moving past a stage-gate to the next stage in the budget and funding process. Our business cases state the risk and need that drives the requirement for a project, alternative options that were considered and the cost for each option. Our works cost estimates are detailed providing an overview of the total estimated cost of the works, the portion that is required to develop the design of the works, funding required for early procurement of long lead items and the portion required to move to full project funding. Business cases and cost estimates undergo a rigorous peer review process and then a controlled approval process via our SAP business software workflow procedure.

Vector Programme Management Function provides programme governance and act as custodians for our project management systems, which enable a live and continuous update of the progress of projects, both physical delivery and financial progress. This system allows integrating project time-line forecasts with financial forecast for the delivery of capital projects. It provides a one-stop-shop for improved visibility of projects, associated risks and challenges to the delivery of projects.

A Governance Group is in place with representatives from the Network Performance team and Capital Delivery team that meet on a monthly basis to discuss the asset management plan, challenges, risks, issues, cost, and scope changes. Scope changes are formally recorded.

5.6.2.2 LEVEL OF RISK

Vector business and asset management risks are managed as part of an ISO31000 aligned risk management system supported by Donesafe as the recording application with controls, actions, assignment of responsibilities and target dates for assessment, review and completion. We use a risk matrix that considers consequences and likelihood to assess and score risks. The risk scores are assigned in our Donesafe software application. Initiatives to address a risk could also present itself as an opportunity for new solutions and innovations. In certain instances, risks are accepted within the business, and such decisions are recorded in Donesafe as well as in the corporate risk register.

5.6.2.3 PERFORMANCE LEVELS

Our performance levels for our network supplies are stated in our Security of Supply standard. Our SAIDI and SAIFI are calculated in our advanced distribution management system (ADMS), and the data is retained for reporting and analysis and reported annually to the Commerce Commission in our compliance statement. Our average network customer base is calculated using our Gentrack billing and revenue system application.

When the AMP is implemented, Vector applies an integrated set of delivery controls to ensure expenditure, risk exposure and service performance remain within approved settings. Investment and delivery activities are managed through staged planning and approvals and formal change control with material scope, cost and schedule variation reviewed through established governance procedures. Lessons learned from delivery performance, cost and risk monitoring are used to refine asset strategies and inform future AMP updates as part of Vector's continuous improvement approach. For further details, please refer to section 16.

5.6.3 ASSET HEALTH, MODELLING AND INVESTMENT SCHEDULE

For our asset fleet we have developed an asset strategy for each Header Class asset. These strategy documents clearly describe the asset class equipment, their status and condition, challenges, future management, and maintenance and replacement strategies. These strategy documents thus inform and facilitate the prioritisation of asset replacements, which make up the annual update of the rolling 10-year CAPEX forecast, the capital investment programs and capital budget. Asset investment is reviewed continually as part of governance processes that review asset reliability, and risk, as well as feasibility of delivery. Any forecast changes are incorporated into the 10-year CAPEX forecast, and asset management plan.

The CBARM models have been developed for all major distribution assets. These models which use condition data, risk data, as well as environmental conditions and location, provide a data driven basis for the planning of projects and programmes rather than a pure focus on annual planning within a defined financial budget. The CBARM model incorporates inputs relating to asset configuration, recorded condition data, environmental factors and obsolescence to determine a health score for each asset in the network. A criticality score based on public safety, network impact and environmental impact determine the failure consequences, which when combined with the health score provides a risk profile for each of the modelled asset classes. This risk basis provides a critical input to defining the asset strategies, budget allocations and asset management decisions for capital budgeting, reactive and corrective work. The figure below is a flow diagram for our CBARM models.

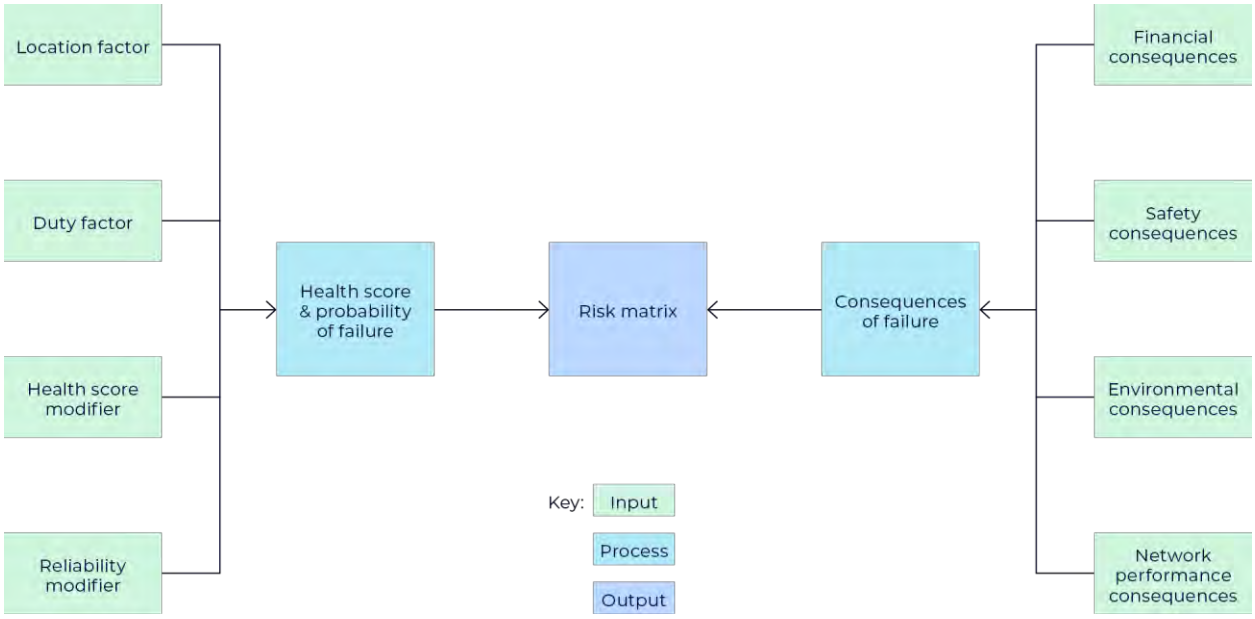


FIGURE 5-4: CBARM FRAMEWORK OVERVIEW (SOURCE: DNO COMMON NETWORK ASSET INDICES METHODOLOGY, 2021)

5.6.4 SYSTEMS AND INFORMATION MANAGEMENT DATA

Vector's Asset Management System is underpinned by enterprise platforms that provide authoritative data and support decision-making. The asset management information systems are covered in section 6.

5.6.5 ASSET MANAGEMENT DOCUMENTATION, CONTROLS AND REVIEW

Document control is stipulated and governed by our standard USD001, Controlled Document Management standard. Policies, strategies, and standards are circulated for reviews and updates via our Sharepoint application including our external partners such as field service providers or consulting engineers. This software platform allows automation in terms of review dates, completion of review dates, review comments etc. It enables a high level of control of the documentation process and a historic record of reviews. Updates of asset management documents, standards, standard drawings are issued via an automated process in this application. Each asset management document has a revision number, current date, and a date at which it needs to be reviewed.

This document control process also applies to outsourced works. The issuing, changes and return of changed documents are controlled via our Meridian software application with a revision recording and history of changes system in place as part of the application.

Reviews are undertaken on both a scheduled and event-driven basis to ensure controlled documents remain current, compliant and fit for purpose. Review outcomes are assessed, approved where required, and incorporated into updated standards, processes and templates, with change communicated to internal teams and delivery partners to support consistent application across AMP delivery.

5.6.6 COMMUNICATION OF THE ASSET MANAGEMENT PLAN

Our website portal (www.vector.co.nz), provides a wide range of asset management information to external parties. It provides information with regard to new connections, connection of distributed generation, outages and faults, work in close proximity to our networks, planned outage notifications, and our asset management plan amongst others. Our asset management plan, for both OPEX and CAPEX are formally communicated with our field service providers via formal meetings and programme of works schedules.

Vector has also launched an Open Data Portal with network asset location information, including distribution and sub-transmission overhead lines and underground cables on Vector's electricity distribution network. The site allows third parties the ability to access location information for electricity and gas feeders electronically. In addition to creating map views, third parties can download the data or connect their systems directly to Vector data. This initiative ensures that infrastructure companies, construction companies and entities like Auckland Council and Civil Defence have access to up-to-date information about Vector assets. This is also another way in which Vector can assist construction companies to prevent third party asset damage.

Our Capital Delivery Team has three portfolio managers who manage the relationships with our construction contractors and consultants including communicating the asset management plan. We also run quarterly contractor forums that includes our key contractors, design and project management consultants, and specialist service providers. We also have strategic relationship and account managers that are continuously connected with other Auckland infrastructure providers and developers.

Section 4 provides more information on stakeholder engagement.

5.6.7 AUDIT OF THE ASSET MANAGEMENT PLAN

Entrust, Vector's majority shareholder, biennially conducts an independent review of the state of Vector's network that includes an assessment of our asset management plan, targets, and outcomes. With support from external asset management specialists, we use these reviews to address gaps and inform our plans to improve our asset management practice. The latest report can be found here https://www.entrustnz.co.nz/media/judn3moo/dreor-network-security-2024.pdf

This Asset Management Plan will be subject to the same independent review process. Vector also undergoes annual safety audits of its network and management practices in terms of NZS7901, Public Safety.

5.6.8 OPERATIONAL MANAGEMENT IMPROVEMENTS

Following the successful commissioning of the Advanced Distribution Management System (ADMS) and completion of Phase 1, Vector is progressing Phase 2 of the ADMS programme, which focuses on extending functionality and embedding advanced operational capabilities. Phase 2 builds on the core SCADA and network visualisation capability already in place and enables the progressive implementation of a modern Outage Management System (OMS), Switch Order Management System (SOMS) and other advanced applications. These include enhanced fault location, improved outage prediction and restoration management, and deeper integration with customer, asset and network data.

Through Phase 2, ADMS will further support control room operations by improving situational awareness, decision support and automation, strengthening safety outcomes, reducing outage duration, and improving overall network performance and resilience. These capabilities support more efficient operational responses to both planned and unplanned events and contribute to improved customer outcomes, including reduced outage impacts and more timely, accurate information during network events.



SECTION 06

Governance, risk management and information management

6 – Governance, risk management and information management

6.1 Overview

This section provides an overview of Vector's governance and organisational structure, accountable for delivering effective and fit for purpose asset management planning. Fundamental to effective governance is a strong awareness and focus on risk management. Therefore, this section also includes an overview of our enterprise risk management framework, key risk practices and event management documentation that includes emphasis on high impact, low probability risks. Finally, our data and privacy management practices are covered, which includes a summary of information systems and our approach to cybersecurity. These elements are key enablers in ensuring Vector's asset management practice.

6.2 Governance and organisational structure

Vector's asset management governance and organisational structure is shown in Figure 6-1. This structure provides oversight and leads all aspects of our asset management practice.

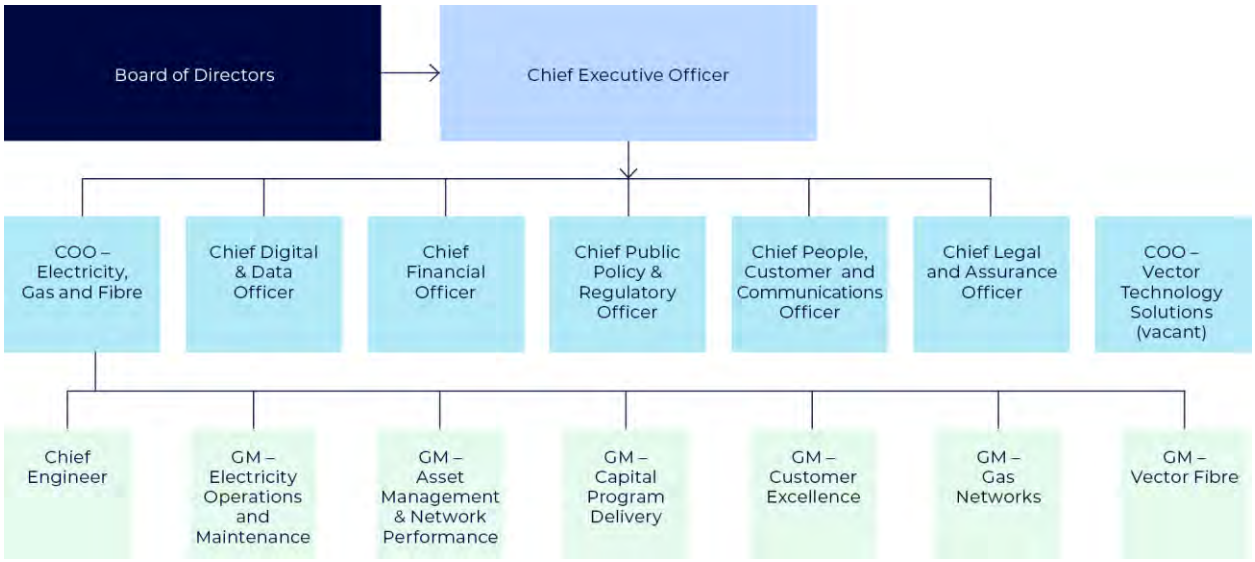


FIGURE 6-1: VECTOR'S ASSET MANAGEMENT GOVERNANCE AND ORGANISATIONAL STRUCTURE

Figure 6-1 pictorially represents the governance and organisational structure accountable for delivering effective and fit for purpose asset management planning for Vector's electricity distribution business. An overview of the asset management accountabilities and responsibilities within three levels of this structure are set out below.

- **Board of Directors** – At the highest level, the board of directors provides governance over all aspects of Vector's asset management practices on behalf of Vector's shareholders. The board exercises oversight of the objectives of asset management (see Section 5 on Asset Management Systems), its strategic direction, process for investment approvals and the customer service level outcomes achieved by Vector's electricity distribution network. Overall budgets, significant expenditures and asset investments are reviewed and approved at the board level.
- Vector's Board of Directors maintains its asset management oversight through the implementation of governing policy, a delegated authority framework, management reporting and periodic reviews including internal and external operational audits. The board also receives performance reporting against key service levels and regulatory reliability targets.
- Further details of Vector's board members, the executive leadership team and our corporate governance structure are available on our website.
- **Chief Executive Officer** – Under the delegated authority framework, the approved strategic plan, approved annual budgets, and day-to-day operation of the business is the responsibility of the Chief Executive Officer (CEO). The CEO maintains oversight of Vector's asset management practices, including effective risk management (both strategic and operational), service level outcomes, strategic direction and investment approvals. To assist with this oversight, the CEO receives performance reporting against key metrics and service levels, which includes reporting against regulatory reliability targets.
- **Chief Legal and Assurance Officer** – Under delegation from the board and the CEO, the Chief Legal and Assurance Officer is accountable for providing Vector's legal advice as well as policy, frameworks and governance for enterprise risk and resilience, assurance, health, safety and environment, compliance and privacy (via a dedicated Privacy Officer). Responsibility for the delivery

of these functions at a business unit level is appropriately disseminated and delegated throughout the business through dedicated management functions and ownership models.

- **Chief Operating Officer – Electricity Gas & Fibre** – Under delegation from the board and the CEO, the Chief Operating Officer (COO) has full responsibility for Vector's electricity asset management practice. This includes the establishment and enforcement of Vector's Asset Management Policy, the overall performance of Vector's electricity distribution network, development and implementation of the approved AMP, and budgetary control within the delegated authority framework.
- **Chief Engineer** – Integral in strategic business model design and strategic business opportunities, this role works alongside project teams and executive sponsors to ensure Vector's electricity networks and services are of the best practicable quality. This includes using cutting-edge digital technologies to deliver affordable for customers energy safely and effectively.
- **General Manager Electricity Operations and Maintenance** – This role is accountable for network operational performance, contractor-managed field crews and the Electricity Operations Centre (EOC). Vector's field crew are managed through an outsourced contracting model. As such, the GM Electricity Operations and Maintenance is accountable for the contractual relationships and performance of field crews delivering our maintenance programme. Work is centred around the delivery of CAPEX and OPEX maintenance plans in accordance with Vector standards and reactive response to outages.
- **General Manager Asset Management and Network Planning** – This role is accountable for future network planning, capital and maintenance investment planning, and developing detailed asset management plans and standards for all asset classes required to achieve Vector's asset management objectives.
- **General Manager Capital Programme Delivery** – This role is accountable for the delivery of the annual capital programme, including project engineering, project management, and procurement and tendering of capital works.
- **General Manager Customer Excellence** – Acts as the critical link between asset management delivery and Vector's customers, driving high-quality, customer-focused operational performance across EGF. The role is accountable for end-to-end execution of customer contracts, connections, and programme delivery, ensuring strong regulatory compliance and disciplined commercial governance.
- **General Manager Gas Networks** – This role is accountable for asset management planning and delivery for Vector's gas distribution business. All asset management roles support the enhancement of electricity asset management through synergies and cross-functional skillsets.
- **General Manager Fibre** – This role is accountable for asset management planning and delivery for Vector's Fibre business.

The governance framework overarching each of these roles is supported by the Code of Conduct and Ethics, Vector's Delegated Authority Framework (DAF), and position descriptions for each role. Vector's Board has delegated specific authorities to the CEO and authorised delegation of certain authorities to other levels of Vector's management. The limits and rules applied to delegations are prescribed in the DAF documentation and govern the authority to commit to transactions or expose Vector to risk.

Vector's Enterprise Resource Planning (ERP) System (SAP) is the primary management system used to implement the DAF. Financial delegations for approvals under the DAF for OPEX and CAPEX are set and managed within Vector's SAP system. A periodic audit of the DAF is undertaken to ensure ongoing compliance. The ERP system also provides control of asset management workflows, as well as the management of information that enables our asset management and project management practices.

6.3 Risk management

6.3.1 ENTERPRISE RISK POLICY AND FRAMEWORK

Risk management practices form an integral part of Vector's asset management processes. Vector's Risk Management Policy establishes clear principles which provide for a purpose-built flexible approach to the application of risk management across Vector.

Our activities in risk management:

a) Create and protect value in our organisation;

b) Form an integral part of all organisational processes and decision-making;

c) Explicitly address uncertainty;

d) Are systematic, structured and timely;

e) Are customised to suit our organisational context and individual business activities;

f) Take into account human and cultural factors;

g) Are transparent and inclusive; and

h) Are dynamic and responsive to change.

The above principles form the basis of Vector's risk management approach allowing for the development of risk management objectives and a clear framework that is applicable across the Vector Group. Our Enterprise Risk Management (ERM) framework is based on the international standard for risk management, ISO 31000. It allows for a single, company-wide view of risk, aligning several profiles and contexts across Vector, to support the achievement of our strategic objectives.

Vector's ERM framework (summarised below in Figure 6.2) is focused on understanding, monitoring and proactively treating the uncertainty and risks within the business. The management and tracking of identified risks and associated treatment plans are undertaken using Vector's ERM system.

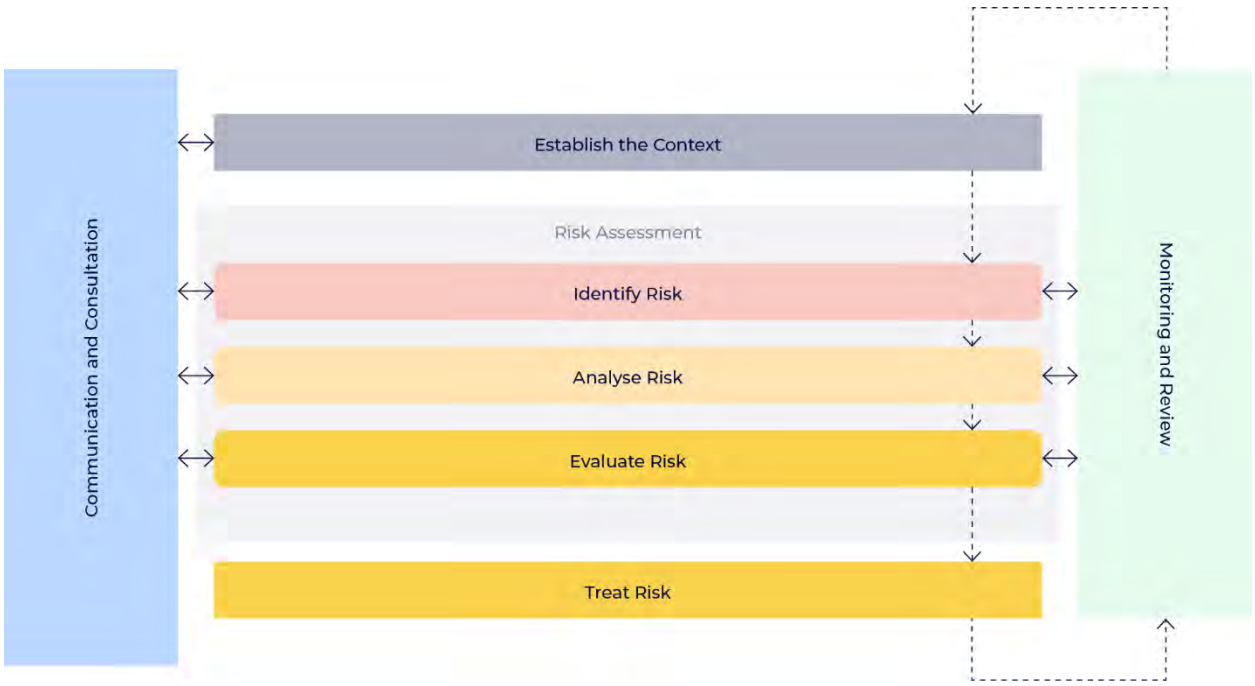


FIGURE 6-2: VECTOR'S ENTERPRISE RISK MANAGEMENT FRAMEWORK

Vector's risk management processes and tools are embedded within its business operations to drive consistent, effective, and accountable decision-making. All Vector people are responsible for applying Vector's ERM framework within their individual roles to proactively identify, analyse, evaluate, and treat risks. This risk mindset is consistent with the "Three Lines Model" and has been implemented through:

- Awareness of risk management's value at operational, executive team and board level;
- Embedding of risk assessments and discussions within key decision-making processes; and
- Continuous development through both internal and external reviews.

6.3.2 RISK PROFILES

Vector operates both a top-down and bottom-up approach to risk management.

At the top level, the board sets the risk appetite and strategic direction for the business. The board has established a Board Risk and Assurance Committee (BRAC)[8] which assists the board in fulfilling its responsibilities to protect the interests of shareholders, customers, employees and the communities in which Vector operates. The BRAC provides oversight of Vector's risk and assurance policies and practices, monitors risk performance concerning Vector's risk appetite and business objectives, provides guidance regarding the development of the ERM framework, and ensures rigorous processes for internal control and legal compliance.

Vector's Group Risk function (reporting to the Chief Legal and Assurance Officer) is tasked with the ongoing development and implementation of the ERM framework and risk processes. In addition to monitoring the changing risk landscape and macro-economic trends, this function integrates and works with all Vector business units to facilitate smart risk-based decision-making as well as consistent bottom-up risk analysis and evaluation of risk against Vector's risk appetite. These perspectives inform the development of the Group Key Risk Profile which provides both the board and executive team with a consolidated view of:

(i) the strategically focused risks which could have a significant impact on the long-term value and sustainability of Vector's business; and
(ii) the material operational risks facing Vector as part of its business-as-usual activities which require significant oversight and control.

To inform the Vector Group key risk profile, business unit and operational risk profiles are developed based on the objectives and operating context specific to each business unit. Key risk indicators are applied to monitor risks against Vector's risk appetite, ensuring risk visibility and supporting appropriate mitigation measures as necessary. Figure 6-3 shows the alignment of Vector's risk profiling structure.

[8] The BRAC contains at least three members of the board.

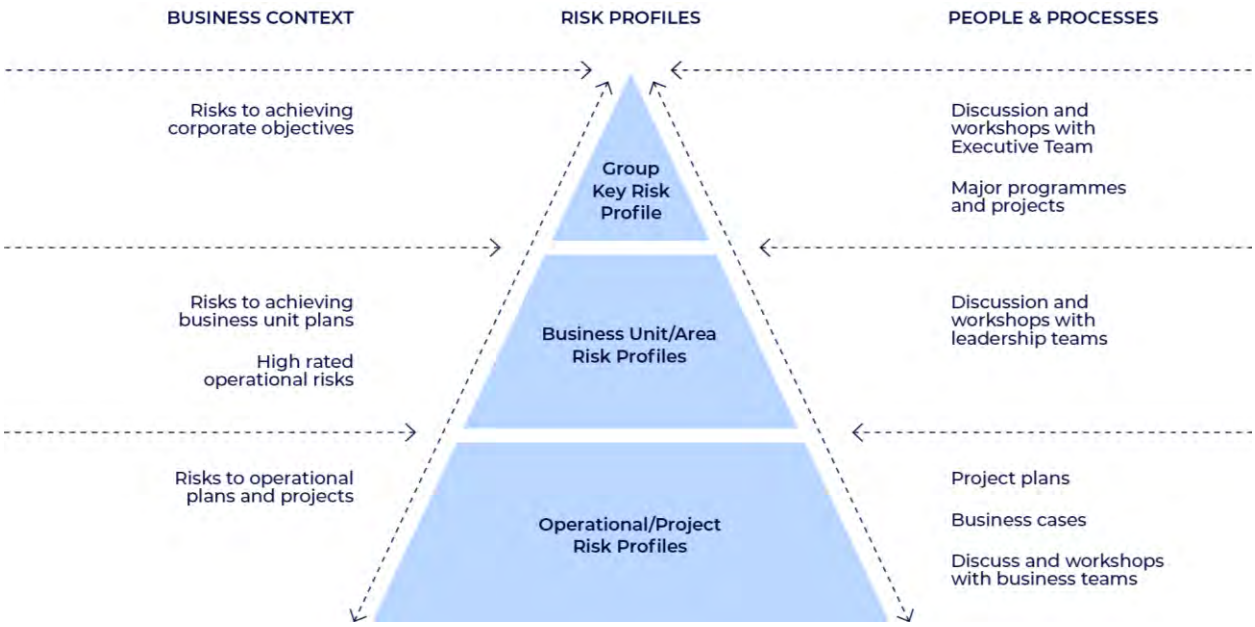


FIGURE 6-3: VECTOR'S RISK PROFILING STRUCTURE

6.3.3 ELECTRICITY DISTRIBUTION RISK MANAGEMENT

The development of Vector's electricity distribution risk profile broadly considers eight risk groupings (Figure 6-4). Risks across various teams are analysed and evaluated against Vector's risk criteria and then treated to modify the risk level if required. Risk treatment considers the level of risk tolerability which is informed by applicable legislation and industry standards (including the Health and Safety at Work Act and the Electricity Act).



FIGURE 6-4: ELECTRICITY DISTRIBUTION RISK GROUPINGS

Vector's risk management processes are integrated into the asset investment process and the development of asset class strategies to ensure appropriate treatment plans (which supplement existing controls) are developed and prioritised. Asset investment considers asset condition and risk through the development of our CBARM model to ensure the health of Vector's asset portfolio remains acceptable.

In line with Vector's Business Performance and Internal Audit Policy, Vector operates a Three Lines Model, with its Business Performance and Assurance function managing an assurance programme to monitor risk management functions and applicable business processes. This independent and objective function conducts and coordinates audits and performance reviews to provide assurance and confidence in the effectiveness of the risk management framework and supporting activities.

6.3.4 HIGH IMPACT LOW PROBABILITY (HILP) RISKS

Network resilience and the ongoing management of HILP risks is a priority for Vector with proactive investment allocated to manage future events. We undertake regular critical site reviews, monitor reference material and global trends, have developed comprehensive event and contingency management plans and have engaged a variety of experts to help influence our planning and management of HILP events.

Identification and management of HILP risks include consideration of both our internal and external operating environment. Figure 6-5 below provides a representation of HILP events influenced by a range of factors that require ongoing and evolving management to both prevent the occurrence and mitigate the impact so far as is reasonably practicable.

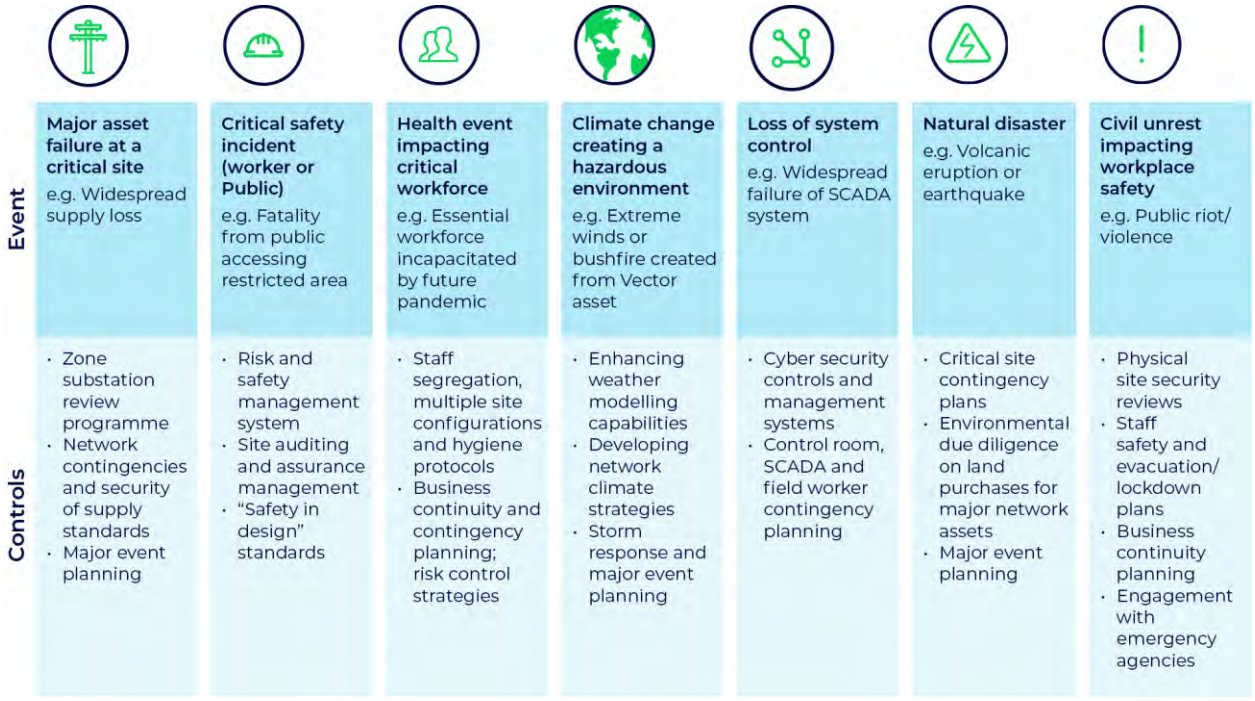


FIGURE 6-5: EXAMPLE OF HILP EVENTS

Taken together, the electricity distribution risks (Figure 6.4) and our ongoing HILP assessments (Figure 6.5) indicate that the material risk themes for the AMP period include health and safety risk; network reliability and resilience - with an emphasis on the network's ability to continue evolving to meet customer needs; and data/information risks (including cyber and data protection). Our risk management practices are used to continually assess the resilience of both the network and our asset management systems. These conclusions are reflected in the AMP's resilience and reliability programmes (refer Section 11) and are supported by the emergency response and contingency arrangements in section 6.4.

6.3.5 ELECTRICITY DISTRIBUTION CLIMATE RELATED RISKS

Vector actively monitors climate risks, which play a pivotal role in informing our climate related disclosure. Alongside the ongoing weather volatility brought about by climate change, it's important to also note that under a disorderly decarbonisation scenario the electricity distribution network and its connected customers are potentially exposed to reliability and affordability challenges. An absence of timely policy, regulatory and market changes results in customer peak demand increasing faster than average annual usage. More details of this can be found in Vector's annual climate-related disclosure[9] .

6.4 Event management and emergency response

As a supplier of an essential service to more than 630,000 ICPs across Auckland and a nominated "lifeline utility" under the Civil Defence Emergency Management (CDEM) Act 2002, Vector has developed a suite of documentation that defines our key event management plans and processes (detailed in Table 6-1). This documentation ensures Vector maintains coordinated and clear management protocols to respond to events efficiently and effectively.

DOCUMENT	DESCRIPTION
Business Continuity Management Policy	Formal representation of Vector's commitment to business continuity management, which forms an essential part of Vector's enterprise risk management framework. Defines key business continuity management roles, responsibilities, accountabilities and reporting requirements. Approved by the Board, it is consistent with the following Standards: • AS/NZ 5050:2020 "Managing disruption-related risk" • ISO 31000:2018 "Risk management – Guidelines" • ISO 22301:2019 "Security and resilience - Business Continuity Management System – Requirements" • ISO 22313:2020 "Societal security – Business continuity management systems – Guidance"

[9] https://www.vector.co.nz/investors/reports

DOCUMENT	DESCRIPTION
Crisis Management Plan	Provides the enterprise-wide framework and structure to assess and respond to any crisis-level incident or event affecting Vector, its customers and/or employees, contractors, and other stakeholders. Crisis management / business continuity exercises are undertaken in line with Vector's annual resilience calendar to reinforce preparedness and promote continuous improvement of Vector's response capability.
Crisis Communications Plan	Standalone plan governing the communications and external relations approach and processes during a crisis, emergency or business continuity events.
Networks Event Management and Investigation Process	A formal focused and coordinated process to effectively manage network events. The process defines the approach such that Vector can: • Recognise, assess and respond to an event quickly and effectively • Notify the appropriate individuals and organisations about the event • Organise response activities • Escalate response efforts based on the severity of the event • Recover from event • Gather evidence to support and complete investigations
Specific Event Response Processes	Individual and detailed processes that ensure Vector is prepared for (and responds efficiently to) specific events that may occur on the network. These events include credible incidents and emergencies, for example storm response.
Business Continuity Plans	Individual business unit / team plans identify the critical functions and services provided by a unit/team and outline the recovery procedures to be undertaken during a disruptive event to maintain or resume these functions.
EOC Emergency Evacuation Plan	Ensures Vector's Electricity Operations Centre (EOC) is prepared for, and responds quickly to, any incident that requires the short, medium or long-term evacuation of the EOC. Vector's network control centre has a fully operational disaster recovery site. Regular evacuation exercises are held to ensure evacuation of the control centre can proceed smoothly.
Switching Plans	Restoration switching plans developed for each zone substation at a feeder level.
Emergency Load Shedding Obligations	Vector is required under the Electricity Industry Participation Code (2010) to provide emergency load-shedding by way of Automatic Under-frequency Load Shedding, to maintain the electricity security of the grid and avoid cascade trippings under emergency conditions.

TABLE 6-1: VECTOR'S EVENT MANAGEMENT PLANS AND PROCESSES

6.5 Privacy

Vector takes its obligations under the Privacy Act seriously. The volume and potential sources of data which are required to effectively manage and operate the network continue to expand. For example, new network and customer devices generate increasingly important information about consumption patterns, faults, performance and resilience which enables us to manage the network more efficiently and effectively. Vector understands its legal obligations and also its "social licence" to use this information responsibly. Vector has established protocols which define how any personal data is required to be protected, managed, and used by approved personnel.

Our data governance programme takes a holistic view of how data is gathered, managed and governed to ensure privacy related risks are appropriately managed. A number of functions exist which assist in ensuring Vector adheres to its privacy obligations.

FUNCTION	ACCOUNTABILITY
Privacy Officer	Setting policy and supporting privacy-related activities or issues. Dealing with privacy breaches, including reporting requirements to the Office of the Privacy Commissioner.
Enterprise Data & Information Management	Development and implementation of the group data and information policy. This function supports all aspects of data and information management and provides operational support to the privacy officer.
Cyber Security	Establishment and monitoring of security controls for the protection of all data.
Operational Information Management	Operational management, quality assurance and improvement of data.

FUNCTION	ACCOUNTABILITY
Data Owners	Accountable for ensuring appropriate processes and systems are in place for all sensitive (confidential and private) data and for implementing the requirements of data-related policies and procedures into their operations.
Data Stewards	Responsible for implementing the requirements of data related policies and procedures and managing the data to such standards

TABLE 6-2: DATA GOVERNANCE ACCOUNTABILITIES

6.6 Asset management information systems

Vector has a suite of information systems that support its asset management practice.

6.6.1 PRIMARY SYSTEMS

Many of Vector's information systems operate through an integration layer that extends across systems and enables reporting and data analytics that support Vector's asset management processes. The following table provides an overview of the primary systems and provides insight into how they support asset management.

PRIMARY SYSTEM	FUNCTIONAL OVERVIEW
SAP	SAP is Vector's ERP System. It contains records for all assets and is used for managing the asset lifecycle from procurement and operation to maintenance and disposal. SAP also provides financial management related to asset management and project management
SAP Planned Maintenance (PM)	SAP PM is our asset maintenance management system used for planning, scheduling, executing and recording all maintenance activities on our assets.
GE Smallworld	This system provides the geographic, schematic and connectivity information used in managing Vector's network assets
ARC-GIS	This system provides geospatial visualisation and analytics tools
Siebel	Siebel is Vector's customer relationship management system. This system is used for managing customer requests for new connections, quality of supply complaints management, and fault and outage management
Gentrack	Gentrack provides records for all connected ICP's as well as their regulatory and market attributes. It is used to manage energy consumption, revenue assurance and interfaces with the Electricity Authority registry
Modern Data Platform	This is a cloud-based data platform that provides multiple-system data integration, transformation, and data modelling for asset management. This platform presents data to the analytics layer that enables decisions to be made about asset management.
Data Analytics Layer	This is a bespoke integration layer that provides reporting, monitoring and associated analytics related to network assets. It is a critical source of information for most of Vector's asset management processes
GE Power On	This is Vector's ADMS (Advanced Distribution Management System). It is used to monitor and control operations on the network, and record and provide critical asset data.
Donesafe	Donesafe is Vector's enterprise risk and health and safety management system. It supports effective asset and contractor management through risk assessment, reporting and incident management in line with Vector's policies.
Stationware	Stationware is Vector's system to record and manages all protection settings in its primary and distribution networks

TABLE 6-3: PRIMARY SYSTEMS OVERVIEW AND INSIGHTS

Asset management data from these systems (including asset master, maintenance history, condition and test results, outage/fault performance, operating profiles and network connectivity) is consolidated through Vector's integration and analytics environment to inform asset health and risk assessment models used in the electricity distribution business. These models use the underlying asset management datasets to generate consistent asset health indicators and risk-based prioritisation outputs for key asset categories.

6.6.2 OTHER IMPORTANT SYSTEMS

Vector uses several other information systems, computer models and computer-based tools in the management of its electricity distribution assets. In particular:

- **DERMS:** a Distributed Energy Resource Management System. This application is constantly processing and optimising the use of any DERs connected to it. The system has a 24-hour load forecast and will automatically provide operating envelopes to all DERs, ensuring the network remains within equipment ratings. This minimises customer connection and network reinforcement costs. As more DERs are connected, the importance of and reliance on this system will increase.
- **OSIsoft PI:** is a real-time network performance management system that utilises data from various corporate systems (e.g. SCADA – see above) and provides a Microsoft Excel link to support analysis. This tool provides a permanent archive of historical network

data that supports the capture and management of operational and asset condition data, enabling performance monitoring, asset health assessment and evidence-based asset management decisions.

- **Granular Customer Model and Database:** this is a bespoke model implemented as SQL Database that brings together all of Vector customer and energy information with information from third party sources (e.g. socioeconomics). It can zoom in on specific customer attributes, specific network locations and extreme events, without being exposed to the limitations of small samples. It uses data from Stats NZ (census data) and detailed property information for all rateable buildings in Auckland. Half-hourly metering data is also used as well as a host of other data sources. The granular customer model is the foundation of our scenario model.
- **Scenario Model and Network Allocation Model:** this is a bespoke bottom-up customer load model implemented in Microsoft Excel to analyse the impact of future changes on network demand. It is used in Vector's network planning practice to forecast the yearly maximum demand for summer and winter periods at a feeder and zone substation level. It makes use of information from recorded historical demand data, the forecast scenario model and known step loads from large projects. Section 10 describes how the scenario model is used for load forecasting as part of the network planning process.
- **Forecast model:** this is a bespoke model implemented in Microsoft Excel. This model established current loading by normalising for natural variability. It then provides load forecasts across network levels by combining scenario model results allocated by network asset, new or upgraded large-scale customer load requests and manual re-adjustments due to changes in topology
- **Network constraint model:** this is a bespoke model implemented in Microsoft Excel. It is used in Vector's network planning practice to forecast the ability to backstop individual feeders or entire zone substations in the event of failure. The model uses the demand forecast, individual feeder/zone substation capacity and backstop points between feeders to highlight any shortfalls in backstop capacity for the period of the AMP
- **Digsilent:** is a network modelling tool that provides network power flow and fault levels analysis. It uses information from Smallworld, the Demand Forecast, the Rating Datasheets and Gentrack to maintain its network model. This includes scripts that enable the automatic execution of certain workflows
- **CYMCAP:** is a software tool that calculates cable ratings based on ground thermal conductivity test results and standardised cable installation practices. It is used to set the ratings of all subtransmission cables
- **HV Spec:** is Vector's system of record for all outage information, including fault interruption and duration data. This system is used to calculate and report on Vector's reliability measures such as SAIDI and SAIFI
- **Rating Datasheets:** this is a Microsoft Excel based database that contains summer and winter ratings for subtransmission plant and considers future network constraints. Our rating datasheet is manually updated on an annual basis.
- **Ion:** Centralised server for data gathering all power quality metering information from zone substations and GXPs
- **Zone Substation Equipment Ratings:** this is a Microsoft Excel based database that contains details of the ratings of the primary plant in our zone substations and at GXPs. It considers N-1 ratings for winter and summer conditions and identifies points of constraint. It is manually updated on an annual basis

6.7 Information and data management

Vector has a holistic approach to the management and governance of its information and data assets. The following capabilities have been established reflecting the operational, strategic and governance overlaps across the functions.

Data & Information Governance: This function delivers and supports the group data & information management program that manages the people, processes and technology that provide control over the structure, processing, delivery and usage of data and information required for management and business intelligence purposes. Providing compliance and governance frameworks applicable to both physical and electronic information.

Network Information Management: This function provides governance to the operational application of information and data management across the electricity network's systems of record for assets and operational activities, through the development, execution and supervision of plans, policies, programs and practices that control, protect and enhance the value of data and information assets throughout their life cycles.

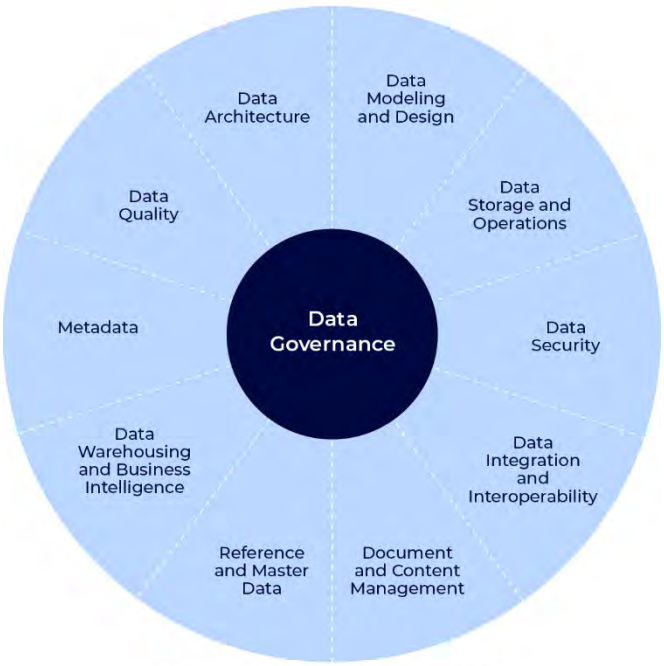
Data Engineering & Platforms: A technical function, this team is responsible for the management and development of the data and analytics platforms including integration, enrichment and transformation of data.

Business Intelligence, Analytics & Data Science: Primarily a technical function, this team provides the data modelling, visualisation and reporting capability to the business. The team also provides the technical analytics capability and highly specialised business operational knowledge to support all core functions within the Networks business and to provide the research, advanced modelling and data science capability.

Data governance: Vector's Group Data and Information Policy and Information Governance Framework are the foundations that set out the governance requirements and operating model for the information lifecycle. This covers both information in electronic and physical form, as well as disciplines for the process of creating, obtaining, transforming, sharing, protecting, documenting and preserving data. In preparing the policy and operating model, Vector has followed the principles and framework as set out in the Data Management Association's body of knowledge [10].

The Group Data and Information Policy is supplemented and supported where necessary by other operational and policy documents including our Privacy Statement and Cyber Security Policy.

10 DAMA-DMBOK, Data Management Body of Knowledge, Second Edition, DAMA International



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FIGURE 6.6: DATA MANAGEMENT ASSOCIATION FRAMEWORK

6.7.1 OPERATING MODEL

Vector's data and information management model is represented in the diagram below. Operationally, the Data and Information Governance function within the Digital & Data business unit provides capability horizontally across all other business units. Within each business unit, data stewards have been established to work with the defined data owners to ensure that business (i.e. operational) and governance requirements are met for each data set. The data stewards are trained and overseen by the Data & Information Governance function.

Vector operates a 'as-required' virtual Information Governance Council responsible for setting and supporting the implementation of the Group Data and Information policy. This includes being the escalation point for data related events and advice on the treatment and usage of data. Importantly the Council is made up of core disciplines and functions from across the business that impact privacy and data management including, but not limited to, Data & Information Governance function, Privacy, Legal, Information Management and Data and Analytics. In addition, Cyber Security and Digital Architecture teams also provide subject matter expertise where required to support the Council in managing risk and maintaining good practice.

Operationally, the electricity business maintains a dedicated Networks Information Management team to perform the majority of the data activities as depicted in the box titled "Operations – Information Management". This team is responsible for defining and ensuring the implementation of data standards, as well as managing the data within the System of Record for asset, asset performance, geo-spatial and customer data (specifically connectivity). The team also manages regulatory reporting (including one off requests) as well as managing other third-party data requests such as location information and asset information.

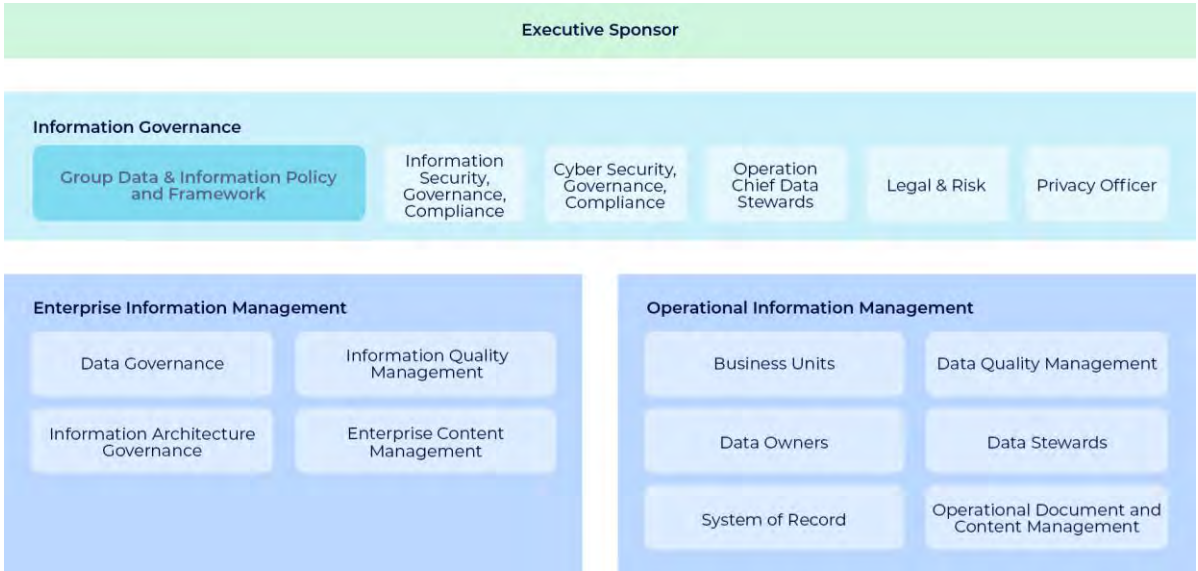


FIGURE 6-7: VECTOR'S DATA AND INFORMATION MANAGEMENT MODEL

6.7.2 DATA QUALITY AND OPPORTUNITIES FOR IMPROVEMENT

While Vector's core systems provide a strong foundation for asset management, there are limitations in the availability and completeness of some asset management datasets. These limitations primarily relate to: (i) completeness and accuracy of low voltage (LV) connectivity and phase information; (ii) completeness and consistency of some asset master data fields across legacy systems; (iii) the level of condition and performance data available for some asset categories where intrusive inspection is not efficient or practicable; and (iv) constraints on the timeliness and granularity of some third-party data inputs (including aspects of smart meter data access). These limitations are managed through targeted improvement initiatives listed below, such as LV circuit and ICP connectivity enhancements, asset master data and OT timeseries uplift, improved access to real-time operational and smart meter data, and better capture and use of asset imagery and video, so the datasets used for asset management decision-making and disclosure are progressively more complete, accurate and transparent.

The Network Information Management function has an ongoing programme of work relating to the assurance and improvement of data that support the asset management practice. The programme has had a key focus on the alignment of asset management data with operational data, and a number of improvements have been completed since the last AMP.

1. Overhead asset quality and ownership improvement – Completed
2. Improved access to Real-Time operational data - Completed
3. Management of asset image and video data – Completed.
4. Improved vegetation fault data
5. Enhancement of asset master data.
6. Enhancement of OT Timeseries data management.
7. Network section and bay data improvement.
8. Data defect recording improvement.
9. Electronic as-built recording.

An ongoing focus remains on improving LV data, with the following key initiatives underway:

1. LV circuit data management.
2. ICP connectivity system of record enhancement.
3. Hot water smart meter data and control.
4. Improved access to smart meter data from MEPs (Network Operational Data).
5. Improved access to high-speed smart meter data
6. Improvement of network visibility including LV connectivity, ICP service fuse connection and phase assignments.

6.8 Cyber security

In the context of our Asset Management Plan, our cyber strategy continues to be focused on the people, process and technology related controls and processes related to:

1. The protection of critical operational network assets from unauthorised access that could result in disruptions to service, physical damage or safety concerns
2. Safeguarding and restricting access to any personal/customer data that is used for network management purposes
3. Safeguarding and restricting access to any sensitive operational data about the electricity network

Our sector is continuously under threat from malicious cyber security threats that are constantly evolving in their nature, tactics and potential impacts. We therefore continue to maintain and improve our security posture as a key priority, investing in tools and technology to help appropriately manage our cyber security risks.

We continue to improve our ability to detect and prevent potential cyber security threats via our Security Operations Centre (SOC), which provides 24/7/365 monitoring of our Information Technology (IT) and Operational Technology (OT) environments, along with other preventative and detective controls across our network.

Execution of the Vector cyber security strategy and roadmap has resulted in advances such as the ongoing development of security orchestration, automation to help reduce manual effort and time required to analyse and remediate security incidents as well as streamlining the identification, assessment, and remediation of vulnerabilities. Our network modernisation initiative supports our direction towards a zero-trust architecture along building strong foundations in logical access and service management with identity management lifecycle automation to help manage security risk, operational efficiency and visibility.

The Vector cyber security team continues to work with key global tier-1 security providers to apply a global perspective to cyber security assurance and technology, as part of an integrated Cyber Security Operating Model. We're also continuing our engagement and contribution to key New Zealand industry security forums, across public and private sectors.

The management of risk associated with cyber security is a sector wide concern. The Vector cyber security team continues to uplift cyber security capability across the industry by collaborating with key organisations to better understand how further improvements can be made and promote security awareness and greater levels of maturity. The continuing evolution and global nature of cyber threats means collaboration between partners and industry participants is critical to help provide deeper understanding and visibility of potential risks through actionable threat intelligence and access to the latest technologies and thought leadership.



SECTION 07

Our service levels

7 – Our service levels

This section sets out the service levels and performance measures (KPIs) Vector uses to monitor delivery for our customers, stakeholders and regulators. Vector sets both external targets (for example, targets required under regulatory and legislative frameworks, and service standards published for customers) and internal targets (used to manage day-to-day performance, drive continuous improvement and inform investment decisions). External targets are primarily set to meet regulatory obligations and statutory requirements, and to reflect customer and stakeholder expectations. These include, for example, reliability and quality measures that are defined and reported under the relevant price-quality path and information disclosure requirements. Internal targets are set to support and, where appropriate, exceed external requirements. They are established using a combination of historical performance, customer experience insight and Voice of Customer feedback, risk and criticality, operational capability, and the level and timing of planned investment over the AMP period. Internal targets are reviewed through Vector's performance and planning processes, and are updated where our obligations change, customer expectations shift, or performance opportunities and risks are identified. Stakeholder expectations are identified through our customer engagement and feedback processes (as outlined in section 5) and are translated into measurable service levels and targets that are monitored and reported to drive accountability and improvement.

The asset management objectives set out in section 5.3 provides a link between Vector's focus areas and any applicable performance measure in this section.

The targets are forecast to remain consistent across the AMP period for the measures in this section. The necessary forecast expenditure to maintain performance against the target is reflected also across the AMP.

7.1 Published service standards

Vector publishes on its website its service standards regarding the levels of network performance that a customer can expect on its website www.vector.co.nz. There are different standards for residential and commercial customers as well as for urban, CBD and rural. These differences reflect the different needs of customers as well as the realities of the network and surrounding geography.

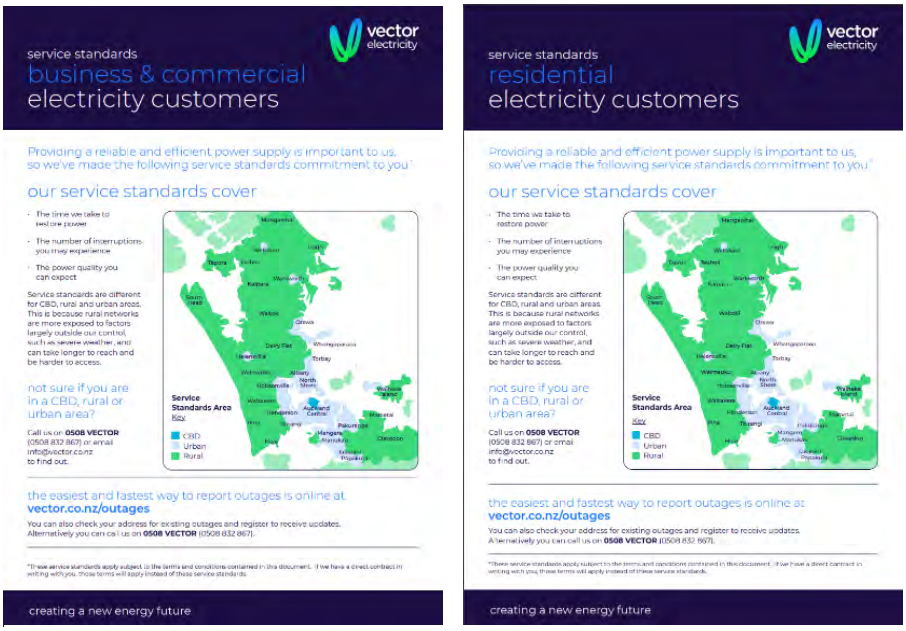


FIGURE 7-1: VECTOR SERVICE STANDARDS AS PUBLISHED ON COMPANY WEBSITE

7.2 Customer experience and customer satisfaction

The measures in this section take into account the metrics for each consumer type including residential, commercial and direct billed customers where appropriate.

7.2.1 ADVANCE NOTIFICATION OF PLANNED OUTAGES

7.2.1.1 DEFINITION

To provide customers with timely, accurate and reliable notification of planned outages.

7.2.1.2 MEASUREMENT

To provide a consistent measure of the Planned Outage notification service level, Vector has aligned calculations with the requirements under the DPP3 regulatory framework relating to the notification of customers of planned outages. Vector has made several significant system and operational changes to precisely track and record exact times that customers were notified of planned outages. These notices are published on the Vector website and are sent to customers via email or paper letter based on the contact details they have provided to retailers.

These changes were implemented and measured from the start of the RY21 year.

7.2.1.3 OUR HISTORICAL PERFORMANCE

DESCRIPTION	RY21	RY22	RY23	RY24	RY25
Notified Planned Interruption Accuracy	76%	81%	76%	76%	77%
Late Notice Limit	9.35%	7.14%	13.03%	14.92%	16.18%

TABLE 7-1: ADVANCE NOTIFICATION OF PLANNED OUTAGES

The two measures are designed to measure both the accuracy of notification to customers according to the defined service levels, as well as measuring the degree of accuracy when executing on planned outages.

Notified Planned Interruption Accuracy measures the percentage of planned outages which were notified according to the target service levels and carried out to plan.

Late Notice Accuracy measures the % of planned SAIDI incurred from late notification to customers.

7.2.1.4 OUR TARGET

Under the DPP3 regulatory framework, Vector is required to give residential and commercial customers a minimum of 4 working days' notice of a planned outage, and direct billed customers a minimum 10 working days' notice. Vector incurs additional SAIDI penalties for planned outages that are notified to customers in breach of these timeframes, and which do not meet the DPP3 requirements of a "Notified Interruption". To better meet residential and commercial customer's expectations, and to allow for postage and handling delays which could impact achievement of the regulated 4 working day notice period (where applicable), Vector has chosen to adopt a target of 7 working days' notice for residential and commercial customers.

The targets set apply consistently to residential, commercial and direct billed customers. The targets apply from RY 2026 onwards covering the whole AMP period.

To best serve our customers we have adopted an overall target of:

- Notified Planned Interruption accuracy target - 80%
- Late Notified target limit - No greater than 10% of planned SAIDI to be incurred from late notification of planned outages to customers.

Vector compares annual results to the notified interruption accuracy target (80%) and the late notice limit (≤10% of planned SAIDI). Where performance is below target, Vector investigates root causes (including data quality, process adherence and retailer contact detail availability) and prioritises improvements through customer communications and operational process changes.

7.2.2 CALL CENTRE GRADE OF SERVICE (GOS)

7.2.2.1 DEFINITION

To answer all customer calls concerning faults on the network within an acceptable agreed timeframe. Our customers want to be satisfied in their dealings with us when they call.

7.2.2.2 MEASUREMENT

Vector uses the Grade of Service (GOS) call centre measure to judge how well it is doing. The GOS measures the number of calls made to the contact centre that are answered within 20 seconds.

7.2.2.3 OUR HISTORICAL PERFORMANCE

DESCRIPTION	RY20	RY21	RY22	RY23	RY24	RY25
Average Grade of Service (GOS)	80%	84%	76%	74%*	87%	85%

* RY23 Grade of service includes the extreme weather events in January and February 2023 of the Auckland Floods and Cyclone Gabrielle. The Grade of Service outside of these events is 79.4%.

TABLE 7-2: CALL CENTRE GRADE OF SERVICE

The contact centre Key Performance Metrics (KPMs) include a target for Grade of Service (GOS): 80% of calls must be answered within 20 seconds. The contact centre is incentivised to meet this, as performance against this target can impact its performance score, and subsequently its remuneration.

Vector is continuously working with its contact centre provider to improve GOS results, including increasing contact centre resource and driving efficiencies to enhance the contact centre's ability to handle high volume. We also continue to investigate self-service online capability which is at the customers' control.

Note: Some data may be excluded from GOS under a contractual Force Majeure with Telnet, covering exceptional events.

7.2.2.4 OUR TARGET

Our grade of service target is to have 80% of calls answered within 20 seconds. The targets apply to residential, commercial and direct billed customers. The targets apply from RY2026 onwards covering the whole AMP period.

Performance is assessed annually against the 80% within-20-seconds target. Significant variances are reviewed with the service provider to identify demand drivers (including major event conditions) and to confirm improvement actions and resourcing settings.

7.2.3 SPEED OF QUOTES FOR NEW CONNECTIONS (SMALL CONNECTION CUSTOMERS)

7.2.3.1 DEFINITION

This service level applies to customers dealing with fewer than ten lots and applies to the average time taken to quote on new connection applications. The speed of quotes for new connections is important to our customers, so we want to provide them with the information as quickly as possible.

7.2.3.2 MEASUREMENT

Measurement starts when a connection is requested and runs to the time the quote is provided.

7.2.3.3 OUR HISTORICAL PERFORMANCE

At present, 78% of quotes for non-standard connections are sent out within seven days. These measures were implemented in RY18 when standard charges were introduced for residential, 60-amp, single phase customer connections.

DESCRIPTION	RY20	RY21	RY22	RY23	RY24	RY25
Speed of quotes for new connections – Standard (discontinued from 1 December 2023)	93%	96%	95%	98%	90%	N/A
Speed of quotes for new connections – Non-standard	75%	60%	70%	88%	88%	78%

TABLE 7-3: SPEED OF QUOTES FOR NEW CONNECTIONS

7.2.3.4 OUR TARGET

Vector aims to have 85 per cent of non-standard quotes sent out within seven days. These are reassessed every two years and Vector will continue this practice over the AMP period.

The targets apply from RY2026 onwards covering the whole AMP period.

Performance is assessed annually against the 85% within-seven-days target for non-standard quotes, with material deviations investigated and used to prioritise process and resourcing improvements.

7.3 Power quality

Vector publishes all service standards on its website https://www.vector.co.nz/personal/electricity/about-our-network/our-service-standards , which include regulated voltage service standards, and instructions to customers on how to contact Vector to report voltage issues.

Vector delivers supply voltages as required under the Electricity (Safety) Regulations 2010. Maintaining the network within the permissible range is getting more complex and geographically diverse. Distributed generation (e.g. solar PV) is pushing the network voltage towards the upper threshold in summer, new electric loads, such as EV charging are testing the lower threshold. In time, rapid and synchronised response of large numbers of devices to external signals, such as energy spot prices, system frequency, or time-based retailer offerings, could also cause volatility in local voltage.

We are currently developing our capability to harness power quality from smart meter data through active trials with metering equipment providers. Additionally, we are rolling out a dedicated distribution transformer monitoring pilot in areas of the network that helps to complement smart meter data.

We are continuing to take the following two approaches to managing power quality, to work around a lack of access to customer smart metering data. Firstly, we have an active programme to install power quality meters (PQMs) at several of our zone substations and GXP sites to monitor the network at a HV level. Secondly, we take a reactive approach to investigate any incidents identified by customers.

Vector has installed PQMs to primarily baseline and trend harmonic levels on the network. This is especially helpful to us in monitoring and understanding the impact of power electronics operating at the residential level, particularly the increasing

numbers of inverters associated with solar PV, electric vehicle, and battery charging. This also enables us to proactively address any power quality issues we identify.

As LV monitoring coverage increases, Vector is able to use a combination of HV monitoring and aggregated LV data to improve visibility of network performance beyond the zone substation level. LV data (including voltage trends and indicators of loading where available) is analysed in an aggregated form to identify emerging constraints on LV feeders and distribution transformers, including utilisation trends and potential distribution transformer capacity issues. These insights help Vector to prioritise investigation and targeted interventions (for example, tap setting adjustments, phase balancing, network reconfiguration or reinforcement) and to better inform forward planning and investment decisions.

When we are notified of instances of the network operating outside the regulated voltage range, we investigate and then remedy the problem. The combination of data from PQMs, smart meters and Transformer monitoring devices is analysed to determine the cause of any network disturbances, and changes made to improve our performance to meet regulatory requirements.

The power quality requirements are summarised as:

- Electricity Safety Regulations requires that Low Voltage must remain within 10% of the nominal voltage (230V for single phase)
- AS/NZSS 61000 and its Parts sets out the requirements for voltage and current waveform distortions
- Voltage and frequency requirement for distributed generation (customer connections) are set out Vector's website

7.3.1 IMPROVING PRACTICES FOR MONITORING LV NETWORK VOLTAGE QUALITY

Vector's current practice regarding voltage services levels is to respond reactively to all customer reports of voltage issues. These are promptly investigated and where they relate to the quality of voltage at the customer's point of supply, are resolved by reconfiguring or upgrading the distribution network.

Vector has two key initiatives to improve visibility of the LV network and specifically provide greater visibility of LV voltage. These two initiatives will allow Vector to proactively monitor customer LV network voltage quality, which is a step change from currently reacting to customer reports.

1. Distribution transformer LV monitoring

Vector is piloting a programme of work to install power quality instrumentation on a sample of its distribution transformer fleet. This will provide highly precise measurement of LV Feeder and LV Phase voltage performance. This data will be available in near-real-time and can be used to proactively identify and respond to voltage performance issues.

2. Smart meter power quality data

Vector is actively engaged with the two primary Metering Equipment Providers (MEPs) on the network to obtain comprehensive power quality data from smart meters installed on the network. Vector now has access to approximately 40% of ICP's operational smart meter data which includes voltage recorded at 5-minute intervals. Full network coverage is anticipated to take up to 5 years as the aging fleet of smart meters in the region is upgraded to support the supply of operational data required for power quality monitoring.

Access to full network coverage of power quality data will provide a substantial improvement of Vector's ability to monitor the performance of the LV network as recorded at the customer's meter. This data will enable Vector to identify individual ICPs, as well as LV circuits and individual LV Phases experiencing voltage issues to proactively respond and resolve issues. Additionally, this data will enable Vector to identify the potential root cause of voltage issues, such as unregistered or non-compliance DER installations, and EV charging clustering.

7.3.1.1 COLLECTING AND PROCURING DATA

Vector has data contracts and systems in place to acquire and ingest data to support modelling and analysis. The following primary source of data are in place.

1. Smart meter data acquisition - Vector has made substantial progress in acquiring smart meter data from retailers and Metering Equipment Providers (MEPs). This includes:
   - Monthly supply of 30-minute kWh data for 98% of smart meters on the Vector network, with approximately five years of historical data acquired.
   - Daily supply of operational power quality data (voltage, current, phase angle) for approximately 40% of the network.
   - Four hourly supply of operational power quality data (voltage, current, phase angle) for approximately 40% of the network.
   - Vector has signed a data services contract for the supply of operational power quality data (voltage, current, phase angle) for the remaining fleet of approximately 60% of smart meters on the Vector Network. An initial tranche of meters will come online by July 2026, with the remaining to be delivered over the next 5 years. Note this is dependent on the upgrade of legacy meters installed on Vector's network. The data will be delivered daily.
2. Distribution transformer monitoring data. As part of a pilot initiative, power quality data measured at the LV network feeder and phase level is available in near-real-time for a limited amount of sites. The data is accessible by API for ingestion into Vectors data platforms.

7.3.1.2 MODELLING AND ANALYSIS

Based on the power quality data available from provisioned meters (currently around 40% of installed meters on the Vector network), Vector undertakes a range of modelling and analysis activities to support customer outcomes, operational response and network planning. Examples include:

1. Customer investigations - Smart meter power quality data is used to investigate customer complaints or enquiries. Where available, the data is analysed to confirm and characterise voltage performance at the customer's point of supply (for example, high or low voltage events, duration and frequency).

2. Customer anomaly identification - Smart meter power quality data is analysed daily to proactively identify anomalies on the LV network (for example, loose neutral defects). Where potential issues are identified, Vector raises a fault service request and dispatches a field crew to investigate and, where required, rectify the issue.
3. Distribution transformer voltage profiling - Smart meter power quality data is used to develop and validate distribution transformer voltage profiles (including time-of-day and seasonal trends) to support voltage management and identify locations that may require further investigation.
4. ICP-to-transformer and ICP-to-phase connectivity modelling - Smart meter power quality data is used to infer LV connectivity (which ICPs are supplied by which distribution transformer and on which LV phase). The accuracy and coverage of this analysis is constrained by the current availability of smart meter power quality data.
5. Customer scenario modelling
6. Network wide modelling for constraint detection
7. Bespoke load voltage drop models

7.3.1.3 ASSUMPTIONS AND LIMITATIONS

Historic smart meter consumption data is not used directly for LV voltage quality management. This is because consumption data is typically received in arrears (for example, monthly), is generally aggregated over long intervals, and measures energy (kWh) rather than voltage magnitude and quality. As a result, it does not provide the time resolution required to identify short-duration voltage events (such as sags, swells or flicker), nor does it provide information on voltage at the customer's point of supply, LV phase imbalance, reactive power or power factor. Consumption is also influenced by customer behind-the-meter behaviour and local DER (e.g., solar PV and EV charging), meaning energy volumes alone are not a reliable proxy for network voltage performance or compliance at a specific location.

Modelling and analysis is limited by the availability of operational power quality data (voltage, current, phase angle). At present Vector only has access to operational power quality data (voltage, current, phase angle) for approximately 40% of the smart meters on the network. A further approximately 20% of the meters will begin providing operational power quality data (voltage, current, phase angle) from July 2026. The remaining approximately 40% of meters will come online over the next 4 to 5 years.

Where gaps exist in smart meter data supply, missing data is interpolated where possible through data modelling.

7.3.1.4 ADDRESSING KNOWN NON-COMPLIANCE

If any voltage non-compliance issues are identified from customer complaints and confirmed by data, then a technical investigation will ensure that the issue is not created by poorly configured customer-side equipment (e.g. induction motors or inverters) and will then identify the most suitable solution to address the issue. Typical solutions to address power quality constraints include altering the tap setting on the distribution transformer, reconfiguring the network, reconductoring the line or upgrading the transformer.

7.3.1.5 RESPONDING AND REPORTING

Vector responds reactively to all reported voltage issues. All reported issues are recorded as a voltage investigation service requests in our CRM system Siebel, including tracking investigation volumes, issue type, status and outcomes. These insights are used to identify emerging LV voltage quality risks and inform forward planning and investment decisions as LV visibility improves. These may be identified by our customers or by our field service providers.

The customer resolutions team manage the resolution of all investigation requests. Initially an investigation will be conducted into the nature of the issue. Typically, this will result in an on-site investigation. If power quality smart meter data is available for the customer's property, an investigation into past performance will be undertaken using smart meter data. If smart meter is unavailable for a customer's property , a power quality logger may be installed and run for a minimum of 1 week to log the power quality at the point of supply.

7.3.1.6 COMMUNICATING TO CUSTOMERS

All voltage investigations are dealt with by the customer resolutions team. A representative will contact customers directly, to inform them of all work being undertaken on the network to address voltage issues.

Further information on customer complaints resolution can be found below in section 7.8 (complaints management).

7.4 Safety

Vector is committed to the continuous improvement of our health and safety culture and performance to ensure the health and safety of our staff, those delivering work on our behalf and the public. We work collaboratively with our key contracting partners to promote an open learning environment focused on the most important preventative measures to minimise harm and enhancing in-field critical risk control verifications. We have implemented a new incident management system to better track corrective actions and lessons learned from high potential events to ensure insights are identified and risk controls improved. A robust 'Three Lines of Defence' audit and assurance programme supports our approach which includes internal assessment, external third-party review and retaining our accreditations of ISO45001 (Health and Safety Management Systems), ISO14001 (Environmental Management Systems) and NZS7901 (Public Safety).

7.4.1 TOTAL RECORDABLE INJURY FREQUENCY RATE

7.4.1.1 DEFINITION

The total recordable injury frequency rate (TRIFR) encompasses all network incidents resulting in medical treatment, restricted work injury, lost time injury or fatality, which impacts Vector people including all contractors and FSPs.

7.4.1.2 MEASUREMENT

The incident count is divided by the number of hours worked for the same measurement timeframe, Vector reports TRIFR as a rolling 12-month average which is then normalised to report TRIFR in per million hours worked.

7.4.1.3 HISTORICAL PERFORMANCE

Table 7-4 shows the Networks TRIFR performance under the definition of this service level metric.

DESCRIPTION	RY20	RY21	RY22	RY23	RY24	RY25
Total recordable injury frequency rate (TRIFR)	5.82	7.45	6.25	2.25	6.64	6.80

TABLE 7-4: TRIFR

7.4.1.4 TARGET

TRIFR is a lagging indicator used to measure trends and provide transparency. Vector does not set a target for this measure.

7.4.2 ASSET SAFETY INCIDENT MEASURE

7.4.2.1 DEFINITION

The asset safety incident measure is a count of incidents that resulted in harm to personnel, members of the public or damage to property, resulting from a deficiency or failure in any equipment on Vector's electricity distribution network.

7.4.2.2 MEASUREMENT

The asset safety incident measure is calculated by identifying the number of asset safety incidents in Vector's Risk and Incident Management System (Donesafe) which have caused harm or damage to people or property.

7.4.2.3 HISTORICAL PERFORMANCE

Table 7-5 shows the asset safety incident performance following the definition of this service level metric.

DESCRIPTION	RY20	RY21	RY22	RY23	RY24	RY25
Asset safety incident	4	0	1	1	4	0

TABLE 7-5: ASSET SAFETY INCIDENTS

The number of asset safety incidents increased to four during RY24 and reduced to zero in RY25.

7.4.2.4 TARGET

Asset safety incident count is a lagging indicator used to measure trends and provide transparency. Vector does not set a target for this measure.

7.5 Reliability

This considers the ability of the network to deliver electricity consistently when demanded under normal design conditions. Vector is committed to achieving compliance with the Regulatory quality metrics.

7.5.1 PROVIDING NOTICE AND COMMUNICATION OF PLANNED AND UNPLANNED INTERRUPTIONS TO CUSTOMERS

7.5.1.1 PLANNED OUTAGES

Ahead of all planned outages Vector conducts an extensive assessment of the customers to be affected. In particular, careful consideration is given to the operating hours of affected businesses and organisations such as medical centres, churches and schools, and wherever possible Vector will adjust the schedule of planned outages to reduce the effect on customers. If necessary, Vector will contact customers directly to discuss scheduling.

Vector directly notifies customers of scheduled planned outages via letter and/or email, depending on the availability of email contact information provided by the retailers. Vector also sends SMS reminders for notified planned outages to customers that have valid mobile numbers. Vector has a target service level for sending direct notice to customers: a minimum of (i) 7 working

days for residential and commercial customers and (ii) 10 working days for direct billed customers, in advance of the notified planned outage, with the exception of critical fault repairs done under planned works. It is worth noting that the quality and availability of data for communicating to customers directly via electronic mechanisms (email and SMS) is dependent on data supplied to Vector by the customer's retailer. Where this has not been supplied to Vector, a physical letter is mailed to the customer's postal address and the physical address of the property affected (should they be different).

For planned outages that impact 20 customers or fewer (excluding direct-billed customers), notifications are sent via email, SMS and letters where applicable, at least 5 working days in advance of the outage.

Notice for postponement of a notified planned outage must be given to customers at the earliest convenience and is only allowed if the customer was notified of alternate dates and times on the original outage notice. Vector's target is to have customers informed of postponements prior to the proposed original start time.

Notice for cancellation of a notified planned outage must be given to customers at the earliest convenience. Vector's target is to have customers informed of cancellations at least 24 hours prior to the proposed notified start time.

All scheduled planned outage information is also published on Vector's website via the Outage Centre *https://help.vector.co.nz/planned* . This service allows customers to search an address to see upcoming planned outages. Customers can also view a map of Auckland to see planned outages currently being executed.

Improvements recently made to planned outage communications is the ability to send planned outage overrun notices directly to customers who have email/ SMS contact information, at times where outages unexpectantly take longer than originally notified. This will help to manage customer expectations when outages do not go to plan.

7.5.1.2 CHANGES TO OUR PLANNED INTERRUPTION COMMUNICATIONS

The following are changes that have been made since the last AMP:

- Added the ability to send planned outage overrun notices directly to customers who have email/ SMS contact information, at times where outages unexpectedly take longer than originally notified. This will help to manage customer expectations when outages do not go to plan
- Introduction on SMS messaged 10 days prior to Planned Outage (launched in Nov last year)
- Improved planned outage templates including updates to design and improved mobile readability
- New tailored letters for specific sites that receive generation including Kindergartens and Schools
- Tailored letter and SMS to Medically Dependant Customers who have a planned outage coming up or who experience a planned outage overrun.

The following are initiatives planned to improve customer communication in the future :

- Review of the customer journey for planned outages from the customer's perspective. This work will help identify opportunities to improve communication and inform the development of new initiatives, which will then be prioritised based on their importance and impact on customers.

7.5.1.3 UNPLANNED OUTAGES

Vector has several channels for communicating to customers about unplanned outages. These are outlined below:

1. Website – Outage Centre

All known unplanned outages are shown on Vector's website https://help.vector.co.nz/address. Customers can either check their address or view a map of the Vector network to identify and track the status of known unplanned outages. Customers can also use the Outage Centre to report an outage if it is not currently displayed.

The Outage Centre is Vector's primary channel for providing interactive updates to customers on the progress of unplanned outage restoration. Customers can subscribe to receive SMS or email updates on the restoration progress of an unplanned outage. Wherever possible an estimated time of when the power will be restored is posted along with the reason of why the outage happened.

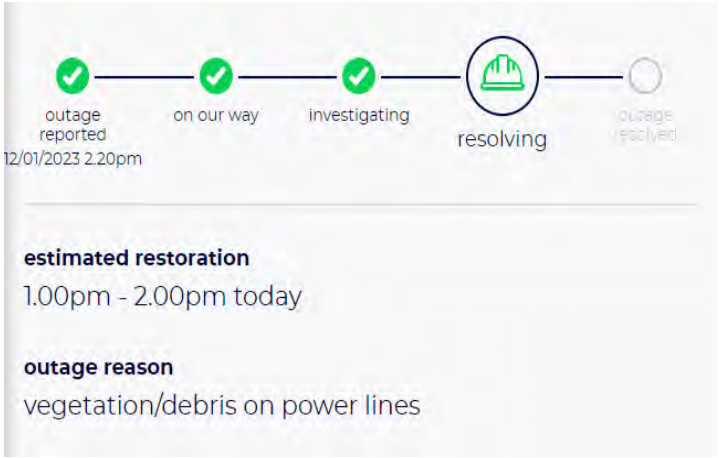


FIGURE 7-2: VECTOR'S WEBSITE OUTAGE CENTRE NOTIFICATION

2. SMS / TXT messaging

Should an unplanned outage occur which affects one or more high voltage feeder circuits, all affected customers, who have provided their electricity retailer with a valid mobile telephone number, are sent an SMS message detailing the nature of the fault and expected restoration time.

3. Call Centre & IVR

Vector operates a 24 x 7 call centre using the telephone number 0508 VECTOR or 0508 832 867. The call centre provides the ability for customers to report unplanned outages, as well as get updates on the status of current unplanned outages via a call centre operator. In addition, an Interactive Voice Response (IVR) tool is integrated with the call centre, which provides automated verbal updates on known unplanned outages to customers and redirects customers to the Outage Centre. The IVR also incorporates the use of AI to enable customers to create No Power and No Hot Water jobs without the need to speak to an agent. The IVR minimises customer call waiting times during time of high call numbers.

4. Social Media

Before and during large scale events (such as a storm) with multiple unplanned outages, Vector communicates to customers using social media.

5. Bespoke communications

Where a specific group of customers requires targeted communication due to the nature or duration of a specific unplanned outage, Vector will deliver targeted bespoke communications. These are in the form of an email or SMS.

Vector is committed to keeping our customers informed when unplanned outages occur, and Vector constantly drives improvements in making this happen.

7.5.1.4 CHANGES TO OUR UNPLANNED INTERUPTION COMMUNICATIONS

The following are changes that have been made since the last AMP:

- Introduction of 23 regional customer zones on our Outage Centre that can provide more detailed and specific communications and updates on specific parts of the network to customers during large-scale events, such as tropical cyclones.
- Addition of a proactive ‘power on?’ SMS communication added during large-scale events, such as tropical cyclones, to provide confirmation LV customers have power back on.
- Tailored SMS to Medically Dependant customers who experience an unplanned outage informing them to enact their emergency backup plan.
- An internal dashboard has been implemented to identify sensitive customers. Criteria are based on previous outage frequency, enabling the communications team to quickly identify impacted customers and respond faster.
- Automated alerts for sensitive feeders, notifying the communications team when customers on those feeders experience outages.

The following are initiatives planned to improve customer communication in the future :

- Improved automated communication with earlier preliminary Estimated Times to Restore (ETRs) relating to customer faults.
- Guest reporting and an improved the user interface via the outage centre.
- Enablement of hot water fault reporting by customers.
- Support for partial restoration on the outage centre.
- Review of the customer journey for unplanned outages from the customer’s perspective. This work will help identify opportunities to improve communication and inform the development of new initiatives, which will then be prioritised based on their importance and impact on customers.

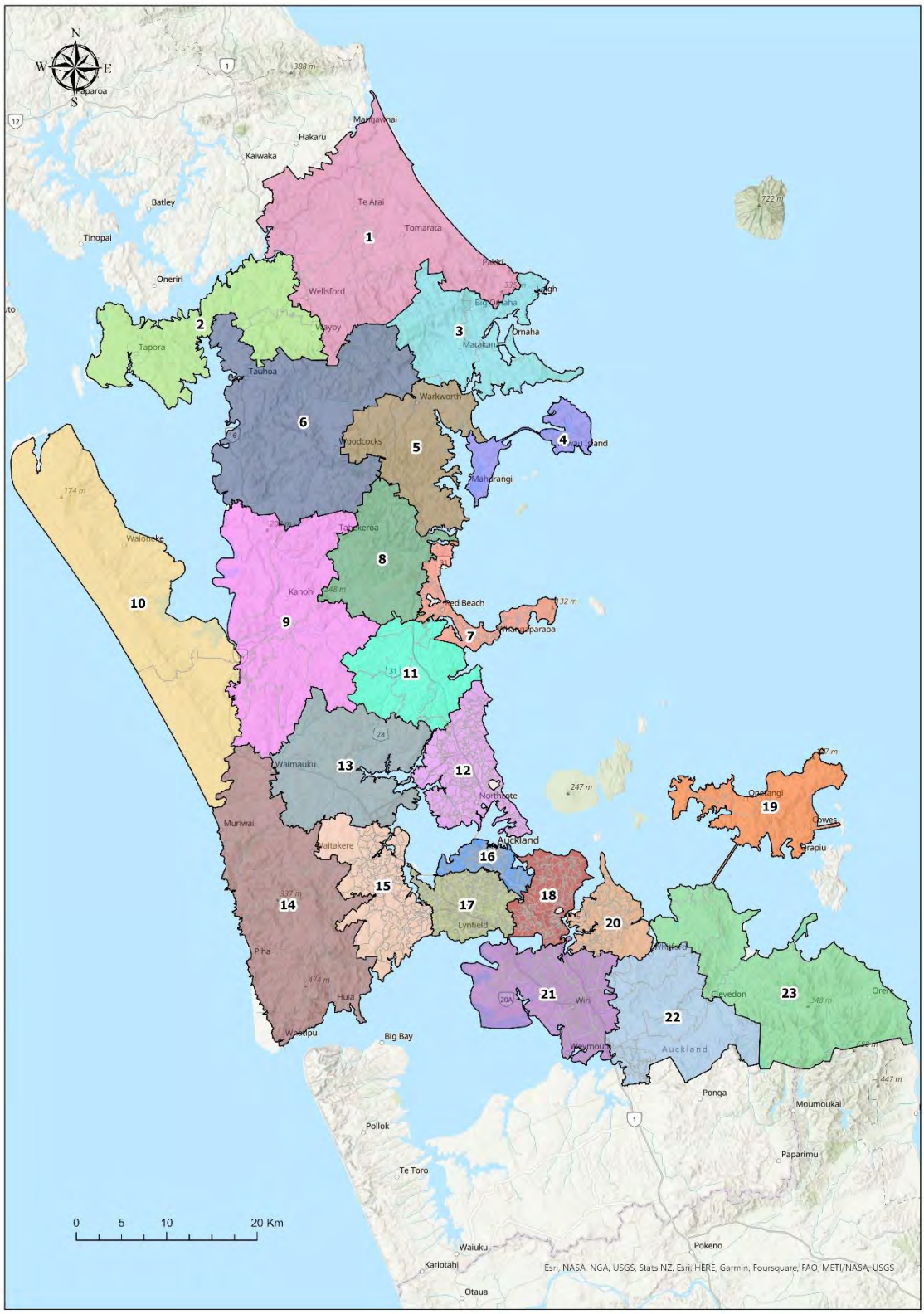


FIGURE 7-3: VECTOR CUSTOMER ZONES FOR OUTAGE COMMUNICATION

7.5.2 SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)

7.5.2.1 DEFINITION

SAIFI measures the average number of outages per customer per regulatory year, the value expressed in the number of interruptions. This is one of the key metrics used to assess the reliability of the network. It is calculated as the total number of customer interruptions divided by the total number of customers served, where interruptions are for 1 minute or longer.

In order to align with information disclosure requirements set out under the electricity distribution service default price-quality path determination (DPP3), from RY21 Vector has moved to measuring planned and unplanned SAIFI as two separate measures, with respective targets.

It is noted that Vector does not record SAIFI according to the 'successive interruption method' as defined in the 2022 Targeted Information Disclosure Review.

7.5.2.2 MEASUREMENT

SAIFI= (total number of interruptions) / (average number of customers)

SAIFI only measures outages caused by an event on the HV network and does not include the LV network. Unplanned SAIFI is limited where a major event has occurred (e.g. storms), to prevent these extreme events from distorting the overall SAIFI data. The following formula is used for the planned SAIFI calculation:

$$SAIFI\ planned, assessed\ = SAIFI_B$$

Where:

$SAIFI_B$ is the sum of the SAIFI values:

(a) for Class B interruptions commencing within the assessment period.

The following formula is used for the unplanned SAIFI calculation:

$$SAIFI\ unplanned, assessed\ = SAIFI_C$$

Where:

$SAIFI_C$ is the sum of the SAIFI values:

(a) for Class C interruptions commencing within the assessment period, where the SAIFI value for each 30-minute period that starts on the hour or half past the hour within a SAIFI major event that exceeds 1/48th of the SAIFI unplanned boundary value for that assessment period is replaced with 1/48th of the SAIFI unplanned boundary value for that assessment period.

The SAIFI Unplanned Boundary Value is calculated as per the Commerce Commission process. This limit is set to 0.037 for the current regulatory period (1 April 2020 to 31 March 2025).

Class B interruptions - means planned interruptions by a non-exempt EDB

Class C interruptions - means unplanned interruptions originating within the system fixed assets of a non-exempt EDB

All of Vector's interruption data is held in our HV Spec database which is used to calculate and report on SAIFI performance. SAIFI is continually monitored including reporting to the Strategic Reliability Management (SRM) fortnightly meeting and reported on a monthly and annual basis to inform asset management practices. For regulation purposes, SAIFI is reported to the Commerce Commission on an annual basis. SAIFI reporting to the Commerce Commission is subject to an external audit.

The SAIFI target is set by the Commerce Commission's regulatory determination every 5 years. It is largely based on the average SAIFI performance over a 10-year historical Reference Period. The process for setting this target is specified in the DPP Determination.

DESCRIPTION	RY20	RY21	RY22	RY23	RY24	RY25
SAIFI – Combined	1.58					
SAIFI – Planned		0.342	0.269	0.256	0.311	0.282
SAIFI – Unplanned		1.070	1.048	1.194	1.129	0.899

TABLE 7-6: SAIFI

For the 2025 assessment period, Vector did not exceed its reliability limits and was compliant with the DPP3.

Vector considers the matter of quality compliance of utmost importance. To improve our network reliability, we have invested significantly in network improvements and operational processes to improve network reliability.

7.5.2.3 TARGET

For the Regulatory Period, (1 April 2020 to 31 March 2025) Vector's annual SAIFI target has been set based on the limits defined within the DPP3. It is worth noting that from 1 April 2020 these targets have been split according to Planned and Unplanned events.

Unplanned SAIFI Limit = 1.337

Planned SAIFI Limit = 0.576 (average annual)

(refer to the DPP3).

Note: RY25 was the last year under DPP3. The DPP4 methodology applies from 1 April 2025 to 31 March 2030, and Vector's performance targets during this period will follow DPP4 limits. For the next five disclosure years, Vector forecasts that planned and unplanned SAIFI will remain within the applicable DPP4 limits; the forward-looking values are disclosed in the AMP schedules for the relevant disclosure years.

Unplanned SAIFI Limit = 1.40

Planned SAIFI Limit = 0.63

7.5.3 SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI)

7.5.3.1 DEFINITION

The SAIDI index measures the average duration of outages per customer per RY, the value is expressed in minutes. This is one of the key metrics used to assess the reliability of the network. It is calculated as the sum of the duration of all customer duration interruptions divided by the total number of customers served, where interruptions are for 1 minute or longer.

In order to align with information disclosure requirements set out under the DPP3, from RY2021 Vector has moved to measuring planned and unplanned SAIDI as two separate measures, with respective targets.

7.5.3.2 MEASUREMENT

SAIDI = (total interruption minutes) / (average number of customers)

SAIDI only measures outages caused by an event on the High Voltage (HV) network and does not include the LV network. The SAIDI dataset is normalised using a process defined by the Commerce Commission in the DPP. This process reduces notified planned interruptions by 50% as it is considered that customers are less impacted by interruptions that are planned. It also limits unplanned SAIDI on days where a major event has occurred (e.g. storms) to prevent these extreme events from distorting the overall SAIDI data. The following formula is used for the planned SAIDI calculation:

$$SAIDI\ planned, assessed\ = SAIDI_B + \frac{SAIDI_N}{2}$$

Where:

$SAIDI_B$ is the sum of the SAIDI values:

(a) for any Class B interruptions commencing within the assessment period that are not Class B notified interruptions; and

(b) in respect of any Class B notified interruptions commencing within the assessment period that have occurred partially or wholly outside of their specified notified interruption window or alternate day, the SAIDI value attributable to the period of minutes that falls outside of that specified notified interruption window or alternate day.

$SAIDI_N$ is the sum of:

(a) the SAIDI values attributable to any minutes that fall within the specified notified interruption window or alternate day of any Class B notified interruptions commencing within the assessment period, where the SAIDI value is the greater of that calculated based on:

(i) the duration of minutes accumulated for each ICP that the Class B notified interruption occurred for; and

(ii) the period of the notified interruption window minus two hours;

(b) the 'intended SAIDI values' of any intended interruption cancelled without notice in the assessment period, where the 'intended SAIDI value' for each of those intended interruptions cancelled without notice is the greater of that calculated based on:

(i) the duration of minutes accumulated for each ICP that the intended interruption occurred for, which will be nil; and

(ii) the period of the notified interruption window minus two hours; and

(c) the 'intended SAIDI values' of any intended interruption cancelled with notice in the assessment the period, where the 'intended SAIDI value' for each of those intended interruptions cancelled with notice is nil.

The following formula is used for the unplanned SAIDI calculation:

$$SAIDI\ unplanned, assessed\ = SAIDI_C$$

Where:

$SAIDI_C$ is the sum of the SAIDI values:

(a) for Class C interruptions commencing within the assessment period, where the SAIDI value for each 30-minute period that starts on the hour or half past the hour within a SAIDI major event that exceeds 1/48th of the SAIDI unplanned boundary value for that assessment period is replaced with 1/48th of the SAIDI unplanned boundary value for that assessment period.

The SAIDI Unplanned Boundary Value is calculated as per the Commerce Commission process. This limit is set to 4.83 for the current regulatory period (1 April 2020 to 31 March 2025).

Class B interruptions - means planned interruptions by a non-exempt EDB

Class B notified interruption - means a Class B interruption that a non-exempt EDB has given additional notice for, and the Class B interruption is recorded as a 'Class B notified interruption' in the non-exempt EDB's internal systems

Class C interruptions - means unplanned interruptions originating within the system fixed assets of a non-exempt EDB

All of Vector's interruption data is held in our HV Spec database which is used to calculate and report on SAIDI performance. Supply interruptions are identified by the Supervisory Control and Data Acquisition (SCADA) system or through calls to the Customer Excellence team. Once faults have been resolved by the FSP, details of interruptions are logged in HV Spec. The customer interruptions are updated as supply is restored, with SAIDI calculated for each step in the restoration process. Where faults are identified through the Customer Excellence team, details are also captured in Siebel and linked back to HV Spec. SAIDI is continually monitored including reporting to the SRM fortnightly meeting and reported on a monthly and annual basis to inform asset management practices. For regulation purposes, SAIDI is reported to the Commerce Commission on an annual basis. SAIDI reporting to the Commerce Commission is subject to an external audit.

The SAIDI target is set by the Commerce Commission's regulatory determination every 5 years. It is largely based on the average SAIDI performance over a 10-year historical reference period. The process for setting this target is specified in the DPP.

DESCRIPTION	RY20	RY21	RY22	RY23	RY24	RY25
SAIDI – Combined	167.5					
SAIDI – Planned		46.54	40.48	43.87	55.77	49.18
SAIDI – Unplanned		86.3	92.42	118.74	98.37	76.56

TABLE 7-7: SAIDI

For the 2023 assessment period, Vector exceeded its reliability limits and was not compliant with the DPP Determination for unplanned SAIDI. As of 26 January 2023, Vectors unplanned SAIDI and SAIFI were on track to be compliant for the 2023 assessment period as measured against the prorated year-to-date limit at that date. However network performance was impacted by sustained adverse weather conditions, notably severe flooding in late January and cyclone Gabrielle in early February which left the network in an abnormal state. Even though the events were classified as Major Events the ongoing tail from cyclone Gabrielle adversely impacted unplanned SAIDI resulting in the limit being exceeded. However despite these events the unplanned SAIFI limit was not exceeded.

Vector considers the matter of quality compliance of utmost importance. To improve our network reliability, we have invested significantly in network improvements and operational processes to improve network reliability.

7.5.3.3 TARGET

For the Regulatory Period, (1 April 2020 to 31 March 2025) Vector's annual SAIDI target have been set based on the limits defined within the DPP3. It is worth noting that from 1 April 2020 these targets have been split according to Planned and Unplanned events.

Planned SAIDI Limit = 117.08

Unplanned SAIDI Limit = 104.83

(refer to the DPP3).

Note: RY25 is the last year under DPP3. The DPP4 methodology applies from April 1, 2025 to March 31, 2030, and Vector's performance targets during this period will follow DPP4 limits. For the next five disclosure years, Vector forecasts that planned and unplanned SAIDI will remain within the applicable DPP4 limits; the forward-looking values are disclosed in the AMP schedules for the relevant disclosure years.

Unplanned SAIDI Limit = 110.1

Planned SAIDI Limit = 128.8

7.5.4 NUMBER OF CUSTOMER INTERRUPTIONS PERFORMANCE AGAINST AGREED SERVICE STANDARDS

7.5.4.1 DEFINITION

This service level measures the number of unplanned supply interruptions experienced by customers on Vector's distribution network. It differs from SAIFI as it is the actual number of interruptions that a customer experiences rather than the average across the network. As with SAIFI, the interruptions are those of 1-minute duration or greater. At this stage, this metric only includes outages on the HV network. We see this measure as a much more effective representation of the impact of outages on customers, than an average measure such as SAIDI, that enables us to effectively engage customers affected by outages on issues such as cost quality trade-offs, etc.

The Default Distributor Agreements between Vector and energy retailers and Vector's Service Standards for Residential and Business & Commercial Electricity Consumers define the standard for customer interruptions. The standard states the number of interruptions, longer than 1 minute, that a consumer experiences per year should not exceed:

- 4 interruptions per annum in the CBD and urban areas; and 10 interruptions per annum in rural areas.

7.5.4.2 MEASUREMENT

All of Vector's interruption data is held in the HV Spec system, which is used to calculate and report on the number of customer interruptions performance. This metric is measured on an annual basis.

DESCRIPTION	RY20	RY21	RY22	RY23	RY24	RY25
Customer interruptions performance	97.3%	98%	98.6%	98.2%	98.2%	99.7%

TABLE 7-8: CUSTOMER INTERRUPTIONS PERFORMANCE

The number of customer interruptions exceeding the agreed service standards decreased last year, bringing performance within Vector's target. The factors affecting this measure are similar to those affecting Vector' s SAIDI and SAIFI service standards, however, these service standards do not include any events outside of Vector's direct control (such as storms or third-party damage to the network).

7.5.4.3 TARGET

Vector's target is to meet or exceed 99% compliance. For the next five disclosure years, Vector expects to maintain performance at or above this target, based on the planned reliability and maintenance programmes set out in this AMP.

7.6 Security of supply

Security of supply of the electricity network is the ability of the network to meet customer demand without interruption. Security of supply needs to balance the cost of redundancy with customer expectations and the benefit of supply availability for customers and society. The benefit for customer and society is progressively changing and in general increasing due to the growth of the service economy, electrification of transport and heat, and normalisation of remote working arrangements.

Security of supply specifies the network capability for restoring power after single or multiple asset failures (unplanned outages) and maintenance (planned outages). The general principle is that the higher the network level, the more demand is at risk from a single event, and the stricter the requirements to provide demand restoration before the fault(s) are repaired. The reliability metrics SAIDI and SAIFI are closely related to security of supply. These metrics measure asset performance and outage management across the network (for assets ≥11 kV), while the SoS defines network architecture and restoration requirements (including redundancy of assets).

Vector uses a probabilistic approach in the security of supply standard (ESP010). These are based on nine categories, classified according to sub-transmission, distribution and CBD or non-CBD, as shown in Table below. Very importantly, the SoS standard sets the criteria for network development about when and where reinforcement is needed.

CLAUSE	DEMAND	CATEGORY	STANDARD
1	Any	Single events incurring greater than 4 SAIDI minutes	>4 SAIDI minutes: investment evaluated using a risk-based approach
2	Any	CBD ZSS and sub-transmission	N-1: All demand (first contingency – no interruption) N-2: All demand (second contingency – restored in 2 hours)
3	Any	Non-CBD ZSS and sub-transmission	N-1: All demand restored in 2.5 hours (urban), 4.5 hours (rural). This requirement to be met for 95 percent of the year for primarily residential substations and 98 percent of the year for primarily commercial substations
4	Any	CBD distribution feeders (22 kV or 11 kV)	Demand restored to all but a single distribution substation in 2.0 hours. Remainder restored in repair time
5	Any	Non-CBD distribution feeders (22 kV or 11 kV)	Primarily underground: demand restored to all but 800 kVA within 2.5 hours (urban). Remainder restored in repair time Primarily overhead: Demand restored to all but 2.5 MVA within 2.5 hours (urban) and 4 hours rural. Remainder restored in repair time. This requirement to be met for 95 percent of the year for primarily residential feeders and 98 percent of the year for primarily commercial feeders
6	Any	Distribution substations (11/0.4kV)	Restored within repair time
7	Any	Distribution feeders (400V or 230V)	Restored within repair time
8	Any	All sub-transmission and zone substations	Maximum of one month on security reduced with respect to clause 2 and 3
9	Any	All sub-transmission and zone substations	Spatial separation of primary network assets sufficient to avoid common mode failure

TABLE 7-9: SUMMARY OF SOSS

7.7 Cyber security

As our electricity network continues to evolve, the digital capabilities required to support some of the changes continue to increase and this can mean our cyber threat profile also changes. We therefore remain committed to investing in technology solutions, processes and capabilities to ensure that we appropriately protect and detect potential disruptive security events that could impact customer privacy or our network services. The threat of an attack is ever-present, and we cannot rely solely on detective and preventative controls to mitigate the risk and providing security educating to our staff is a key focus as they form an important line of defence. Robust recovery strategies are also required to be able to quickly respond and recover to limit the impact.

While our ability to meet any service targets is highly dependent on the nature and complexity of each attack, we have set ourselves clear performance targets for the detection, containment and recovery from a cyber security incident. Robust processes and procedures have been developed to ensure our service targets can be met (or where possible exceeded) and Vector is very committed to achieving these. Regular simulations are conducted to ensure our response remains effective. A description of the service levels is included below however; we do not publish the actual service level targets due to commercial sensitivities and for security reasons.

The table below summarises how we prioritise security incidents for our environment:

Priority	Incident Type	Description
1	Critical Incident (**P1**)	Under attack or threat. High probability of significant level of damage or disruption to the Network which is likely to have a severe impact on business operations or damage to critical assets.
2	Priority Incident (**P2**)	Potential attack or threat. Moderate probability of material level of damage or disruption to the Network which is likely to have an impact on business operations or damage to critical assets but is not a P1 event.
3	Standard Incident (**P3**)	There is an event occurring in the Network which may have an impact on business operations or critical assets but is not a P1 or a P2. No immediate risk to business operations or critical assets.
4	Request for Service (**P4**)	Not a security incident. Any other requests for other service.

TABLE 7-10: INCIDENT PRIORITY DEFINITIONS FOR CYBER SECURITY

7.7.1 INCIDENT AND REQUEST SERVICE LEVELS

SERVICE LEVEL NAME	SERVICE LEVEL
Incident Management **Incident Response**	P1: 90% of P1 Incidents responded to within 2 hours P2: 90% of P2 Incidents responded to within 4 hours P3: 90% of P3 Incidents responded to within 8 business hours
Incident Management **Incident Response**	P1 incident reports for service impacting events issued as and when agreed for the specific event
Request Fulfilment	P4: 90% of Service Requests are actioned within 5 business days

TABLE 7-11: INCIDENT AND REQUEST SERVICE LEVELS

7.7.2 INCIDENT SUPPORT HOURS

SEVERITY	SUPPORTED HOURS
1 – Critical Incident	24x7
2 – Priority Incident	24x7
3 – Standard Incident	Business Hours
4 – Request for Service	Business Hours

TABLE 7-12: INCIDENT SUPPORT HOURS

7.8 Complaints management

This information is in addition to that provided in section 7.3.1 (addressing known LV non-compliance).

Vector manages complaints in an efficient and pragmatic manner balancing legitimate customer concerns with Vector's long-term interests. Areas of complaints include:

- Planned outages: planned outages include programmed maintenance; project works and customer-initiated connections
- Network reliability: trees on lines, general unplanned disruption
- Power quality
- Other combined: includes location of assets, self-service, quality of work, timelines, response times, etc
- Communication and information
- Connection costs

Complaints may be lodged through a range of channels, including the contact centre (primary channel), online channels (including social media), email, surveys and written correspondence. On receipt, Vector records the complaint and issues an acknowledgement (by email or letter) confirming that the complaint has been received. Vector also provides the customer with a copy of the Vector Disputes Resolution Process, which aligns with the Energy Complaints Scheme rules (as administered by Utilities Disputes).

Vector triages complaints to determine the appropriate investigation pathway. Where a complaint requires additional investigation (for example, a site visit, technical analysis or specialist review), Vector will advise the customer of the expected timeframes and provide updates throughout the investigation and resolution process.

7.8.1 COMPLAINT ACKNOWLEDGEMENT

Vector will acknowledge receipt of a complaint within two working days. The acknowledgement will confirm that the complaint has been registered, provide a reference number, and advise the customer of the responsible Customer Resolutions contact. Complaints are then triaged and assigned for investigation, with information gathered from relevant internal systems and, where required, field service providers. Customers may provide additional information at any time to support the investigation.

7.8.2 COMPLAINT RESOLUTION TIMEFRAMES

Vector will provide an update and/or work to resolve the complaint within seven working days of receipt. Where the matter cannot be resolved within this timeframe, Vector will advise the customer of the reason for the delay, confirm the next steps, and provide an expected resolution timeframe of up to 20 working days. Where an extension is required (for example, to enable a site visit, undertake technical testing or complete specialist review), Vector will provide ongoing progress updates and, once complete, confirm the outcome and any actions taken. If the complaint remains unresolved, customers may escalate the matter in accordance with the Vector Disputes Resolution Process, including referral to Utilities Disputes where applicable.

7.8.3 UTILITIES DISPUTES LIMITED (UDL)

If Vector has not resolved a customer' s complaint within 20 working days, or 40 working days where the customer has been advised of the reasons for a longer timeframe, or if the customer is not happy with resolution to your complaint, then the customer has the option of contacting UDL.

Further detail can be found on the Vector website: dispute resolution process



SECTION 08

Network maintenance

8 – Network maintenance

8.1 Section overview

This section describes the key elements of Vector's approach to the maintenance of our network assets. These activities are crucial to ensuring that the assets are well maintained and can continue to operate safely and effectively while delivering to our asset management objectives.

Vector's maintenance portfolio covers a broad spectrum of activities and includes investment across both opex and capex profiles. The key elements of the portfolio include planned maintenance (inspection and servicing), corrective maintenance, reactive maintenance and vegetation management.

A strategic review of maintenance practices in 2024 highlighted opportunities to enhance maintenance processes, Following the review, changes and improvements were made to our network maintenance approach (see section 8.4.3).

In FY26 we've updated our maintenance standards accordingly. These updated standards drive the collection of improved data quality through our maintenance portfolio. We anticipate that the improved asset health data will enable us to become more predictive and better able to identify and resolve defects before they become outages. This information will also support our longer-term Condition Based Asset Risk Management (CBARM) modelling initiatives and associated asset lifecycle decision making.

8.2 Network maintenance activity overview

The key elements of our network maintenance program are as follows:

Planned maintenance (PM) – this activity delivers our routine maintenance programme for inspections, testing and servicing of our assets in accordance with our maintenance standards.

Corrective maintenance (CM) – this activity primarily addresses issues identified through planned maintenance. Action is taken to restore functionality, and assets are repaired or replaced as required to ensure that the network can continue to operate safely and effectively.

Reactive maintenance (RM) – this activity primarily focuses on restoration of supply when a fault or other network incident occurs. Reactive maintenance incorporates our faults response and the remediation work needed to restore supply.

Vegetation management – this activity focuses on the tree trimming, removal and clearance to ensure our assets can continue to operate safely and effectively. It also includes grounds maintenance to ensure the integrity and safety of our ground mounted assets.

8.3 Asset management objectives

The asset management objectives that are addressed through our network maintenance activity and investments are set out in the table below:

FOCUS AREA	OBJECTIVES
Safety, environment and network security	• Prevent harm to workers, contractors and the public through our work practices and assets so far as is reasonably practicable. • Ensure health and 'safety always' is at the forefront of decision making for the business. • Comply with relevant safety and environmental legislation, regulation and planning requirements. • All staff are competent and trained in their applicable roles with the right equipment available to work safely and effectively. • Asset management activities align with environmentally responsible and sustainable behaviours enabling wider emissions reductions. • Minimise the impact on the environment with regards to our assets and work practices. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change).
Customers and stakeholders	• Provide a high-quality customer service experience across all interactions. • Listen to and learn from our customers to ensure our service offering aligns with customer expectations. • Consider the impact of our operational decisions on customers and minimise the disruption of planned outages and unplanned outage response times. • Ensure the long-term interest of our customers by endeavouring to provide an affordable and equitable network.

FOCUS AREA	OBJECTIVES
Network performance & operations	• Comply with regulatory quality standards set out in the DPP4 Determination. • Maintain accurate and comprehensive information management systems to drive continuous improvement of our asset health database and information records and meet regulatory reporting obligations. • Continual improvement of our asset management system and alignment to ISO 55001. • Strive to optimise asset lifecycle performance through increased asset standardisation, clear maintenance regimes and the development of fact-based investment profiling. • Maintain compliance with security of supply standards through risk identification and mitigation. • Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. • Collaborate with teams throughout Vector to leverage different thinking, skillsets and asset management capabilities. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings. • Manage performance of field service providers through effective commercial arrangements and regular review.
Future energy network	• Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network. • Improve our visibility of, and ability to control, the LV network including management of the information required.

TABLE 8-1: ALIGNMENT TO ASSET MANAGEMENT OBJECTIVES

8.4 Planned maintenance

8.4.1 OVERVIEW

Planned maintenance includes a range of scheduled activities carried out on all of Vector's assets to ensure they can continue to operate safely and effectively, to ensure reliability and resilience of the network and to maximise the service life of our assets. It also gathers important asset condition information which is a primary input into our predictive asset strategies and replacement plans and ensures compliance with regulatory requirements.

Vector has a suite of maintenance standards which are a key control in managing the risks associated with all our assets. These documents define the specific requirements and schedules for inspections and servicing for each type of asset in service.

The main type of activities conducted during planned maintenance are:

- **Functional inspections** – regular inspections and patrols ensure the integrity of the network and focus on identifying issues that may have a more immediate impact on safety and reliability. Functional inspections are our most frequent asset inspections and primarily feed into Vector's corrective maintenance regime.
- **Servicing and testing** – maintenance tasks that are performed on an asset in accordance with our maintenance standards to ensure that our assets can continue to operate safely and effectively.
- **Full inspections** – inspections that primarily record detailed asset condition information that is used to support our predictive asset strategies and analysis.

8.4.2 PLANNED MAINTENANCE OBJECTIVES

We have identified the following objectives to guide our planned maintenance programme.

ASSET MANAGEMENT OBJECTIVE	PLANNED MAINTENANCE PORTFOLIO OBJECTIVE
Safety, environment and network Security	Ensure that our planned maintenance regime is an effective control for the risks associated with owning and operating a network and our commitments to the environment and public safety are not compromised.
Customers and stakeholders	Minimise planned outages to our customers by grouping and prioritising works effectively, and where economically practical use alternative supply options to reduce planned interruptions.
Network performance & operations	Asset reliability - maximise asset life and improve reliability by ensuring that planned maintenance is completed in accordance with our maintenance strategies. Monitor asset performance and reliability and review our planned maintenance requirements to ensure they are up to date. Operational efficiency - ensure that our planned maintenance requirements and expectations are clearly defined, and our supporting systems are configured to reflect this. This ensures that our delivery resources can focus on delivery and improving efficiency.

ASSET MANAGEMENT OBJECTIVE	PLANNED MAINTENANCE PORTFOLIO OBJECTIVE
	Asset lifecycle information - ensure that asset lifecycle and condition assessment information is recorded through our planned maintenance activities. Ensure that our asset data sets are consistent, complete and are of a high quality to support our predictive strategies.

TABLE 8-2: PLANNED MAINTENANCE OBJECTIVES

8.4.3 MAINTENANCE REVIEW

A strategic review of maintenance practices in 2024 highlighted opportunities to enhance maintenance processes. The following changes and improvements were made following the review:

- Restructure the Network Performance team to create three asset management teams (zone substations, high voltage overhead lines and cables, and ground mounted equipment including low voltage assets), each with accountability for the end-to-end lifecycle of an asset, i.e. asset management policies, asset strategies & maintenance strategies.
- The risk-based approach implemented in 2019 was repurposed to give Vector more control in directing defect remediation through our field service providers to drive the resolution of high likelihood defects more efficiently.
- Additional validation of the existing defect pool was introduced, and ongoing regular validation of new defects were instigated with field service providers
- Functional inspections were realigned to focus more on defect rectification to reduce the likelihood of asset failures.
- New maintenance techniques, with a focus on aerial inspections, were embedded and operationalised following successful pilots, replacing ground base inspections where practical.
- Leverage modern, advanced photography for asset inspections to improve data quality and the quality of images.
- Leverage advanced digital platforms, machine learning and AI to automate the asset inspection process, including our partnership with Tapestry on the GridAware platform.

8.4.4 PLANNED MAINTENANCE IMPROVEMENT INITIATIVES

Vector seeks to continuously improve our approach to asset management and maintenance. The initiatives presented below are targeted at improving our planned maintenance programme.

INITIATIVE	DESCRIPTION
Maintenance standard updates	Throughout 2025, the team's principal objective was to overhaul the maintenance standards across all asset classes. Every standard has undergone a comprehensive review, harnessing new technologies to enhance efficiency and effectiveness. This process is now complete, with updated activities in progress. Notable advancements include a strong emphasis on technology adoption for process efficiencies and data quality improvement, such as conducting overhead inspections via drones and helicopters. These inspections now encompass all assets located on poles, which has resulted in improved efficiencies, since all overhead assets in one location can be inspected at the same time, rather than different asset types following different inspection schedules. Additionally, the standards are designed to enhance safety measures for inspectors.
CBM – switchgear	The implementation of a new condition-based maintenance (CBM) regime for primary and overhead switchgear, designed to supplement existing time-based planned maintenance actions, is now complete and has been incorporated into the new maintenance standards.
Continuous improvement	Network risks and asset strategies are reviewed regularly to ensure they are aligned with Vector's network performance expectations. Proposed changes to planned maintenance requirements are collated into a register for implementation into the maintenance standards.

TABLE 8-3: PLANNED MAINTENANCE IMPROVEMENT INITIATIVES

8.4.5 PLANNED MAINTENANCE OPEX FORECAST

Our planned maintenance expenditure forecast is presented in Figure 8.1. The forecast incorporates changes to our planned maintenance activities through the introduction of our new maintenance standards and the introduction of new initiatives that are aimed at increasing our condition assessment knowledge base.



FIGURE 8-1: PLANNED MAINTENANCE OPEX EXPENDITURE FORECAST

8.5 Corrective maintenance

8.5.1 OVERVIEW

Corrective maintenance is the action to restore and renew functionality of our assets before they fail by remediation of condition issues predominantly identified through our planned maintenance activities. It can also include out-of-cycle or unscheduled asset inspections. These actions are crucial to ensure the assets can continue to perform their intended function safely and reliably. Corrective maintenance activities assist with extending the service life of assets without compromising our performance expectations and are complementary to our proactive CBARM driven asset replacement initiatives.

Health and safety, asset performance, and other SAIDI related initiatives, including proactive CBARM asset replacement introduced in prior periods, continues to be a focus.

Our corrective maintenance investment can be broken down into the following key areas.

- **Corrective maintenance repairs** – These are minor corrective works undertaken to restore assets to a safe and functional state. These activities are classified as opex.
- **Corrective asset replacements** – These are corrective asset replacements that are undertaken to ensure that the network can continue to operate safely and reliably without compromising performance. These activities are classified as capex.

Vector has implemented a new condition-based maintenance (CBM) regime for primary and overhead switchgear to supplement existing time-based planned actions. This regime, now embedded in the latest maintenance standards, is enabled through advanced analytics, including tools like LiDAR and aerial imagery, which have improved our ability to assess, prioritise, and plan asset remediation. Required actions from this regime are delivered through dedicated corrective maintenance programmes to remediate backlogs. The clarity provided by updated standards has strengthened collaboration with service providers, facilitating the assembly and execution of work packages that aim to minimise customer outages and maximise reliability.

8.5.2 CORRECTIVE MAINTENANCE OBJECTIVES

We have identified the following objectives to guide our corrective maintenance programme:

ASSET MANAGEMENT OBJECTIVE	CORRECTIVE MAINTENANCE PORTFOLIO OBJECTIVE
Safety, environment and network Security	Ensuring that the network can continue to operate effectively without detriment to the environment or the safety of our people and customers. Our work is prioritised accordingly.
Customers and stakeholders	Improve the overall experience for our customers and community by improving overall network performance and wherever possible, maximizing the utilisation of any planned customer outage to complete work that is required.
Network performance & operations	Asset reliability – maximizing asset life and reduce the incidence and impact of failures to our customers by prioritizing work accordingly and reducing overall risk. Operational efficiency – enable efficient planning, coordination, optimisation, and delivery of all corrective work activity.

TABLE 8-4: CORRECTIVE MAINTENANCE OBJECTIVES

8.5.3 CORRECTIVE MAINTENANCE INITIATIVES

INITIATIVE	DESCRIPTION
Line clearance	This programme to ensure safe line clearance distances away from structures continues, supported by dedicated opex and capex budget and has been increased to accelerate remediation activities.

INITIATIVE	DESCRIPTION
Backlog remediation program	With the improvements introduced in FY26 through the new maintenance standards and inspection techniques, our asset condition assessment knowledge base will expand. This condition information is usually recorded in the form of notifications associated with our assets. As a result, we've seen the notification pool grow larger as the network undergoes comprehensive inspection using new methods. This has created a temporary backlog of notifications for prioritisation and remediation. To address this, a dedicated programme for remediation has been established. The improved quantum and quality of information will further support our corrective maintenance and proactive CBM initiatives and improve the efficiency of our delivery.
Continuous improvement	Continuous improvement of our overall corrective maintenance activities.

TABLE 8-5: CORRECTIVE MAINTENANCE INITIATIVES

8.5.4 CORRECTIVE MAINTENANCE OPEX AND CAPEX FORECAST

Because of the increase in notifications following the introduction of our new maintenance standards, we are now forecasting an increase in corrective capex and opex;

- In RY27 and RY28 to allow focus on the remediation of maintenance backlogs for specific asset classes
- Increased standard budget allowance from FY27 to resolve higher risk line clearance intrusion notifications.

Our corrective maintenance opex and capex expenditure forecasts are presented in Figure 8-3 and Figure 8-4. respectively.

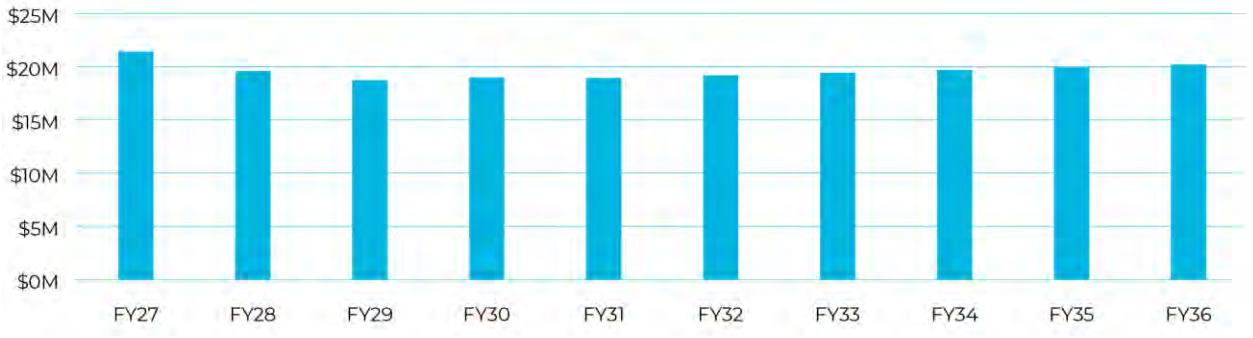


FIGURE 8-2: CORRECTIVE MAINTENANCE OPEX EXPENDITURE FORECAST

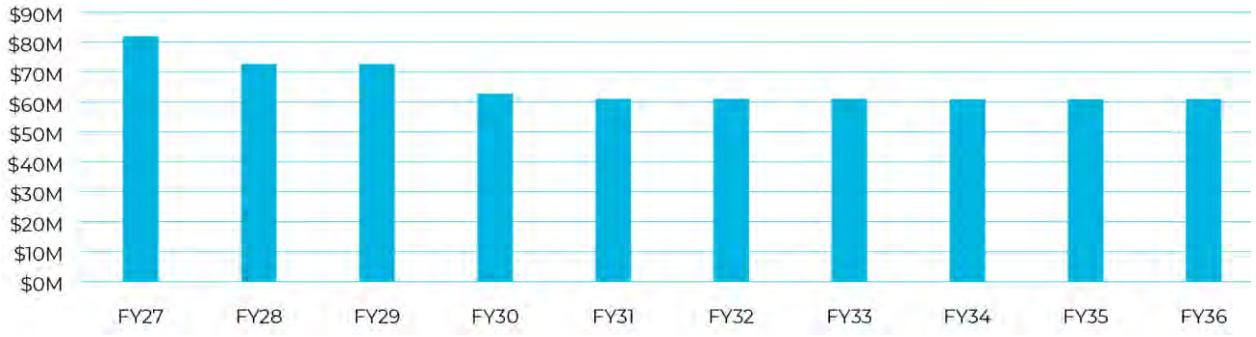


FIGURE 8-3: CORRECTIVE MAINTENANCE CAPEX EXPENDITURE FORECAST

8.6 Planned and corrective maintenance expenditure by asset class

Vector's forecast expenditure for planned and corrective maintenance activity is set out in forecast operational expenditure (Schedule 11b) in appendix 8 as part of the disclosure Report on Forecast Operational Expenditure. A typical breakdown of Vector's expenditure on planned and corrective maintenance activity across the primary asset categories is shown in Table 8-6.

Note the asset classes listed cover the categories set out in the Report on Forecast Capital Expenditure in Schedule 11a(iii).

ROUTINE AND CORRECTIVE MAINTENANCE AND INSPECTIONS	FY27 – FY36
Sub transmission switchgear	5%
Power transformers	6%
Underground cables	6%
Overhead lines	19%

ROUTINE AND CORRECTIVE MAINTENANCE AND INSPECTIONS	FY27 – FY36
Distribution equipment	27%
Auxiliary systems	18%
Infrastructure and facilities	14%
Protection and control	5%

TABLE 8-6: PLANNED AND CORRECTIVE MAINTENANCE – FORECAST EXPENDITURE BY ASSET CLASS

8.7 Reactive maintenance

8.7.1 OVERVIEW

Reactive maintenance relates to activities associated with our response to faults and other unplanned network events. These can be broken down into the following activities:

- **First response** – This is our rapid faults response to unplanned network events. The primary functions here are to make the network safe, initiate and co-ordinate any switching to isolate the fault, restore supply where possible, and to confirm the nature of any remedial work required.
- **Fault restoration and repair** – This activity primarily focuses on the restoration of supply to all affected customers. This can include the installation of generation, temporary or permanent repairs, and the restoration of the network to a fully operational state. Often this work is carried out by a second response crew attending site.

Reactive maintenance addresses all types of faults on the network including faults inherent to the degradation of the asset and faults due to environmental factors. Faults due to environmental factors (vegetation, weather events, animals, third party damage etc.) continue to dominate unplanned outages. To mitigate the impact of these to our customers, a range of initiatives have been implemented through our Strategic Reliability Management Plan (SRMP) response. Those specifically associated with reactive maintenance activities include significant changes to the scheduling and resourcing of response crews, their locations as well their ability to access materials.

8.7.2 REACTIVE MAINTENANCE OBJECTIVES

ASSET MANAGEMENT OBJECTIVE	REACTIVE MAINTENANCE PORTFOLIO OBJECTIVE
Safety, environment and network security	Ensuring that the network can continue to operate effectively without detriment to the environment or the safety of our people and customers. Our work is prioritised accordingly.
Customers and stakeholders	Minimise impact to our customers and optimise restoration through faster response times, fault isolation and partial feeder restoration, and repairs.
Network performance & operations	Asset reliability - manage restorations without compromising asset reliability. Operational efficiency - continue to seek improvements to our response, isolation of faults to smaller localised areas and reduce impact to our customers.

TABLE 8-7: REACTIVE MAINTENANCE OBJECTIVES

8.7.3 REACTIVE MAINTENANCE INITIATIVES

Planned and corrective maintenance strategies are aimed at improving supply reliability, resulting in fewer equipment faults on the network. When a fault does occur, the reactive maintenance initiatives target two key areas:

- Reducing the number of customers who lose supply when a fault occurs.
- Reducing the duration of the outage for customers who do experience a loss of supply.

INITIATIVE	DESCRIPTION
Continuous improvement	Vector continues to review and improve the fault response model we operate with our service providers.

TABLE 8-8: REACTIVE MAINTENANCE INITIATIVES

8.7.4 REACTIVE MAINTENANCE OPEX AND CAPEX FORECAST

Our reactive maintenance opex and capex expenditure forecasts are presented in Figure 8-5 and Figure 8-6 respectively.

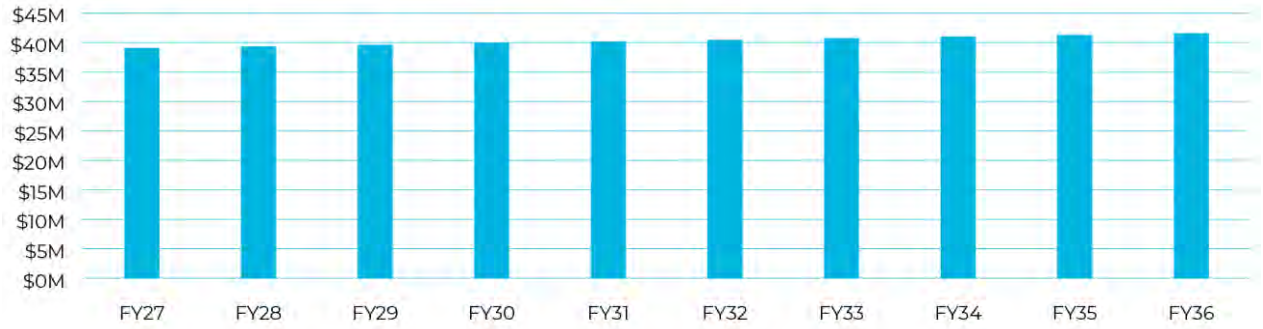


FIGURE 8-4: REACTIVE MAINTENANCE OPEX EXPENDITURE FORECAST

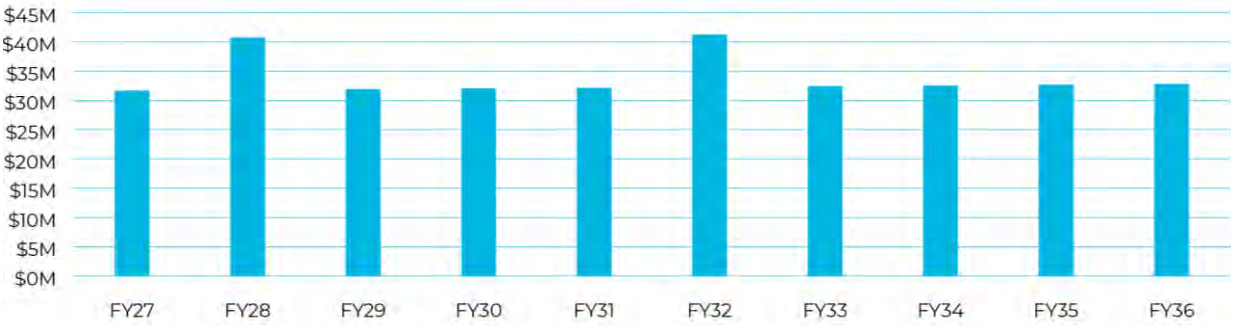


FIGURE 8-5: REACTIVE MAINTENANCE CAPEX EXPENDITURE FORECAST

8.8 Vegetation management

8.8.1 OVERVIEW

Control of vegetation in the vicinity of network assets is an essential activity for a distribution network to ensure we can continue to deliver a safe, reliable, and resilient service for our customers. Management of vegetation is a complex issue, primarily due to the challenges associated with balancing ownership and accountability with amenity and utility value while also ensuring the reliability of the network.

The Electricity (Hazards from Trees) Regulations 2003 (as amended in 2024) provide the updated statutory framework for managing vegetation near network assets. Vector welcomes the 2024 amendments, which modernise the regulations to better align with proactive risk management. Some of the amendments are:

- **Enabling proactive notification:** The Notice Zone allows Vector to issue Cut or Trim Notices (CTNs) before vegetation breaches the critical Clearance Zone, preventing immediate hazards.
- **Addressing fall-distance risks:** New provisions allow for the notification of trees outside the zone that pose a direct fall hazard, addressing a critical gap where approximately 80% of historical vegetation-related outages originated.
- **Streamlining responsibilities:** The amendments clarify tree owner obligations and cost-recovery mechanisms, supporting Vector's shift towards a data-driven, risk-based maintenance program rather than one driven solely by reactive clearance breaches.

Vector is actively integrating these regulatory tools into its vegetation strategy to drive improved network resilience.

The elements of Vector's vegetation management program are:

- **Inspection:** Routine and targeted inspections of the network are used to identify and record vegetation encroachment and likelihood of failure, utilizing both ground-based assessment and aerial LiDAR data.
- **Consequence modelling**: Vegetation risks are assessed not just on likelihood of failure, but on the consequence of that failure to network reliability, stakeholder impact, bush fire risk and public safety. All factors are directly linked to Vector's wider risk outcomes.
- **Management and prioritisation of work packages**: This activity consolidates vegetation work into efficient work packages prioritised by risk, aiming to send resources to where they are needed most.
- **Delivery of works**: Activities focused on the physical delivery of vegetation management works, ranging from routine cyclic trimming to targeted "Cycle Busting" of high-risk trees.
- **Customer liaison**: Proactive engagement with tree owners to explain risks, obligations, and coordinate access for remediation.
- **Management of tree registers and data**: Maintaining a comprehensive, accurate database of vegetation assets, risk scores, and maintenance history to inform long-term planning.

Vector separates the accountabilities associated with these programs. The inspection and administration component is undertaken by a specialist arborist contractor (Arborlab). The physical vegetation management is undertaken by vegetation service providers (Treescape and Asplundh).

Vector continues to work closely with Auckland Council over an electricity network resilience targeted rate, designed to enable more effective tree management of Council-owned vegetation encroaching on the electricity network. The relationship involves sharing tree registers and alignment of workflows. This ensures a coordinated approach to managing vegetation risk in alignment with Vector network objectives.

8.8.2 VEGETATION MANAGEMENT APPROACH

Our investment in vegetation aims to proactively mitigate risk on the network to ensure safety and reliability. Vector implements a Quantified Tree Risk Assessment (QTRA) approach, which shifts the focus from simple compliance distances to a holistic view of network risk. This approach assesses the likelihood of failure of any tree—irrespective of its current proximity to powerlines—while weighing the consequences of that failure using a risk-based criticality model.

The QTRA framework determines the risk of vegetation coming into contact with electricity assets and applies proportionate mitigations based on three critical impact areas:

- **Network resilience:** Prioritising the removal of fall-distance trees that pose a threat to critical sub-transmission and backbone feeders, ensuring the network remains robust during extreme weather events.
- **Bushfire mitigation:** Identifying and managing high-risk vegetation within designated high-fire-threat zones to prevent ignition events and protect public safety.
- **Customer impact:** Weighting interventions to prioritise feeders serving highly impacted customers (those experiencing frequent outages) or critical community infrastructure, directly improving their service experience.

Vector's vegetation asset management strategy (VAMS) forms an integral part of its strategic reliability management plan (SRMP). The operationalisation of the QTRA framework is designed to be adaptable to new arboriculture and operational data, as well as the different needs of communities and regions, whilst providing a robust and consistent process.

8.8.3 VEGETATION MANAGEMENT OBJECTIVES

Vector's vegetation management strategy reflects our strategic asset management objectives. Vector's overhead network exposure to vegetation comprises approximately 8,236 km of total route length. Vegetation in the proximity of these powerlines has a major influence on network performance, especially during storms and high winds.

ASSET MANAGEMENT OBJECTIVE	VEGETATION MANAGEMENT PORTFOL.IO OBJECTIVE
Safety, environment and network security	Ensure network safety and effectiveness without detriment to the environment, staff, or customers so far as is reasonably practicable. Mitigate fire risk and manage work within significant ecological areas responsibly.
Customers and stakeholders	Improve customer outcomes by enhancing network performance and coordinating planned outages to maximize work completion and minimize disruption.
Asset reliability	Maximise asset life and reduce customer impact by prioritising risk-based work. Enable efficient planning, coordination, optimisation, and delivery of all vegetation activity.

TABLE 8-9: VEGETATION MANAGEMENT OBJECTIVES

8.8.4 VEGETATION MANAGEMENT INITIATIVES

The key initiatives being delivered under Vector's vegetation management strategy are:

INITIATIVE	DESCRIPTION
Evolution of risk-based approach	Growth rate modelling: assessing and developing capability to predict vegetation growth rates based on species and climatic conditions to improved forecasting accuracy. Cut optimisation modelling: introducing modelling to determine the optimum intervention time for each span, ensuring cutting occurs at the most cost-effective point in the growth cycle while maintaining compliance.
Key Relationships	Auckland Council: further alignment with Auckland Council to coordinate vegetation management efforts and share data. Provider agreements: revised service agreements with key providers to ensure commercial models incentivise risk reduction and quality outcomes.
Digitisation of processes	Single System Integration: consolidating all inspection, cut trim notices, workflow, financial and completion data into a single system to improve visibility and reporting. LiDAR integration: increasing the use of aerial-based LiDAR data to support growth rate modelling, validate risk assessments, and provide quality assurance for clearance works.
Operational performance monitoring	Audit program: implement an external audit program to provide inspection and clearance works quality assurance and influence appropriate contractor behaviour/performance.

TABLE 8-10: VEGETATION MANAGEMENT INITIATIVES

8.8.5 VEGETATION MANAGEMENT OPEX FORECAST

Our vegetation management expenditure forecast is presented in Figure 8-6 including the core assumptions that underpin it.

The changes to the regulations have not been considered in the forecasts. While the regulation changes will help lower the risk to power lines from trees, leading to fewer outages, the costs will ultimately be borne by our customers. This is because the regulations still require that we pay for any actions taken to protect the electricity supply where the tree owner declares no interest on a tree, or when the tree is assessed to be high risk and out of zone. The obligation to trim or remove the tree remains with us. If we determine that, to secure more customer benefit, more expenditure is required for tree management over and above our current forecasts, we may need to apply to the Commerce Commission for a reopener to secure the reliability and resilience benefits for our customers.

The uplift in our expenditure forecast incorporates lifting our vegetation management activities including increased arborist capacity and independent scoping and auditing.

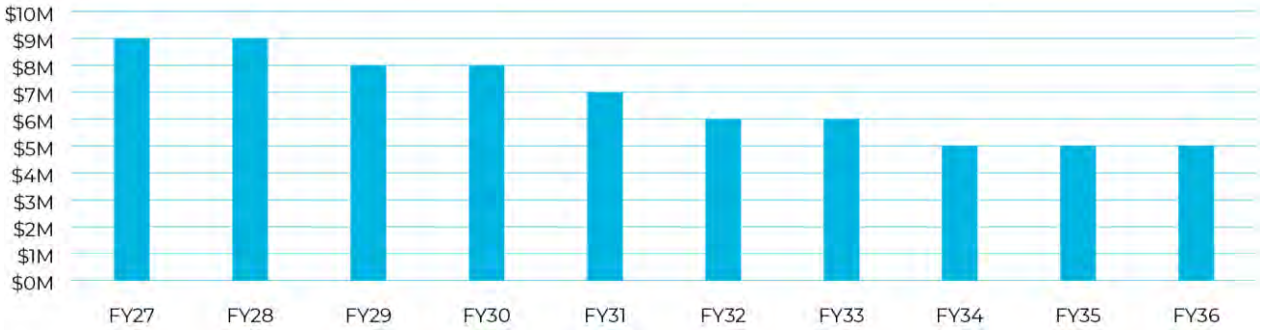


FIGURE 8-6: VEGETATION OPEX EXPENDITURE FORECAST



SECTION 09

Customer connections

9 – Customer connections

9.1 Section overview

This section explains our approach to connecting new customers, changing existing customer connections including both load and generation/export connections, managing customer cost and communication, and forecasting expenditure for these connections.

Section 1.3.2 outlines the comprehensive assessment we have done on our customer connections process to make it easier for customers to connect.

9.2 Customer connection growth

Reflecting Auckland's continued growth, electricity total net connections continue to grow with electricity connections up 1.2% in FY25 on FY24 to 632,106[11] . However, new connections in FY25 have been 3,411 lower than FY24, reflective of the broader economic slowdown. Additional connections include a range of connections; from small connections such as for residential properties and special vehicle lane cameras to large connections for commercial buildings and industrial properties.

At Vector we utilise our pipeline data in conjunction with modelling (detailed in Section 10 Network Growth) to forecast connection growth. We also work with our customers to understand their planned development activities and intended timeframes for these.

9.2.1 EXTERNAL IMPACTS

Towards the end of 2025 the easing of inflationary pressures look to have resulted in cautionary optimism for developers which may result in increased connection requests in 2026.

9.3 Providing cost effective customer network connections

We connect new customers to the network as required through our customer connection process. To ensure an efficient and cost-effective service, small or simple connections are provided by our FSP for that part of the network based on unit rates. For larger or more complex connections, customers can elect for a price from both FSPs to ensure a competitive pricing process.

Vector provides full information on our website in relation to:

- our process for providing new connections or changing existing connections.
- our policy on customer capital contributions to new connections or changes to existing connections.
- our approach to planning and managing communication with consumers about new or altered connections; and
- the factors that may impact on the potential timeframes for different connection types.

9.3.1 DESIGN AND BUILD PROCESS

Customers can initiate a connection request through several different channels, including our web self-service portal, contact centre or by contacting our customer contracts team or their key account manager directly. Customers also have the ability online to (i) order multiple ICPs at the same time within one order, (ii) track progress (including explanations of what is currently happening and next steps) and (iii) cancel an order. Customers receive email notifications as their jobs progress to different stages. Larger connections customers have a dedicated Vector and Field Service Provider contact who keep them updated on the status of their jobs.

Depending on the complexity of the proposed connection(s) the connection request will be administrated by our connections team (small / simple connections) or managed by either our customer projects team (large connections) or our major projects team (large complex connections or infrastructure relocations). A simple connection is generally completed within 6 to 8 weeks after payment is received. Vector provides a high level, desk top based assessment of approximate scope and cost for large connections within 10 working days after sufficient information has been received on the required scope. Each large connection request needs to be assessed in relation to complexity, and Vector aims to provide an indication of timeframes within a week after a design fee has been paid.

The Vector network is divided into two areas, each of which has a Field Service Provider (FSP) that is responsible for designing, building and maintaining the network in their area (zone). Small or simple connections are priced using agreed unit rates and the connection will always be built by the zone FSP. This is to enable a quicker turnaround from request to completion of the connection. For large and complex projects, customers have the option for their connection to be priced by both FSPs, ensuring a competitive pricing process. Our customer contract advisors work closely with customers to understand their requirements and provide further information such as possible consent requirements or impact of legislation related to building near existing electrical infrastructure. In all cases we aim to provide a design and quote that is as affordable as possible, while meeting our and our customer's requirements.

Our Customer Delivery Advisors work closely with our customers and the service provider project managers during the build phase of the connection assuring that the installation is as per the agreement. Delivery timeframes may be adversely impacted

[11] Number of electricity connections (2025 Annual Report)

when there is a sudden increase in work volumes, adverse weather conditions impacting on civil works, third party requirements such as traffic management services, approval of consents to work near other utilities or trees, consideration of public impact by outages or road closures etc.

Vector's engineering teams have developed robust design standards to ensure that a safe and resilient network is built in accordance with legislative requirements, and which meets our asset management objectives. All customer connections are designed to comply with these standards ensuring the integrity of our network and quality of supply to existing and new customers. Our planning engineers review all material changes to the network ensuring that the network is reinforced at the right times to cope with new connections being added.

The process, timeframes and cost of connections may vary depending on a number of factors, including:

- The type of network connection supply point required - which depends on the available capacity
- The number of connections you require and whether the connections are temporary or permanent
- The available capacity as well as fuse and phase requirements (your electrician will provide these details)
- Whether an easement is required to allow gas and electricity equipment owned by Vector to be installed and to remain on private property. An easement provides us with ongoing access and maintenance rights in respect of that equipment.
- The conditions of the work site and the complexity of the job
- Vector's current work volumes
- When traffic management services are next available (as these are managed by third parties) and the availability of equipment required
- Other technical, legal, regulatory and administrative factors (including resource constraints)

We manage these commonly encountered issues by confirming information requirements early, identifying capacity and consent dependencies during assessment, and coordinating third-party requirements and outage windows to progress connections as efficiently as practicable.

9.3.2 COST OF CONNECTION AND DEVELOPMENT CONTRIBUTION

In some circumstances the connection applicant may undertake some of the work that would otherwise be covered by the capital contribution. Customers can undertake the preparatory work using appropriately trained persons and with all work to be completed to Vector's standards and requirements prior to Vector installing the new electricity infrastructure. Preparatory work could include trenching and or civil work, reinstatement and laying of duct.

9.3.2.1 ELECTRICITY AUTHORITY (EA): DISTRIBUTION CONNECTION PRICING CODE AMENDMENT

Vector is working to implement policy, system and process changes to comply with EA code amendments. Mid 2025 the EA confirmed that they were progressing four of the five measures proposed to improve pricing methodologies for connecting to the network, the fifth is being consulted on separately. The four pricing methodology requirements are:

- enhancement cost allocation
- network capacity costing
- pioneer scheme
- connection charge reconciliation.

The new requirements apply to quotes for connections for load applications received from 1 April 2026 with network capacity costing applicable to quotes received on and after 1 April 2027.

Vector is also working to implement EA code changes in relation to Distributed Generation (DG) and load connection. Changes with regard to DG will come into effect from December 2026 and changes to load applications will come into effect from June 2027.

9.3.3 LARGE AND COMPLEX CONNECTIONS

The decisions of central and local government, as well as large local and international commercial enterprise infrastructure investment decisions, directly impact on our capital investment choices. We have recently seen strong growth in data centres being built in Auckland and significant investment in commercial and public transport EV chargers. Government driven examples include major motorway development projects; electrification of buses and ferries and continuing investment related to Watercare, Auckland Transport, Auckland Council, universities.

Our key account team manage the direct electricity conveyance contracts with several large customers on our network. These customers understand our network performance but also make individual decisions around network resilience and configuration to manage their unique requirements. They also provide dedicated account management for the large roading, rail and water infrastructure projects around Auckland. This ensures these large infrastructure projects have the greatest possible synergies and cause the least possible disruption for the public.

9.3.4 CONNECTION OF CUSTOMER DISTRIBUTED ENERGY RESOURCES (DER)

One of our asset management objectives is to enable the connection of customer DERs. When a customer wants to connect a DER to Vector's network the application is done via Vector's website. The website provides clear guidelines and standards that ensure that the network has sufficient capacity and capability to provide the required service levels and allow for the orderly and safe connection of distributed generation for a new application.

Vector needs to know where all distributed generation is connected and located to ensure that the equipment meets safety and operational standards as well as to ensure compliance with Part 6 of the Electricity Industry Participation Code (2010).

Vector will review all DER applications (for both new DG connections and changes to existing DER connections e.g. changes to nameplate capacity) and identify situations where the connection of DER may compromise the safety and operational performance of the network. If in Vector's assessment, the connection of the proposed DER will result in network congestion, we will offer guidance to the applicant to help enable them to meet our requirements. If the proposed DER installation is still unable to meet our requirements to avoid congestion, the application to connect to the network will be declined (with an explanation). Where the application is declined, the applicant may wish to resubmit a revised application addressing the issues in the original application.

For larger DER proposals (>10kW), Vector may work with the applicant to identify potential solutions that may allow us to reverse a declined application. For example, this may include restricting export to certain time periods.

There are two options on Vector's website for distributed generation: less than 10kW or more than 10kW: the first step is for a customer to check whether there is congestion in the network (for DERs rated less than 10kW, congestion is usually not an issue but if it is Vector will inform the customer). Furthermore, customers need to ensure, as part of the application, that the inverter that they plan to use has been pre-approved for use in Vector's network; the Vector website provides a list of pre-approved inverters with full details.

The application form to install a DER and connect it to Vector's network is available on Vector's website. Vector aims to acknowledge an application within five days and will review and approve (or decline if there is a reason), an application within thirty days. The last step in this process, after a DER installation has been approved, installed and tested, is for the customer to provide a signed certificate of compliance that outlines the scope of the installation and as well as confirm compliance with the AS/NZS standards for inverters and wiring installations.

The process for DERs greater than 10kW is very similar to those for less than 10kW but there is a chance in some parts of the network, that congestion could preclude the connection of a DER, especially where the proposed DER will contribute significantly to fault levels.

9.4 Customer connection forecast expenditure

Customer connection CAPEX is primarily driven by population growth (residential) and growth in commercial/industrial activity. Our forecast expenditure is based on trending historical connection activity using the FY23 forecast as a baseline and incorporating econometric parameters and customer growth insights. Step changes due to connection requests from major customers are included in our 10-year forecast.

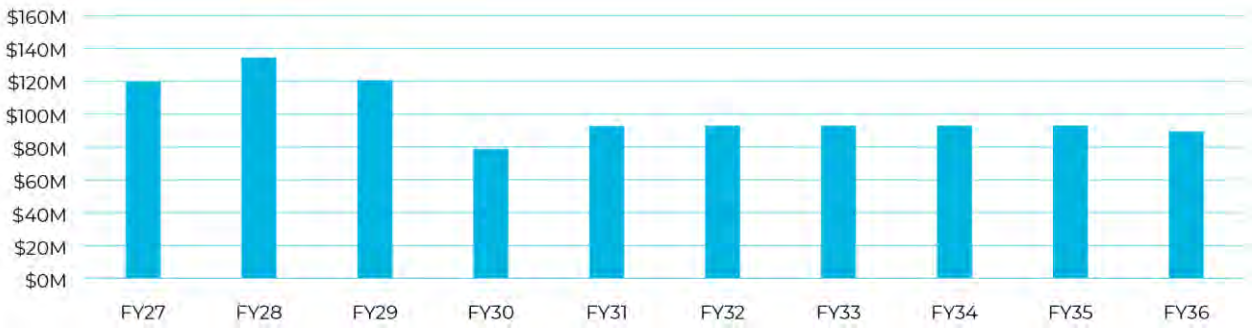


FIGURE 9-1: CUSTOMER CONNECTION EXPENDITURE FORECAST (GROSS)



SECTION 10

Network growth and security

10 – Network growth and security

10.1 Overview

This section describes the processes and systems Vector has implemented to identify where investment is required on the network to resolve network constraints, meet changes in electricity demand, manage changes in customer consumption behaviour, improve climate resilience and create the future energy network.

Network planning is about providing a reliable and resilient network in the long-term interest of our customers by developing a cost-effective electricity supply to meet new and future demands (e.g. organic growth, new development, urbanisation) and changing customer needs (e.g. energy efficiency, electrification of transport). This requires balancing supply side options with demand side solutions to ensure a network that is more flexible and responsive to changing customer behaviour and the increasing rates of renewable technology adoption.

Given electricity infrastructure typically has a life of more than 40 years, even planning for the near-term (next 5 years) must consider the long-term need for infrastructure, managing uncertainty and avoiding stranded assets. Today, uncertainty is higher than ever due to rapid technology innovation and changing customer preferences which also challenge market and policy prospects. To navigate this rapidly evolving landscape shaped by broad-market trends and shifting societal expectations , Vector's network planning must be scenario-based and increasingly flexible. This dynamic approach allows us to pivot and adjust as the future evolves, while maintaining our commitments to timely investment and delivery of network projects.

We also recognise the changing technology landscape and how our customers use the network may change as a result. In comparison to a few years ago when our largest market segment, the residential market, primarily used electricity for cooking and heating, we are seeing electricity being increasingly used for sewerage management (e.g. pumped schemes are substituting gravity flow systems), working from home and home-based education (e.g. step increase following the COVID-19 pandemic), transport (e.g. the electrification of transport) and responses to pricing signals. Additionally, the integration of Artificial Intelligence into daily life and business operations has created a new baseline for high-availability power, requiring the network to support increased data processing loads for all customers. This customer transition forms a significant input to our planning, to ensure we only build assets that are needed for the long term and reduce the risk of stranded assets.

To this end, our planning aims to transform our network to enable customers to interact and actively participate through distributed energy resources (i.e. solar PV and batteries) and load control. This will promote a lower-cost, smarter, and more decentralised electricity network which will also improve its resilience. This is in essence Vector's Symphony strategy from a network development perspective.

The following sections describe:

- overview of the asset management objectives and strategies applicable to network growth and security (sections 10.2 and 10.3)
- our network planning approach and process, including (section 10.4):
  - the critical steps in the planning process,
  - demand modelling and constraints identification.
  - how different solutions to address the constraint or meet the demand growth are assessed, including non-network options, and
- opportunities for non-wires alternatives (section 10.5)
- major investments in security and growth projects to address identified constraints and demand growth (section 10.6)

10.2 Growth and security objectives

10.2.1 ASSET MANAGEMENT OBJECTIVES

The asset management objectives that are addressed through the network growth and security programme of works and investments are set out in the table below.

FOCUS AREA	OBJECTIVES
Safety, environment and network security	• Comply with relevant safety and environmental legislation, regulation, and planning requirements. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change).
Customers and stakeholders	• Enable customers' future energy and technology choices. • Ensure the long-term interest of our customers by providing an affordable and equitable network.
Network performance and operations	• Utilise clear business case processes, integrate risk management and complete post investment reviews to inform our decision making and analysis.

FOCUS AREA	OBJECTIVES
	• Maintain compliance with Security of Supply Standards through risk identification and mitigation. • Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. • Collaborate with teams throughout Vector to leverage different thinking, skillsets, and asset management capabilities. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings.
Future energy network	• Prepare the network for future changes that will be driven by: – technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc. – environment: climate disruption and network resilience – customer: decarbonisation of the economy, electrification of transport, etc. – operations: transition to distribution system operator model and whole-of-system planning. • Embed network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third-party flexibility traders and retailers. • Facilitate customer adoption of new technology while ensuring a resilient and efficient network. • Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network. • Develop digital and data platforms to meet changing customer needs and enable the future network in partnership with new entrants to the energy market. • Improve our visibility of, and ability to control, the LV network including management of the information required. • Collaborate with the industry, partners, thought leaders and subject matter experts to ensure Vector remains at the leading edge of future energy solutions.

TABLE 10-1: ALIGNMENT TO ASSET MANAGEMENT OBJECTIVES

Additionally, the following customer-related objectives specific to system growth apply:

- Manage the increasing load forecast uncertainty due to the unpredictability of the timing of large customer projects, changing customer behaviour (e.g. hybrid working arrangements) and the rate of our customers' adoption of new energy technologies (e.g. EV) and AI technologies.

10.3 Strategies to achieve the objectives

To meet these objectives, the following strategies are employed.

10.3.1 UNDERSTAND FUTURE TRENDS FOR LONG TERM PLANNING

Our planning process is anchored on granular bottom-up data analysis at customer level[12]. We use a Customer Scenario Model to forecast trends and their impact on our network and gain a clearer understanding or predictions of the future energy demand for the next 30 years. This modelling forecasts electricity growth based on expected volumes and locations of new customer connections, technology uptake and energy efficiency gains. It uses data from customer usage trends and changes to customer behaviour (from smart meter data), as well as results from industry trials (EV Smart Charging Trial and Smart Hot Water Trial), regional and national forecasts, and consumer surveys. To ensure that we adapt and respond to changes, the model is continuously refined and updated. Further details of our scenario modelling areas are set out in section 10.4.

Vector is monitoring an emerging trend where customer responses to retail (and, implicitly, EDB) pricing signals are creating secondary demand peaks at 9 pm. While these signals successfully shift load away from traditional system-wide peaks, they present a growing challenge to localised network security, as localised peak demand is increasing. This new trend is not yet captured in our current scenario model and we will integrate it when the behaviours mature.

[12] Heinen, S., Richards,, P., (2020), Towards customer-centric energy utilities - A granular data-driven bottom-up approach to understanding energy customer trends, The Electricity Journal, Volume 33, Issue 9, 2020.

CASE STUDY: CUSTOMER RESPONSE TO PRICING SIGNALS

In 2024 and 2025, our smart meter data analysis identified a new trend: a new secondary 9pm peak which coincides with retailer pricing signals. The retailer's price periods were mirroring (passing through) the timing of the peak periods in the major EDBs' pricing, including Vector's. The intent of the pricing signal is to move demand away from traditional peak periods. At a system-wide level, this objective is being achieved as the high volume of customers provides sufficient demand diversity to smooth aggregate demand. However, our analysis found that as demand is examined progressively down the network hierarchy levels, particularly at LV level, diversity is lost and a new artificial demand peak appears at 9pm. This new peak tends to be bigger than the historic 6pm peak, when behaviour remains diversified.Figure 10-1 captures the results of the investigation and illustrates two primary themes:

- Flat Rate Plan Stability: Customers on flat rate plans have shown little change in their winter weekday load profiles over time. This is agnostic of EV presence

- TOU Plan Load Shifting: Customers on TOU tariffs have increasingly shifted their energy use away from daytime and peak periods to nighttime (after 9pm), as more customers have adopted TOU plans. The 9pm peak among TOU customers has grown consistently, reflecting the impact of synchronized load and reduced diversity in usage patterns (a concept referred to as "herding"). This is also largely agnostic to EV presence

The new secondary peak has not caused any network security issues yet, however an investigation was undertaken to assess the impact at all network levels. To develop future-fit solutions that maintain network security.

Flexibility providers and retailers are expected to increasingly optimise customer behaviour and devices based on price signals – those provided both by EDBs and from the wholesale market. In the future, automatic algorithmic control decisions based on price signals take the human behaviour further out of the loop. The natural diversity of customer behaviour is therefore at risk of being eroded. Unmanaged synchronization of demand will create localised stress that becomes increasingly acute as you move from sub-transmission and distribution HV levels down to the LV network, where diversity is lowest. Maintaining security across all voltage levels, will require us to avoid and manage these 'artificial' peaks. Because our pricing signals are a key driver of this new behaviour, Vector has ongoing engagement with retailers to understand how we can evolve our pricing and put extra controls in place to influence retail products in the market, and therefore customer behaviour. We have made changes to our pricing from 1 April 2026 to address these issues and will continue to refine our prices as system behaviour evolves.

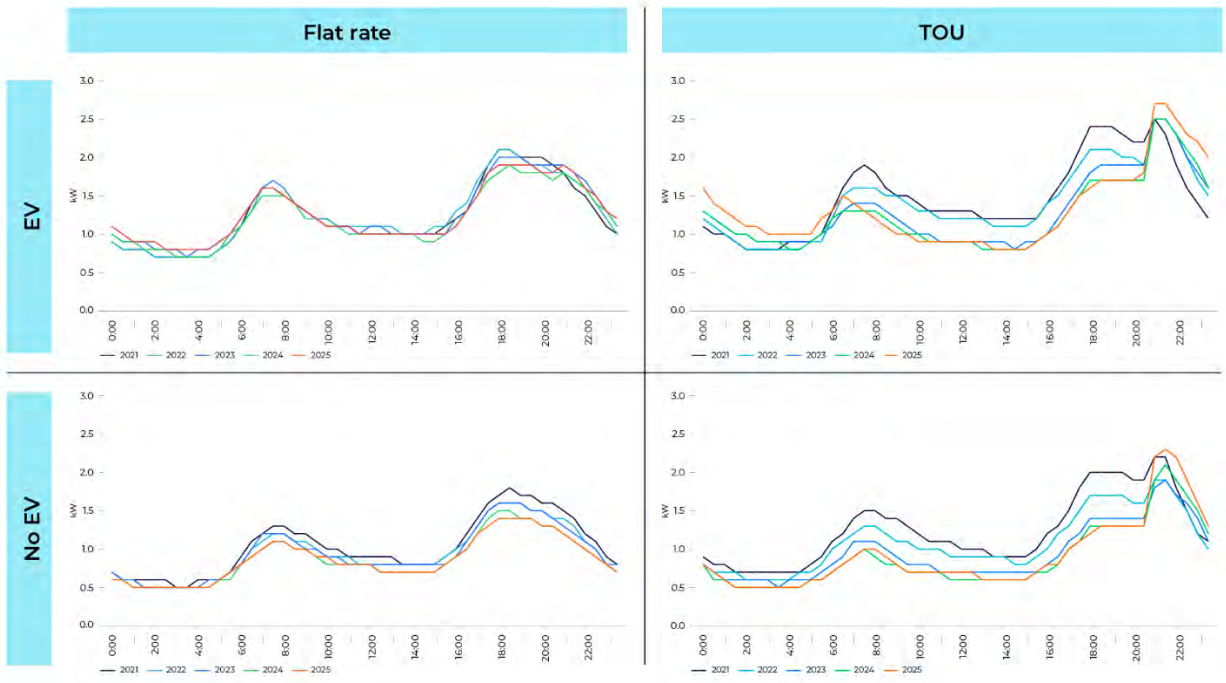


FIGURE 10-1: AVERAGE WINTER WEEKDAY LOAD PROFILES FOR CUSTOMER CATEGORIES OVER THE LAST FIVE YEARS.

10.3.2 ENGAGE WITH CUSTOMERS & STAKEHOLDERS

In an uncertain environment, customer and stakeholder engagement is pivotal. We have dedicated teams that engage with small and small to medium commercial customers, developers of large residential and commercial projects, large commercial customers, and Auckland infrastructure providers (e.g. road, rail, public transport, telcos, water). Those engagements identify synergies for system growth projects and customer projects, therefore minimising direct and indirect costs, such as disruption of traffic and local businesses. Those engagements also mean that our network developments plans are informed by latest developments of large-scale customers as well as new connections. (incl. distributed generation and storage). Our open data portal and the two new interactive maps (see case study below on interactive maps) also facilitate very early-stage engagement with customers and stakeholders but do no replace a formal connection process.

We develop large-scale connections and connections in close collaboration with the customer and their consultant and continuously ensure alignment to the system growth projects. Customers submit details like their demand/injection levels, presence of special equipment (such as industrial motors or large inverters) and required redundancy, based on which Vector

will develop connection options. At this stage, synergies with system growth projects are also considered. If the customer commits formally, and from that point the new or expanded customer connection will also be reflected in the load forecast and network constraint modelling (See Section 10. 4). To manage network risks for all connected customers, all customer projects need to comply with key standards and regulations (see next section). Preliminary connection requests are not reflected in the asset management plan process (e.g. load forecast and network constraint modelling). However, not all committed customer projects go ahead as initially planned, given that our customers operate in a dynamic market where conditions change. Continuous customer engagement means latest customer information (demand/injection, connection date) is received, and, given that the physical delivery timeframe (engineering design, construction, and commissioning) of our system growth projects is typically less than 2-3 years, there is opportunity to refine the plans.

The recent boom of data centre connection applications has demonstrated that our process is robust and flexible to adapt to unexpected requests. Over the last two years, several large tech and data centre providers have announced to build data centres in Auckland due to the exponential rise in cloud-based services, demand to store data in New Zealand for governance reasons and excellent connectivity of Auckland to global fibre backbone. Early and continuous customer engagement means that Auckland now already has over 50MW of connected data centre capacity (demand is still below the connected capacity) and a much larger connection pipeline.

CASE STUDY: INTERACTIVE MAPS FOR NETWORK HEADROOM AND SYSTEM GROWTH PROJECTS

To support customer and stakeholder engagement, Vector publishes key network information on its open data portal (https://data.vector.co.nz/) where users can not only visualise detailed geospatial information of the network but also conveniently download the raw information for use in their own systems or more detailed analysis in expert tools. The information available includes location of assets (ZSS and distribution feeders), the boundary of our coverage area and ongoing and future works for network projects (within next 2 years).

Based on customer and stakeholder feedback, the open data portal now also hosts two new interactive maps for network headroom and all system growth projects covered by this 10-year AMP. The network headroom map indicates the headroom in the distribution network for winter and summer peak conditions. The expectation is that this map supports early-stage customer engagement. For system growth projects, the AMP always provides a comprehensive view of expected expenditure, timing and options considered (Section 10.6 and Section 10a). The new interactive map will complement this information by providing a spatial visualisation, which ensures the stakeholders and customers can easily identify the projects planned in their area of interest.

10.3.3 COMPLY WITH SECURITY OF SUPPLY, POWER QUALITY AND OTHER REGULATIONS

Vector will comply with the relevant regulatory obligations and industry standards. The most relevant to growth and security are compliance with Vector's Security of Supply Standard (SoSS) (ESP010) which contribute to achieving the DPP4 Quality Standards and Power Quality requirements.

Our SoSS (summarised in Section 7) sets the probabilistic planning criteria for network development. This defines the number of coincident outages that can occur without loss of supply to customers and the time allowed to restore supply after an asset failure. If our network can by design not deliver this requirement, then a system growth project is triggered. The SoSS will provide customers with an acceptable reliability of supply at an acceptable cost. This involves understanding where there may be short- or long-term network constraints and planning for them.

We use our load forecast model, which combines organic growth from the scenario model with point loads (e.g. residential developments, data centres), to identify load requirements across the different network voltage levels (e.g. GXP, sub-transmission, zone substation (ZSS) and feeder) over the next 30 years. These load requirements combined with asset rating information and the SoSS, is then used to identify network constraints and capacity shortfalls using network modelling tools (e.g. load flow modelling). Reinforcement options and eventually network and non-wires projects are then designed to mitigate the SoSS breach. The capacity of new assets required to be installed are determined based on the size of constraints identified, the forecast demand growth and specifications of standard assets used by Vector.

Power quality is achieved through ensuring appropriate voltage levels and harmonics are maintained within prescribed limits. Where power quality issues are identified, Vector investigates the cause and follows the planning process to develop the most appropriate solution (See Section 7).

10.3.4 CONSIDER DIVERSE TOOLBOX OF SOLUTIONS FOR NETWORK PLANNING

To invest efficiently we use new technologies and understand future trends and customer behaviour, so we invest in a much smarter way. Our aim is to run the existing network smarter and only invest in new infrastructure when we absolutely have to. The traditional approach to meet increased network demands and our SoSS has been to increase the capacity of existing assets or add new assets such as zone substations and distribution feeder circuits. With the change in customers' behaviours and needs, the current and future advancement of technologies and the attention to carbon emissions, our toolbox of solutions for network planning has become much more diverse. Our approach promotes a lower cost, smarter, more decentralised but more connected network, rather than potentially overcapitalizing in projects that could result in stranded assets.

When planning for network development, we consider:

- The long-term (life cycle) costs of investments in the long-term interest of consumers;
- The use of probability-based incremental planning methods;
- Risk-based scenario models
- Continuous engagement with large-scale customers to ensure demand and timing-of connections is kept updated
- The agility and flexibility of solutions to be able to adapt to emerging technologies and urban development trends;
- The use of non-network solutions such as digital platforms to enable distributed energy resource integration;

- Use of data analytics and advanced operational practices;
- Non-network solutions such as demand side management strategies (including engagement with customers and third-party service providers) to reduce peak, and
- Network reconfiguration to improve the utilisation of existing assets and reduce losses.

These considerations are made via our capital expenditure justification process that is described in Section 10.5 and Section 10.6.

10.3.5 NETWORK FLEXIBILITY, NON-WIRES ALTERNATIVE (NWA) AND DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM (DERMS)

Network flexibility (NF), non-wires alternative (NWA) or non-network solutions refers to the ability of the distribution network to manage peak congestion by dynamically adapting to changes in electricity demand, generation, and network conditions without relying solely on traditional network reinforcement (like building new lines or transformers).

Flexibility doesn't necessarily replace reinforcement entirely. Instead, it can defer, reduce, or optimise reinforcement by matching network capacity more closely to actual customer needs. This enables faster, more targeted solutions and, critically, allows demand and generation customers to connect more cost-efficiently when future load is uncertain or a standard firm 24/7 supply is not required.

In doing so, flexibility expands customer choice by offering alternative connection arrangements aligned to how customers actually use the network. Flexibility is becoming essential as uncertainty and complexity grow. Peak congestion is likely to be short-duration, solar and EV uptake is difficult to predict, power quality is becoming an issue due to the potential of millions of inverters and batteries being distributed across the network and embedded behind the meter.

Flexibility applications can be summarised as:

- Network upgrade and asset deferment. Flexibility can defer, reduce, or optimise traditional network reinforcement by actively managing demand and generation during periods of localised constraint. This approach is beneficial in circumstances where demand forecast is uncertain, asset off-loading improves operational lifespan or deferment opens cost synergies with other infrastructure projects (including reduced public disruption of public roads and spaces).
- Operational and security support. Flexibility enhances day-to-day network operations by supporting congestion management, voltage and power quality control, and response during outages or emergency events. These capabilities improve situational control, resilience, and restoration performance, particularly as the network becomes more dynamic with increasing inverter-based resources.
- Flexible (non-firm) connections and DER integration. Flexible and non-firm connection arrangements enable customers to connect sooner and at lower cost where firm 24/7 capacity is not required. By integrating connections and DER within defined network limits, flexibility expands customer choice, supports electrification, and accommodates growth without triggering immediate network reinforcement.

To deliver those applications, Vector has defined four flexibility resources, as shown in table 10.2, to support efficient network utilisation, timely customer connections, and better management of uncertainty.

Flexible demand side	**Flexible distributed generation**
The ability to shift or temporarily reduce customer electricity demand during peak periods, local network constraints, or emergencies. Typical applications include managed EV charging, controlled hot water, and space heating, where demand can be deferred or curtailed without materially affecting customer outcomes.	The ability to actively manage distributed generation exports to address network constraints and avoid or defer network investment. This includes curtailing or ramping down DER export (such as rooftop solar) during periods of network congestion where export capacity is limited.
Flexible storage	**Operational flexibility**
The use of electrical storage to provide controllable demand and injection for network support, including peak management, voltage support, and resilience during outages or emergencies. Examples include: • Network connected batteries (BESS) that charge during low-demand periods, and discharge during peak demand • Community batteries to absorb excess solar • Microgrids, including permanent, relocatable, or mobile storage solutions for constrained or high-risk areas • Customer-owned batteries, including vehicle-to-grid (V2G) capability	Using digital platforms, near real time systems, and artificial intelligence to dynamically manage the network within existing asset limits. Examples include: • Dynamic line ratings • Advanced distribution management system (ADMS) • Real-time monitoring and automation • Network reconfigurations and switching to relieve congestion These capabilities increase usable capacity and headroom of existing assets and improve fault response and service restoration during outages and emergency events.

TABLE 10-2: CATEGORIES OF NETWORK FLEXIBILITY

These four flexibility resources will be enabled by a range of activation mechanisms, which are continuously evolving as customer and network needs change and industry capability develops. Customer and demand-side flexibility is a key pathway of our Future Network Roadmap presented in Section 2.

Table 10.3 shows the key activation mechanisms that Vector will keep on deploying and exploring further throughout this AMP period to dynamically manage congestion, voltage, and peak demand. Pricing incentives are overlaid onto those mechanics where they serve to promote efficient investment, as opposed to being required to maintain security of supply. The table also maps in the main applications introduced above, summarised as deferment, operational and connections.

The activation mechanisms can operate in a layered coordination architecture. Under normal operating conditions, increasingly complex price signals provide the baseline coordination. Flexible connections and direct load control add targeted, controllable responses where greater precision or assurance is required, including support for emergency events. Contract-activated flexibility is used selectively to provide firm, time-bound assurance for forecast network constraints and investment deferral. Across all layers, physical safeguards (including dynamic operating envelopes, inverter settings, and emergency controls – via load management protocols or direct load control) ensure the network remains within safe operating limits under both normal and emergency conditions.

ACTIVATION MECHANISM	DESCRIPTION	APPLICATION
Direct load control	The ability to manage customer demand through an explicit control instruction from the network control room or system in response to network needs (incl. emergencies), such as: • Ripple control of hot-water loads • Direct control (incl. via MEP system) of smart meters • Direct control (incl. via aggregator system) of customer DER The ability for the EDB to do so is usually procured through an explicit commercial arrangement (e.g. control tariff) or a mandate to guarantee usage in exceptional and rare emergency events.	Deferment, operational, connection
Decentralised control	Utilising pre-configured inverter and device settings to enable automatic, localised responses to network conditions without the need for real-time dispatch or direct operator intervention. This includes functions such as Volt-VAR and Volt-Watt control, where DER and inverter-connected devices autonomously adjust reactive power or active power output in response to local voltage conditions. These are typically required by mandate (e.g. centralised inverter standards or regulations).	Operational, connection
Dynamic operating envelope	The ability for customer demand and DER export/import to operate dynamically within network-defined limits that vary by location, time, and prevailing network conditions. Operating envelopes set clear physical parameters within which customers or third-party systems must autonomously adjust demand or export in response to network needs and operate withing the physical limits of the network. This includes: • Direct contracts with customers, where Vector's distributed energy management system (DERMS) communicates dynamic limits to the customer's site-management system • Flexible export and import limits (flexible connection agreements) that vary allowable demand or generation in response to network conditions However, some customers may elect, in response to another commercial incentive, such a price signal, further optimise their load or injection within an envelope that may be tighter than required by the operating envelope.	Deferment, connection
Contract-activated (or Flex Market based) (i.e. non-wires alternatives)	The procurement of a defined, assured ability to shift, reduce, or increase customer demand to address forecast network constraints in specific locations and time periods. This commercial mechanism, such as an availability and activation fee, provides a firm, time-bound commitment to deliver flexibility where and when it is needed, rather than relying on implicit signals or passive behaviour. Contract-activated flexibility is typically delivered through bilateral contracts with customers, retailers or aggregators, procured through competitive flexibility tenders or auctions (such as local flexibility markets). Contracts specify key service parameters, including availability windows, response requirements, performance obligations, and verification arrangements. Vector's new residential DER tariff , which requires retailer-led demand control, forms the basis of contracted (indirect) flexibility that in future can support network deferment when deployed at high concentration to localised constraint areas. Vector signposts the locations where NWA are needed in Section 10.5.	Deferment
Reactive price response	The use of time- and location-varying price signals that give the consumer and/or retailer an informed, cost-reflective option to shift, reduce, or increase demand or injection, and the cost/benefit of inaction/action:	Deferment

ACTIVATION MECHANISM	DESCRIPTION	APPLICATION
	• Simple, static time-of-use tariffs (per Vector's current published tariffs) • Sophisticated time-varying and location-based network tariffs, either static or dynamic	

TABLE 10-3: KEY ACTIVATION MECHANISMS FOR NETWORK

We are actively enabling the transition to more flexibility in our distribution networks through our use of our distributed energy resources management system (DERMS). DERMS is a platform that controls and manages the ever-growing number of third-party owned Distributed Energy Resources (DERs) connected to the network. DERMS provides visibility and active demand management so that DERs can maximise their consumer and system value within the available network limits (considering actual operational conditions) (Figure 10-2). This reduces the need for traditional network reinforcement, accelerates the adoption of DERs and provides customers an alternative to a firm 24/7 connection. We are built capability to offer flexible connections to customers (typically large commercial energy users – see case study on powering Auckland's E-Bus Fleet) onto Vector's Distributed Energy Resource Management Systems (DERMS) platform. While communication protocols are rapidly evolving, we have published our preferred interoperability mechanisms in the DERMS connection standard (ESS900). Engagement with technology providers, customers and third-party service providers have concluded that the key protocols for DER integration today are IEEE 2030.5, OpenADR and OSCP. While the protocols will continue to evolve, based on today's perspective, we can provide a clear direction to customers and third-party service providers on how we can communicate real-time network information to them. Together, our demand management systems and DERMS enable reduction of peak demand that needs to be supplied through our network, therefore allowing us to defer investment, maintain reliability and minimise costs to our customers.



FIGURE 10-2: CUSTOMER AND NETWORK INTEGRATION VIA DERMS (ESS900)

CASE STUDY: VECTOR AND AUCKLAND TRANSPORT POWERING UP AUCKLAND'S E-BUS FLEET

We've joined forces with Auckland Transport (AT) to help electrify Auckland's bus fleet. That's no mean feat with 1,400 buses to be converted to zero emissions vehicles by 2035. The work began in 2020 when Vector and AT signed a Memorandum of Understanding to look for opportunities to reduce the costs of bus charging infrastructure, so that the transition can be more affordable. Vector and AT have regular meetings to discuss operational, resilience and future planning matters.

Six bus depots were partly electrified by 2026 (and there are a further three planned to be electrified in 2026). The head of metro services at AT said this project would help reduce carbon emissions and improve air quality in the city. The newly electrified bus depots will have capacity to charge 20 to 60 buses each. This will mostly happen overnight, and the charging will be 'fleet managed' to achieve as smooth a load profile as possible.

Both these factors will reduce the impact on the electricity network, leading to cost efficiencies for Vector and Auckland Transport, which then benefit both organisations' customers. The fleet managed charging is coordinated through Vector's Distributed Energy Resource Management System (DERMS), which provides the transparency and simplicity required to make this work. The first DERMS-connected depot went live in January 2023. This collaborative project is a stellar example of Vector's Symphony strategy, finding innovative ways to deliver positive benefits for the customer, the business, and the environment.

10.4 Network planning and implementing process

Vector has developed an integrated Symphony planning approach to meet our SoSS, QoS, and PQ requirements. Symphony planning starts with developing a model that describes the demands placed on the network from a customer-level and builds our understanding of future network requirements from the bottom-up. The advantage of this approach is that locational differences are reflected and can inform options analysis. Also, new customer behaviour and technology adoption can be observed and considered in its early stages, allowing for more foresight and preparedness in the planning process, as well as more active customer engagement. Finally, our options analysis considers not only traditional solutions (e.g. cables, lines, transformers) which continue to serve us well, but also innovative non-wires solutions (e.g. smart hot water control, batteries, smart EV charging that is often owned by customers or third-party providers), in line with our strategy to only build new infrastructure when there are not more affordable solutions available. In the context of heightened uncertainty over future planning scenarios, non-wires solutions offer additional benefits: they are less intrusive in road corridors and heavy engineering works are reduced (i.e. a smaller community impact and more agile to deploy); and they are also more modular (i.e. can start at a small scale and grow incrementally) reducing the risk of stranded assets by dynamically matching needs as they evolve over time.

The following planning process applies to all asset categories. Projects are prioritised through a multi-criteria assessment that considers the required delivery date, risk analysis, customer impact, project deliverability, and alignment with Vector's overall corporate strategy. The preferred option is then approved via established governance processes.

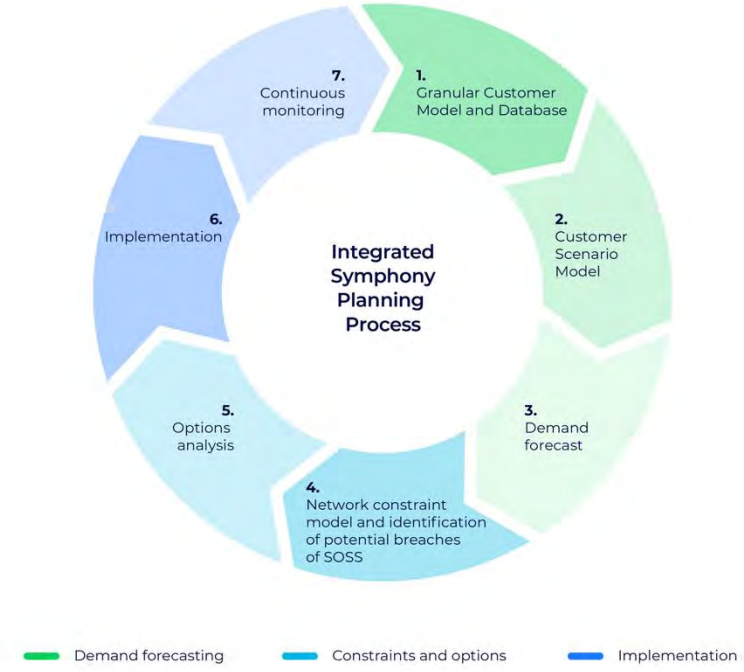


FIGURE 10-3: STEPS IN INTEGRATED SYMPHONY PLANNING PROCESS

The planning process is initiated by an annual assessment of the customer peak loading on all distribution feeders and zone substations. This reassesses the summer and winter peak loading and security levels. The distribution network loading and security assessment includes thermal limits and voltage modelling.

The capital expenditure justification process, described in section 10.5, ensures appropriate governance and rigor is applied to network development and investment decisions made through this network planning process. Once a preferred option is approved, network development projects are implemented through a structured delivery lifecycle that moves from concept and detailed design through procurement and construction/installation, testing and commissioning, and operational handover. Delivery is managed using defined governance and assurance checkpoints (including confirmation of scope, cost, schedule and risk controls), and lessons learned and post-investment reviews are fed back into future planning and prioritisation.

10.4.1 DEMAND FORECASTING

The first three steps of the network planning (Figure 10-3) process are related to demand forecasting based on a detailed bottom-up build that takes into account historical demand, customer demographics and emerging trends.

The **Granular Customer Model and Database (Step 1)** is the basis of the bottom-up modelling process and brings together all information of Vector's customer today. The granular customer model and database combines all of Vector customer and energy information and links it to a wider set of information such as building characteristics and socioeconomics. The resulting model operates at ICP level and provides a granular view on changing energy consumption patterns, customer profiling and new technology adoption[13].

The **Customer Scenario Model (Step 2)** draws from the detailed Customer Model and additional demographic data to model future changes in incremental electricity demand and consumption. The model considers future changes due to population

[13] A detailed paper on this is publicly available at https://www.sciencedirect.com/science/article/abs/pii/S1040619020301287

growth, employment growth, energy efficiency, as well as electrification- and decarbonisation-driven trends like distributed solar PV and battery energy storage systems, electric vehicles, water heating load and gas-to-electricity conversion. Learnings and data from various Vector trials are fed into the model. Non-wires solutions that can be owned by customers or third-party providers and are managed via DERMS to avoid network reinforcement are also modelled. While the AMP covers a 10-year period, we run all our scenarios over a 30-year horizon to portray longer term impacts and derive short-term actions that prepare us for the future. Figure 10.4 provides an overview of the model.

The Customer Scenario Model represents our Auckland service territory in 548 geographical areas. Each zone, called Macro Strategic Model zones (MSM), cover roughly 1000 homes and is the size of a small suburb. The definitions of these zones and the socioeconomic inputs are unified across various government departments and service organisations via the Upper North Island Forecasting Network (UNIFN, previously Auckland Forecasting Network)[14].

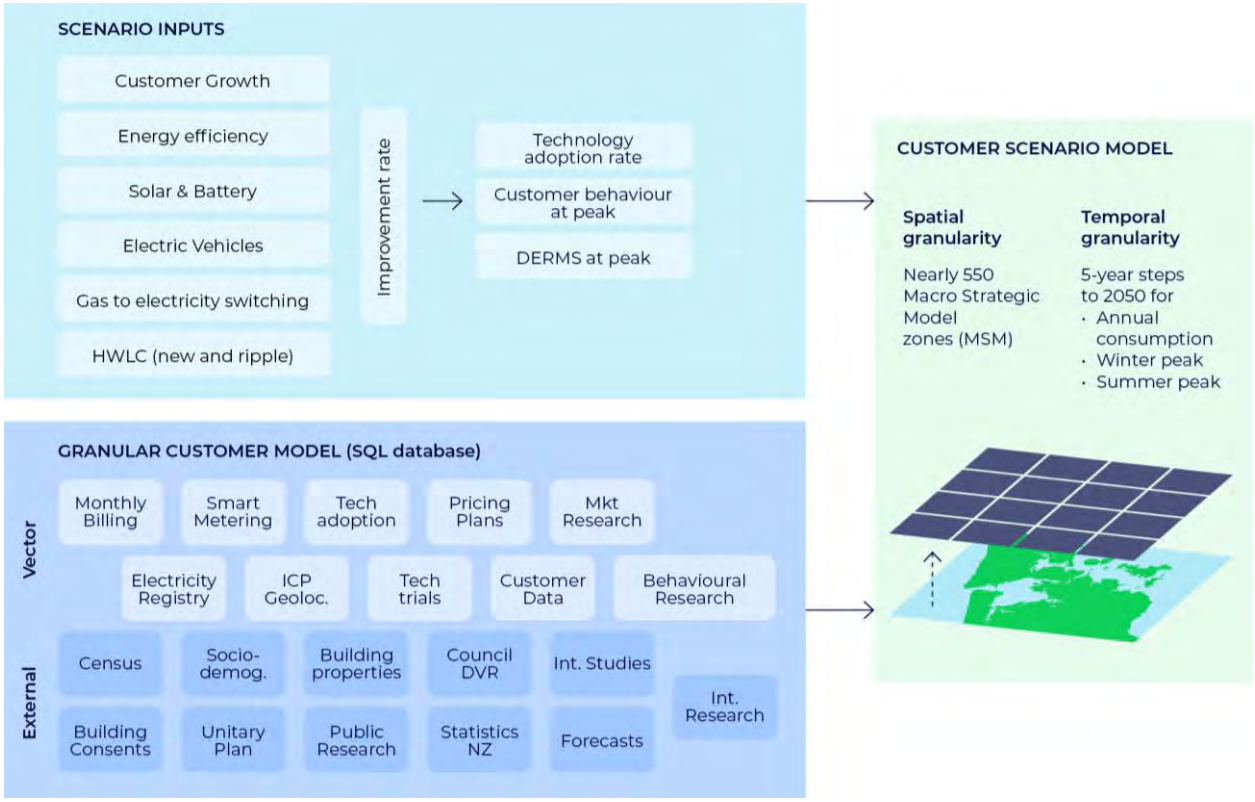


FIGURE 10-4: OVERVIEW OF CUSTOMER SCENARIO MODEL

Demand forecast (including network allocation) (Step 3) brings together the organic growth from the customer scenario model with non-standard or large customer projects such as known large housing developments, new commercial developments, or factories, and, increasingly, data centres. The present asset peak loading is established based on preceding years and normalization for abnormal network configurations. The incremental growth from the Customer Scenario model, which runs at neighbourhood level, is then allocated to electricity network assets based on network topology. Combined with non-standard and large customer projects, the demand 11 kV forecast for the next 30 years is then derived across different network levels (GXP< zone substation, 11 kV/22 kV feeder) by taking demand diversity into account. Customer-level smart meter data is then used to link the Customer Scenario results to network assets.

10.4.1.1 EV UPTAKE

Over the last two years, EV uptake has dropped back to lower levels following the removal of government incentives and the addition of road user charges.

Vector closely monitors the uptake of EVs on our network (figure 10-5). We anticipate EV growth to return and over long term, EVs to become the dominant light passenger vehicle technology while also assuming the size of the light passenger vehicle fleet to reduce by 20% due to increased modal shift to other forms of transportation. However, it is still extremely difficult to forecast the associated demand with levels of confidence. Whilst the regulatory settings seem to have stabilised the adoption of new EV's, the increased uptake of flexible pricing schemes and the scheduling of EV charging accordingly has introduced uncertainty around network peak periods at various levels of the network hierarchy. See the case study on customer response to pricing signals for more details.

[14] Upper North Island Forecasting Network (UNIFN) - Previously known as Auckland Forecasting Network, the purpose of the UNIFN is to support the delivery of timely, tailored and effective public infrastructure, social and community services through consistent, integrated, responsive and best practice demand forecasting. The 30+ UNIFN members include organisations that either: (i) Deliver the key public infrastructure, social, employment, visitor and community services in and/or for Auckland, or (ii) Agencies responsible for population, employment, visitor and land use forecasting scenarios and projections

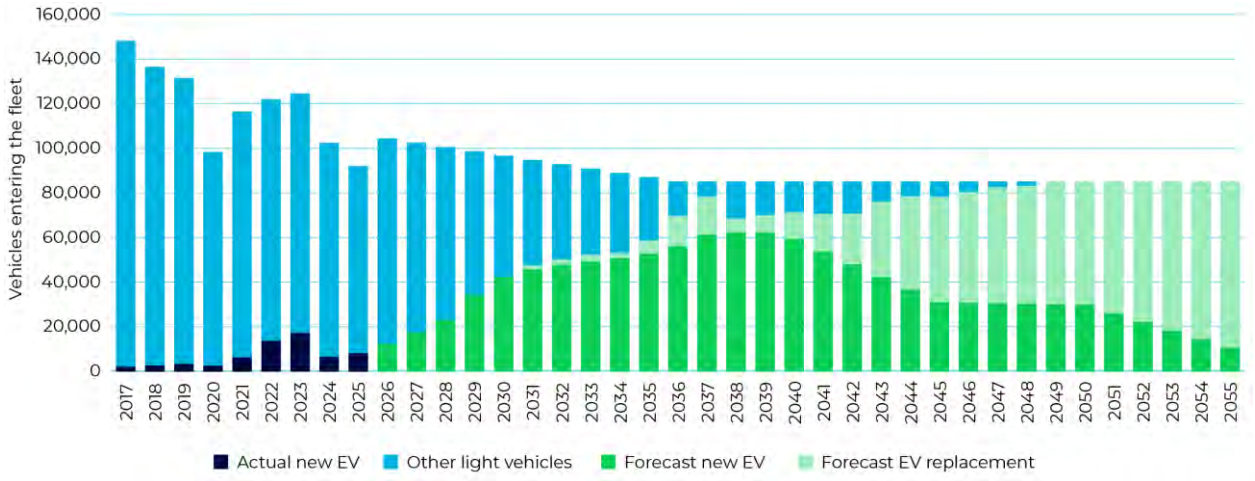


FIGURE 10-5: AUCKLAND ANNUAL NEW REGISTRATIONS OF LIGHT DUTY VEHICLES

10.4.1.2 DISTRIBUTED GENERATION

Distributed Generation (DG) introduces a unique problem in that is does not closely resemble a typical demand profile. Most distributed generation on the Vector network is solar and while electricity demand is naturally spread out because people use power at different times, which is referred to as demand diversity. Solar generation is different: when the sun is shining, almost all solar panels generate strongly at the same time, so their output is coincidental with very little diversity.

Vector's policy is to connect DG customers up to the upstream equipment rating without triggering reinforcements. However, due to the volume of connection requests and the requirement to meet application response SLA's, Vector accepts there will be cases where reinforcements are required. This is reflected in the DER (solar/EV) LV network reinforcement allocation (section 10.6.15)

The lack of diversity is particularly important to consider when connecting customers to the LV network. As such, Vector currently limits the export at single-phase customers to a fixed 5 kVA (they can install larger systems, only the export is limited). Future connections will be allowed to export greater than 5 kVA once flexible connections have been enabled.

DG impacts identified through demand and injection forecasting are carried into constraints identification and options analysis (Section 10.4.2) and, where reinforcement or non-wires solutions are required, are reflected in the signposting and project development plans in Sections 10.5 and 10.6.

The customer-facing DG connection pathway (including application steps, technical standards and approval timeframes) is set out in Section 9 (Customer Connections) and should be read together with this section's planning policy for integrating DG into network development.

10.4.2 CONSTRAINTS AND OPTIONS

Steps four and five of the planning process (Figure 10.3) identify network constraints throughout the 10-year AMP window based on demand forecast and then develop options for remediation. The constraints and options are identified through a sub-process as shown in the diagram below.

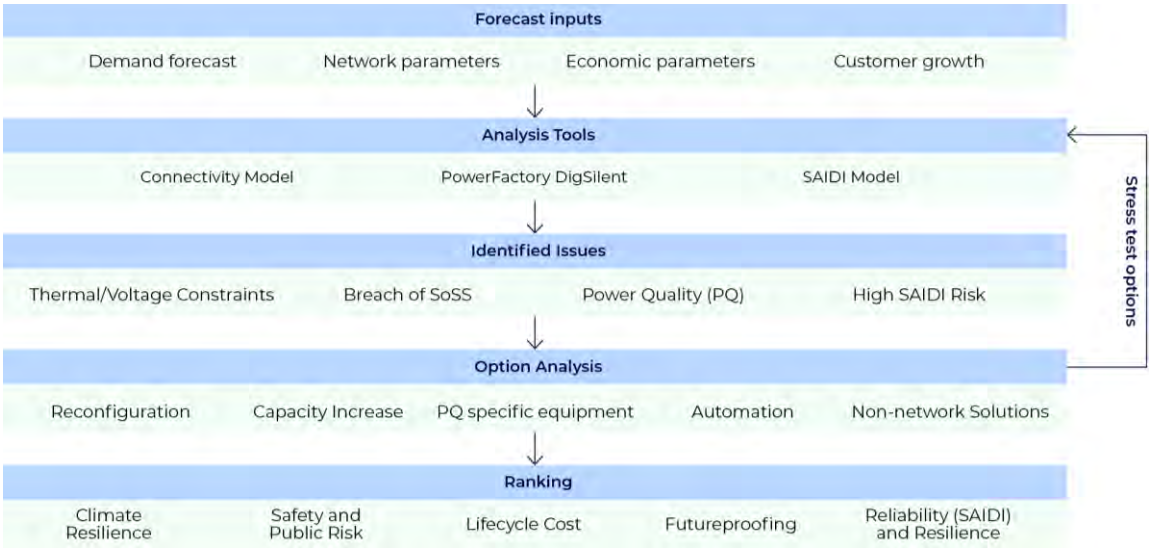


FIGURE 10-6: CONSTRAINTS AND OPTIONS PLANNING PROCESS

The **Network constraint model (Step 4)** uses the demand forecast to identify where and when capacity shortfalls resulting in a breach of our security of supply standard (Section 7) are expected over the next 10-year period for feeders and zone substations. This model also helps to identify options for alleviating shortfalls by re-routing the network from a location with excess capacity and therefore optimise existing capacity availability. The model captures connectivity of the network and backstopping can be modelled to understand if sufficient capacity is available to avoid a shortfall under contingency conditions (subject to SoSS). We have substantially improved this capability in the last two years by developing automation scripts that run power flow simulations (using Digsilent PowerFactory) for the full 10-year AMP horizon for system health and system backstopping. The outputs identify thermal and voltage constraints on network assets, and for cables and lines specific sub-sections, that cause the constraints, which expedites the options analysis. In parallel, we will continue to operate our legacy connectivity model to ensure consistency and robustness of process.

Once the type, location and timing of a constraint is identified, **Options Analysis (Step 5)** is undertaken to identify and evaluate the best solution. We use several analytical tools and visualizations to assist with identifying the demand, network constraints and benefits of different options. If more detailed analysis on network constraint or technical assessment of the options is required, we will run specific power flow simulations as required.

A full suite of options is developed. These include:

- Reconfiguration to improve utilization of existing capacity and assets
- Augmentation to add new capacity
- Augmentation to expand the network
- Network flexibility or non-wires alternatives (refer Section 2.2)

As required, we will also engage with customers and stakeholders (e.g. community organisations, other infrastructure providers, technology vendors) in this phase to assess additional risks for implementation of options and also identify synergy opportunities.

Non-wires solutions are the preference when feasible within customer, regulatory and economic constraints as they can help customer affordability by deferring or preventing the need for major investment, provide flexibility not available from traditional network solutions, and improve asset utilisation. These alternatives are not limited to options Vector could self-supply but could also be provided 'as a service' by a third-party provider under contract, if that would come at a lower cost to our customers. Non-wires alternatives can include:

- Real time monitoring and control of DERs through our ADMS and DERMS platforms
- Battery Energy Storage Solutions (BESS) to shave peak demand and/or control voltage
- Microgrids
- Demand side management through customer DER solutions (including third-party service providers), such as smart hot water and smart EV charging
- Increased network automation
- Improvements to visibility and control of the LV network

To identify the best solutions and optimise and prioritise the network investment, Vector takes a whole of life cycle approach to their evaluation. All the options identified are assessed and ranked based on benefits to network safety, life cycle cost and its impact on customer affordability (initial investment plus ongoing operational costs), reduction to network risk, ability to meet performance requirements and climate resilience (e.g. risk exposure).

Implementation (Step 6) involves, for both network and non-wires solutions, finalising detailed design, confirming delivery scope, cost and schedule controls through established governance, obtaining necessary approvals or permits, procurement, construction and commissioning of the project.

Finally, Vector undertakes **Continuous Monitoring (Step 7)** of its network, investments and asset performance to ensure alignment with asset management objectives. The review process ensures the investments are achieving the planned outcome and that Vector continually learns and improves. The requirement for continual monitoring is a feature of Vector's Asset Management System and include:

- Asset Management Control, Review, Audit and Assurance
- Asset Performance and Health Monitoring
- Post Investment Reviews
- Stakeholder Engagement for implementation
- Sustainability impact

Findings from the reviews are fed back into the planning process.

10.5 Signposting opportunities for flexibility or non-wires alternatives

Vector Networks has successfully deployed six large-scale battery energy storage systems to defer investments in traditional wires solutions. Additionally, we have trialled various NWAs to understand the technology and customer behaviour. Examples include the rollout of 250 SunGenie residential solar-battery programme (2014), the smart hot water trial (part 1: 2018; part 2: 2022), the peak-time rebate trial (2018) and the EV Smart Charging Trial (2019). At the back of these trials, Vector has developed a deep knowledge base around the technical potential of NWAs and has subsequently included the use of NWA to defer network reinforcement into the network planning process. In 2022, we also launched a public registration of interest to find NWAs that could help alleviate a security constraint in the wider Warkworth area.

As part of the options analysis of the network planning process (Step 5), different solutions are evaluated based on cost. However, wires and non-wires alternatives are not directly comparable based on their upfront cost alone, as they have different characteristics (see Table 10-2) and do not provide the same network reinforcement 'service'. In particular:

- Wires (or network) solutions involve reinforcement of the network due to load growth. They eliminate a network constraint for generally 15+ years and have a lifetime of more than 40+ years. The investment in these solutions is typically lumpy 'no-return' or irreversible, which means that, once it is deployed, the solution can't be economically re-sized and means spare capacity is created.
- Non-wires alternatives have very different characteristics – a) the decentralised nature of the solution means that it is adaptable/modular/scalable so that it can be adapted as load changes over time ; b) the technology has shorter lifetime (certainly less than 20 years, but often even less than 10);c) they introduce new performance risks due to customer behaviour and technology (e.g. communication) and ; d) if load growth is high or an unexpected new large customer connects, the need for the wires/network alternative is only deferred, not eliminated, and the deferment period could be much shorter than predicted or contracted (and paid) for.

	WIRES	NON-WIRES
Size of solution/investment	Lumpy	Modular and scalable
Lifetime	40+ years	10-20 years
Deferment of constraint (typical)	>15 years	about 5 years (more possible)
Performance risk	Typical electricity asset risks	Typical asset risks and new customer behaviour, contractual and technology (e.g. communication) risks

TABLE 10-4: COMPARISON OF WIRES AND NON-WIRES CHARACTERISTICS

Hence, a different framework is needed to understand the value of NWAs compared to wires/network solution and assess if an NWA makes sense from an economic perspective. Essentially, an NWA can be considered economic from a societal/customer perspective if the NWA deployment cost is lower than the deferral value of the wires/network investment.

10.5.1 ASSESSMENT FRAMEWORK

To increase our collaboration opportunities with customers and third-party providers, who consider DER projects, this year's AMP signposts the reinforcement projects, where we expect the NWA would be most competitive with network solutions. While our system growth projects have always been reflected in the AMP, this section is our effort to have a simpler, more transparent engagement with customers, communities and potential providers of non-network solutions:

1. Only system growth projects that deliver capacity are suitable (e.g. remove other system growth projects like recloser installations, land purchase, SAIDI improvement projects).
2. Focus only on wires projects with capital value larger than $2M over 10 years, reflecting the feasibility of the current NWA market to deliver cost-effective solutions.
3. Customer scenario model's bottom-up approach is used to determine how much potential of controllable load (e.g. smart EV chargers, controllable hot water, batteries) is forecasted in each area.
4. Finally, the deferment value is calculated based on load reduction delivered from NWA and the projects with a deferment value greater than $500k are flagged. This deferment value does not include the cost of the NWA nor the risk assessment, but it is a gauge to understand the economic potential. Note that the deferment value calculation captures uncertainty around future so that the specific characteristics described in this subsection are captured. NWAs have different characteristics from an investment perspective. NWAs can scale and adapt to load growth as well as providing the option to 'buy time'/'wait and see how' when dealing with uncertain load growth. Clearly this provides value, and our probabilistic framework captures sensitivities around the following i) future cost uncertainty ii) commissioning year (due to load growth uncertainty) and iii) deferment period (due to technology risk and customer behaviour around non-wires alternatives).

Figure 10-7 illustrates the assessment process and highlights the number of projects in each step of the process.

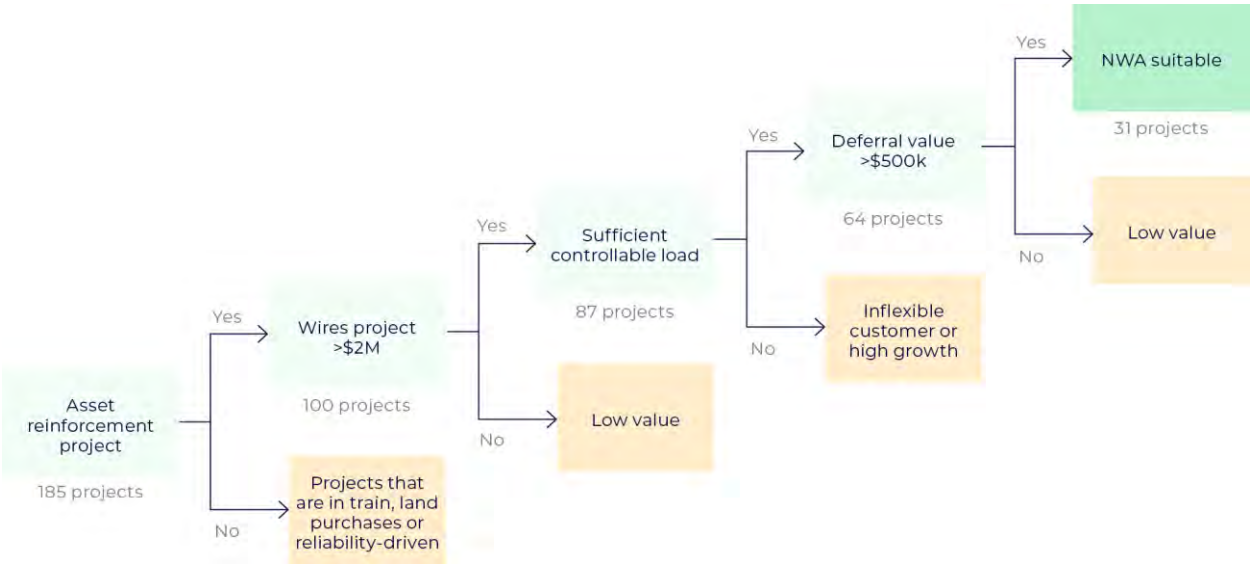


FIGURE 10-7: PROCESS TO IDENTIFY SIGNPOSTED NON-WIRES ALTERNATIVES

10.5.1.1 LIST OF REINFORCEMENT PROJECTS MOST SUITABLE FOR NWA

Our assessment framework has identified 31 projects with suitable characteristics for NWAs (Table 10-3:). This is based on value of deferment. The implementation of an NWA as final solution will depend on NWA cost, customer behaviour and regulatory environment. In general, the NWA needs to be contractually secured before the network solution project is started to maximise efficiency and needs to operate from the commissioning date onwards Key information on all projects is provided in the network planning area section (Section 10.6). For major projects (i.e., more than $1M investment) within next 5 years, more detailed information (including a description of the options considered) are available in Section 10A - Appendix: Growth and Security Projects. Our capital forecast presented in the AMP is based on the network solution and where non-network solutions are secured, we will amend the forecast accordingly as required.

Any NWA solution which is implemented would then be reflected in the demand forecast (deferring the wires investment requirement.

PROJECT NAME	CONTROLLABLE LOAD REQUIRED (MVA)	PROJECT START DATE (FINANCIAL YEAR)	COMMISSIONING DATE (FINANCIAL YEAR)
Greenhithe 33/11kV 2nd TX	2.5	2035	2036
Greenhithe 3rd Subtrans cable	2.3	2033	2035
Albany GXP Coatesville Subtrans Cable Reinforcement	1.6	2036	2036
Torbay 33/11kV TX upgrade T1	1.7	2031	2031
Maraetai 33/11kV T1 & T2 Upgrade	2.3	2031	2033
Waimauku 33kV 2nd SUBT cable and 33kV SWBD	1.6	2031	2031
Mangere East Third Transformer and 33kV cable	6	2033	2035
Waiake 33/11kV TX upgrade T1	1.1	2031	2032
McLeod Rd 33/11kV TX upgrade T1	1.2	2032	2033
Avondale Tx upgrade	5.4	2035	2035
Hillcrest 33kV Subtransmission Cable Upgrade	4.6	2035	2036
Ranui 2nd 33/11kV TX & existing transformer T1 upgrade	3.4	2030	2032
Clevedon 11kV New Feeder	0.4	2031	2032
Ponsonby substation upgrade	2.6	2031	2033
Henderson Valley 33/11kV TX upgrade T2+T3	2.2	2032	2033
West Wiri Subtransmission Cable	2.9	2032	2033
New Lynn 33/11kV TX upgrade T1+T2	2.5	2033	2035
Hobsonville Point third transfomer T3	7.2	2032	2034
Bairds ZSS Capacity Upgrade	3.9	2033	2035
Woodford 33/11kV 2nd TX and 33kV cable	1.2	2034	2035
Papakura 3rd Tx, Subt Cable and Swbd Extension	5	2035	2036
Milldale ZSS	0.8	2028	2031
Redhills Zone Substation New	1.6	2029	2031
Warkworth South Zone Substation New	1.8	2030	2032
Kingsland ZSS 110kV SWBD and cables	7.8	2030	2032
Mt Albert ZSS 2nd Tx and new subtran cables	1.5	2030	2032
Mt Eden Zone Substation New	4.5	2031	2034
Hobsonville 33/11kV T1+T2 TX Upgrade	1.8	2033	2035
Brickworks 33/11kV 2nd TX and new 33kV cable	2	2034	2035
Rockfield ZSS 3rd TX and subtran	3.1	2033	2036
Newmarket substation upgrade	6.3	2034	2036

TABLE 10-5: MOST SUITABLE PROJECTS FOR NWA'S

Beyond this list there may be opportunities to defer other reinforcement projects if developers or customers are planning on installing a large DER (e.g. battery, generation plant) or a high number of DERs in a highly concentrated area. All our reinforcement projects are listed in this section, and a new interactive online map also visually represents them on a map (see case study above on interactive maps).

We invite all interested parties to contact us via an email to flexibility.opportunities@vector.co.nz.

10.6 Network planning areas, reinforcement and replacement

This section sets out Vector's network growth projects for the next 10-year period. The projects are related to the expansion and interconnection of the electricity network to account for Auckland's growth, the densification of suburban areas, the urbanisation of rural areas, and the improved resilience for more isolated rural communities.

The forecast peak winter demand within the AMP period is expected to increase by roughly 1100MW from 1800MW today. This highlights the importance of the next decade of having the right plans, processes and people to succeed. In terms of transport electrification, this AMP demand forecast includes the adoption of light-duty EVs in line with government targets and the electrification of buses (see case study above on powering Auckland's E-Bus Fleet) and Ferry fleet in line with Auckland Transport (AT) plans.

To effectively manage investment planning, the network has been divided into geographical planning areas, which correspond to existing individual GXPs or group of GXPs. From the top down each subtransmission and ZSS supplied from the respective GXP is covered under the corresponding planning area. Where a new GXP is forecast to be needed in the future, then this is included in the planning area based on today's view. The figure below shows the network planning areas.

Each Network Planning Area summary describes the physical bounds of the area, the GXP, the ZSSs supplied from the GXP, demand forecast, and network development projects. In developing the projects, Vector takes into account any asset replacements or other investment that is planned for other drivers (such as condition) to ensure a coordinated and efficient approach to expenditure. The options that were considered when assessing each of the material projects are described in the Security and Growth section 10a.



FIGURE 10-8: NETWORK PLANNING AREAS

Auckland's growth is based on the Future Development Strategy which informs the Future Urban zoning laid out in the Auckland Unitary Plan. The Plan covers the areas of Auckland supplied by Vector's Northern and Auckland network regions. Under this plan, the network will need to expand into new undeveloped areas (e.g. Takanini and Wainui) and densify in sparsely developed regions (e.g. Whenuapai). These areas are currently supplied by low-capacity rural feeders and intensification to urban residential levels

requires investment in both new ZSSs and distribution reticulation. The spatial distribution of future homes is aligned with the UNIFN for load forecasting (See Section 10.4.1). This includes two main intensification policies:

a) The National Policy Statement for Urban Development 2020 (NPS-UD) allows for greater housing density (i.e. buildings of six storeys or more) within walkable distances of the city centre, ten metropolitan centres, and rapid transit stops (train stations and rapid busway stops) and
b) The Resource Management (Consenting and Other System Changes) Amendment Act 2025 which requires Auckland Council to enable building heights of:
    i. At least 10 storeys within walkable catchments of the Mount Albert and Baldwin Avenue train stations; and
    ii. At least 15 storeys within walkable catchments of the Maungawhau (Mount Eden), Kingsland, and Morningside train stations.

Within each planning area, Vector works with Transpower to ensure that demand at each GXP is managed efficiently to avoid over-expenditure on the transmission network when the constraint can be addressed at the distribution network level. This AMP discusses these projects under the subtransmission subheadings below. Any expenditure within the GXP that is not related to Vector owned assets is excluded.

Figure 10-9 visualises the forecasted MVA growth in each GXP area over the AMP period.

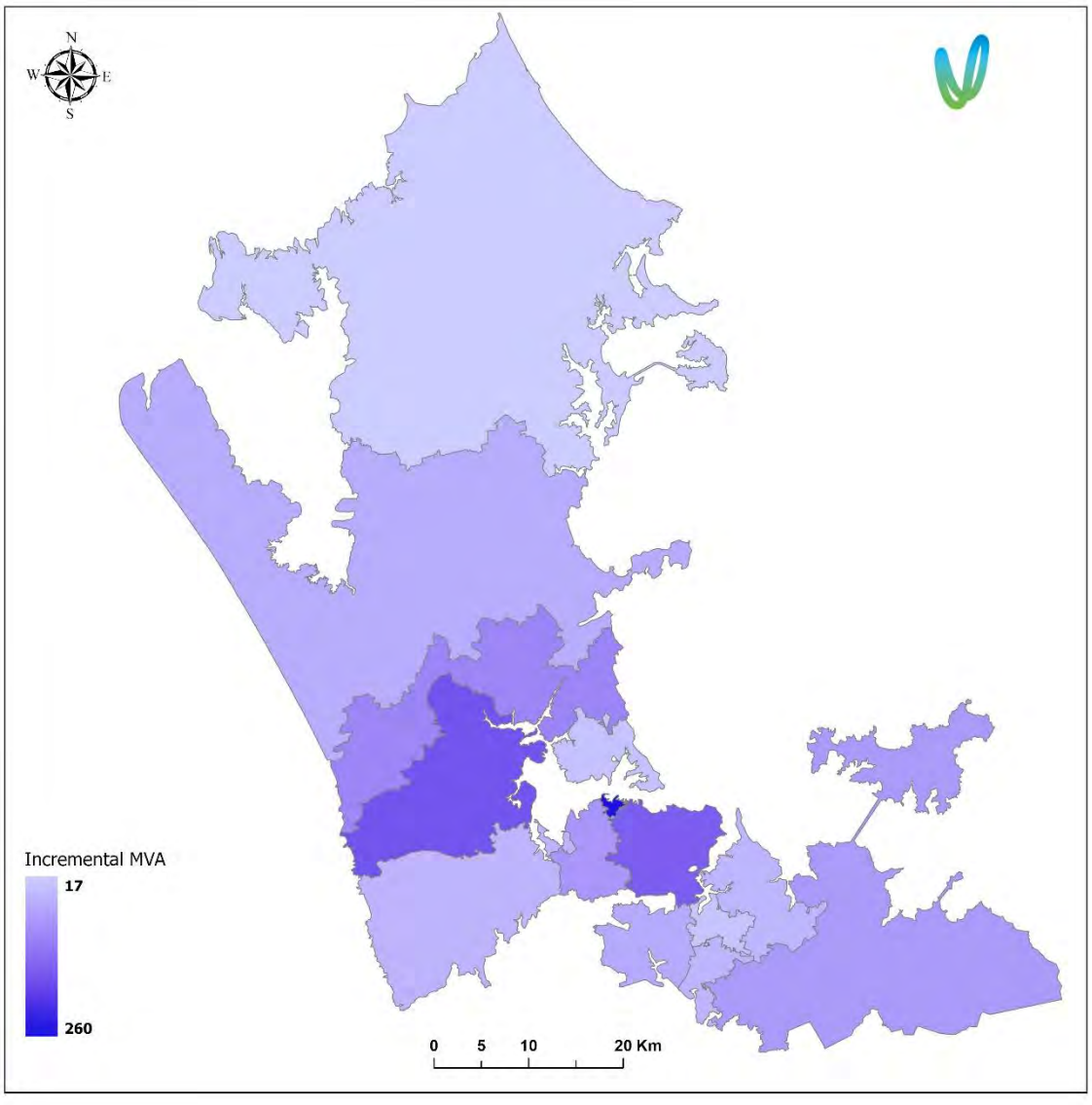


FIGURE 10-9: LOAD GROWTH IN GXP AREAS

To ensure efficient expenditure, the need for augmentation of any zone substation is assessed with consideration of the support that can be provided from adjacent zone substations. In many cases, multiple zone substations supply an area, so the ability to transfer load between substations to avoid significant expenditure is considered.

Some highlights during the AMP period include:

- 9 land purchases (for land purchase projects, the expenditure forecast per project is not disclosed, as this would compromise Vector's commercial position during the land purchase process).
- 7 new substations
- 41 substations upgraded
- 3 new GXPs (Southdown, Huapai and Rosedale)

Figure 10-10 is a visual representation of new, upgraded and existing zone substations on Vector's network over the AMP period.

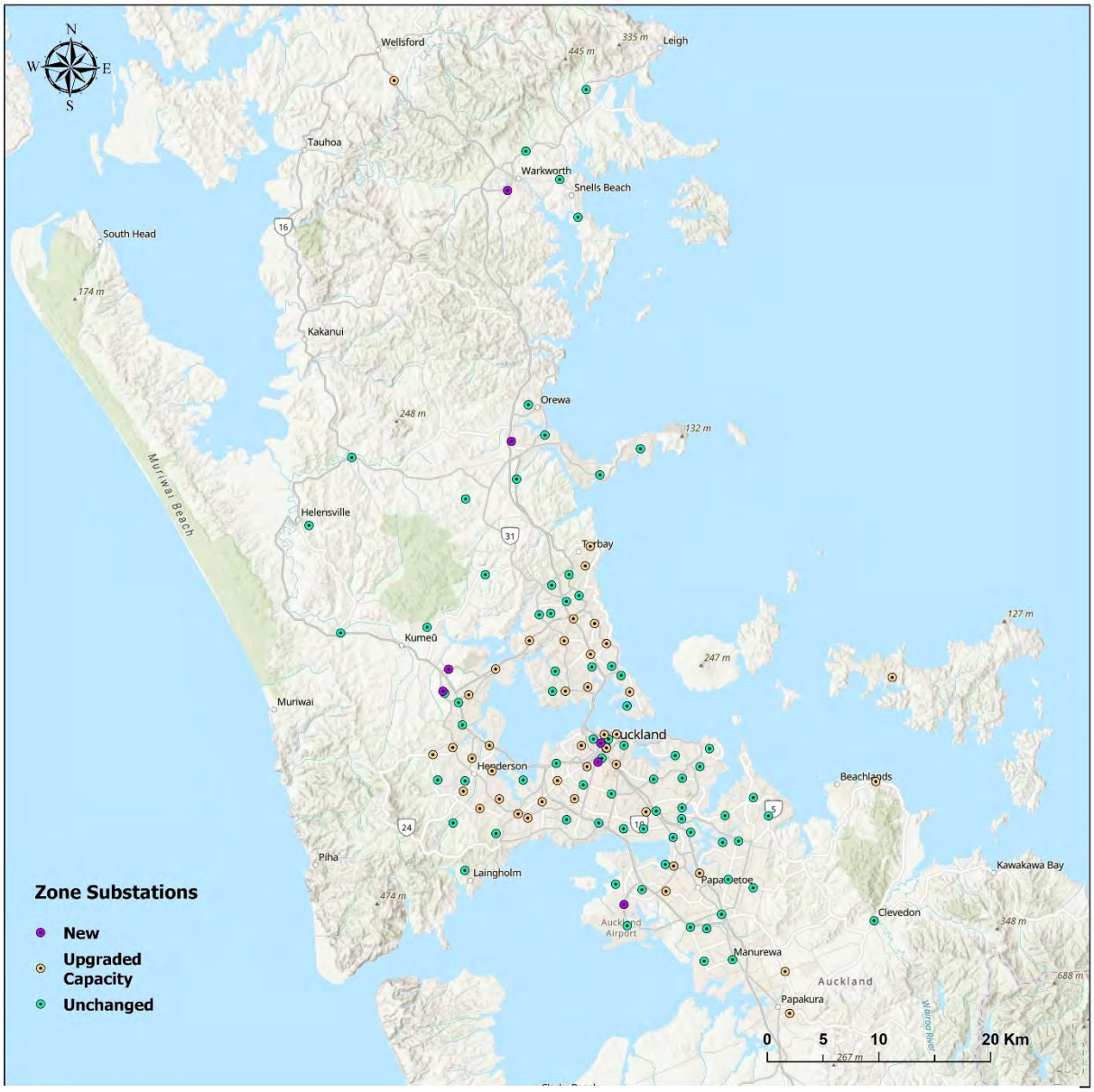


FIGURE 10-10: VECTOR ZONE SUBSTATIONS OVER THE AMP PERIOD

The following section describes each of the planning areas and material projects planned for the 10-year period of RY27 through to RY36.

The options analysis for projects exceeding $1M that are planned to commence within the next 5 years are listed in Section 10a.

10.6.1 WELLSFORD PLANNING AREA

10.6.1.1 OVERVIEW

The Wellsford Planning Area is the most northern in Vector's network; it stretches from Puhoi north to Mangawhai, and Tapora east to Kawau Island. It includes the townships of Wellsford, Warkworth, Matakana, Sandspit, Omaha, Leigh and Snells Beach.

The Wellsford planning area is supplied by Transpower's GXP located at Wellsford. Vector owns five existing zone substations at Wellsford, Warkworth, Big Omaha, Snells Beach and Sandspit Road. The subtransmission network operates at 33 kV and

distribution at 11 kV. The 33 kV overhead subtransmission lines are primarily on private land, with some on rough or heavily vegetated terrain.

The Auckland Unitary plan forecasts significant growth in the Warkworth area. Access to the area will be significantly improved due to the recently completed Puhoi to Warkworth motorway and Te Honohono ki Tai Matakana Link Rd, and the proposed Warkworth to Te Hana motorway.

Changes to the urban boundary open significant new land for development, particularly for commercial and industrial development. As a result, the number of ICPs is forecast to grow from 17,000 at present to 23,200 over the next 30 years.

The existing demand is typical for residential customers with a peaky daily load profile and high winter to summer seasonal variation.

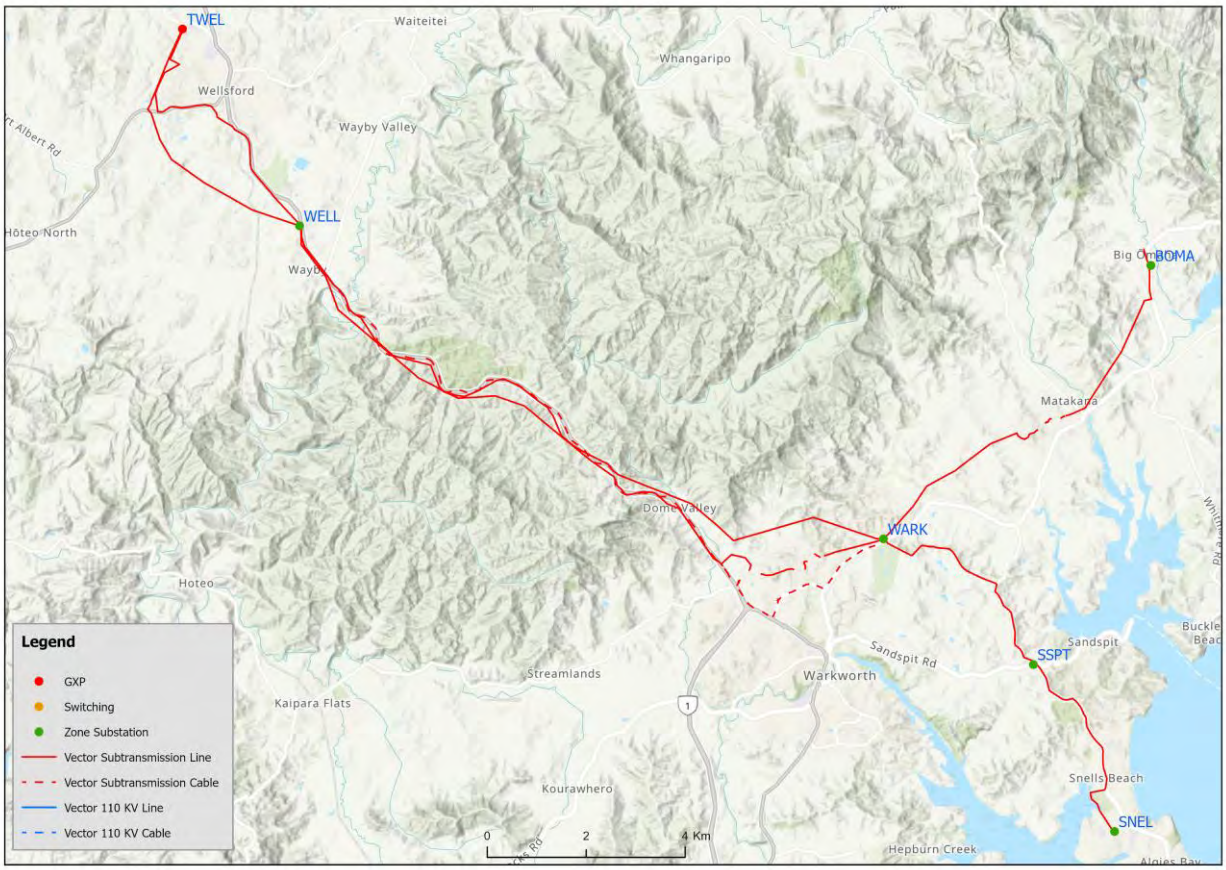


FIGURE 10-11: WELLSFORD SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Big Omaha	RES	7.9	8.0	8.1	8.2	8.2	8.4	8.6	8.8	9.0	9.2	9.5
Winter	Snells Beach	RES	5.8	5.9	6.1	6.2	6.4	6.6	6.8	7.0	7.2	7.5	7.7
Winter	Warkworth	RES	18.5	19.2	19.7	20.2	20.7	21.8	22.8	23.9	24.9	25.9	27.4
Winter	Wellsford	RES	9.7	9.9	10.2	10.5	11.0	11.8	12.6	13.6	14.1	14.6	15.3
Winter	Sandspit	RES	1.2	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.7

TABLE 10-6: WELLSFORD LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.1.2 GRID EXIT POINT

Two Transpower 110/33 kV transformers supply Wellsford's load, providing a total nominal installed capacity of 60 MVA and an N-1 capacity of 40 MVA. The transformers have no on-load tap changers and there is no spare unit onsite. Due to the absence of 110 kV line circuit breakers at Wellsford, a fault on the 110 kV line results in the disconnection of a transformer. The peak demand in 2025 was 40 MVA and the latest demand forecast indicates that peak load at Wellsford will exceed the N-1 transformer capacity from winter 2026.

To manage this capacity shortfall, Vector can dispatch BESS systems at Warkworth and Snells Beach totalling 4.5 MW. Vector has also entered into a Service Level Agreement (SLA) with Transpower to allow increased transformer loading under post-contingent conditions.

The agreed post-contingent 60-minute transformer ratings are:

- Summer: T1 or T2 — 761 A (43.5 MVA)
- Winter: T1 or T2 — 782 A (44.7 MVA)

As outlined in the Transpower Transmission Planning Report, the existing 2 × 30 MVA supply transformers are scheduled for replacement by 2029 under a risk-based replacement programme. The replacement will involve higher-capacity transformers, with a 33 kV outdoor-to-indoor conversion planned for implementation over the same timeframe.

The Transpower Wellsford 33 kV bus represents a single point of failure. In the event of a bus fault, the entire bus would be cleared, resulting in loss of supply to all three Vector Wellsford incomers and potentially impacting the entire Far North network. Vector has engaged with Transpower to remediate this risk.

10.6.1.3 SUBTRANSMISSION

The 33 kV overhead lines from Wellsford GXP to Wellsford ZSS and Warkworth ZSS were constructed in 1964, are approximately 22 km long (route length) and access to the circuits is difficult as the lines traverse complex terrain and multiple privately owned properties.

Vector has completed the installation of a 33 kV cable and a spare duct between Wellsford and Warkworth to provide additional capacity south of Wellsford and to address the inherent risk associated with the overhead lines.

The Warkworth to Te Hana new state highway project is progressing, with procurement currently underway as a Public Private Partnership (PPP). Detailed design and construction are expected to commence in late 2026. A completion date for Ara Tūhono – Warkworth to Te Hana will be confirmed following procurement. It is currently anticipated to be around 2034. Vector intends to install two 33 kV circuits between the Wellsford and Warkworth ZSS which will allow for the eventual decommissioning of the 33 kV overhead lines in the dome valley.

In accordance with Vector's Symphony strategy, steps have been taken to use non-wires solutions to delay the need for reinforcement. It is proposed to establish two new 2.5 MVA diesel generating stations at strategic points in the network to enhance security of supply for the Big Omaha region, which will defer the requirement for a second WARK–BOMA 33 kV supply.

10.6.1.4 ZONE SUBSTATIONS

Wellsford GXP supplies five ZSS's: Wellsford (2 transformers), Warkworth (3 transformers), and Snells Beach, Sandspit and Big Omaha (both single transformer).

Battery Energy Storage Systems (BESS) with a total capacity of 4.5 MW have been installed in 2019 at Snells Beach and Warkworth South to reduce the network peak demand.

Warkworth, Wellsford and Snells Beach are expected to exceed transformer capacity in 2032, 2035 and 2036, respectively. The transformer capacity constraints will be resolved by constructing a new ZSS at Warkworth South in 2032 and redistribution of the load between the group of substations.

10.6.1.5 DISTRIBUTION NETWORK

The distribution network in this planning area covers a very large rural area that contains the longest 11 kV rural overhead distribution circuits within Vector's network. The long feeders are susceptible to outages, resulting in poor reliability, and poor power quality.

The recently commissioned Sandspit ZSS has increased distribution capacity, improved the quality of supply and improved reliability at Sandspit, Snells Beach, Algies Bay and greater the Warkworth areas.

10.6.1.6 CONSTRAINTS AND NETWORK REINFORCEMENT

The following network reinforcement projects are planned for this area.

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Wellsford substation breaches capacity	Wellsford 33/11 kV TX upgrade T1+T2	FY29	8.8
SoSS constraints at Big Omaha ZSS	Big Omaha Backup Diesel Generators	FY29	5.0
Warkworth area transformer capacity breaches SoSS	Warkworth South Zone Substation New	FY32	16.7
Sub-transmission circuits to Warkworth breaching SoSS under N-1 conditions	Wellsford ZSS to Warkworth new subtrans cable + duct via new NZTA state highway	FY35	37.5
Warkworth feeder K13 breaches SoSS	WARK K13 Kaipara Flats 11 kV feeder automation and backup supply	FY35	1.0
Wellsford feeder K07 breaches SoSS	WELL K07 11 kV Feeder Reinforcement	FY36	2.1

TABLE 10-7: WELLSFORD CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.2 SILVERDALE PLANNING AREA

10.6.2.1 OVERVIEW

The Silverdale planning area extends from Albany north to Waiwera, and Whangaparaoa west to Helensville and the west coast. The highest population density is to the east of State Highway 1 (SH1) and comprises the Whangaparaoa, Gulf Harbour, Orewa, Millwater, Red Beach, and Silverdale areas. A MW-scale generation facility from is operating from a landfill in the area. New medium density developments are forecast to expand westwards from Millwater towards Wainui and Dairy Flat.

Millwater south precinct is located northwest of Silverdale GXP and 51ha of the Milldale Development is bordered by Wainui Rd, and Pine Valley Rd to the South. The neighbourhood will support 4,000 residential dwellings and be catered by a wide range of amenities and facilities. Auckland council have indicated roading and wastewater infrastructure will be built to support an additional 5000 dwellings in the surrounding area. A new Milldale ZSS is required to support 9000 dwellings within Milldale, and for future development inland of Wainui. The substation will also support the general industry growth of Millwater which is currently feed by Orewa which is forecasted to exceed feeder capacity.

The Auckland Future Development Strategy 2023-2053 identifies upper Orewa as a suitable greenfield development, with four main infrastructure prerequisites: Wainui road upgrade, Milldale and Grand drive connection, North shore rapid Transit and Army Bay Wastewater treatment plant (completion due 2031). As a result, the forecast is for 2,500 new residential ICPs plus industrial and commercial growth, which will increase demand by 14 MW (excluding potential major customers) over the next 10 years. The development of Milldale substation will offload sufficient load from Orewa ZSS to provide capacity for this area.

As part of Auckland Council's Future Urban Land Supply Strategy 2017 that spans over 30 years from 2017- 2047, the Silverdale West Dairy Flat area of North Auckland is to be zoned for future industrial growth. The area is specifically designated for business development and is anticipated to be development ready by 2037. It provides 350ha of developable land, including 294ha of light industry and 56 ha of heavy industry. Significant new land area is zoned for commercial and industrial development in the Dairy Flat area with one large new customer identified.



FIGURE 10-12: SILVERDALE SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	**ZONE SUBSTATION**	**SOSS CATEGORY**	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Gulf Harbour	RES	8.1	8.2	8.3	8.4	8.5	11.3	11.5	11.7	11.9	12.1	12.4
Winter	Helensville	RES	10.2	10.3	10.5	10.7	10.9	11.2	11.5	11.9	12.2	12.5	13.0
Winter	Kaukapakapa	RES	6.4	6.5	6.5	6.5	6.6	6.7	6.9	7.0	7.2	7.3	7.5
Winter	Manly	RES	18.1	18.3	18.5	18.7	18.8	19.3	19.8	20.3	20.8	21.3	21.9
Winter	Orewa	RES	23.9	26.2	27.7	29.2	30.3	31.8	32.8	33.8	34.8	35.8	37.0
Winter	Red Beach	RES	22.8	24.2	25.2	26.0	26.9	28.1	29.1	30.1	31.1	32.1	33.3
Winter	Spur Road	RES	14.5	15.5	15.8	16.2	16.5	17.1	17.8	18.4	19.1	19.7	20.5

TABLE 10-8: SILVERDALE LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.2.2 GRID EXIT POINT

The Silverdale GXP is supplied by two 220/33 kV transformers rated at 120 MVA and 100 MVA There is no 220 kV bus.

The peak load in 2025 was 100 MVA and due to data centre uptake, major customer developments and ongoing residential and commercial growth in Silverdale, demand at the GXP is forecasted to reach firm capacity within the first half of 2030s.

Vector has initiated a project with Transpower which will see a 3rd 120MVA, 220/33 kV transformer installed along with a new 220 kV bus and an additional 33 kV switchroom.

10.6.2.3 SUBTRANSMISSION

The subtransmission network operates at 33 kV and consists of predominately overhead lines. The 33 kV network is a primarily meshed with only the Gulf Harbour ZSS supplied by a radial line. The network includes a 52km long overhead line ring from Silverdale to Helensville.

Forecasted constraints on the sub-transmission circuits from Silverdale GXP to Orewa, Manly and Spur Rd ZSS will be addressed by cable replacement projects which are expected to be completed by FY27. The new Milldale substation will be supplied by integrating it into one of the Silverdale–Orewa circuits.

10.6.2.4 ZONE SUBSTATIONS

Silverdale GXP supplies five two-transformer ZSSs at Helensville, Manly, Red Beach, Orewa and Spur Road. Gulf Harbour and Kaukapakapa are single transformer substations.

A new zone substation at Milldale (single transformer initially) is planned to resolve the forecasted capacity constraint expected as a result of the new residential development on the western side of SH1 towards Wainui. This additional capacity will also provide supply to upper Orewa developments. Vector has land east of the motorway but at the same time is seeking suitable land west of the motorway.

The outdoor 33 kV switchgear at Horseshoe Bush is has been replaced by a new indoor switchboard, as the first stage in a future ZSS.

The 33/11 kV transformers at Manly ZSS are approaching threshold when a sub transmission contingency occurs at Gulf Harbour. To address this security shortfall, a non-wired alternative is being considered by means of onsite generation.

The Silverdale West precinct will be developed under a staged approach, with stage one commencing in the early 2030s and stage two planned for the late 2040s. A new Dairy Flat substation will be required to support stage one development. Initially, a temporary connection will be provided from the Spur Road ZSS. As demand increases, this supply will be transferred to the Dairy Flat substation. To assist with supply the developers of the precinct have offered to provide a 2212sm site for Vector to purchase for the future Dairy Flat ZSS.

10.6.2.5 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead in the rural areas and underground in the urban areas. The rural distribution network covers a very large area with long feeders that are susceptible to outages. A temporary backup generator has been installed in the remote South Head peninsula network to improve resilience, and a project is planned to make this a permanent installation.

Distribution network constraints mean the new Millwater ZSS and associated distribution network reinforcement will be required to provide capacity and maintain distribution feeder security to the growing greenfields urban development areas west of Orewa, in Wainui, Milldale and Dairy Flat.

The construction of the Highgate Bridge across SH1 at Milldale will enable Vector to install a feeder cable to meet the new demand.

The Waka Kotahi PenLink highway project in Whangaparaoa will provide an opportunity to install a new 11 kV cable on a new bridge across the Weiti River and improve security of supply to the Whangaparaoa peninsula.

10.6.2.6 CONSTRAINTS AND NETWORK REINFORCEMENT

The following network reinforcement projects are planned for this area.

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Subtransmission and distribution capacity shortfall	Dairy Flat land purchase for ZSS	FY26	Not discl.
Breach of SoSS on the subtransmission network under N-1 scenarios	Silverdale GXP, Orewa and Manly Subtransmission Cable Upgrade	FY28	5.8
Spur Sub transmission SoSS capacity	Spur Rd 3rd 33 kV Cable	FY37	6.7
Reliability/Resilience	South Head Permanent Standby Generation	FY31	1.5
Manly Sub transmission SoSS Capacity (project timing determined by external roading project)	Penlink Whangaparaoa reinforcement	FY29	3.1
Capacity for development	Milldale Land purchase for ZSS	FY28	Not discl

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Distribution capacity shortfall	New two transformer Milldale Substation	FY31	13.1[5]
Gulf Harbour SoSS security Breach	Gulf Harbour Permanent Standby Generation	FY27	1.0
Capacity constraint at Silverdale GXP	Silverdale GXP expansion Vector 33 kV cable works	FY32	2.5

TABLE 10-9: SILVERDALE CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.3 HENDERSON PLANNING AREA

10.6.3.1 OVERVIEW

The Henderson GXP area extends from Riverhead, Whenuapai, Hobsonville and Te Atatu westwards through Ranui, Swanson, Henderson Valley, and the Waitakeres to the west coast from Muriwai down to Te Henga.

The urban part of the region is one of the major growth areas in the Auckland region, with large population growth over the next 10 years projected in the Auckland Unitary plan. The growth is driven by major residential brownfield developments at Hobsonville and Hobsonville Point; major residential greenfield developments at Whenuapai, Riverhead, and Kumeu, and major residential, commercial and industrial development at Westgate and Redhills. This growth equates to approximately 12,000 net additional dwellings and an approximate additional load of 36 MW over the next 10 years.

A number of large-scale data centres have been recently commissioned or are in construction or planning. This may result in over 200 MVA in installed capacity in a concentrated area around Westgate/Hobsonville.

Two new zone substations Whenuapai and Redhill are planned to be commissioned in 2028 and 2031 respectively.

Vector is engaging with Transpower to increase the supply capacity at Henderson GXP and is in consultation over a future GXP in Huapai.

Load will be transferred to Albany GXP from Henderson GXP in order to manage demand on Henderson.



FIGURE 10-13: HENDERSON SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	**ZONE SUBSTATION**	**SOSS CATEGORY**	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Hobsonville	RES	17.1	17.9	18.8	19.7	19.7	20.2	20.8	21.3	21.8	22.3	23.3
Winter	Hobsonville Point	RES	20.0	23.1	24.4	25.7	27.6	29.0	30.3	31.6	32.7	33.5	34.6
Winter	Ranui	RES	16.6	18.1	19.6	21.0	22.5	23.6	24.7	25.8	26.9	27.9	28.8
Winter	Riverhead	RES	13.6	13.9	14.1	14.3	14.6	15.1	15.6	16.1	16.6	17.2	17.9
Winter	Simpson Road	RES	5.0	5.0	5.1	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8
Winter	Swanson	RES	12.8	13.9	14.1	14.2	14.3	14.6	14.9	15.2	15.5	15.8	16.2
Winter	Te Atatu	RES	22.8	23.1	23.5	23.9	24.3	25.0	25.7	26.5	27.2	28.0	28.9
Winter	Triangle Road	RES	14.9	15.2	15.6	15.9	16.3	16.8	17.3	17.8	18.3	18.8	19.4
Winter	Westgate	COM	14.2	19.0	21.7	22.3	22.9	23.7	24.4	25.2	25.9	26.7	27.6
Winter	Woodford	COM	10.0	10.2	10.4	10.6	10.7	11.1	11.4	11.8	12.1	12.4	12.9

TABLE 10-10: HENDERSON LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.3.2 GRID EXIT POINT

Two Transpower 120 MVA, 220/33 kV transformers supply Henderson's load, providing a total nominal installed capacity of 240 MVA with an N-1 rating of 143 MVA. The peak load at Henderson GXP was 130 MVA in 2025 and it is forecasted to exceed the N-1 capacity from winter 2026. A 220kV bus is in place at which largely mitigates the risk of a contingency however Vector can manage the emerging capacity constraint operationally by transferring load between the Henderson and Hepburn Road.

A project has been initiated with Transpower which will see a third120 MVA 220/33 kV transformer installed along with a new 33kV bus in the existing switchroom building.

A new Huapai GXP is planned for a commissioning date 2032, to offload demand from the Henderson GXP and enable the growth in West Auckland.

10.6.3.3 SUBTRANSMISSION

The subtransmission network operates at 33 kV and consists of predominately overhead lines.

New data centres in combination with residential and commercial developments set out by the Auckland Unitary plan will create constraints on the subtransmission network. A new GXP at Huapai in 2032 will resolve the constraints.

A SafeRoads project for State Highway 16 (SH16) is in progress and Vector is taking the opportunity to lay ducts to connect the future Huapai GXP to Whenuapai and Redhill.

10.6.3.4 ZONE SUBSTATIONS

Henderson GXP supplies 10 zone substations of which four are single-transformer ZSSs, namely Simpson Road, Swanson, Ranui, and Woodford. There are six two-transformer ZSSs, namely Triangle Road, Te Atatu, Westgate, Hobsonville, Hobsonville Point, and Riverhead.

Organic growth and major customer connections are driving constraints in Whenuapai (supplied from Hobsonville, Hobsonville Point and Riverhead) and Redhills (supplied from Westgate, Triangle and Riverhead). The constraints will be addressed through construction of two new zone substations at Whenuapai and Redhills.

The demand forecast shows that there are expected to be breaches of the SoSS at Ranui ZSS (2029) and Swanson ZSS (2026). As these zone substations are adjacent to each other, the installation of a second transformer at Swanson ZSS along with network reconfiguration will remediate the constraints. This project is expected to complete by June 2028.

A transformer capacity constraint is forecast at Hobsonville Point ZSS which will be addressed by a transformer uprating project (installation of cooling fans).

Transformer capacity constraints are forecast at Hobsonville, Te Atatu, and Woodford Rd which will be addressed by transformer replacement projects.

10.6.3.5 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead in the rural areas and a combination of overhead and underground in the urban areas. The rural distribution network covers a very large area with long feeders that are susceptible to outages.

Continuing commercial and industrial development at the Westgate shopping centre is resulting in capacity constraints which will be addressed by the Fred Taylor Drive 11 kV reinforcement project (in delivery), and later by the new Redhills ZSS.

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Hobsonville Point feeder K10 breaches SoSS	HPOI K10 Nugget Ave 11 kV Backstop reinforcement	FY27	0.6
Capacity constraint at Swanson and Ranui ZSS's	Swanson 33/11 kV 2nd TX	FY27	2.2
Constraints on the 11 kV distribution network in the Whenuapai area	Whenuapai land purchase for ZSS	FY27	Not discl.
	Whenuapai Zone Substation New	FY29	28.4
Capacity constraint at Hobsonville Point ZSS	Hobsonville Point T1+T2 Tx ONAF uprating	FY28	0.3
Woodford feeder K01 breaches SoSS	Lincoln Rd 11 kV reinforcement	FY28	1.0
Capacity constraints at Te Atatu ZSS	Te Atatu 33/11 kV TX upgrade T1+T2	FY28	5.5
Constraints on the Westgate K04 11 kV distribution network in the Redhills area	Redhills land purchase for ZSS	FY28	Not discl.
	Redhills Zone Substation New	FY31	18.0
	Redhills ZSS 11 kV ducts install	FY31	6.0
Hobsonville point sub-transmission supply breaches SoSS	Henderson to Hobsonville point Subtrans future-proofing ducts + Cable via Hobsonville ZSS & Trig Road	FY32	4.1
Henderson GXP and sub-transmission capacity.	Huapai to Riverhead 2 x Subtrans future-proofing ducts + cable	FY32	7.2
	Huapai to Kumeu future proofing ducts	FY32	3.4
	Huapai GXP 33 kV SUBT cables	FY32	23.7
Capacity constraints at Ranui ZSS	Ranui 2nd 33/11 kV TX & existing transformer T1 upgrade	FY32	9.0
Ranui feeder K04 breaches capacity and SoSS	Ranui K04 Glen Road 11 kV reinforcement	FY32	2.9
Capacity constraint at Hobsonville Point ZSS	Hobsonville Point third transformer T3	FY34	10.1
Capacity and SoSS constraints at Woodford ZSS	Woodford ZSS 33/11 kV TX upgrade T1	FY34	4.3
	Woodford 33/11 kV 2nd TX and 33 kV cable	FY35	10.7
Capacity constraint at Hobsonville ZSS	Hobsonville 33/11 kV T1+T2 TX Upgrade	FY35	10.4
Swanson feeder K07 breaches capacity and SoSS	SWAN K07 Bethells 11 kV reinforcement, automation and backup supply	FY35	2.0
Riverhead feeder K09 breaches SoSS	RIVE K09 Kumeu 11 kV Reinforcement	FY36	0.3

TABLE 10-11: HENDERSON CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.4 HEPBURN PLANNING AREA

10.6.4.1 OVERVIEW

The Hepburn area includes Avondale, Te Atatu South, New Lynn, Green Bay, Titirangi and Laingholm, extending west to Piha and south to Parau, Cornwallis and Huia. Relatively low growth is forecast with pockets of re-development around the old Brickworks site in New Lynn, Keeling Road and the Sabulite areas.

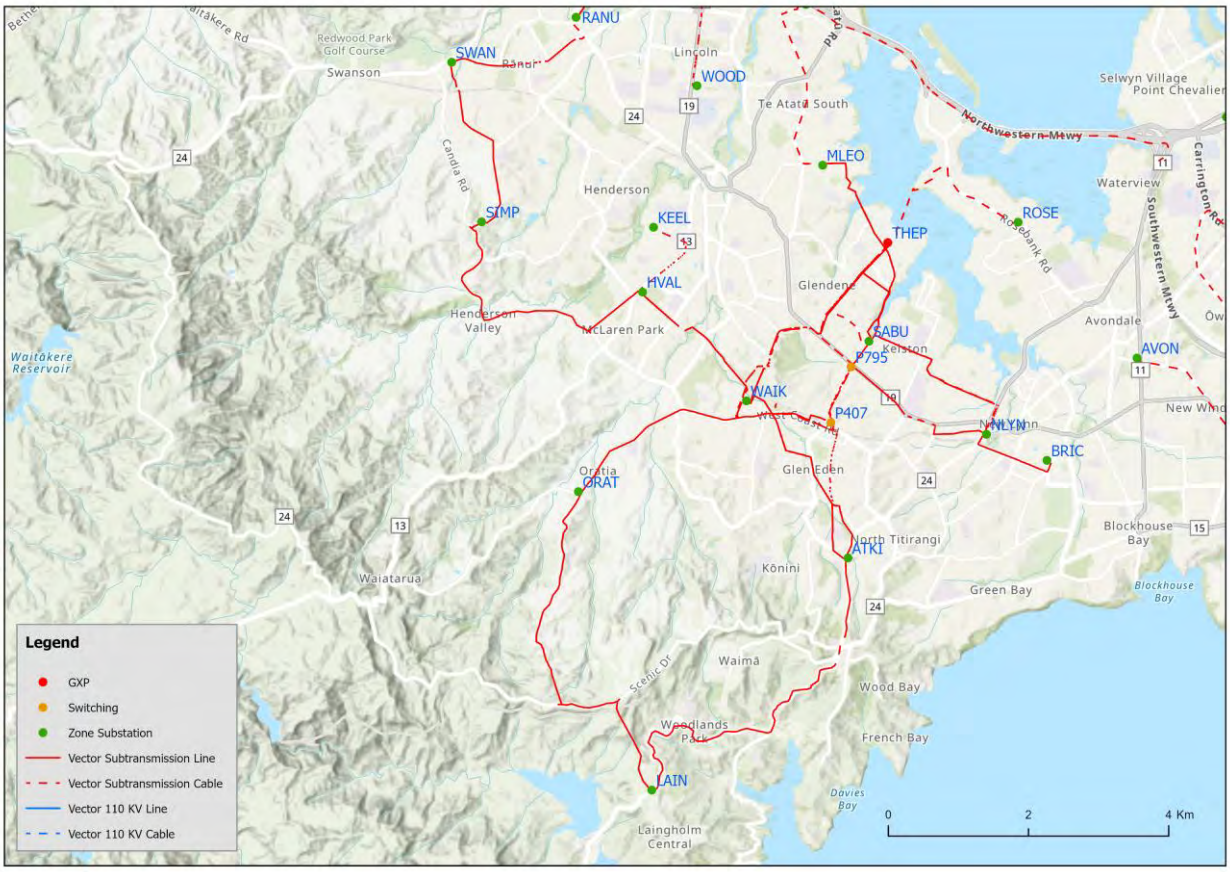


FIGURE 10-14: HEPBURN SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	**ZONE SUBSTATION**	**SOSS CATEGORY**	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Atkinson Road	RES	18.6	18.7	18.9	19.0	19.2	19.6	19.9	20.3	20.7	21.1	21.6
Winter	Brickworks	COM	10.4	11.4	11.8	12.8	13.3	13.8	14.3	14.9	15.4	15.9	16.6
Winter	Henderson Valley	COM	17.1	17.4	17.8	18.2	18.5	19.2	19.9	20.6	21.4	22.1	23.0
Winter	Keeling Road	RES	17.4	17.7	18.0	18.3	19.1	19.6	20.2	20.8	21.3	21.9	22.6
Winter	Laingholm	RES	9.3	9.4	9.4	9.4	9.4	9.6	9.7	9.8	10.0	10.1	10.3
Winter	McLeod Road	COM	10.6	10.7	10.8	11.0	11.1	11.3	11.6	11.9	12.1	12.4	12.8
Winter	New Lynn	RES	13.8	14.1	14.5	14.8	15.2	15.8	16.5	17.1	17.8	18.4	19.2
Winter	Oratia	RES	6.7	6.7	6.8	6.8	6.8	6.9	7.0	7.0	7.1	7.2	7.3
Winter	Rosebank	COM	21.7	23.0	23.4	23.8	24.2	24.9	25.6	26.4	27.1	27.9	28.8
Winter	Sabulite Road	COM	22.0	22.4	22.7	23.0	23.4	24.1	24.8	25.6	26.3	27.0	28.0
Winter	Waikaukau	COM	7.1	7.1	7.2	7.3	7.3	7.5	7.6	7.8	8.0	8.1	8.4

TABLE 10-12: HEPBURN LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.4.2 GRID EXIT POINT

The area is supplied from the Hepburn GXP. Three Transpower 110/33 kV transformers (two rated at 120 MVA and one rated at 85 MVA) supply Hepburn Road's load, providing a total nominal installed capacity of 325 MVA. The peak demand in 2025 was 140 MVA and the forecast remains within the N-1 firm capacity over the planning period.

10.6.4.3 SUBTRANSMISSION

The subtransmission network operates at 33 kV and consists of predominately overhead lines. The area mostly consists of low-density urban terrain, except for the subtransmission ring to Atkinson Road, Oratia and Laingholm which traverses hilly and heavily vegetated areas having a higher impact to reliability.

Despite a low growth forecast, Vector has identified that under N-1 conditions—specifically when the Waikaukau to Atkinson Road ZSS line is out of service, network constraints are expected to arise. The Hepburn to Atkinson Road constraint will be mitigated through subtransmission cable reconfiguration, with reinforcement of the Atkinson Road subtransmission cables scheduled for completion by June 2032.

10.6.4.4 ZONE SUBSTATIONS

Hepburn GXP supplies 10 zone substations of which four are single-transformer ZSSs, namely Oratia, Brickworks, Waikaukau, and McLeod Road and six are two-transformer ZSSs, namely Keeling Road, Henderson Valley, Atkinson Road, Laingholm, Sabulite Road, and New Lynn.

Capacity constraints are forecast at Sabulite, Waikaukau, Brickworks, McLeod Rd, Henderson Valley and New Lynn ZSS, which will be addressed by transformer projects.

10.6.4.5 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead in the rural areas and a combination of overhead and underground in the urban areas. The distribution network covers a very large rural area that contains long overhead line which present reliability challenges.

In particular, Vector have taken steps to improve reliability and resilience issues on the radial 11 kV overhead feeder supplying the greater Piha area. These include installation of temporary standby generation and a cable project along Scenic Drive.

10.6.4.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Waikaukau ZSS capacity	Waikaukau 33/11 kV TX upgrade T1	FY27	1.0
Sabulite ZSS capacity	Sabulite 33/11 kV TX upgrade	FY27	1.4
Subtransmission breaches SoSS.	Atkinson Rd Subtrans Cable Reinforcement	FY31	0.3
Henderson Valley ZSS capacity	Henderson Valley 33/11 kV TX upgrade T2+T3	FY33	7.1
McLeod Road ZSS capacity	McLeod Rd 33/11 kV TX upgrade T1	FY33	4.3
KEEL K06 capacity	KEEL K06 Hickory Avenue 11 kV reinforcement	FY35	3.2
New Lynn ZSS capacity	New Lynn 33/11 kV TX upgrade T1+T2	FY35	14.7
Brickworks ZSS capacity and SoSS breaches	Brickworks 33/11 kV 2nd TX and new 33 kV cable	FY35	8.5
Reliability	Piha Permanent Standby Generation	FY36	1.9

TABLE 10-13: HEPBURN CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.5 ALBANY PLANNING AREA

10.6.5.1 OVERVIEW

The Albany Planning Area extends from Totara Vale and Forrest Hill north to Fairview Heights, to the East Coast Bays from Castor Bay to Torbay, including Paremoremo, Coatesville, and Dairy Flat. Important load centres include the Watercare Rosedale treatment facility and the Massey University campus.

The major residential and commercial growth areas are centred around Rosedale and steady densification of both residential and commercial areas (taller buildings and higher density construction) is driving an increase in demand in existing areas of Albany (i.e. Sunset, Bush, Rosedale, and East Coast ZSS). The overall growth in these areas in the next 10 years is forecast to be 20+ MVA. Additionally, a few large commercial facilities will be connected in the area. Load will also be transferred to Albany GXP from Wairau and Henderson GXP to manage demand.

A major customer facility has been approved with multiple direct connection to the GXP. If this load were to materialise faster than anticipated, security capacity may exceed before 2036. Due to capacity and limited available space for 33 kV switchboard extension Vector has engaged Transpower to build a new GXP in the Rosedale area.

Waimauku ZSS is supplied from Albany, however, it is included in the Henderson planning diagram as it is closer to Henderson GXP and supplies customers considered to be within the Henderson planning area. The long-term plan is to supply Waimauku ZSS from a new GXP at Huapai.

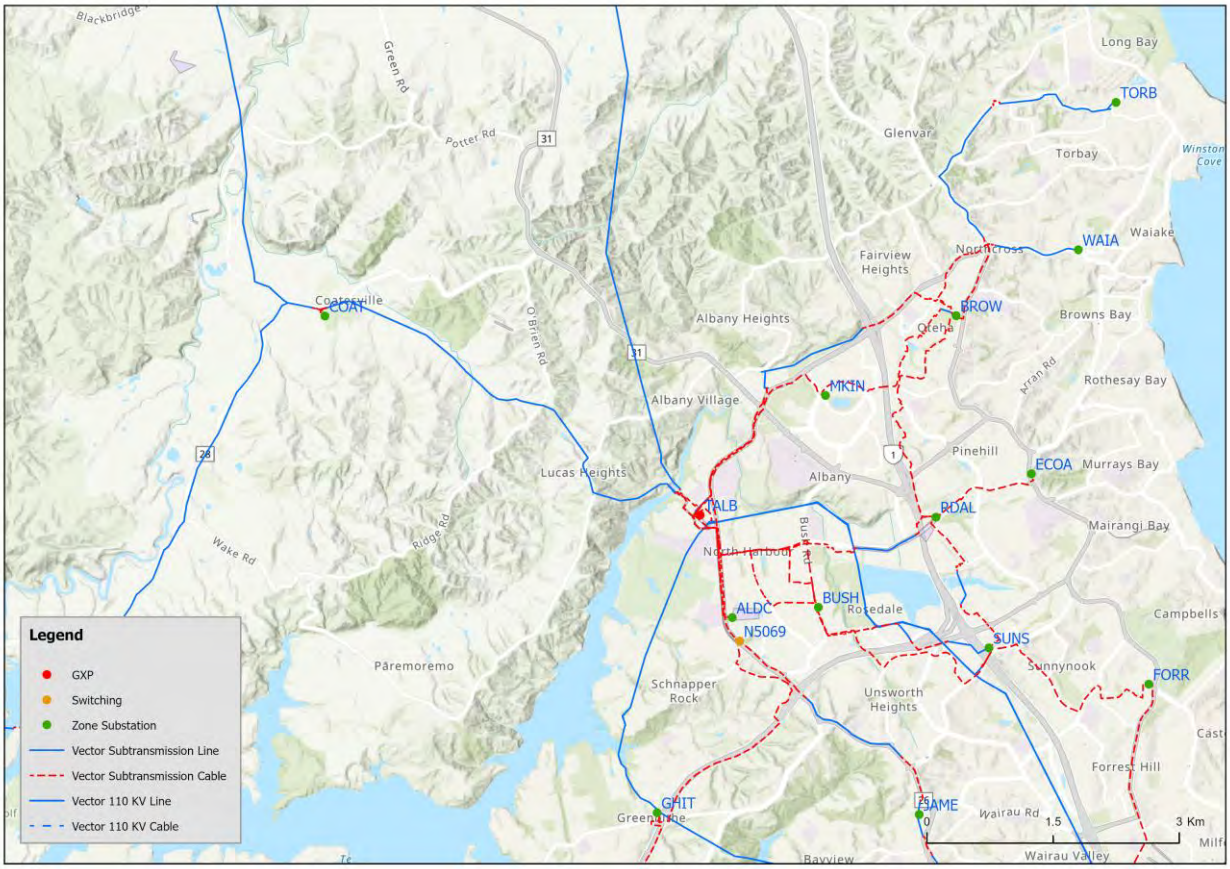


FIGURE 10-15: ALBANY SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	**ZONE SUBSTATION**	**SOSS CATEGORY**	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Browns Bay	RES	16.4	16.6	16.9	17.2	17.5	18.0	18.5	19.1	19.6	20.1	20.8
Summer	Bush Road	COM	21.5	21.7	22.0	22.2	22.5	23.1	23.7	24–.3	24.9	25.5	26.3
Winter	Coatesville	RES	10.4	10.5	10.6	10.6	10.7	10.9	11.0	11.2	11.3	11.5	11.7
Winter	East Coast Road	RES	16.3	16.5	16.7	16.8	17.0	17.4	17.8	18.2	18.6	18.9	19.4
Winter	Forrest Hill	RES	15.2	15.3	15.5	15.7	15.9	16.2	16.6	17.0	17.3	17.7	18.1
Winter	Greenhithe	RES	10.8	11.0	11.1	11.3	11.4	11.7	11.9	12.2	12.5	12.7	13.0
Winter	Hobsonville Point	RES	18.7	24.0	23.7	23.7	24.7	26.5	27.3	28.2	29.0	29.7	30.3
Winter	James Street	RES	20.3	20.6	20.8	21.1	21.4	22.0	22.7	23.3	23.9	24.5	25.3
Winter	McKinnon	RES	22.6	23.2	23.8	24.3	24.9	25.8	26.6	27.5	28.3	29.2	30.2
Winter	Rosedale	COM	14.8	15.2	15.6	15.9	16.3	18.5	19.2	19.9	20.7	21.4	22.4
Winter	Sunset Road	COM	13.2	13.6	14.0	14.3	14.7	15.5	16.2	16.9	17.6	18.4	19.3
Winter	Torbay	RES	9.8	10.0	10.1	10.2	10.4	10.6	10.9	11.1	11.4	11.6	11.9
Winter	Waiake	RES	7.8	8.0	8.1	8.2	8.4	8.6	8.9	9.1	9.4	9.6	10.0
Winter	Waimauku	RES	13.3	13.4	13.6	13.8	14.0	14.3	14.6	14.9	15.2	15.5	15.8

TABLE 10-14: ALBANY LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.5.2 GRID EXIT POINT

The GXP has three 120MVA 220/33 kV transformers providing a total installed capacity of 329MVA and a 258MVA N-1 capacity. The site also includes one 220/110 kV transformer.

The 33 kV supply was upgraded in 2018 with the commissioning of a three section 33 kV indoor switchboard. The switch room was designed to accommodate future expansion.

The peak demand in 2025 was 141 MVA and the forecast indicates the firm capacity will be exceeded by winter 2033 (this is dependent on data centre uptake). A new Rosedale GXP is planned to offload the Albany GXP and the heavily loaded subtransmission network.

There is approximately 10MVA of generation resulting in peak reduction at this GXP.

10.6.5.3 SUBTRANSMISSION

The area is supplied from the Albany GXP. The subtransmission network operates at 110 kV and 33 kV and consists of predominately overhead lines in the rural areas and underground in the urban areas. The area mostly consists of low-density urban subdivisions, with a number of commercial centres.

The 33 kV subtransmission to Waimauku zone substation is a single overhead line and even though it has two transformers, the substation is on N security. This is not a major risk as the overhead line is accessible and repairs can be carried out quickly to fully restore supplies and maintain compliance with the SoSS. As part of NZTA's Safe roads project initiative, ducts have been laid for a future second circuit. These ducts will only be populated once the Huapai GXP has been commissioned.

Recently connected major customer load, along with multiple future subtransmission constraints supplying the Rosedale-Browns Bay-Mckinnon, Bush Road mesh, drives the need for Rosedale GXP.

As preparation for the new GXP, the 110 kV OHL from Albany GXP to Wairau GXP will be decommissioned. Portions of the circuit corridor will be re-used to reinforce the 33kV sub-transmission network, whilst difficult to access sections over private land will be removed. Please refer to Section 10.6.6.2 which details the risks around decommissioning the 110 kV network.

Relatively minimal cable investment is required to integrate the Bush Road, Rosedale, Sunset Road, Forrest Hill, and East Coast Road zone substations with the new Rosedale GXP.

To increase the firm capacity at Greenhithe, one of the Albany-Wairau 110 kV lines will be converted to 33 kV. Greenhithe will then have three subtransmission circuits which will allow Hobsonville Point to be fed from Albany.

Future forecast constraints on the Albany-Coatesville subtransmission circuits will be addressed by cable replacement projects.

10.6.5.4 ZONE SUBSTATION

Albany GXP supplies 12 zone substations of which four are single-transformer ZSSs, namely Greenhithe, Waiake, Torbay and East Coast Road and eight are two-transformer ZSSs, namely Coatesville, Waimauku, McKinnon, Browns Bay, Rosedale, Bush Road, Sunset Road, and Forrest Hill.

Capacity constraints are forecast at Torbay, Waiake, Forrest Hill and Sunset Rd ZSS, which will be addressed by transformer installation projects. As part of an AT road improvements involving Glenvar and East Coast Rd, a duct will be laid for future second circuit to supply Torbay.

10.6.5.5 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead in the rural areas and underground in the urban areas.

10.6.5.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Albany to Greenhithe subtransmission circuits breach SoSS	Albany - Greenhithe 110 kV to 33 kV subtransmission OH conversion	FY26	3.1[4]
Albany to Greenhithe subtransmission circuits breach SoSS	Albany to Greenhithe 3rd circuit	FY35	14.3
Transformer Capacity	Greenhithe 33/11 kV TX 2nd TX	FY38	4.5[4]
Albany subtransmission breaches SoSS	Albany GXP Coatesville Subtransmission Cable Replacement	FY36	2.1
Albany GXP capacity constraint	Rosedale GXP subtransmission cables	FY32	11.8[5]
Transformer Capacity	Waiake 33/11 kV TX upgrade T1	FY33	8.6[3]
Transformer Capacity	Sunset Road 33/11 kV TX upgrade T1+T2	FY38	10.1[2]
Transformer Capacity	Forrest Hill 33/11 kV TX upgrade T1+T2	FY38	10.1[3]
Transformer Capacity	Torbay 33/11 kV TX upgrade T1	FY31	8.1[2]
Torbay sub transmission capacity	Torbay 33 kV duct enabling works	FY28	0.2[5]
Capacity constraint	Rosedale GXP sub transmission cables	FY32	14.1
Asset age/condition plus future capacity constraint	Rosedale enabling works	FY29	15
Sub transmission SoSS Capacity	Waimauku 2nd 33 kV cable	FY31	6.8[3]

TABLE 10-15: ALBANY CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.6 WAIRAU PLANNING AREA

10.6.6.1 OVERVIEW

The Wairau Planning Area comprises the urban North Shore from Bayview and Milford, south to the Devonport peninsula and the Waitemata Harbour.

Important load centres include Takapuna (the North Shore CBD), the New Zealand Navy base in Devonport, the North Shore Hospital, and Auckland University of Technology Akaranga campus. Some zone substations in the Wairau Valley area have been targeted to supply the planned electrification of ferries.

A forecast capacity constraint at the Wairau Valley bulk supply substation is being addressed by a Transpower project for a second 220/33 kV transformer at Wairau GXP. Vector has also initiated a project with Transpower to install a third 120 MVA, 220/33 kV transformer to address security limits at Wairau.

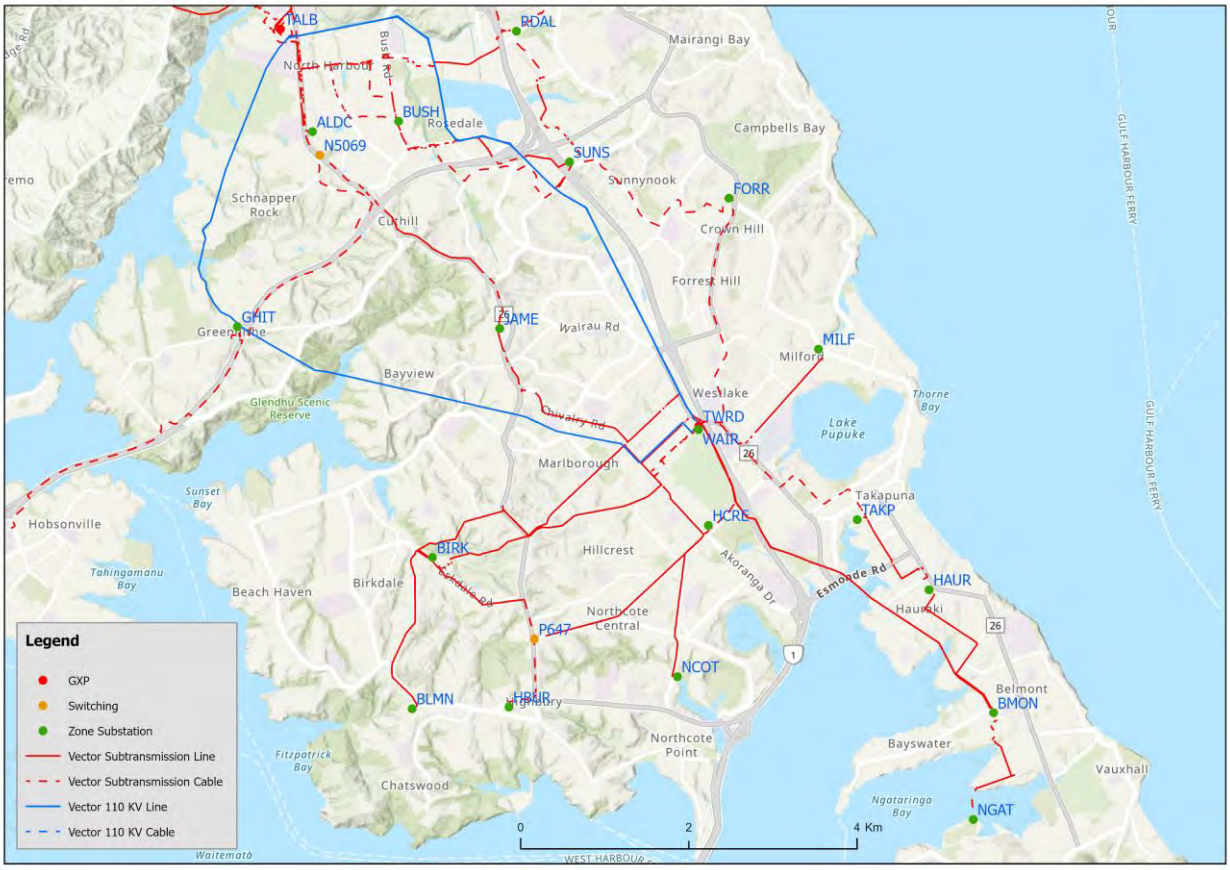


FIGURE 10-16: WAIRAU SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Balmain	RES	8.4	8.5	8.5	8.6	8.7	8.9	9.1	9.3	9.5	9.7	9.9
Winter	Belmont	RES	13.6	13.9	14.1	14.3	15.6	16.0	16.4	16.8	17.2	17.6	18.1
Winter	Birkdale	RES	21.9	22.1	22.2	22.4	22.5	22.9	23.3	23.7	24.1	24.5	25.1
Winter	Hauraki	RES	8.5	8.7	9.0	9.3	9.6	10.0	10.5	10.9	11.4	11.8	12.4
Winter	Highbury	COM	12.0	12.2	12.5	12.7	12.9	13.4	13.9	14.3	14.8	15.3	15.9
Winter	Hillcrest	RES	20.5	21.0	21.6	22.2	22.8	23.7	24.6	25.5	26.4	27.4	28.5
Winter	Milford	RES	7.1	7.2	7.4	7.6	7.7	8.0	8.4	8.7	9.0	9.3	9.7
Winter	Ngataringa Bay	RES	6.6	6.8	6.9	9.5	9.6	9.9	10.1	10.3	10.6	10.8	11.1
Winter	Northcote	RES	5.7	5.8	5.9	6.0	7.8	8.1	8.3	8.5	8.7	8.9	9.2
Winter	Takapuna	COM	6.5	7.0	7.3	7.6	9.3	9.8	10.2	10.7	11.2	11.7	12.3
Winter	Wairau Road	COM	20.2	21.1	21.9	23.1	23.5	26.0	26.7	27.3	28.0	28.6	29.5

TABLE 10-16: WAIRAU LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.6.2 GRID EXIT POINT

Wairau is currently supplied by three 80 MVA, 110/33 kV transformers and a single 120 MVA, 220/33 kV transformer. A second 120 MVA 220/33 kV transformer (T9) is planned to be commissioned in the third quarter of 2026.

The peak demand was 147 MVA in 2025

The three Vector 110/33 kV transformers and the 110 kV circuits from Albany are approaching the end of their life and are planned to be removed soon after T9 is commissioned. This arrangement reduces the N-1 capacity at the GXP and a third 220/33 kV, 120 MVA transformer project has been initiated with Transpower.

The N-1 risk will be managed by transferring load to Albany using the 33kV subtransmission network.

There is an emerging transmission network resilience risk which is introduced should a second harbour crossing happen. Initial indications are that the 220 kV cable on both sides of the bridge will need to be shifted. This would potentially put Wairau on N security for several months. A 2nd 220kV cable that runs between Wairau and Albany would eliminate the risk but if Transpower cannot meet these timings, Vector, as a prudent network operator, will be forced to re-invest in the 110 kV network to maintain resilience.

10.6.6.3 SUBTRANSMISSION

The subtransmission network operates at 33 kV and consists of predominately overhead lines.

A constraint on the subtransmission network appears on the Wairau – Takapuna 33 kV circuit in FY34.

A loss of one of the Hillcrest 33kV circuits, causes thermal overload on the other in FY38, a third circuit will be required to address this constraint.

10.6.6.4 ZONE SUBSTATION

Wairau GXP supplies 12 zone substations of which seven are single-transformer ZSSs, namely Highbury, Balmain, James St, Northcote, Milford, Hauraki, Ngataringa Bay and Takapuna and four are two-transformer ZSSs, namely Wairau Valley, Birkdale, Hillcrest, and Belmont.

Capacity constraints at Wairau Rd, James St, Milford, and Balmain ZSS will be addressed by transformer installation projects.

As a result of E-Ferry, gas to electrical substitution and organic growth, Highbury zone substation is reaching capacity in 2027. This is also the cause of backstop shortfalls at other zone substations. A project for a second transformer and accompanying sub-transmission circuit is in delivery.

Two issues have been triggered the decision to decommission Ngataringa Bay ZSS:

- The 33 kV oil-filled submarine cable to Ngataringa Bay ZSS is approaching the end of its serviceable life which presents a network security risk and also an environmental risk from oil leaks
- Ngataringa Bay ZSS is low-lying and close to the coast, making it vulnerable to flooding. The flooding risk is expected to increase under forecast climate change scenarios

Installation of a third transformer at Belmont ZSS to supply the area via new cables is planned for FY27 to provide capacity after the decommission and removal of Ngataringa Bay ZSS. The implementation of a third transformer with the existing transformers and switchgear presents a reliability concern as the fault level prevents parallel operation. An additional project is in progress to upgrade existing two transformers and switchgear.

Upcoming Northcote township development and the expected North Shore Hospital expansion necessitate an upgrade to Hillcrest ZSS.

10.6.6.5 DISTRIBUTION NETWORK

The distribution network operates at 11 kV with a combination of overhead and underground circuits. In the urban and commercial areas, steady densification (taller buildings and higher density construction) is driving an increase in demand on some 11 kV feeders. A feeder upgrade is planned for Highbury ZSS.

10.6.6.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Belmont ZSS capacity	Belmont 33/11 kV T3	FY27	9.4[4]
Belmont ZSS fault level	Belmont 33/11 kV T1+T2 upgrade	FY28	9.1[92]
Highbury sub transmission Capacity	Highbury 33/11 kV 2nd transformer and 2nd 33 kV cable	FY27	6.2[22]
Highbury 11 kV	Highbury 11 kV switchboard upgrade	FY35	3.6[8]
Hillcrest subtransmission capacity	Hillcrest 33 kV Cable Upgrade	FY36	6.2[8]
Project co-ordinated with Transpower	Wairau 220/33 kV 2nd transformer T9 enabling works	FY27	0.9[4]

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Transformer capacity	James St 33/11 kV TX upgrade T1+T2	FY28	12.3
Transformer capacity	Milford 33/11 kV TX upgrade T1	FY35	4.0
Transformer capacity	Wairau 33/11 kV TX upgrade T5+T6	FY28	9.3
Transformer capacity	Northcote 33/11 kV TX upgrade T1	FY35	2.7[4]
Takapuna Sub transmission Capacity	Wairau-Takapuna 33 kV cable upgrade	FY33	4.3[8]
Takapuna 11 kV capacity	Takapuna New feeder	FY34	1.0[4]

TABLE 10-17: WAIRAU CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.7 AUCKLAND CBD PLANNING AREA

10.6.7.1 OVERVIEW

The Auckland CBD covers the area bounded by the Northern Motorway (State Highway 1, SH1) towards the Harbour Bridge, the extension of (State Highway 16, SH16) down Grafton Gully and the Waterfront. The CBD network supplies about 37,500 customers (ICPs) with a total demand of 163 MVA.

The CBD is undergoing a transformation driven largely by the redevelopment of existing commercial sites including Precinct development (ex-Downtown carpark), the City Rail Link (CRL) project, the Electric Ferry project at the Downtown Ferry Terminal (DTFT), and a data centre at Nelson St. The commercial development at Wynyard Quarter is also being carried out progressively including a potential data centre.

Streetscape improvement projects (e.g. Quay St and associated wider Britomart area) provide the opportunity to future proof the network such as through installation of cables and ducts at a lower cost. These opportunities are assessed on a case-by-case basis.

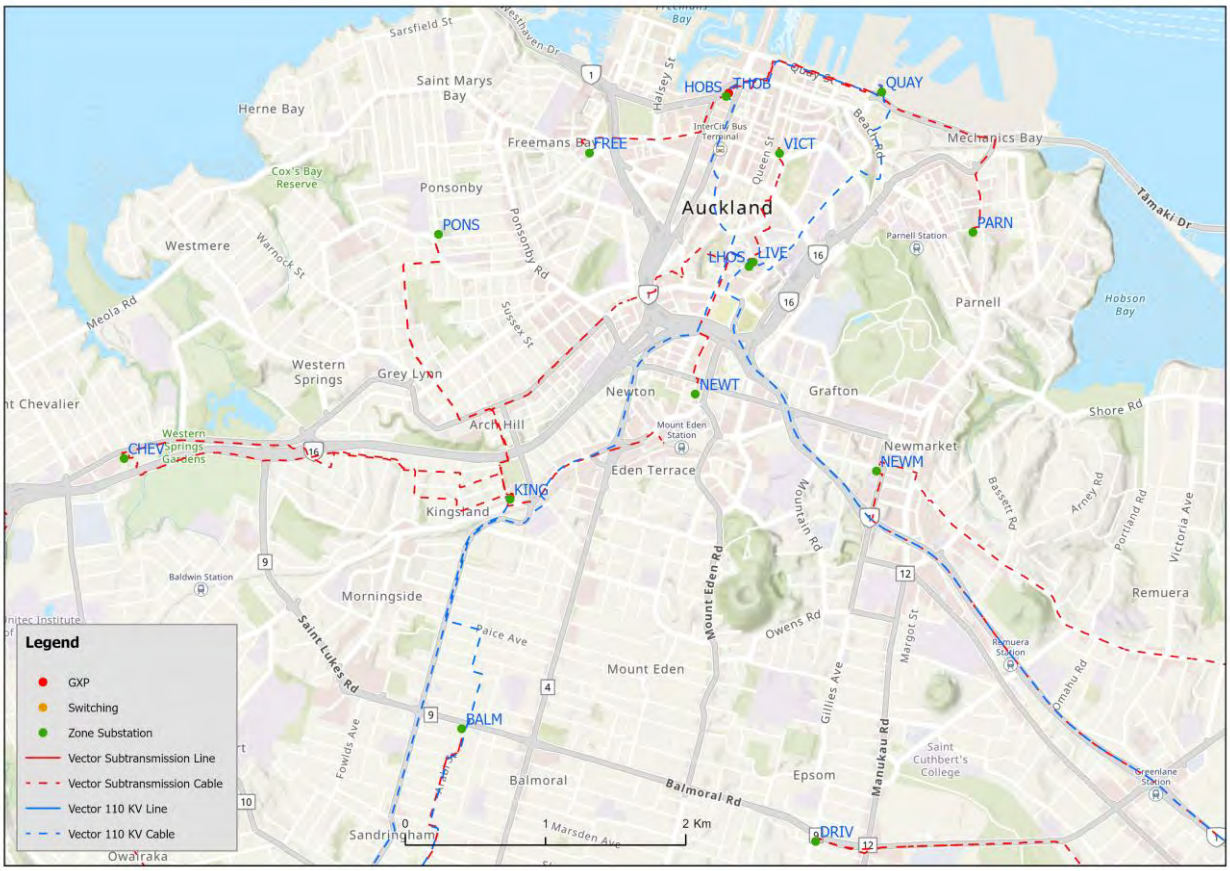


FIGURE 10-17: AUCKLAND CBD SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
PEAK SEASON	ZONE SUBSTATION	SOSS CATEGORY	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Freemans Bay	COM	18.5	19.2	20.0	20.8	21.5	22.7	23.9	25.0	26.2	27.4	28.8
Summer	Hobson 110/11 kv	CBD	12.3	12.6	12.9	13.3	13.6	14.1	14.7	15.2	15.8	16.3	17.0
Summer	Hobson 22/11 kv	CBD	7.8	8.2	8.5	8.9	9.3	9.9	10.5	11.1	11.7	12.3	13.0
Winter	Hobson 22 kv	CBD	61.2	65.9	70.7	67.7	76.4	90.6	97.2	103.8	107.3	109.9	113.2
Winter	Liverpool	CBD	33.0	34.2	35.5	36.6	37.8	39.4	41.9	43.5	45.0	46.5	48.3
Winter	Liverpool 22 kv	CBD	94.0	106.3	115.3	145.4	158.9	168.0	173.5	179.0	184.4	189.8	196.4
Winter	Newton	COM	18.2	20.1	21.6	23.1	24.6	26.6	27.8	29.8	31.9	33.9	36.3
Winter	Parnell	COM	17.1	17.9	18.7	19.5	20.3	21.6	22.9	24.2	25.5	26.8	28.3
Summer	Quay	CBD	12.7	12.9	13.1	15.5	14.1	14.5	14.8	15.1	15.5	15.8	16.2
Summer	Quay 22 kv	CBD	49.7	50.9	52.1	55.4	59.2	61.1	63.0	64.9	66.8	75.7	78.0
Summer	Victoria	CBD	15.4	15.8	16.2	16.7	17.1	17.8	18.6	19.3	20.1	20.8	21.8

TABLE 10-18: CBD LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.7.2 GRID EXIT POINTS

Two GXP's, Penrose 110kV and Hobson 110kV, are operated in parallel with the Transpower network to supply the CBD, and Roskill 110kV GXP as backup.

There is sufficient capacity for the foreseeable future, however, in medium to long term, the Penrose – Liverpool 110kV circuits are expected to be overloaded due to the through flow issue during contingency condition in Transpower's grid. Options are being investigated including splitting the CBD 110kV network with the two GXPs operated separately in medium term and installing 2nd 220/110kV transformer at Hobson GXP in long term.

10.6.7.3 SUBTRANSMISSION

The CBD is supplied by subtransmission circuits at 110 kV and 22 kV. All subtransmission circuits are underground cables to improve resilience of the network.

The 110 kV network is supplied by two independent 110 kV grid sources, with two feeders from Penrose GXP and one feeder from Hobson GXP. This provides network security at N-1 without an outage and N-2 with a short outage. An independent backup supply is available from Roskill GXP.

The 22 kV subtransmission network is installed between the three primary ZSSs, namely Hobson ZSS, Liverpool ZSS and Quay ZSS to provide additional backup to the 110 kV supply. The 22 kV subtransmission network is then used to supply four other ZSSs, namely Freemans Bay ZSS, Newton ZSS, Parnell ZSS and Victoria ZSS.

No constraints are identified to occur in the subtransmission network, during the AMP planning period.

10.6.7.4 ZONE SUBSTATION

The CBD area is served by three primary ZSSs, namely Liverpool, Hobson and Quay. The ZSSs are connected to the 110 kV network via a total of eight 110/22 kV transformers and the 22 kV buses are interconnected via 22 kV subtransmission circuits. Each of these three primary ZSSs also has multiple 22/11 kV transformers to step the voltage down to distribution level and ensure security of supply.

The 22 kV subtransmission network supplies an additional four 22/11 kV ZSSs, namely Freemans Bay ZSS, Newton ZSS, Parnell ZSS and Victoria ZSS.

A security breach is forecasted at Quay ZSS 22 kV due to the proposed load from the downtown electric ferry terminal and the commercial building development in the Quay St area. To bring the security of supply at the ZSS up to standard, projects alongside the asset replacement program have started to upgrade the two existing 110/22 kV 60MVA transformers to 75MVA each, and to replace the existing 22 kV switchboard, adding additional circuit breakers. A 3rd 110/22 kV 75MVA transformer and a 110 kV switchboard will be installed at later stage, circa 2035, when required due to load growth.

Security breaches are also forecast at Hobson ZSS and Liverpool ZSS 22 kV due to the major new load from the Downtown Carpark redevelopment and two data centres, one at Nelson St and another at White St, to be built between 2026 and 2031. The following projects will address the constraints:

- Upgrade one of the two 110/22/11 kV 65/40/25MVA transformers at Hobson ZSS with a 110/22 kV 75MVA unit. The project is at design stage.
- Establish a new ZSS with two 110/22 kV 75MVA transformers and a 22 kV switchboard to supply the data centre at Nelson St and off load Liverpool ZSS. 110 kV cables will be installed to connect the new ZSS to Hobson 110 kV switchboard. Additional 110 kV circuit breakers will be installed to extend the existing 110 kV switchboard at Hobson ZSS for the connection. 22 kV new feeders will be installed from the new ZSS integrating into the existing distribution network in CBD. Land has been purchased for the new ZSS. The project is at preliminary investigation stage.

- Install new 22 kV circuit breakers to extend the existing 22 kV switchboard at Liverpool ZSS. The project is required to connect the dedicated new 22 kV feeders to supply the data centre at White St. Additional circuit breakers will also be installed for future use including the connection of the proposed new feeder to supply the increased load at University of Auckland. The project is at design stage.
- Upgrade the remaining 110/22/11 kV 65/40/25MVA transformer and the two existing 22/11 kV transformers at Hobson ZSS at later stage, circa 2037, when required due to load growth.

The load forecast shows the SoSS is expected to be breached at Newton ZSS from 2034, resulting from the proposed developments in the Mt Eden precinct after completion of the CRL works. Vector currently plans to establish a new ZSS at Mt Eden to resolve the constraint (refer to Roskill Planning Area for project details).

Security breaches are also forecast at Liverpool and Victoria 11 kV around 2032 and 2034 respectively, due to the load growth in the existing 11 kV network. Vector's plan is to convert selected 11 kV distribution substations to 22 kV and transfer the load to the 22 kV distribution network. New load will be connected to the 22 kV network wherever feasible. This approach will avoid the costly upgrade at the two ZSSs and is in line with the long-term plan to upgrade the CBD distribution network from 11 kV to 22 kV.

10.6.7.5 DISTRIBUTION NETWORK

The distribution network in the CBD is comprised of both 11 kV and 22 kV feeders from the ZSSs. The feeders are generally radial and interconnected via open points to meet Vector's SoSS.

As mentioned above, the long-term plan for the CBD distribution network is to progressively expand the 22 kV network coverage with the goal of replacing the aging 11 kV network and increase capacity in the CBD. The 22 kV network is required in the CBD to service the load density of large new customer connections (typically for large new building developments). Conversion of existing 11 kV distribution load will also be carried out when existing 11 kV assets require replacement and when future constraints on the 11 kV network are forecast.

Auckland Transport has been carrying out the streetscape project in the Britomart area bounded by Quay St, Queen St, Customs St and Britomart Place, and additional new potential loads have been identified. Auckland Transport has also started the design for the Downtown Development Program which integrates the former Downtown West and Downtown Bus Improvements projects. As the roads are being renewed (dug up and reinstated) and existing cables relocated, there are synergies and opportunities to expand the 22 kV network coverage to future proof the network by installing 22 kV cables and ducts. If Vector does not take this opportunity, then it may be difficult to get access to excavate these roads within the time period required to meet the growing demand of the CBD.

10.6.7.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Synergy opportunity to future proof for CBD 22 kV distribution network to meet long term growth	Auckland CBD White St 22 kV FP ducts	FY27	1.28
Risk of capacity and security breach resulted from aged 11 kV PILC cables	Swanson tunnel de-risk network reconfiguration	FY27	1.00
Synergy opportunity to future proof for CBD 22 kV distribution network to meet long term growth	CBD Hobson St Bradnor Lane 22 kV FP ducts	FY27	0.58
Synergy opportunity to convert 11 kV distribution substations to 22 kV aligning with CBD long term plan	CBD C-1432 4 Short St 11 kV to 22 kV conversion	FY27	0.28
Hobson feeders HBOS J38, LIVE J05 and LIVE J17 breach capacity and SoSS due to DC load	NextDC Data Centre Hobson St CBD Feeder	FY27	0.22
Hobson ZSS 22 kV breaches SoSS due to major commercial developments	Hobson ZSS 2nd 75MVA 110-22 TX	FY28	4.91
Liverpool ZSS 22 kV breaches SoSS due to major commercial developments	Nicholas New 110-22 kV ZSS	FY31	18.14
Required for new Nicholas ZSS connection to 110 kV network	Nicholas ZSS 110 kV cables from Hobson ZSS	FY31	12.67
Required for new Nicholas ZSS connection to 22 kV network	Nicholas ZSS new 22 kV feeders	FY29	9.14
Required for connection of new feeders to supply major commercial customers and future developments	Liverpool ZSS 22 kV SWBD Extension	FY29	5.38
Synergy opportunity to convert 11 kV distribution substations to 22 kV aligning with CBD long term plan	CBD Bankside St 22 kV extension and conversion	FY29	6.29
Synergy opportunity to convert 11 kV distribution substations to 22 kV aligning with CBD long term plan	Customs St Bus Priority 22 kV Conversion	FY29	4.96

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Synergy opportunity to convert 11 kV distribution substations to 22 kV aligning with CBD long term plan	Downtown Car Park Demo 22 kV Conversion	FY29	3.63
Quay ZSS 22 kV breaches SoSS due to major commercial developments	Quay ZSS 2x New 75MVA 110-22 kV Txs	FY30	11.33
Required for connection of new feeders to supply major commercial customers and future developments	Quay ZSS additional 22 kV CBs	FY29	2.25
Hobson feeders J02 & J09 breach SoSS	Hobson Waterfront 22 kV feeders new	FY29	6.17
Synergy opportunity to convert 11 kV distribution substations to 22 kV aligning with CBD long term plan	CBD Eden Cre and Anzac Av 22 kV extension and conversion	FY30	5.10
Synergy opportunity to future proof for CBD 22 kV distribution network to meet long term growth	AT Wellesley Bus Improvements Stage 2 RNF3	FY30	1.80
Liverpool feeder K01 breaches SoSS	CBD 11 kV to 22 kV conversion for security in LIVE K01	FY31	4.12
Hobson feeder J15 breaches capacity and SoSS due to major commercial development	Hobson new 22 kV feeders to Lower Hobson St	FY31	4.12
Synergy opportunity to convert 11 kV distribution substations to 22 kV aligning with CBD long term plan	CBD Liverpool St 22 kV extension and conversion	FY32	4.60
Synergy opportunity to convert 11 kV distribution substations to 22 kV aligning with CBD long term plan	CBD Vincent St 22 kV extension and conversion	FY32	2.10
Liverpool ZSS 11 kV breaches SoSS	CBD Liverpool 11 kV to 22 kV conversion for security	FY32	4.00
Parnell feeder K04 breaches SoSS	CBD 11 kV to 22 kV conversion to off load PARN K04	FY34	4.00
Victoria ZSS 11 kV breaches SoSS	CBD Victoria 11 kV to 22 kV conversion for security	FY34	4.00
Quay ZSS 22 kV breaches SoSS due to major commercial developments	Quay ZSS 3rd 75MVA 110-22 kV TX	FY35	2.43
Required for 3rd TX connection	Quay ZSS 110 kV SWBD	FY35	12.92
Hobson ZSS 22 kV breaches SoSS	Hobson ZSS 3rd 75MVA 110-22 kV TX	FY36	5.00
Hobson ZSS 11 kV breaches SoSS	Hobson ZSS T1 and T2 upgrade	FY36	3.09
Victoria feeders K14 & K24 breach SoSS	CBD 22 kV extension to off load VICT K14 & K24	FY36	2.06
Risk of capacity and security breach resulted from aged 11 kV PILC cables	CBD 22 kV Network Rollout	FY36	20.41
Risk of capacity and security breach resulted from aged 11 kV PILC cables	CBD distribution sub 11 kV to 22 kV conversion	FY36	8.51

TABLE 10-19: CBD CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.8 ROSKILL PLANNING AREA

10.6.8.1 OVERVIEW

The Roskill planning area is located to the west of Auckland CBD and extends from Mt Eden west to Avondale and north to Herne Bay. In total, the GXP supplies about 72,000 customers (ICPs) with a total load of about 163 MVA.

Commercial multi-level buildings and multi-level high density residential load growth is expected around Mt Eden station. Significant housing intensification by Kainga Ora in wider Roskill area is underway and forecast to add 17,000 dwellings over the next 20 years.

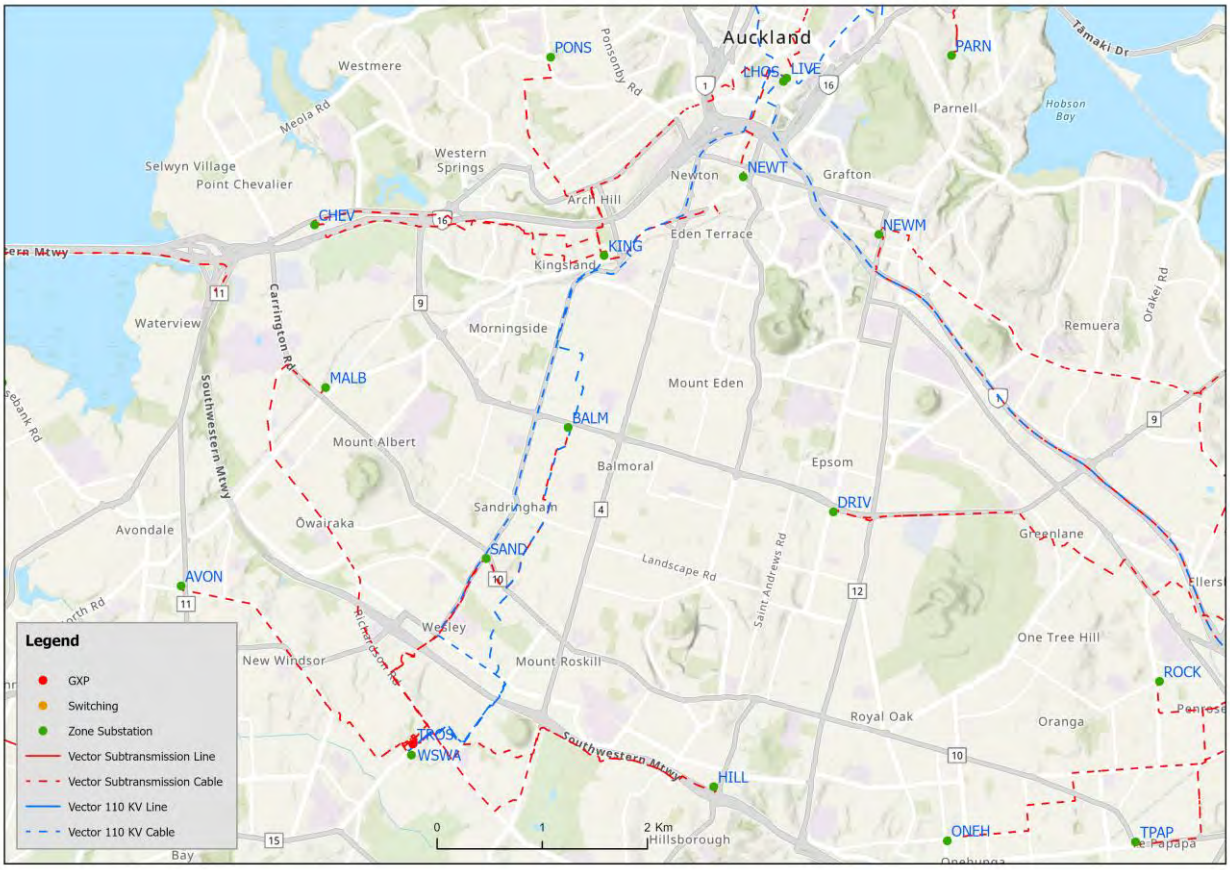


FIGURE 10-18: ROSKILL SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
PEAK SEASON	**ZONE SUBSTATION**	**SOSS CATEGORY**	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Avondale	RES	28.4	29.0	27.8	28.4	29.0	30.1	31.1	32.2	33.2	34.3	35.6
Winter	Balmoral	RES	12.6	13.0	13.3	13.7	14.0	14.6	15.1	15.7	17.6	18.2	19.0
Winter	Chevalier	RES	20.1	21.0	21.8	22.7	23.6	24.8	26.1	27.3	28.6	29.8	31.3
Winter	Hillsborough	RES	19.5	20.2	18.1	18.7	19.3	20.0	20.8	21.5	22.2	23.0	23.8
Winter	Kingsland	RES	24.6	25.8	27.5	28.7	29.8	31.6	33.4	35.2	37.0	38.8	41.0
Winter	Kingsland 22 kV	RES	62.2	64.7	67.7	70.2	72.7	76.5	80.3	84.1	87.9	91.6	96.2
Winter	Mt Albert	RES	7.6	8.2	8.8	9.4	10.0	10.7	11.4	12.1	12.8	13.5	14.3
Winter	Ponsonby	RES	14.9	15.4	15.8	16.3	16.7	17.5	18.3	19.0	19.8	20.6	21.5
Winter	Sandringham	RES	25.6	26.4	27.1	27.9	28.7	29.9	31.1	32.2	32.1	33.2	34.7
Winter	Sandringham 22 kV	RES	36.3	37.3	38.4	39.5	40.5	42.2	43.9	45.5	47.2	48.9	64.6
Winter	White Swan	IND	23.7	24.2	27.5	28.0	28.5	29.4	30.2	31.0	31.9	32.7	33.8

TABLE 10-20: ROSKILL LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.8.2 GRID EXIT POINT

Roskill GXP provides a 110 kV supply to Vector's Kingsland 110/22 kV ZSS and a separate 22 kV supply to six Vector ZSSs. Roskill 110kV GXP also provides backup to the CBD 110kV network via a single 110 kV circuit connecting to Liverpool ZSS 110kV bus.

Roskill 110kV GXP is connected to Transpower's 110kV grid with 110kV circuits connected to the other GXPs including Hepburn, Mangere and Otahuhu.

Roskill 22kV GXP is supplied from the 110kV GXP via three 110/22kV transformers. Load at the 22kV GXP is forecasted to breach N-1 SoSS from mid of 2030s. Upgrading the existing transformers will solve the problem.

10.6.8.3 SUBTRANSMISSION

There are two 110kV circuits connected between Roskill 110kV GXP and Kingsland 110/22 kV transformers. A separate 110kV circuit is connected between Roskill 110kV GXP and Liverpool 110kV bus providing backup to CBD 110kV network.

A 22 kV circuit connecting between Kingsland 22 kV bus and Liverpool 22 kV bus is used for backup purposes.

Capacity and security constraints are identified in the subtransmission circuits at Mt Albert and Sandringham from 2033 and 2038, respectively. Reinforcement projects have been proposed to resolve the constraints.

At Kingsland 110/22 kV substation, the existing two 110 kV circuits and the backup 22 kV circuit from Liverpool are all fluid filled cables over 50 years old. It makes the substation vulnerable upon any fluid filled cable failure. Also, the substation is forecast to breach SoSS from 2034. A project is proposed to install a 110 kV switchboard at the substation connecting to the 110 kV circuit between Roskill and Liverpool utilising the capacity available. The feasibility will be investigated, and a decision made in due course.

10.6.8.4 ZONE SUBSTATION

There are nine ZSSs supplied from Roskill GXP, three via Kingsland ZSS using 22 kV subtransmission circuits, two via Sandringham 22 kV bus, and the remaining four directly from Roskill 22 kV bus.

Mt Albert substation is currently supplied from Roskill 22 kV GXP via a single subtransmission circuit and single transformer. Due to the age and condition, the transformer has been replaced in 2023 under an asset replacement project. The subtransmission circuit is planned for replacement within 10 years. The new transformer improves the capacity and security at Mt Albert substation until 2033 when the load is forecasted to exceed the load limit. Vector has identified the preferred solution to resolve the constraint as the installation of a second transformer and new subtransmission circuits connecting the ZSS to the Sandringham 22 kV bus, instead of the Roskill 22 kV GXP, to take advantage of shorter cabling distances and existing spare circuit breakers, thus lowering cost. The project is planned to be completed by FY32.

The proposed commercial and housing development at Mt Eden precinct by City Rail Link is expected to add significant load in the area. Capacity and security constraints are identified at Newton substation (included in CBD Planning Area), Kingsland substation, and various 11 kV feeders from 2034. It is proposed to establish a new ZSS at Mt Eden area to resolve the constraints.

Kingsland 22 kV is supplied via two 110/22 kV transformers and two 110 kV circuits. A 3rd transformer will be required to meet the load growth and SoSS in the long term. Vector plans to reuse the 110/22/11 kV transformer that is to be removed from Hobson substation during the Hobson transformer upgrade project. The transformer will initially be installed at Kingsland substation for standby purposes.

Ponsonby ZSS and Avondale ZSS are forecast to exceed loading limits in FY34 and FY36, respectively. It is proposed to upgrade the transformers at the ZSSs to resolve the constraints.

10.6.8.5 DISTRIBUTION NETWORK

The distribution network in the area comprises of 11 kV feeders from the ZSSs. The feeders are mainly radial and interconnected with open points in between to meet Vector's N-1 SoSS.

11 kV feeders at the various ZSSs are expected to breach security between 2033 and 2037. It is proposed to install new 11 kV feeders from the ZSSs connecting to the existing network and reconfigure the feeders in the area to remove the constraint.

10.6.8.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Synergy opportunity to future proof for cable installation at later stage	White Swan Rd future proofing ducts	FY28	3.40
Synergy opportunity to reuse ex Hobson T4	Kingsland ZSS 110-22-11 kV TX	FY28	1.10
Capacity and security constraints at Mt Albert ZSS and Sandringham ZSS	Mt Albert ZSS 2nd Tx and new subtran cables	FY32	26.61
Kingsland ZSS 22 kV supply at risk upon outage in both 110 kV fluid filled cables	Kingsland ZSS 110 kV SWBD and cables	FY32	19.72
Synergy opportunity to future proof for Mt Roskill housing development in coordinated with multiple third parties' projects	Mt Roskill Precinct futureproof ducts and cables	FY33	3.44
Capacity constraints at Ponsonby ZSS	Ponsonby substation upgrade	FY33	8.45

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Kingsland feeder K20 breaches SoSS	Kingsland new 11 kV feeders for capacity and security in KING K20	FY33	4.12
Capacity and security constraints at Kingsland ZSS (11 kV), Newton ZSS, and various feeders due to housing development in Mt Eden precinct	Mt Eden Zone Substation New	FY34	34.58
Capacity constraints at Avondale ZSS (11 kV)	Avondale Tx upgrade	FY35	4.12
Mt Albert feeder K16 breaches SoSS due to Wairaka housing development	Mt Albert new 11 kV feeders for capacity and security in MALB K16 (Wairaka housing)	FY36	4.43
Avondale feeder K02 breaches SoSS	Avondale 11 kV reinforcement for security in AVON K02	FY36	2.00
Sandringham ZSS 33 kV breaches SoSS	Sandringham subtran upgrade	FY36	4.00
Sandringham feeder K18 breaches SoSS	Sandringham Stoddard Rd 11 kV feeders new (KO driven)	FY36	4.00

TABLE 10-21: ROSKILL CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.9 PENROSE PLANNING AREA

10.6.9.1 OVERVIEW

This is Vector's largest planning area from Mt Eden east to the Tamaki River. The area has over 89,300 customers (ICPs) with a total demand of 295 MVA. The area is supplied by Transpower's Penrose GXP at 33 kV and 22 kV.

The planning area is well developed with limited greenfield development areas. The growth is mainly driven by redevelopment and densification of existing areas. The major housing redevelopment is Kainga Ora's Tamaki regeneration project in Glen Innes, Panmure and Point England. The housing growth based on the latest medium forecast is an additional 13,000 ICPs by 2036, and 18,600 ICPs by 2046.

Ongoing commercial development is expected to continue in the Newmarket and Sylvia Park precincts. A data centre is also planned in the area.

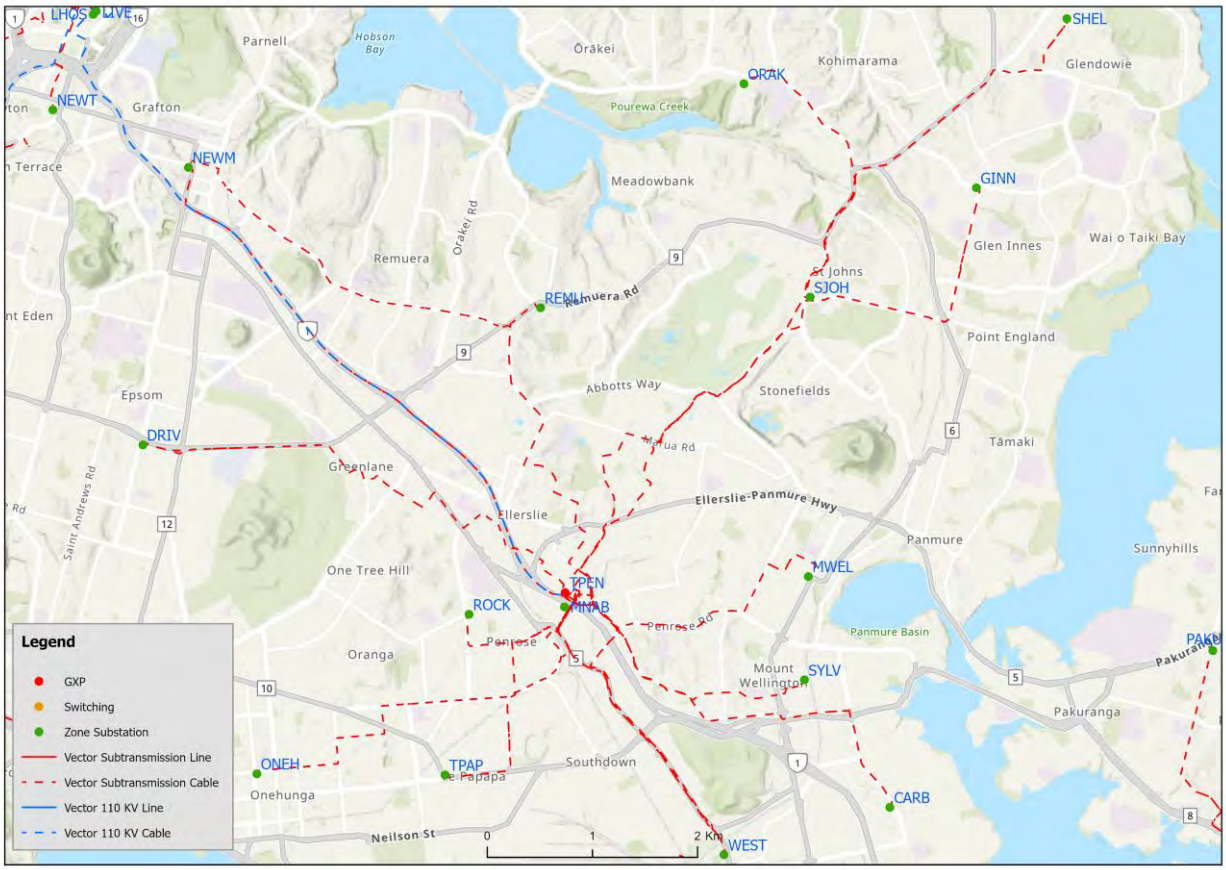


FIGURE 10-19: PENROSE SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
PEAK SEASON	ZONE SUBSTATION	SOSS CATEGORY	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Carbine	IND	15.8	16.0	16.3	16.5	16.7	17.1	17.4	17.8	18.1	18.5	18.9
Winter	Drive	RES	24.6	25.3	26.8	27.5	28.1	29.1	30.1	31.2	32.2	33.2	34.4
Winter	Glen Innes	RES	16.8	17.4	18.1	18.8	19.4	20.2	21.1	21.9	22.7	23.6	24.5
Winter	McNab	IND	37.8	50.3	51.1	51.9	52.7	54.1	55.4	58.5	59.9	61.2	62.8
Winter	Mt Wellington	IND	16.1	16.8	17.6	18.4	19.2	20.5	21.7	22.9	24.2	25.4	27.0
Winter	Newmarket	COM	34.5	36.4	37.4	39.1	40.9	43.5	46.1	48.8	51.4	54.0	57.1
Winter	Onehunga	IND	17.6	18.2	18.8	19.4	20.6	21.5	22.4	23.4	24.3	25.2	26.4
Winter	Orakei	RES	22.7	23.2	23.7	24.2	24.7	25.5	26.4	27.1	27.8	28.6	29.5
Winter	Remuera	COM	28.1	29.1	29.7	30.4	31.0	32.0	33.1	32.4	33.5	34.5	35.8
Winter	Rockfield	RES	21.9	22.4	22.9	23.3	23.8	24.6	25.4	26.2	27.1	27.9	28.8
Winter	St Heliers	RES	20.6	21.0	21.5	21.9	22.3	23.0	23.6	24.3	25.0	25.6	26.4
Winter	St Johns	RES	19.1	19.7	20.2	20.8	21.3	22.2	23.0	23.8	24.7	25.5	26.4
Winter	ST Johns 33 kV	RES	56.2	57.5	58.9	60.2	61.5	63.6	65.7	67.7	69.7	71.7	74.1
Winter	Sylvia Park	COM	15.5	15.7	15.8	16.0	16.2	16.5	16.8	17.1	17.5	17.8	18.2
Summer	Te Papapa	IND	16.3	16.8	17.3	17.8	18.4	19.1	19.8	20.5	21.3	22.0	22.8
Winter	Westfield	IND	26.6	27.1	27.7	28.3	28.8	29.7	30.5	31.4	32.2	33.1	34.1

TABLE 10-22: PENROSE LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.9.2 GRID EXIT POINT

Penrose 33kV GXP is the largest GXP in our network and supplies 15 ZSSs, with a total demand of 295MVA. The GXP has four 220/33kV transformers installed, three operated in parallel for normal supply and the 4th hot standby with the 33kV incomer circuit break normal open. This arrangement is required to limit the fault level at the 33kV busbar within the design fault level.

Penrose 22kV GXP is supplied from the 33kV GXP via three 33/22kV transformers. The 22kV GXP supplies two ZSSs, Onehunga and Westfield.

The peak demand in 2025 was 298 MVA at the Penrose 33 kV bus (i.e., the combined 33kV and 22kV load) and is forecasted to breach security limits in the mid-2030s. The GXP is space constrained for further expansion and exposes to the risk of common mode failure due to the concentration of the load. To solve the problems, a new GXP is proposed to be established at Southdown. The plan is to divert the existing ZSSs in the area including Onehunga, Westfield, Te Papapa and Carbine to the new GXP when the subtransmission cables at the ZSSs are due for replacement. The new GXP was targeted to be completed by FY27, however, was put on hold until NZTA finalised the alternative route for East West Link. The new GXP is now targeted to be completed by FY29, and two ZSSs, Onehunga and Westfield, to be transferred to the new GXP upon completion of the subtransmission cable replacement projects around the same time. Penrose 22kV GXP will then be decommissioned.

10.6.9.3 SUBTRANSMISSION

The subtransmission network in the area is comprised of 33 kV and 22 kV circuits connected between Penrose GXP and Vector's ZSSs.

The subtransmission cables supplying Onehunga ZSS and Westfield ZSS are being replaced due to age and condition. Upon completion of the replacement projects, the two ZSSs will be connected to the new Southdown GXP diverting the load from Penrose 33 kV GXP.

10.6.9.4 ZONE SUBSTATION

There are 15 ZSSs supplied from Penrose GXP. 10 are supplied directly from Penrose GXP at 33 kV, 3 are supplied via the switching station at St Johns substation, and 2 are supplied directly from Penrose at 22 kV. The Glenn Innes ZSS also includes a 1 MW / 2.3 MWh BESS installed in 2017.

Load at Drive ZSS and Newmarket ZSS are forecasted to exceed load limits from 2036. To off load the two ZSSs, Vector's preferred solution is to establish a new ZSS on the same site as the existing Newmarket ZSS utilising the spare space available.

St Johns ZSS (11 kV) is expected to breach the SoSS at some stage in the long term due to the significant housing development by Kainga Ora's Tamaki Regeneration project. The long-term strategy is to establish a new substation to supply the area. Although the substation is not required within this planning period, Vector will purchase land to secure an optimal site at the design stage of the Kainga Ora development.

Load at McNab ZSS is forecasted to exceed the load limit from 2037. Equipped with three 33/11 kV transformers already, the ZSS cannot be upgraded due to space constraints and fault level restrictions. It is proposed to install a 3rd transformer and subtransmission circuit at the adjacent Rockfield ZSS to off load McNab ZSS.

10.6.9.5 DISTRIBUTION NETWORK

The distribution network in the area comprises of 11 kV feeders from the ZSSs. The feeders are mainly radial and interconnected with open points in between to meet Vector's N-1 security of supply standard.

An 11 kV feeder from St Johns ZSS is expected to breach security from 2035 as a result of load growth from Kainga Ora's housing development in the area. It is proposed to install new 11 kV feeders from St Johns ZSS's connecting to the existing network and reconfiguring the feeders in the area to remove the constraint.

A number of 11 kV feeders from McNab, Te Papapa, and Westfield ZSS's are expected to breach security between 2033 and 2037 due to industrial/commercial load growth in the area. It is proposed to install new feeders from the ZSS's connecting to the existing network and reconfiguring the feeders in the area to remove the constraint.

In the longer term, a new Vector ZSS will be established at Southdown to off-load the existing 11 kV feeders and ZSSs that are expected to breach the SoSS in the area. It is proposed to purchase land at Southdown for the new ZSS in FY28, however, the construction of the new substation is beyond the 10-year window covered by the AMP.

10.6.9.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Project coordinated with asset replacement project and synergy opportunity to future proof for additional cable installation	Westfield to Southdown cables and FP ducts	FY28	15.97
Synergy opportunity to future proof for cable replacement at later stage	Te Papapa to Southdown FP ducts	FY28	13.78
Constraints on the 11 kV distribution network in the Southdown area	Southdown land purchase for ZSS	FY28	Not discl.
Liverpool feeder K14 breaches SoSS	Newmarket new feeders to off load NEWM K19 and NEWM K30	FY28	3.04
Synergy opportunity to future proof for cable installation in the proposed Southdown GXP and ZSS	Southdown on-site future-proofing ducts	FY28	4.25
St Johns substation (11 kV) breaches capacity and security in long term. It is proposed to establish a new zone substation to remove the constraints. Land needs to be purchased to secure an optimal site at design stage of the development.	Tamaki land purchase for ZSS	FY28	Not discl.
Westfield feeder K09 breaches SoSS	McNab new 11 kV feeder to Holloway Place for security in WEST K09	FY32	3.61
St Johns feeder K01 breaches SoSS	St Johns new 11 kV feeders to Morrin Rd (KO driven)	FY34	4.12
Project coordinated with third parties' roadworks	Tamaki future-proofing ducts and cables	FY36	5.10
Capacity constraint at McNab ZSS	Rockfield ZSS 3rd TX and subtran	FY36	21.38
Capacity constraints at Newmarket ZSS and Remuera ZSS	Newmarket substation upgrade	FY36	23.85
McNab feeders K03 and K06 breach capacity and SoSS	Mt Wellington new 11 kV feeders for capacity and security in MNAB K03 and K06	FY36	2.06
Te Papapa feeders K12 and K17 breach SoSS	Te Papapa 11 kV reinforcement for security in TPAP K12 and K17	FY36	4.12

TABLE 10-23: PENROSE CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.10 PAKURANGA PLANNING AREA

10.6.10.1 OVERVIEW

The Pakuranga planning area covers most of the eastern Auckland suburbs, including East Tamaki, Flatbush, Pakuranga, Botany, Howick and all the way out to Bucklands Beach. The areas to the south of Flat Bush are designated greenfield growth areas and an additional 7 MVA increase in demand is expected by 2036.



FIGURE 10-20: PAKURANGA SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	**ZONE SUBSTATION**	**SOSS CATEGORY**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Winter	East Tamaki	COM	20.3	21.2	21.4	21.7	21.9	22.3	22.6	23.0	23.4	23.7	24.2
Winter	Flatbush	RES	22.2	23.1	24.4	24.9	25.4	26.0	26.6	27.2	27.8	28.4	29.1
Winter	Greenmount	COM	39.6	41.1	41.7	42.3	42.9	44.1	45.3	46.5	47.8	49.0	50.5
Winter	Howick	RES	38.7	40.2	40.6	41.0	41.4	42.3	43.2	44.1	44.9	45.8	46.9
Winter	Pakuranga	RES	21.9	22.1	22.4	22.7	23.0	23.5	24.1	24.7	25.3	25.8	26.6
Winter	South Howick	RES	28.6	29.0	29.4	29.8	30.1	31.0	31.8	32.6	33.4	34.3	35.3

TABLE 10-24: PAKURANGA LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.10.2GRID EXIT POINT

There are three 120 MVA, 220/33 kV transformers at Pakuranga GXP providing total installed capacity of 360MVA. The peak demand in 2025 was 136 MVA and there are no forecasted constraints at this GXP.

10.6.10.3 SUBTRANSMISSION

The area is supplied from the Pakuranga GXP. The subtransmission network operates at 33 kV and consists of underground cables that are installed along road reserves and supply six zone substations radially.

There are no subtransmission security constraints identified to occur during the AMP period.

10.6.10.4 ZONE SUBSTATION

Pakuranga GXP supplies six ZSS. Flatbush ZSS, East Tamaki ZSS, South Howick ZSS and Pakuranga ZSS each have two transformers while Howick ZSS and Greenmount ZSS both have three transformers.

There are no substation security constraints identified to occur during this AMP period.

10.6.10.5 DISTRIBUTION NETWORK

The existing 11 kV feeder distribution network is meshed and has sufficient backstopping capacity to feed adjacent ZSS.

The Flat Bush K05 feeder is forecasted to reach capacity in 2028 due to the large residential developments in this area. A new Murphy's Rd feeder is planned to relieve this forecast capacity constraint.

East Tamaki K20 and Howick K05 are forecasted to breach security of supply in 2027-2028 due to commercial and industrial load growth in East Tamaki and residential growth in Howick. New feeders will be installed to add capacity and remove the constraint in these areas.

Vector will install futureproof ducts in cooperation with Auckland Transport's AMETI Busway project, to reduce civil costs and public disruption.

10.6.10.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Third party roadworks	AMETI future-proofing ducts EB2 EB3R and Bridge	FY27	1.2
Flat Bush feeder K05 breaches capacity and SoSS	Flat Bush 11 kV New Feeder - Murphys Rd	FY28	3.5
East Tamaki feeder K20 breaches SoSS	East Tamaki 11 kV New Feeder - Stonedon Ave	FY28	1.5
Howick feeder K05 breaches SoSS	Howick 11 kV New Feeder - Half Moon Bay	FY28	2.2

TABLE 10-25: PAKURANGA CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.11 MANGERE PLANNING AREA

10.6.11.1 OVERVIEW

The Mangere Planning Area covers the Mangere township and surrounding residential, commercial and industrial areas, extending south to the areas identified for future greenfield development surrounding the Auckland airport.

There is significant demand growth forecast due to a large number of dwellings that are planned by Kainga Ora over the next 15 years. These will be located between the Mangere Central area northwards towards Mangere Bridge and eastwards towards Middlemore. The growth will be driven by housing redevelopment and densification of existing areas.

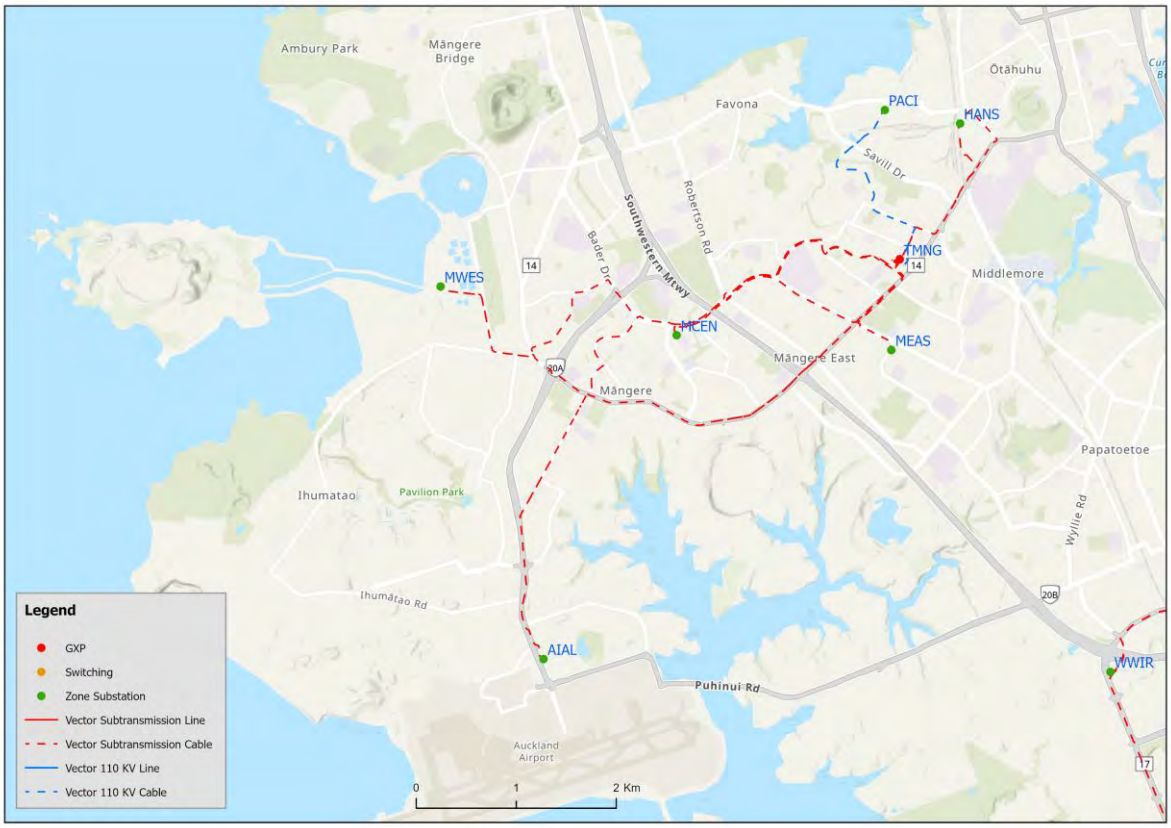


FIGURE 10-21: MANGERE SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	**ZONE SUBSTATION**	**SOSS CATEGORY**	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Hans	COM	26.4	27.2	28.1	28.9	29.7	30.9	32.1	33.3	34.5	35.7	37.2
Winter	Mangere Central	RES	50.5	51.6	52.7	53.7	54.8	56.4	58.0	59.6	61.2	62.8	64.8
Winter	Mangere East	RES	33.9	34.4	34.9	35.3	35.8	36.7	37.5	38.4	39.3	40.1	41.3
Winter	Mangere West	COM	25.0	25.4	25.8	26.2	26.6	27.0	27.4	27.7	28.1	28.5	28.9

TABLE 10-26: MANGERE LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.11.2 GRID EXIT POINT

Mangere GXP supplies Vector at two voltage levels, 110 kV and 33 kV.

The 33kV Network is supplied by two 110/33kV transformers which has an installed capacity of 240 MVA. The peak demand in 2025 was 117 MVA in 2025 at 33 kV and is forecasted to exceed N-1 capacity in Winter 2027. In the interim this constraint will be resolved with load transfer to neighbouring GXPs until a third transformer is installed.

The peak demand at 110 kV was 23 MVA in 2025 and there are no forecasted constraints.

10.6.11.3 SUBTRANSMISSION

The subtransmission network operates at 110 kV and 33 kV and consists of predominately radial underground cables. The two 110 kV feeders supply two 110/33 kV transformers at Pacific Steel and eleven 33 kV feeders supply five 33/11 kV zone substations.

There are no subtransmission security constraints identified to occur during the AMP period. However, the 33 kV network will be extended to connect a third transformer at Mangere East ZSS, Hans ZSS and Airport ZSS, along with the new proposed Mangere South ZSS.

10.6.11.4 ZONE SUBSTATION

Mangere GXP supplies four shared Vector zone substations and two dedicated customer zone substations. Of the four shared Vector zone substation three are two transformer ZSSs, namely Hans, Mangere East, Mangere West and one ZSS has three transformers - Mangere Central.

Vector will obtain an easement (Mangere South) for a 33 kV switchroom and future ZSS. Mangere Central zone substation is forecast to beach security of supply in 2030 due to residential and industrial growth in this area. A new zone substation will be established at Mangere South.

There is a demand constraint identified at Mangere East ZSS which will be deferred with load transfer to Mangere Central and West Wiri with the new feeder projects, followed by the third transformer project completed in FY35.

Hans ZSS also has a constraint during the AMP period due to the residential and commercial growth in the area. A third transformer and subtransmission cable will be installed to address this.

10.6.11.5 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead and underground in this area. The forecasted load growth in the Mangere area is expected to cause a number of feeder constraints which will be addressed through a feeder reinforcement project (Mangere Central K11) and a number of new feeders from Mangere Central zone substation (Mangere Bridge, Massey Rd and Idlewild Ave).

10.6.11.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Mangere Central feeders K01 and K05 breaches SoSS	Mangere Central 11 kV New Feeder - Mangere Bridge	FY27	2.1
Mangere Central substation breaches SoSS.	Mangere South land easement for ZSS	FY28	not discl.
Airport third transformer requirement	Mangere South 33 kV switch room New	FY28	9.1
Mangere Central feeder K11 breaches capacity and SoSS	Mangere Central K11 11 kV Feeder Reinforcement	FY28	1.8
Mangere South substation breaches SoSS	Mangere South 11 kV Switchgear and 33/11 kV Transformers	FY29	13.9
Hans substation breaches SoSS	Hans 33/11 kV 3rd TX and 33 kV cable	FY33	10.0
Mangere East feeder K11 breaches capacity and SoSS	Mangere Central 11 kV New Feeder - Massey Rd	FY35	2.2
Mangere East substation breaches capacity and SoSS	Mangere East Third Transformer and 33 kV cable	FY35	9.1
Mangere Central feeder K17 breaches SoSS	Mangere Central 11 kV New Feeder - Idlewild Ave	FY36	2.2

TABLE 10-27: MANGERE CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.12 TAKANINI PLANNING AREA

10.6.12.1 OVERVIEW

The Takanini Planning Area covers the urban areas of Manurewa, Takanini and Papakura townships, extending east to the more remote areas of Clevedon, Maraetai, Beachlands and Waiheke Island. A MW-scale generation facility from a landfill is operating in the area as well as a 10MW solar farm.

Waiheke Island is supplied by two 33 kV subtransmission cables from Maraetai. The submarine cabling crosses the Tamaki Strait and is then converts to underground cabling upon reaching the island.

Beachlands South will undergo significant development on the former Formosa Golf Course with up to 3000 homes, schools and a large commercial area over the next 10 to 15 years.

The Takanini planning area, excluding Waiheke Island, is driven predominantly by residential growth along with large commercial customers (public transport electrification).

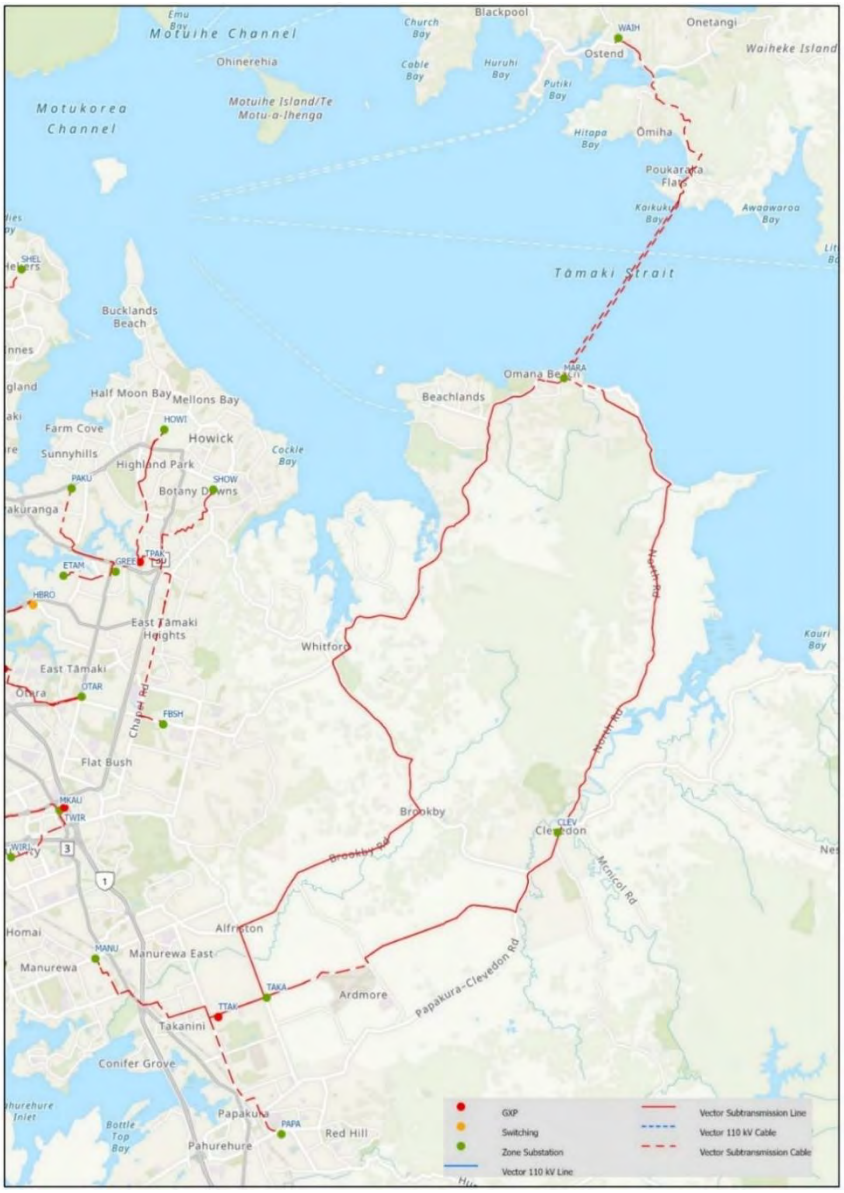


FIGURE 10-22: TAKANINI SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	**ZONE SUBSTATION**	**SOSS CATEGORY**	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Clevedon	RES	3.5	3.6	3.7	3.7	3.8	4.0	4.2	4.4	4.6	4.8	5.1
Winter	Manurewa	RES	55.3	56.1	56.8	57.5	58.2	59.5	60.9	62.2	63.5	64.9	66.7
Winter	Maraetai	RES	14.5	18.6	20.0	23.5	23.6	23.9	24.3	24.6	24.9	25.2	25.6
Winter	Papakura	RES	33.7	34.4	35.1	35.8	36.6	37.8	39.1	40.4	41.7	43.0	44.6
Winter	Takanini	COM	32.4	34.8	35.3	37.1	37.6	38.4	39.1	39.9	40.6	41.4	42.3
Winter	Waiheke	COM	12.2	12.5	12.7	13.0	13.3	13.9	14.4	15.0	15.6	16.2	16.9

TABLE 10-28: TAKANINI LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.12.2 GRID EXIT POINT

Takanini GXP is supplied by two 220/33 kV transformers, which has an installed capacity of 300 MVA. The peak demand was 239 MVA in 2025 and is forecast to exceed the N-1 capacity from winter 2027 due to large customer connections. A third transformer project has been initiated with Transpower to resolve this constraint.

There is approximately 5 MVA of generation resulting in peak reduction at this GXP and another 10 MVA of utility scale solar.

10.6.12.3 SUBTRANSMISSION

The subtransmission network operates at 33 kV and consists of predominately long radial overhead lines and cables supplying Maraetai and two submarine cables supplying Waiheke Island. The network also consists of underground 33 kV cables to supply Manurewa, Takanini and Papakura.

There are no subtransmission security constraints identified to occur during the AMP period. However, the 33 kV network will be extended to connect a third transformer at Takanini ZSS and Papakura ZSS.

10.6.12.4 ZONE SUBSTATION

Takanini GXP supplies six zone substations of which four have two 33/11 kV transformers, namely Maraetai, Papakura, Takanini and Waiheke ZSS. Clevedon ZSS consists of a single 5 MVA 33/11 kV transformer and Manurewa ZSS has two transformers.

The Manurewa capacity constraint will be addressed by load transfer to Clendon ZSS and a Clendon Weymouth Rd 11 kV new feeder (from Wiri GXP) will provide additional capacity for further load transfer in FY28.

Takanini ZSS is forecasted to breach the SoSS in 2027. A third transformer and accompanying sub-transmission cable project is underway and will be complete in FY28, this will add capacity to the zone substation and allow for future commercial and residential developments in the area. In the interim load will be transferred to neighbouring zone substations. A second project is planned to upgrade existing transformers T1 and T2 in FY28 which will add required capacity to this area.

The Papakura constraint will initially be resolved by load transfer to Takanini ZSS. A third transformer and subtransmission cable project is planned for FY36.

As a result of organic growth in addition to high commercial interest, a new Takanini North ZSS is expected to be required in the long term (beyond the AMP period). A project to acquire land is planned for FY31.

A security of supply constraint at Waiheke ZSS will be addressed by a transformer upgrade project.

10.6.12.5 DISTRIBUTION NETWORK

The distribution network in this planning area covers a very large rural area from Takanini in the west, to Clevedon in the south and Waiheke Island in the east. It operates at 11 kV and consists of predominately overhead lines. In Kawakawa Bay, a 1 MW / 1.7 MWh BESS to provide additional resilience for the network and local wastewater treatment facility was installed in 2020.

The 11 kV feeder supplying Kawakawa Bay and Orere Point from Clevedon ZSS is 32km long. The main issue is low voltage, and the feeder already has three voltage regulators. A new feeder is planned for FY32 to address this constraint.

Significant growth caused by a mix of residential and commercial development has triggered the need for new feeders and feeder reinforcements in Manurewa (Alfriston Rd and K08), Takanini (Manuroa Rd, Walters Rd, Grove Rd, K09 and K17) and Maraetai (Beachlands, Jack Laughlin Dr and K01).

Vector will install futureproof ducts in cooperation with NZTA's Mill Rd project, to reduce civil costs and public disruption.

10.6.12.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Takanini feeder K09 breaches SoSS	Takanini K09 11 kV feeder reinforcement	FY27	0.5
Takanini feeder K17 breaches SoSS	Takanini K17 Alfriston-Ardmore Rd Overhead Upgrade	FY27	2.3
Manurewa feeder K08 breaches SoSS	Manurewa K08 Feeder Reinforcement	FY27	0.3
Maraetai feeder K01 breaches SoSS	Maraetai K01 feeder reinforcement	FY27	1.2
Takanini substation capacity.	Takanini ZSS upgrade	FY28	8.3
	Takanini 33/11 kV T1 & T2 upgrades	FY28	10.1
Takanini feeder K19 breaches SoSS	Takanini 11 kV New Feeder - Manuroa Rd	FY28	0.5
Maraetai feeder K01 capacity	Maraetai 11 kV New Feeder - Beachlands Rd	FY28	4.8
	Maraetai 11 kV New Feeder - Jack Laughlin Dr	FY29	1.4
Waiheke substation breaches SoSS	Waiheke T1 & T2 upgrade	FY29	12.2
Manurewa feeders K11 and K12 capacity and SoSS	Manurewa 11 kV New Feeder – Alfriston Rd	FY30	3.3
Manurewa and Takanini substations capacity	Takanini North land purchase for ZSS	FY31	Not discl.
Third party roadworks	Mill Road Future Proofing Ducts	FY32	10.0
Papakura feeder K08 breaches SoSS	Takanini 11 kV New Feeder - Walters Rd	FY32	4.5
Clevedon feeder R140 breaches SoSS	Clevedon 11 kV New Feeder	FY32	10.8
Papakura feeder K02 breaches SoSS	Papakura 11 kV New Feeder - Settlement Rd	FY32	2.3
Maraetai substation breaches SoSS	Maraetai T1 & T2 Upgrade	FY33	14.1
Papakura feeder K10 reaches capacity	Takanini 11 kV New Feeder - Grove Rd	FY35	0.8
Papakura substation capacity and SoSS	Papakura 3rd Tx, Subt Cable and Swbd Extension	FY37	9.0
Clevedon feeder breaches SoSS	Kawakawa Bay Land Purchase	FY36	Not discl.
Takanini GXP capacity.	Brownhill land purchase	FY36	Not discl.

TABLE 10-29: TAKANINI CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.13 OTAHUHU PLANNING AREA

10.6.13.1 OVERVIEW

The Otahuhu planning area is one the smallest non-CBD planning areas. It consists of Highbrook, Bairds and Otara. The area growth is due to intensification of industrial development around Otahuhu GXP and deployment of EV Bus chargers.

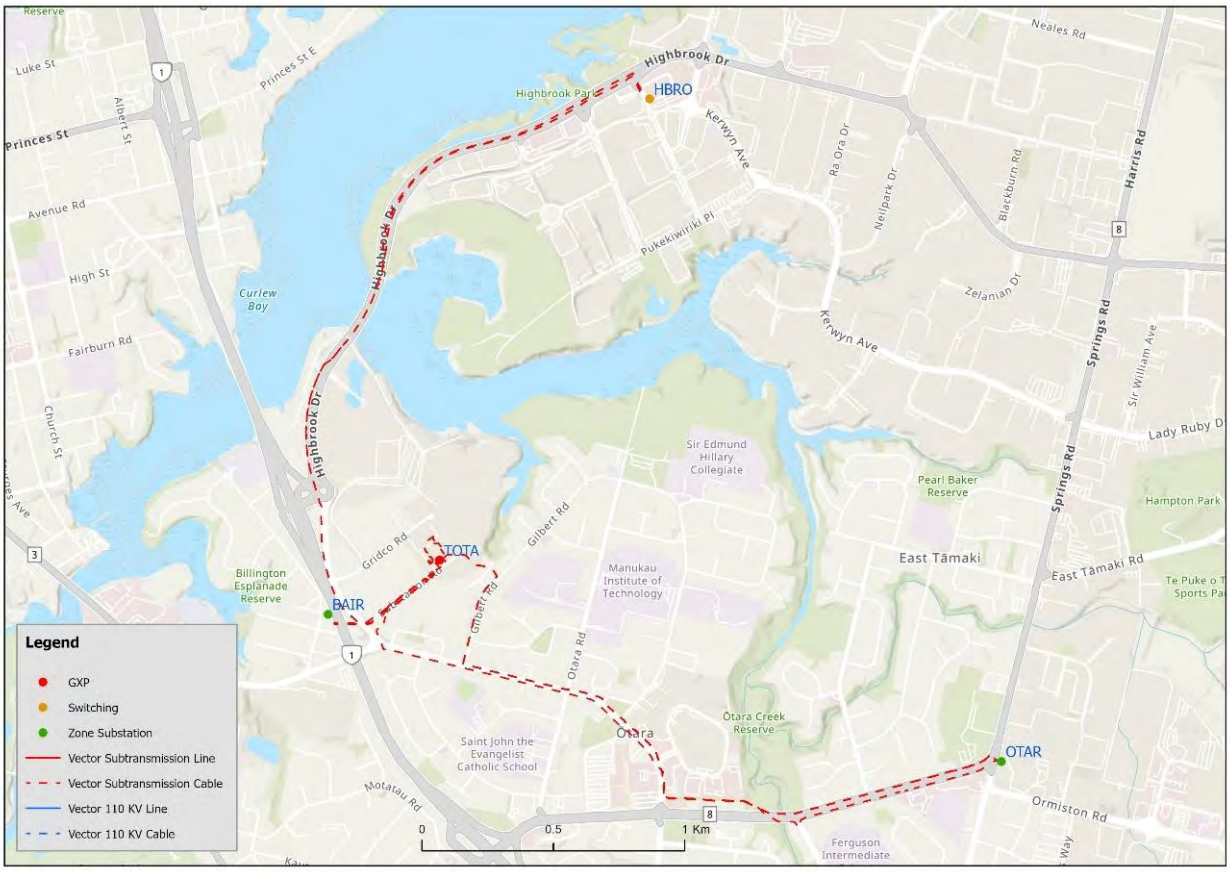


FIGURE 10-23: OTAHUHU SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	**ZONE SUBSTATION**	**SOSS CATEGORY**	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Bairds	RES	27.0	32.9	33.5	34.1	34.7	35.6	36.6	37.5	38.5	39.4	40.7
Winter	Highbrook	COM	9.9	10.1	10.2	10.4	10.5	10.8	11.0	11.2	11.4	11.6	11.8
Winter	Otara	COM	32.3	33.1	33.8	34.6	35.4	36.7	38.0	39.3	40.5	41.8	43.5

TABLE 10-30: OTAHUHU LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.13.2 GRID EXIT POINT

Otahuhu GXP is supplied from two 220/22 kV transformers which has an installed capacity of 160 MVA. The peak demand was 62 MVA in 2025 and there are no forecasted constraints during the AMP period.

10.6.13.3 SUBTRANSMISSION

The subtransmission network operates at 22 kV and consists of underground cables that supply three zone substations. Bairds ZSS and Otara ZSS are supplied radially. Highbrook is supplied by a closed subtransmission loop.

There are no subtransmission security constraints identified to occur during the AMP period. However, the 33 kV network will be extended to connect a third transformer at Bairds ZSS.

10.6.13.4 ZONE SUBSTATION

Bairds ZSS and Otara ZSS have 22/11 kV transformers whilst Highbrook is a switching station, i.e. it does not have transformers and supplies the distribution network which operates at 22 kV. Hence, the two 22 kV cable supplies from Otahuhu GXP that supply Highbrook are considered to be subtransmission due to their function, while the 22 kV feeders used for distribution are considered distribution feeders (similar to Auckland CBD).

There is a security constraint forecasted at Bairds zone substations during this AMP period which will be resolved with a new transformer, subtransmission cable and switchboard extension.

10.6.13.5 DISTRIBUTION NETWORK

As noted above, the distribution network from Bairds ZSS and Otara ZSS operates at 11 kV and can be supported by adjacent substations, however the distribution network from Highbrook operates at 22 kV and is an isolated network with no distribution feeder ties to other zone substations. The industrial growth in the Highbrook region is low, and there is sufficient capacity to supply future growth without breaching the SoSS.

Vector has identified one 11 kV feeder from Otara ZSS that will reach capacity. This will be resolved with a new feeder to Springs Road in FY31.

10.6.13.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Otara K15 breaches capacity and SoSS	Otara 11 kV New Feeder - Springs Rd	FY31	2.4
Bairds substation breaches capacity and SoSS.	Bairds ZSS Capacity Upgrade	FY35	11.4

TABLE 10-31: OTAHUHU PLANNING AREA CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.14 WIRI PLANNING AREA

10.6.14.1 OVERVIEW

The Wiri planning area supplies Manukau CBD, the Wiri Industrial area and Clendon. Growth in this area is being driven the large greenfield industrial subdivision west of Mclaughlins Rd towards Auckland Airport. This will be supplied by the newly established West Wiri ZSS.

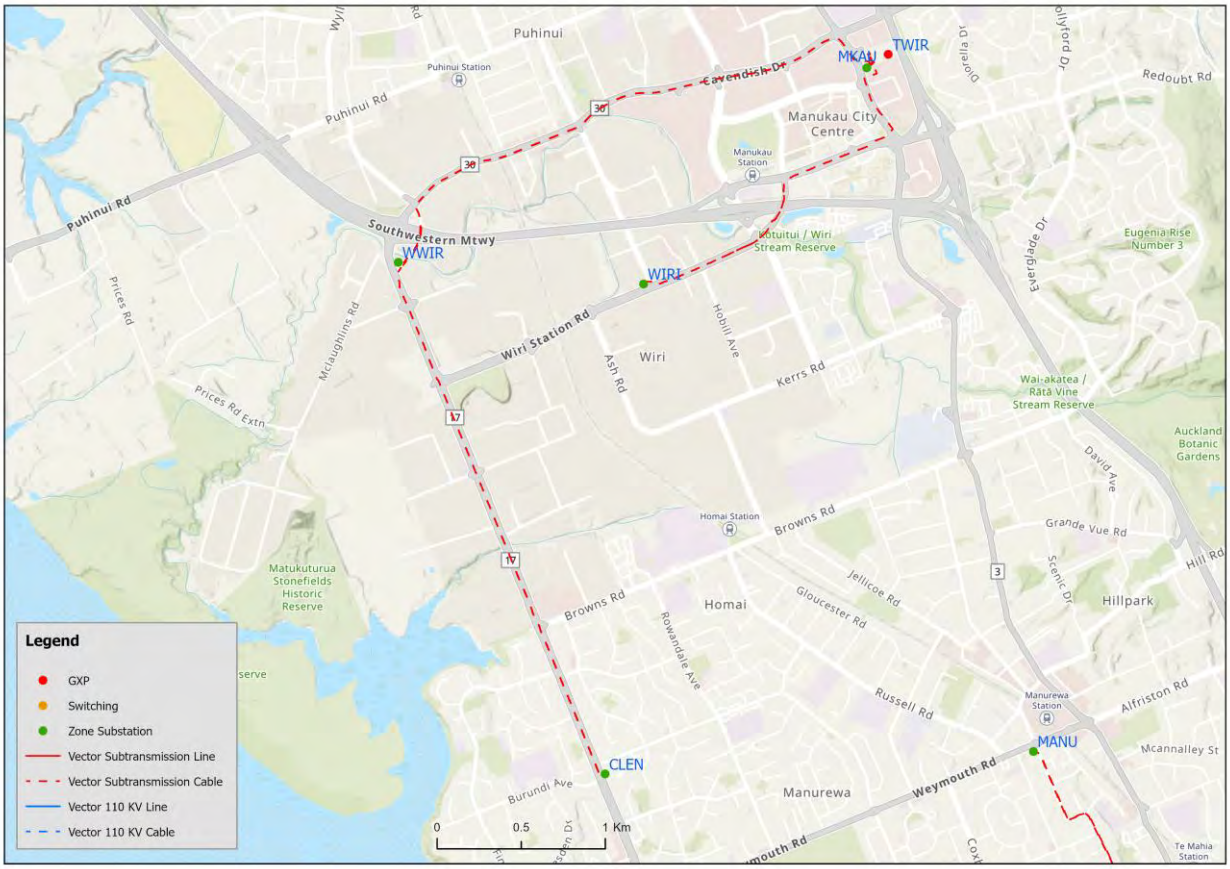


FIGURE 10-24: WIRI SUBTRANSMISSION NETWORK

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Winter	Clendon	RES	21.0	21.2	21.4	21.6	21.8	22.2	22.6	23.0	23.3	23.7	24.3
Winter	Manukau	COM	31.1	31.9	32.8	33.6	34.5	35.9	37.4	38.8	40.2	41.7	43.4
Winter	Wiri	COM	28.9	29.4	32.6	33.1	33.6	34.3	35.1	35.9	36.6	37.4	38.4
Summer	West Wiri	COM	22.5	25.2	27.4	29.6	31.8	34.2	34.7	35.1	35.6	36.0	36.7

TABLE 10-32: WIRI LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.6.14.2 GRID EXIT POINT

Wiri GXP has two 110/33 kV transformers with an installed capacity of 200 MVA. The peak demand was 93 MVA in 2025 and is forecast to exceed N-1 capacity from winter 2028. A project is underway to install a third transformer at Wiri GXP.

10.6.14.3 SUBTRANSMISSION

The subtransmission network operates at 33 kV and consists of underground cables that supply four zone substations: Clendon ZSS, Manukau ZSS, Wiri ZSS and West Wiri ZSS.

There is a subtransmission security constraint identified at the West Wiri zone substation. A new sub-transmission cable is proposed to resolve this constraint.

10.6.14.4 ZONE SUBSTATION

Wiri GXP supplies four zone substations of which two have two 33/11 kV transformers, namely Clendon and West Wiri ZSS. Wiri and Manukau ZSS consists of three 33/11 kV transformers.

Expanding industrial development west of McLaughlin's Road and along Puhunui Road towards the airport is driving significant growth. This area will be supplied by the new West Wiri zone substation.

Manukau zone substation is forecast to reach capacity in the long term. A new zone substation will be established in Papatoetoe once land has been acquired in an optimal location.

10.6.14.5 DISTRIBTUION

Mangere East feeder supplying Puhinui Road area is forecast to reach capacity. A new feeder will be installed from West Wiri zone substation to address this constraint.

Existing feeder Wiri K06 is forecast to breach security and will be reinforced.

10.6.14.6 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Wiri feeder K06 breaches SoSS	Wiri K06 11 kV Feeder Reinforcement	FY27	0.7
Manurewa ZSS (Takanini GXP) breaches SoSS	Clendon 11 kV New Feeder - Weymouth Rd	FY28	3.7
Mangere East feeder K19 (Mangere GXP) breaches capacity and SoSS	West Wiri 11 kV New Feeder - Puhinui Rd	FY28	2.7
West Wiri subtransmission cables breaches SoSS	West Wiri subtransmission Cable	FY33	5.8
Manukau substation capacity	Papatoetoe Land Purchase	FY36	Not discl.

TABLE 10-33: WIRI CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.6.15 NETWORK-WIDE ALLOCATIONS

10.6.15.1 HV REINFORCEMENT AND MONITORING

Our system growth process identifies the major constraints, projects and related budgets, as presented above. While great care is taken in this process to capture all the projects, smaller reactive reinforcement needs or unforeseeable changes may occur that require additional projects. The HV related allocations can be split into three areas:

1. An annual provisional allocation is included in our AMP to cater for HV reinforcements that may arise during the year and need to be carried out with urgency.

2. A similar allocation for the opportunistic installation of future-proofing cable ducts for future reinforcement projects is also included. Civil works are the most expensive component of cable projects so by installing future-proofing ducts during roading alterations, overall costs are reduced.
3. A third allocation is for both the systematic and opportunistic conversion of the CBD distribution voltage from 11 kV to 22 kV. More details can be found in Section 10.6.7.

10.6.15.2 LV REINFORCEMENT AND MONITORING

In the absence of any LV network visibility, legacy practice is to address LV capacity and voltage constraints on a reactive basis. Informed by historic expenditure, an allocation for LV network reinforcement is included. Additionally, new DER connections will increase the need for reinforcement and the increase in LV visibility capabilities will surface constraints not captured reactively. An additional allocation is made to cover those LV reinforcements.

10.6.15.3 CONSTRAINTS AND SOLUTIONS

CONSTRAINTS	ALLOCATION / PROGRAMME NAME	INVESTMENT OVER 10 YEARS $M/YEAR
Un-foreseen HV network constraint	HV network reinforcement	3.5
Future proofing the CBD	CBD 22kV Network Rollout	2.04
	CBD distribution sub 11kV to 22kV conversion	0.85
Opportunistic installation of cable ducts	Futureproofing duct opportunities	1.65
Relieve LV network constraints	LV network reinforcement	3.2
Reinforce the network to relieve voltage and capacity constraints due to DER increase	DER (solar/EV) LV network reinforcement	0.75
	LV Network metering and monitoring	0.3

TABLE 10-34: NETWORK-WIDE ALLOCATIONS AND FUTURE CAPABILITY PROGRAMMES



SECTION 10A

Appendix: Growth and security projects

10a – Growth and security projects

10a.1 Section overview

This section provides additional details of the constraints, options analysis, and preferred solution for major projects required within the next 5 years as outlined in Section 10 - Growth and Security.

Major growth and security projects are those exceeding $1M. Only major projects planned to commence within the next 5 years are listed. The rationale for only discussing the major 5-year projects in detail is due to the uncertainty of the load growth forecasts and the impact of new technologies on project timing beyond 5 years. The options analysis for projects that are already in formal delivery phase are not repeated in this Appendix, and the options analysis and decision rationale for those projects were disclosed in the relevant prior publicly disclosed AMP(s) for the 2024 year in which the project entered delivery and remain applicable unless and until the scope or preferred solution materially changes.

Available options and preferred solutions on the listed major projects in this section may change over time and cost estimates firmed up as projects move towards full funding approval and commencement. These projects are also all subject to detailed technical and financial scrutiny as part of Vector's governance approval process.

10a.2 Wellsford planning area

10a.2.1 WARKWORTH SOUTH ZONE SUBSTATION NEW

WARKWORTH SOUTH ZONE SUBSTATION NEW

CONSTRAINT

The load on Warkworth substation is approaching its firm capacity and 11 kV network capacity in Warkworth township will become constrained. Sandspit ZSS (project in delivery) will defer this constraint.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS in the Warkworth network. This option is not acceptable.
2. **Upgrade Warkworth ZSS transformers and reinforce 11 kV network:** This option proposes installing larger transformers at Warkworth to increase the firm capacity of the substation. Warkworth substation is located 4 km away from the township and load centre, resulting in considerable and unnecessary expenditure on 11 kV feeders to deliver the distant capacity to the township.
3. **Construct Warkworth South ZSS:** This option proposes a new 33/11 kV zone substation in Glenmore Drive, Warkworth on a site owned by Vector. In 2012 a new 33 kV feeder was constructed to Woodcocks Road (currently operating at 11 kV) in anticipation of supplying a future Warkworth South substation. Construction of Warkworth South substation will move the supply centre from Warkworth substation (4 km out of town) to the centre of the "future urban" zone.
4. **Flexibility or non-wire alternative:** this project is signposted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY30, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 3 is preferred. Building a new Warkworth South zone substation will relieve the emerging feeder capacity and SoSS constraints at Warkworth.

10a.2.2 WELLSFORD 33/11KV TX UPGRADE T1+T2

WELLSFORD 33/11KV TX UPGRADE T1+T2

CONSTRAINT

Load growth on Wellsford ZSS means transformer capacity will shortly be exceeded

OPTIONS

1. **Do nothing:** The existing transformers will become overloaded at peak demand. This is not acceptable.
2. **Replace the Wellsford transformers with a larger unit:** Due to asset age/condition, 2 x existing transformers will be replaced with 2 x new larger capacity transformers
3. **Install a third transformer at Waikaukau ZSS:** This would meet the long-term requirements of load growth and would increase security of supply into Wellsford and surrounding areas. It would come at a greater cost than option 2, and may be undertaken at a later date

WELLSFORD 33/11KV TX UPGRADE T1+T2

4. **Implementation of non-wires alternative**: This option does not adequately alleviate the transformer capacity shortfall for Wellsford and does not provide the same security of supply to the wider area

PREFERRED SOLUTION

Option 2 is preferred. This project has forecasted spend in the next 12 months.

10a.2.3 BIG OMAHA BACKUP DIESEL GENERATORS

BIG OMAHA BACKUP DIESEL GENERATORS

CONSTRAINT

At peak demand, the Big Omaha ZSS load cannot be fully restored via 11kV backstopping due to the long and remote overhead circuits. The objective of this project is to ensure an improvement in network security of supply in the Big Omaha Region.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS at Big Omaha ZSS. This option is not acceptable.
2. **Install 2 x backup diesel generators at Big Omaha:** This will address the security of supply constraint.
3. **Install a second sub-transmission circuit between Warkworth and Big Omaha:** This would also address the security of supply constraint, at a much higher cost.

PREFERRED SOLUTION

The preferred option is option 2 as it provides the most cost-effective solution. This project has forecasted spend in the next 12 months.

10a.3 Silverdale planning area

10a.3.1 DAIRY FLAT LAND PURCHASE FOR ZSS

DAIRY FLAT LAND PURCHASE FOR ZSS

CONSTRAINT

A new zone substation at Dairy Flat was part of the long-term strategy in the 2030s for the Redvale/Dairy Flat/Okura area. A new major point load in the area has brought forward the need for a switchroom in the area and a site for this will be secured.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS at Spur Road and Coatesville substations from late 2035. This option is not acceptable.
2. **Early acquisition of a zone substation land at Dairy Flat site:** Identify and purchase a site for a future substation at Dairy Flat site at an early design stage of the development. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly growing development.
3. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in to allow final detailed designs for the new ZSS. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition.

PREFERRED SOLUTION

The preferred option is option 2 to secure a future zone substation site. As a prudent network manager, Vector needs to identify and secure suitable future zone substation sites to ensure Vector can supply future developments cost effectively and reliably.

10a.3.2 SILVERDALE GXP OREWA & MANLY SUBTRANS CABLE UPGRADE

SILVERDALE GXP OREWA & MANLY SUBTRANS CABLE UPGRADE

CONSTRAINT

Orewa and Manly sub-transmission breaches security of supply standard.

SILVERDALE GXP OREWA & MANLY SUBTRANS CABLE UPGRADE

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS at Orewa and Manly substations from 2025. This option is not acceptable.
2. **Install a new Transpower Silverdale to Orewa ZSS subtransmission circuit:** Adding a third circuit would increase the security of supply into Orewa-Red Beach. While futureproof ducts have been installed on about half the Orewa route length, this is still much more expensive than Option 3.
3. **Replace the sections of cable which are limiting the circuit ratings:** This would cost less than Option 2 but does not provide the same increase in security of supply.

PREFERRED SOLUTION

Option 3 is the most cost-effective option in the short term to prevent cable overloading. To further increase capacity to the area when needed and provide improved network resilience and reliability of supply. Option 2 will be considered outside of this AMP period. This project has forecasted spend in the next 12 months.

10a.3.3 SOUTH HEAD PERMANENT STANDBY GENERATION

SOUTH HEAD PERMANENT STANDBY GENERATION

CONSTRAINT

High SAIDI impact and low resilience in South Head led to the installation of a temporary generation station as a permanent solution as part of the SAIDI initiative programmes, similar to Piha generation programme.

OPTIONS

1. **Do Nothing:** Continue ongoing cost associated with temporary generation site, to sustain SAIDI and resilience improvement.
2. **Network reinforcement**: Install a second feeder. Due to the peninsula geographic nature, distance and terrain make land and consents in the area prohibitively expensive and difficult to secure.
3. **Battery systems:** Declined due to cost and unsuitability for long outages, this option would be the least reliable proposal.

PREFERRED SOLUTION

Option 1 address the constraint and is the most cost-effective option. A feeder option may become a viable investment should load further increase by 2 MVA however projected low growth in the foreseeable future does not justify such investment. Option 2 will therefore be considered beyond this AMP period.

10a.3.4 PENLINK WHANGAPARAOA REINFORCEMENT

PENLINK WHANGAPARAOA REINFORCEMENT

CONSTRAINT

O-Mahurangi Penlink are in the process of constructing a new 7 km two-lane highway linking Whangaparaoa Road to State Highway 1, providing a second access route to the Whangaparaoa Peninsula. A new development in the vicinity has requested supply on circuits that will exceed their thermal limits. Opportunity to increase security capacity by connecting SPUR and Manly feeders.

OPTIONS

1. **Do Nothing:** Development requires supply and missed opportunity to install additional 11kV ducts towards peninsula area to increase security capacity for the new development. This is not acceptable.
2. **Install new feeder along with 11kV future-proof duct:** Contribute towards 11kV cable for development during with Penlink works to reduce the cost and public disruption of a standalone civil project later.
3. **Installation of assets at a later stage:** Re-entering public roads after third-party works would increase disruption and cost compared with Option 2, as civil and traffic management costs would not be shared. NZTA consents may also be required and could be difficult to obtain shortly after the original construction. There is a risk that space allocated for electricity services may be lost. Risk of delay in new circuit availability for development connection.

PREFERRED SOLUTION

Option 2 enables the development to connect, and installation of future proof duct will preserve long term planning strategy to bring capacity towards peninsula and avoid. This is the most cost-effective proposal and minimises community disruption. Avoids requirement for applying for further approvals and consents from NZTA. Option 2 avoids risk presented in option 3. This project has forecasted spend in the next 12 months.

10a.3.5 MILLDALE ZONE SUBSTATION NEW

MILLWATER ZONE SUBSTATION NEW

CONSTRAINT

New residential developments are expanding westwards from Millwater towards Wainui and Dairy Flat. Distribution feeders supplying Millwater and Milldale greenfields residential developments are forecast to breach capacity and SoSS by 2031.

OPTIONS

1. **Do Nothing**: Existing Orewa and Spur feeder cables will become overloaded.
2. **Provide feeders from Spur Road ZSS**: Supplying the Millwater area from Spur Road ZSS would require very costly 11 kV cabling and an expansion of the newly installed switchboard. The spare capacity at the Orewa, Red Beach and Spur Rd ZSS would be exhausted in the medium term, requiring the bringing forward of the proposed Dairy Flat ZSS.
3. **Build a new zone substation at Millwater**: Building Milldale ZSS will provide the required capacity to improve the security of supply to Millwater and the new Milldale greenfield development area. It will also relieve capacity at Orewa ZSS to service further growth west of Orewa township.
4. **Install feeder cables from Orewa ZSS, Red Beach ZSS and/or Spur Road ZSS**: This would require very costly 11 kV cabling and switchgear extensions at both substations to supply Milldale. The spare capacity at the Orewa, Red Beach and Spur Rd ZSS would be exhausted in the medium term, requiring the bringing forward of the proposed Dairy Flat ZSS.
5. **Supply Milldale from Dairy Flat zone substation**: Dairy Flat ZSS will be required in any case, but it is more efficient to install the capacity near the load centre. A large investment in 11 kV network would be needed to bring capacity to Millwater from Dairy Flat.
6. **Flexibility or non-wire alternative:** this project is sign posted in Section 10 as a candidate for a Flexibility or Non-wire alternative solution. The project is forecasted to initiate in FY28, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 3 is preferred as it provides the most efficient solution for improved network security and resilience. The Millwater ZSS site is close to the major load centres and is better located than more distant alternative substations.

10a.3.6 GULF HARBOUR PERMANENT STANDBY GENERATION

GULF HARBOUR PERMANENT STANDBY GENERATION

CONSTRAINT

Backstop for the single-transformer Gulf Harbour ZSS comes entirely from the Manly ZSS. In the event of a Gulf Harbour outage the Manly transformers will be overladed at peak demand by 2027.

OPTIONS

1. **Do Nothing:** The SoSS will be breached, and supply will not be maintained following an outage at peak demand.
2. **Replace the transformers at Manly ZS with larger units**: This will address the security of supply constraint.
3. **Implementation of non-wires alternative**: Install standby permanent generation, this is the most cost-effective solution.
4. **Install a second transformer and subtransmission cable to Gulf Harbour ZS**: This would address the security of supply constraint, at a much higher cost than option 2.

PREFERRED SOLUTION

Option 3 is preferred as it provides the most cost-effective solution and defers major investment beyond the AMP period. Until e-ferry load becomes committed, an interim solution is the best approach. Once load at Gulf Harbour exceeds the capacity of the standby generation sets option 2 or 4 maybe be implemented. Option 4 is significantly more expensive and would require substantial load growth to justify investment.

10a.3.7 SILVERDALE GXP EXPANSION VECTOR 33KV CABLE WORKS

SILVERDALE GXP EXPANSION VECTOR 33KV CABLE WORKS

CONSTRAINT

Demand on Transpower's Silverdale GXP is approaching firm capacity, due to strong ongoing residential growth and large point loads. Capacity upgrades will be delivered at Silverdale by Transpower, and Vector will need to re-arrange cable connections and terminations.

10a.4 Henderson planning area

10a.4.1 WHENUAPAI LAND PURCHASE FOR ZSS

WHENUAPAI LAND PURCHASE FOR ZSS

CONSTRAINT

Significant residential development is being planned in the Whenuapai precinct. Forecast major point loads in Whenuapai means the 11 kV network will become capacity constrained and the security of supply standard will not be met.

OPTIONS

1. **Do Nothing:** If a zone substation in the Whenuapai area does not proceed, increasing demand in the precinct will result in deteriorating capacity and breaches of the SoSS at Westgate, Hobsonville Point and Hobsonville ZSSs. This option is not acceptable.
2. **Early land acquisition of a zone substation land at Whenuapai site:** Identify and purchase a site for the location of a future substation in the Whenuapai area at an early design stage of the development in about FY26 or FY27. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly developing area.
3. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition, and risk not being able to secure a suitable.

PREFERRED SOLUTION

The preferred option is option 2 to secure a future zone substation site. As a prudent network manager, Vector needs to identify and secure suitable future zone substation sites to ensure Vector can supply future developments cost effectively and reliably. This project has forecasted spend in the next 12 months.

10a.4.2 WHENUAPAI ZONE SUBSTATION NEW

WHENUAPAI ZONE SUBSTATION NEW

CONSTRAINT

Forecast residential development plus a major point load in Whenuapai means the 11 kV network will become capacity constrained and the security of supply standard will not be met.

OPTIONS

1. **Do nothing:** This option will result in breach of capacity and SoSS for feeders from Hobsonville and Hobsonville Point ZSS. This option is not acceptable.
2. **Install new 11 kV feeders:** New feeders from Hobsonville and Hobsonville Point ZSS would provide capacity in the short term, but transformer capacity limitations would mean option 2 would still be required shortly afterwards, resulting in over-investment in the cable network.
3. **Install new Whenuapai ZSS:** This option will supply the point load and provide capacity and security of supply for Whenuapai into the long term.
4. **Implementation of non-wires alternative**: The need to supply the point load means this option will not address the capacity and security shortfalls.

PREFERRED SOLUTION

Option 3 is preferred because it is an efficient solution to solve the capacity and security breach constraint. This project has forecasted spend in the next 12 months.

10a.4.3 REDHILLS ZSS 11KV DUCTS INSTALL

REDHILLS ZSS 11KV DUCTS INSTALL

CONSTRAINT

The existing Special Housing Area at Redhills is at the design and early construction stage and will comprise 5000 new dwellings. The wider area is forecast to double this. The existing network does not have sufficient capacity to meet these long-term load requirements. Redhills ZSS is scheduled to be constructed by 2031 and will require new distribution circuits from the new ZSS.

REDHILLS ZSS 11KV DUCTS INSTALL

OPTIONS

1. **Do Nothing:** Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies and increasing unreliability. This option is not acceptable.
2. **Install future-proofing duct: A** third party is carrying out project works on the cable route. Ducts will be installed in combination with the works to reduce the cost and public disruption of the standalone civil project later.
3. **Undertake civil works with cable installation:** The civil works will be carried out as part of the cable installation. This will involve re-entering public roads and creating distribution after the third-party works (mentioned in Option 2) have been completed.

PREFERRED SOLUTION

Option 2 is the preferred solution because it is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

10a.4.4 REDHILLS LAND PURCHASE FOR ZSS

REDHILLS LAND PURCHASE FOR ZSS

CONSTRAINT

The existing Special Housing Area at Redhills is at the design stage and will comprise 5,000 new dwellings. The wider area is forecast to double this. The existing network does not have sufficient capacity to meet these long-term load requirements. A new zone substation will be required, and this project is to secure a substation site in anticipation of this expansion.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS, this option is not acceptable.
2. **Early land acquisition of a zone substation land at Redhills site:** This ensures a suitable site is acquired in advance of the design process.
3. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition, and risk not being able to secure a suitable.

PREFERRED SOLUTION

The preferred option is option 2 to secure a future zone substation site. As a prudent network manager, Vector needs to identify and secure suitable future zone substation sites to ensure Vector can supply future developments cost effectively and reliably

10a.4.5 REDHILLS ZONE SUBSTATION NEW

REDHILLS ZONE SUBSTATION NEW

CONSTRAINT

The existing network within the Redhills area is not capable of supplying the forecasted load, particularly on Ranui, Westgate and Riverhead feeders (also note comments for project about Redhills land purchase for ZSS)

OPTIONS

1. **Do Nothing:** Existing Ranui, Westgate and Riverhead feeders will become overloaded. Customers supplied from these feeders will increasingly suffer from supply reliability issues and possible equipment failure. This is not acceptable.
2. **Install new 11 kV cables into Redhills from Whenuapai ZSS and Westgate ZSS feeders:** This would be an expensive solution, and while it would defer the ZSS project for a few years, would result in stranded investment in 11 kV network after the ZSS is commissioned.
3. **Construct a new ZSS in Redhills:** This option represents a lower total cost than option 2 and alleviates the constraint.
4. **Implementation of non-wires alternative**: The growth is high with large housing infill. This option will not adequately address the capacity and security shortfalls.
5. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY29, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 3 is preferred. Building a new Redhills zone substation will relieve the emerging feeder capacity and SoSS constraints Redhills.

10a.4.6 RANUI 2ND 33/11KV TX & EXISTING TRANSFORMER T1 UPGRADE

RANUI 2ND 33/11KV TX & EXISTING TRANSFORMER T1 UPGRADE

CONSTRAINT

Transformer loading at Ranui ZSS breaches capacity and security of supply.

OPTIONS

1. **Do nothing:** Supply to customers will become increasingly unreliable. This is not acceptable.
2. **Upgrade the Rauni transformer T1:** This option meets the short to medium term requirements of load growth and increases security of supply into Ranui and surrounding areas.
3. **Install a second transformer T2 and upgrade the Rauni transformer T1:** This option meets the long-term requirements of load growth and increases security of supply into Ranui and surrounding areas.
4. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.
5. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY30, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 3 is preferred due to the growth and capacity constraint in the area.

10a.4.7 RANUI GLEN ROAD 11KV FEEDER REINFORCEMENT

RANUI GLEN ROAD 11KV REINFORCEMENT

CONSTRAINT

The latest load forecast indicates significant residential growth within the Ranui Glen Road 11kV feeder catchment, resulting in increasing demand that exceeds the available backstop capacity

OPTIONS

1. **Do nothing:** This option will result in breach of capacity and SoSS in feeder Ranui K04. This option is not acceptable.
2. **Install new 11 kV feeder:** This option will relieve load on Ranui K04 and resolve the capacity and SoSS breaches.
3. **Implement demand side**
4. **and non-wires alternative:** This area has a large residential component and implementation of non-network option has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is the preferred option. This option addresses the feeder constraint and provides additional capacity to the high growth area.

10a.4.8 HUAPAI GXP SUBTRANSMISSION CABLES

HUAPAI GXP SUBTRANSMISSION CABLES

CONSTRAINT

Demand forecast indicates that peak load at Henderson GXP will exceed the N-1 firm capacity of the supply transformers from winter 2025 and the N capacity from winter 2033.

OPTIONS

1. **Do nothing:** Doing nothing will lose the synergy opportunity to install future proofing ducts and cables. It will be costly and disruptive to excavate and install the cables at later stage.
2. **Install sub-transmission cable with future proofing ducts:** This option is to install sub transmission cable with future proofing ducts taking advantage of the synergies from the NZTA SH16 works.
3. **Undertake civil works with cable installation**: The civil works will be carried out as part of the cable installation. This will involve re-entering public roads and creating distribution after the NZTA SH16 works (mentioned in Option 2) have been completed.

HUAPAI GXP SUBTRANSMISSION CABLES

PREFERRED SOLUTION

Option 2 is the preferred solution because it is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

10a.5 Albany planning area

10a.5.1 TORBAY 33/11KV TX UPGRADE T1

TORBAY 33/11KV TX UPGRADE T1

CONSTRAINT

Load growth in Torbay has resulted in a shortfall in transformer capacity at Torbay ZSS, especially following an outage at Waiake ZSS

OPTIONS

1. **Do nothing:** The existing transformer will become overloaded at peak demand. This is not acceptable.
2. **Install a second transformer at Torbay ZS:** This would meet the long-term requirements of load growth and would increase security of supply into Torbay and surrounding areas. It would require new 33kV switchgear.
3. **Replace the Torbay transformer with a larger unit:** This addresses the capacity constraint at a lower cost than option 2.
4. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY31, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 2 is preferred as the more cost-effective solution.

10a.5.2 TORBAY 33KV DUCT ENABLING WORKS

TORBAY 33KV DUCT ENABLING WORKS

CONSTRAINT

Load growth at Torbay is anticipated to exceed outside AMP period however AT roading projects initiate an opportunity to install future proof duct for a second sub transmission circuit.

OPTIONS

1. **Do nothing:** Missed opportunity to install future proofing duct. This is not acceptable.
2. **Install 2nd 33kV future proof duct:** Shared civils with third party infrastructure projects and reserve space for electricity services, a second circuit is required for long term capacity growth of Torbay. Avoids community disruption on a high-volume traffic categorised road.
3. **Install at a later date outside AMP period:** This option resolves the capacity constraint but at significantly higher cost, making it uneconomic and disruptive to the surrounding community. Missed opportunities to install earlier have led to asset congestion, resulting in a less direct route for a second circuit and creating unforeseen and complex challenges.

PREFERRED SOLUTION

Option 2 is preferred as the more cost-effective solution and provides a long-term perspective for growth.

10a.5.3 WAIAKE 33/11KV TX UPGRADE T1

WAIAKE 33/11KV TX UPGRADE T1

CONSTRAINT

Load growth in Waiake will result in a shortfall in transformer capacity at Waiake ZSS, especially following an outage at Torbay ZSS

OPTIONS

1. **Do nothing:** The existing transformer will become overloaded at peak demand. This is not acceptable.

WAIAKE 33/11KV TX UPGRADE T1

2. **Install a second transformer at Waiake ZS:** This would meet the long-term requirements of load growth and would increase security of supply into Waiake and surrounding areas. It would require new 33kV switchgear.
3. **Replace the Torbay transformer with a larger unit:** This addresses the capacity constraint at a much lower cost than option 2.
4. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY31, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 2 is preferred as the more cost-effective solution.

10a.5.4 ALBANY TO GREENHITHE 110KV TO 33KV SUBT OH CONVERSION

ALBANY TO GREENHITHE 110 KV TO 33 KV SUBTRANSMISSION OVERHEAD CONVERSION

CONSTRAINT

The Albany GXP to Greenhithe ZSS subtransmission cable is forecast to overload following an outage of the Greenhithe to Hobsonville Point ZSS circuit.

OPTIONS

1. **Do Nothing:** Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies and increasing unreliability. This option is not acceptable.
2. **Convert Albany-Greenhithe-Wairau 110 kV circuit to 33 kV to create a new subtransmission connection to Greenhithe:** This requires the prior installation of Transpower's 220/33 kV T9 transformer at Wairau ZSS. The 110-33 kV conversion project is scheduled for FY27.
3. **Implementation of non-wires alternative**: The growth is high and includes large commercial point loads. This option will not address the capacity and security shortfalls.

PREFERRED SOLUTION

Option 2 is the most cost-efficient option. This project has forecasted spend in the next 12 months.

10a.5.5 ROSEDALE ENABLING WORKS

ALBANY GXP ROSEDALE SUBTRANSMISSION CABLE REINFORCEMENT

CONSTRAINT

The 110 kV assets are nearing the end of their service life and are showing signs of condition deterioration.

OPTIONS

1. **Do Nothing:** Exposed to increased risk of faults, with repair times exceeding SoSS and significantly reduces security capacity. This option is not acceptable.
2. **Upgrade the existing 110kV OHLs, the TP 220/110 transformer as well as the three 110/33kV transformers:** Majority of the pole structures would require replacement, resulting in high construction costs due to the wooden bases. Conductor replacement is also costly due to long spans across three circuits, and special transformers have long lead times and limited availability. Ongoing maintenance costs for 110 kV assets are high. Since Transpower's 2020 decision to remove its 110 kV network, Vector has committed to decommissioning the Albany to Wairau 110kV assets. Reversing this decision would require significant investment with limited benefit, conflicts with customer and community commitments, presents reputational risk, therefore this is not an acceptable option.
3. **Retire the 110kV supply by removing the retired assets:** The 110kV yard will be cleared of all equipment, making it available for expansion of the 220kV part of the GXP. This will enable Rosedale GXP construction.

PREFERRED SOLUTION

Option 3 is the preferred solution. It aligns with long term investment strategy for 220kV network expansion and full utilisation of asset life cycle with future proofing for growth at surrounding GXPs. This project has forecasted spend in the next 12 months.

10a.5.6 ROSEDALE GXP SUBTRANSMISSION CABLES

ROSEDALE GXP SUBTRANSMISSION CABLES

CONSTRAINT

Demand on Transpower's Albany GXP is anticipated to reach security capacity in 2036 however dependent on the uptake of a major customer load connected directly to the 33kV switchboard. There is a risk if the load materialises faster than anticipated this capacity may exceed sooner. Due to the meshed arrangement of the 33kV network, multiple security issues have been identified at the ZSS level which requires additional circuits, and hence circuit breakers to be installed at the GXP. This is a problem as there are limited space to install additional 33kV circuit breakers. Capacity upgrades will be delivered by Transpower, Vector will need to secure land for the new GXP and install new sub transmission cables and terminations.

OPTIONS

1. **Do nothing:** Supply to customers will become increasingly unreliable with restoration times exceeding acceptable (SoSS) limits. This is not acceptable.
2. **Install sub-transmission cable with future proofing ducts and secure GXP land:** The area will transition from a meshed arrangement to a radial 33kV supply, increasing reliability of supply as well as expand the 220kV network towards high dense load areas that is anticipated in the Rosedale region. The new GXP will increase firm and security capacity, no further expansion works required at Albany GXP and will mitigate having a significant amount of load at one GXP, further increasing network reliability.
3. **Expand Albany GXP**: Land is scarce at Albany GXP to cater for the number of additional circuits to address the security capacity shortage at a ZSS level. It is not ideal to have significant amount of demand supplied from one GXP as it results in unreliable supply and increases risk of faults and high supply restoration. A significant amount of investment is required to upgrade old PILC cable circuits to ZSS near Rosedale. Investment benefit is low and is not recommended, this will not address the long-term capacity issue at Albany GXP.
4. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY29, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 2 is the preferred solution because it is cost efficient and provides a long-term solution as it future proofs for anticipated growth near the Rosedale area. With minimal cable investment, the Bush Road, Rosedale, Sunset Road, Forrest Hill, and East Coast Road zone substations can be supplied from the new Rosedale GXP and their demand transferred from Albany GXP. This would address security constraints at both the GXP and sub-transmission circuit level.

10a.5.7 WAIMAUKU 2ND 33KV CABLE

WAIMAUKU 2ND 33KV CABLE

CONSTRAINT

The Waimauku ZSS supplies the rapidly growing Kumeu-Huapai district. The ZSS has a single overhead 33 kV supply. As demand grows the security of supply standard will not be met.

OPTIONS

1. **Do nothing:** Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies and increasing unreliability. This is not acceptable.
2. **Install future-proofing ducts for the second 33 kV circuit and a new 11kV feeder from Waimauku to Huapai:** A Waka Kotahi SafeRoads project is upgrading the highway on the cable route. Ducts will be installed in combination with the roadworks to reduce the cost and public disruption of the standalone civil project later.
3. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY31, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 2 is the preferred solution because it address SoSS breach in the future and aligns with long term strategy for Waimauku load growth.

10a.6 Wairau planning area

10a.6.1 BELMONT 33/11 KV TRANSFORMER T3

BELMONT 33/11 KV TRANSFORMER T3

CONSTRAINT

Ngataringa Bay ZSS in Stanley Point is prone to the risk of flooding in the event of a king tide, an event that has already occurred, and one that is estimated to be a 1-in-10-year or more frequent event in future. Flooding of the ZSS could result in loss of supply to all customers presently supplied from this ZSS.

The ZSS is supplied by an ageing 33 kV oil-filled submarine cable crossing the bay, which poses an environmental risk of oil pollution if it fails or is mechanically damaged and the oil containment elements of its design are compromised.

Besides, Ngataringa Bay ZSS has insufficient 11 kV backstop capacity for an outage at peak demand, hence breaching the SoSS.

OPTIONS

1. **Do Nothing**: The environmental and security of supply risks posed by the single ageing oil-filled submarine cable and by the flooding of Ngataringa Bay zone substation remain. Ngataringa Bay backstop shortfall remains.
2. **Install 3rd transformer at Belmont and install new 11kV switchboard:** Customers presently supplied by 11 kV feeders from Ngataringa Bay ZSS would in future be supplied by new 11 kV feeders from Belmont ZSS. A 3rd 20/28MVA 33/11kV 25% Z transformer would be installed at the Belmont zone substation to accommodate the additional 11 kV demand. The 11 kV switchboard at Belmont ZSS would be extended to accommodate the additional 11 kV transformer feeder and the additional 11 kV feeders to Stanley Point.
3. **Relocate Ngataringa Bay ZSS**: Acquire land and build a new zone substation in a suitable flood risk-free location in Stanley Point; remove (or drain and seal) the existing 33 kV oil-filled submarine cable and replace it with a modern XLPE equivalent; reroute existing 11 kV feeders to suit the new location of the ZSS. The key environmental and security of supply risks would be avoided.
4. **Rebuild Ngataringa Bay ZSS**: Rebuild the zone substation in its existing location, but on elevated foundations to eliminate the security of supply risk posed by the existing low-lying installation; remove (or drain and seal) the existing 33 kV oil-filled submarine cable and replace with a modern XLPE equivalent.

PREFERRED SOLUTION

Option 2 is preferred at a significantly lower cost than options 3 or 4. It also provides several outcomes for the area: alleviation of flood risk, alleviation of environmental pollution risk; and integration of the future Belmont ZSS transformer replacement. This project has forecasted spend in the next 12 months.

10a.6.2 BELMONT 33/11 KV T1+T2 UPGRADE

BELMONT 33/11 KV T1+T2 UPGRADE

CONSTRAINT

A reliability constraint exists because the third transformer at Belmont and the associated new switchboard are incompatible with the existing assets. The high fault level prevents parallel operation of T3 with T1 and T2, as these units have lower impedance. In addition, the existing 11 kV Reyroll switchboard has a lower fault rating, further limiting system operation.

OPTIONS

1. **Do nothing:** Continue to restrict parallel operation, exposing network to ongoing reliability risk and limited load sharing capability.
2. **Upgrade existing T1, T2 transformers and 11kV Reyroll switchboard:** Replacement of T1 and T2 with new T51 and T52 20/28MVA 33/11kV 25% Z transformers to ensure compatibility with T3 and enable parallel operation load sharing. This stage also includes the replacement of the 11kV Reyrolle switchboard as an extension of the new 11kV switchboard works completed in Stage 1.
3. **Implement non-wires solutions:** There is significant load on this substation. This option is expected to have little benefit from economic and network improvement from a reliable and resilience perspective.

PREFERRED SOLUTION

Option 2 is preferred as it addresses the reliability limitation and algins with the long-term growth in the area. This project has forecasted spend in the next 12 months.

10a.6.3 HIGHBURY 33/11 KV SECOND TRANSFORMER AND SECOND 33 KV CABLE

HIGHBURY 33/11 KV SECOND TRANSFORMER AND SECOND 33 KV CABLE

CONSTRAINT

As a result of E-Ferry, gas to electrical substitution of point load customers and organic growth, Highbury zone substation is reaching capacity in 2027. The peak demand is forecast to increase by 8MVA over the next ten-year period. There is insufficient spare capacity at peak demand to provide backstop to neighbouring zone substations.

OPTIONS

1. **Do nothing:** accept Highbury substation is at capacity and supply to customers will become increasingly unreliable.
2. **Install a second transformer and sub-transmission cable:** the second transformer and sub-transmission cable will add capacity to the substation and allow for future commercial and residential developments in the area. There is space for a second transformer on site.
3. **Implement non-wires solutions:** The growth on this substation is dominated by a large point load from the E-Ferry. This option is expected to have little benefit from economic and network improvement due to the large point load. This project has forecasted spend in the next 12 months.

PREFERRED SOLUTION

Option 2 is preferred due to the growth and capacity constraint in the area. This project has forecasted spend in the next 12 months.

10a.6.4 JAMES ST 33/11 KV TRANSFORMER UPGRADE T1 AND T2

JAMES ST 33/11 KV TRANSFORMER UPGRADE T1 AND T2

CONSTRAINT

Transformer loading at James St ZSS breaches security of supply.

OPTIONS

1. **Do nothing:** accept James St ZSS is at capacity and supply to customers will become increasingly unreliable.
2. **Replace the James St transformers T1 and T2 with larger units:** This option meets the long-term requirements of load growth and increases security of supply into James St and surrounding areas.
3. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is preferred due to the growth and capacity constraint in the area. This project has forecasted spend in the next 12 months.

10a.6.5 MILFORD 33/11 KV TRANSFORMER UPGRADE T1

MILFORD 33/11 KV TRANSFORMER UPGRADE T1

CONSTRAINT

Transformer loading at Milford ZSS breaches security of supply.

OPTIONS

1. **Do nothing:** accept Milford substation is at capacity and supply to customers will become increasingly unreliable.
2. **Replace the Milford transformer with a larger unit:** this option meets the long-term requirements of load growth and increases security of supply into Milford and the surrounding areas.
3. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is preferred due to the growth and capacity constraint in the area.

10a.6.6 WAIRAU 33/11 KV TRANSFORMER UPGRADE T5 AND T6

WAIRAU 33/11 KV TRANSFORMER UPGRADE T5 AND T6

CONSTRAINT

Load growth in Wairau will result in shortfall in transformer capacity at Wairau ZSS.

OPTIONS

1. **Do nothing:** accept Wairau substation is at capacity and supply to customers will become increasingly unreliable.
2. **Replace the Wairau transformers T5 and T6 with larger units:** This option meets the long-term requirements of load growth and increases security of supply into Wairau and surrounding areas.
3. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is preferred due to the growth and capacity constraint in the area. This project has forecasted spend in the next 12 months.

10a.7 Auckland CBD planning area

10a.7.1 CBD BANKSIDE ST 22KV EXTENSION AND CONVERSION

CBD BANKSIDE ST 22KV EXTENSION AND CONVERSION

CONSTRAINT

The existing 11kV switchgear and transformers at various distribution substations around Bankside St area in CBD have been scheduled for replacement due to age and condition. Long-term growth forecast shows that the existing 11kV distribution network in CBD is constrained therefore needs upgrading to increase the capacity to meet the load growth.

OPTIONS

1. **Replace the 11kV equipment like for like:** Under this option the capacity in the CBD distribution network will stay as is. Further reinforcement will be required to increase the capacity to meet the load growth in long-term. This option is not a cost-efficient solution nor in line with Vector's strategy for CBD distribution network which is to upgrade the 11kV network to 22kV therefore double the capacity in a cost-efficient way and phase out 11kV eventually.
2. **Convert the substations to 22kV:** This option is to replace the 11kV equipment with 22kV equipment at the selected substations and connect the converted substations to the 22kV distribution network. It is a cost-efficient solution to increase capacity taking advantage of the synergies from asset replacement program.

PREFERRED SOLUTION

The preferred option is option 2. The required asset replacements provide synergy opportunity to convert the 11kV network to 22kV. It is a cost-efficient solution and in line with Vector's strategy for CBD distribution network in long-term. This project has forecasted spend in the next 12 months.

10a.7.2 CBD EDEN CRE AND ANZAC AV 22KV EXTENSION AND CONVERSION

CBD EDEN CRE AND ANZAC AV 22KV EXTENSION AND CONVERSION

CONSTRAINT

The existing 11kV switchgear and transformers at various distribution substations around Eden Cre and Anzac Av area in CBD have been scheduled for replacement due to age and condition. Long-term growth forecast shows that the existing 11kV distribution network in CBD is constrained therefore needs upgrading to increase the capacity to meet the load growth.

OPTIONS

1. **Replace the 11kV equipment like for like:** Under this option the capacity in the CBD distribution network will stay as is. Further reinforcement will be required to increase the capacity to meet the load growth in long-term. This option is not a cost-efficient solution nor in line with Vector's strategy for CBD distribution network which is to upgrade the 11kV network to 22kV therefore double the capacity in a cost-efficient way and phase out 11kV eventually.

CBD EDEN CRE AND ANZAC AV 22KV EXTENSION AND CONVERSION

2. **Convert the substations to 22kV:** This option is to replace the 11kV equipment with 22kV equipment at the selected substations and connect the converted substations to the 22kV distribution network. It is a cost-efficient solution to increase capacity taking advantage of the synergies from asset replacement program.

PREFERRED SOLUTION

The preferred option is option 2. The required asset replacements provide synergy opportunity to convert the 11kV network to 22kV. It is a cost-efficient solution and in line with Vector's strategy for CBD distribution network in long-term.

10a.7.3 CBD LIVERPOOL ST 22KV EXTENSION AND CONVERSION

CBD LIVERPOOL ST 22KV EXTENSION AND CONVERSION

CONSTRAINT

The existing 11kV switchgear and transformers at various distribution substations around Liverpool St area in CBD have been scheduled for replacement due to age and condition. Long-term growth forecast shows that the existing 11kV distribution network in CBD is constrained therefore needs upgrading to increase the capacity to meet the load growth.

OPTIONS

1. **Replace the 11kV equipment like for like:** Under this option the capacity in the CBD distribution network will stay as is. Further reinforcement will be required to increase the capacity to meet the load growth in long-term. This option is not a cost-efficient solution nor in line with Vector's strategy for CBD distribution network which is to upgrade the 11kV network to 22kV therefore double the capacity in a cost-efficient way and phase out 11kV eventually.
2. **Convert the substations to 22kV:** This option is to replace the 11kV equipment with 22kV equipment at the selected substations and connect the converted substations to the 22kV distribution network. It is a cost-efficient solution to increase capacity taking advantage of the synergies from asset replacement program.

PREFERRED SOLUTION

The preferred option is option 2. The required asset replacements provide synergy opportunity to convert the 11kV network to 22kV. It is a cost-efficient solution and in line with Vector's strategy for CBD distribution network in long-term.

10a.7.4 CBD VINCENT ST 22KV EXTENSION AND CONVERSION

CBD VINCENT ST 22KV EXTENSION AND CONVERSION

CONSTRAINT

The existing 11kV switchgear and transformers at various distribution substations around Vincent St area in CBD have been scheduled for replacement due to age and condition. Long-term growth forecast shows that the existing 11kV distribution network in CBD is constrained therefore needs upgrading to increase the capacity to meet the load growth.

OPTIONS

1. **Replace the 11kV equipment like for like:** Under this option the capacity in the CBD distribution network will stay as is. Further reinforcement will be required to increase the capacity to meet the load growth in long-term. This option is not a cost-efficient solution nor in line with Vector's strategy for CBD distribution network which is to upgrade the 11kV network to 22kV therefore double the capacity in a cost-efficient way and phase out 11kV eventually.
2. **Convert the substations to 22kV:** This option is to replace the 11kV equipment with 22kV equipment at the selected substations and connect the converted substations to the 22kV distribution network. It is a cost-efficient solution to increase capacity taking advantage of the synergies from asset replacement program.

PREFERRED SOLUTION

The preferred option is option 2. The required asset replacements provide synergy opportunity to convert the 11kV network to 22kV. It is a cost-efficient solution and in line with Vector's strategy for CBD distribution network in long-term.

10a.7.5 HOBSON WATERFRONT 22 KV FEEDERS NEW

HOBSON WATERFRONT 22 KV FEEDERS NEW

CONSTRAINT

As a result of commercial load growth in Wynyard Quarter, a security shortfall will occur in Hobson J09 and HOBS J39.

HOBSON WATERFRONT 22 KV FEEDERS NEW

OPTIONS

1. **Do Nothing**: This option will result in breaches of security limits in the existing two feeders Hobson J09 and J39. This option is not acceptable.
2. **Install two new 22kV feeders from Hobson ZSS**: Install two new 22 kV feeders from the Hobson zone substation: This option will off-load the existing two feeders supplying Wynyard Quarter and alleviate the constraint in the existing feeders. This option will also provide sufficient spare capacity to meet the load growth in the area for long term.
3. **Install two new 11 kV feeders**: Vector's overall CBD strategy is focussed on building a 22 kV CBD distribution network. New 11 kV feeders would not align with this strategy, as they would use the available space less effectively, each feeder will provide lower capacity and would not provide shared increased capacity for further future expansion.
4. **Implementation of non-wires alternative**: The growth is high and includes large commercial buildings. This option is expected to have little benefit from economic and network security perspective.

PREFERRED SOLUTION

The preferred solution is option 2 because it is a cost-efficient solution for long term and aligns to the long-term strategy for the CBD distribution network.

10a.7.6 HOBSON NEW 22KV FEEDERS TO LOWER HOBSON ST

HOBSON NEW 22KV FEEDERS TO LOWER HOBSON ST

CONSTRAINT

The proposed new loads from commercial developments in Downtown are expected to result in breaches of capacity and SoSS in existing feeders in the area.

OPTIONS

1. **Do Nothing**: Under this option the existing feeders in the area will be overloaded and lack of backstopping capacity under contingency condition. This option is not acceptable.
2. **Install two new 22kV feeders from Hobson ZSS:** This option will provide sufficient capacity and security to supply the new load from the developments for long term.

PREFERRED SOLUTION

Option 2 is the preferred option. The new feeders will provide sufficient capacity and security to supply the new load from the developments for long term.

10a.7.7 CBD 11KV TO 22KV CONVERSION FOR SECURITY IN LIVE K01

CBD 11KV TO 22KV CONVERSION FOR SECURITY IN LIVE K01

CONSTRAINT

An 11kV feeder LIVE K01 is forecasted to breach SoSS due to load growth.

OPTIONS

1. **Do Nothing**: Under this option the feeder LIVE K01 will not have sufficient backstopping capacity under contingency condition . This option is not acceptable.
2. **Carry out 11kV to 22kV conversions**: By converting selected 11kV distribution substations in LIVE K01 to 22kV, it will transfer the load from the 11kV feeder to 22kV therefore reduce the load in the 11kV feeder and remove the constraint.
3. **Install new 11kV feeders to off load LIVE K01**: This option is not a cost-efficient solution nor in line with Vector's strategy for CBD distribution network which is to upgrade the existing 11kV network to 22kV and phase out 11kV in long term. This option is not preferred.

PREFERRED SOLUTION

Option 2 is the preferred option. This option will maintain the SoSS in the feeder LIVE K01 and also align with Vector's strategy for CBD distribution network in long term.

10a.7.8 CBD LIVERPOOL 11KV TO 22KV CONVERSION FOR SECURITY

CBD LIVERPOOL 11KV TO 22KV CONVERSION FOR SECURITY

CONSTRAINT

Liverpool ZSS 11kV supply is forecasted to breach SoSS due to load growth.

OPTIONS

1. **Do Nothing**: Under this option Liverpool ZSS 11kV supply will not have sufficient backstopping capacity under contingency condition . This option is not acceptable.
2. **Carry out 11kV to 22kV conversions**: By converting selected 11kV distribution substations supplied from Liverpool ZSS to 22kV, it will transfer the load from the 11kV network to 22kV therefore reduce the load at Liverpool 11kV bus and remove the constraint.
3. **Transfer load to adjacent ZSS**: The effectiveness of this option is very much limited due to the network configuration and the restriction of the capacity in the feeders from adjacent ZSSs.
4. **Install additional 22/11kV transformers**: This option is not acceptable due to the fault level exceeding the design limit.

PREFERRED SOLUTION

Option 2 is the preferred option. This option will maintain the SoSS at Liverpool ZSS 11kV supply and also align with Vector's strategy for CBD distribution network which is to upgrade the existing 11kV network to 22kV and phase out 11kV in long term.

10a.8 Roskill planning area

10a.8.1 MT ALBERT ZSS 2ND TRANSFORMER AND NEW SUBTRAN CABLES

MT ALBERT ZSS 2ND TRANSFORMER AND NEW SUBTRAN CABLES

CONSTRAINT

Capacity and security breaches are forecast at the ZSS from 2030. This is a single transformer ZSS. The capacity is restricted by the existing 22kV subtransmission circuit.

OPTIONS

1. **Do nothing:** This option will result in overloading in the existing subtransmission circuit and customers losing supply upon contingency conditions. This option is not acceptable.
2. **Upgrade ZSS capacity:** This option is to install 2nd transformer and subtransmission circuit therefore increase the capacity at the ZSS.
3. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY30, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 2 is the preferred solution to increase the capacity and remove the constraint at the ZSS.

10a.8.2 MT EDEN ZONE SUBSTATION NEW

MT EDEN ZONE SUBSTATION NEW

CONSTRAINT

Significant residential development is being planned in the Mt Eden precinct, the area between Newton and Kingsland and centred around Mt Eden railway station, which is being redeveloped as part of the City Rail Link project. At present, the area is mainly supplied by 11 kV feeders from Newton and Kingsland zone substations. Load forecasts show that both substations are expected to breach capacity and security constraints from FY33.

OPTIONS

1. **Do nothing:** This option will result in overloading at Newton ZSS and Kingsland ZSS, and customers losing supply upon contingency conditions. This option is not acceptable.
2. **Establish Mt Eden new ZSS**: This option is to construct a new ZSS by the installation of new transformers, switchgear, subtransmission circuits, and 11kV feeders. Land will be purchased earlier for the new ZSS.

MT EDEN ZONE SUBSTATION NEW

3. **Upgrade Newton ZSS capacity:** This option is to install 3rd transformer and subtransmission circuit therefore increase the capacity at the ZSS. This option is difficult in feasibility due to the space constraint at Newton ZSS and the subtransmission cable installation required in CBD and across motorway bridge.
4. **Upgrade Kingsland ZSS capacity:** This option is to install 3rd 22/11kV transformer therefore increase the capacity at the ZSS. This option is difficult in feasibility due to the space constraint at Kingsland ZSS and the large number of distribution cable installation in major road to reach load centre.
5. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY31, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 2 is preferred because it is a cost-efficient solution to supply the new developments at Mt Eden Precinct for long term. This option will also off load the existing Newton ZSS and Kingsland ZSS.

10a.8.3 KINGSLAND ZSS 110KV SWBD AND CABLES

KINGSLAND ZSS 110KV SWBD AND CABLES

CONSTRAINT

The existing subtransmission cables at Kingsland 110/22 kV substation, including the two 110 kV circuits from Roskill GXP and the backup 22 kV circuit from Liverpool, are all oil filled (OF) cables over 50 years old. It makes the substation vulnerable upon any OF cable failure. Also, the substation is forecast to breach SoSS from 2034.

OPTIONS

1. **Do nothing:** This option will result in customers losing supply for prolonged time upon contingency conditions. This option is not acceptable.
2. **Install new 110kV switchboard and cables**: By installing a new 110kV switchboard, it will enable to connect an additional 110/22kV transformer installed earlier under a separate project at the ZSS. The new 110kV cables will connect the ZSS to the existing Roskill GXP – Liverpool 110kV circuit. Completion of the project will provide the ZSS more capacity as well additional backup from CBD 110kV network.
3. **Replace the OF cables only:** the existing 110kV OF cables and the 110/22kV transformers will be replaced under asset replacement projects. However, the replacement only will not solve the problem of SoSS breach at the ZSS in long term.
4. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY30, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 2 is preferred because it is a cost-efficient solution to solve the security breach problem at the ZSS for long term.

10a.8.4 PONSONBY SUBSTATION UPGRADE

PONSONBY SUBSTATION UPGRADE

CONSTRAINT

The substation is forecast to have capacity constraint from 2034.

OPTIONS

1. **Do nothing:** This option will result in the existing transformers being overloaded. This option is not acceptable.
2. **Upgrade the existing transformers**: By upgrading the existing transformers it will increase the capacity at the ZSS thus removing the constraint.
3. **Flexibility or non-wire alternative:** this project is sign posted in section 10 as a candidate for a flexibility or non-wire alternative solution. The project is forecasted to initiate in FY31, and as such any solution will need to be in confirmed before this date.

PREFERRED SOLUTION

Option 2 is preferred because it is a cost-efficient solution to solve the capacity constraint problem at the ZSS for long term.

10a.9 Penrose planning area

10a.9.1 SOUTHDOWN LAND PURCHASE FOR ZSS

LAND PURCHASE AND DESIGNATION FOR SOUTHDOWN NEW SUBSTATION

CONSTRAINT

As a result of industrial load growth in south of Penrose area, the existing substations Te Papapa and Westfield are forecast to breach SoSS from 2039.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS at Te Papapa and Westfield substations from 2039. This option is not acceptable.
2. **Add new transformers at Te Papapa and Westfield substation:** This option is expected to be more expensive than a new substation at Southdown as the cable routes would be longer.
3. **Early acquisition of a zone substation land at Southdown site:** Identify and purchase a site for a future substation at Southdown site at an early design stage of the development in about FY27. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly growing development.
4. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in to allow final detailed designs for the new ZSS. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition.

PREFERRED SOLUTION

The preferred option is option 3 to secure a future zone substation site. As a prudent network manager, Vector needs to identify and secure suitable future zone substation sites to ensure Vector can supply future developments cost effectively and reliably. This project has forecasted spend in the next 12 months.

10a.9.2 TAMAKI LAND PURCHASE FOR ZSS

TAMAKI LAND PURCHASE FOR ZSS

CONSTRAINT

Tāmaki Regeneration is a 30-year housing intensification project being undertaken by Kāinga Ora in Tāmaki area. The area is mainly supplied by 11 kV feeders from St Johns, Mt Wellington, Glen Innes, St Heliers and Orakei zone substations. St Johns, St Heliers and Orakei substations are supplied from a 33 kV switching station served as bulk supply point (BSP) within St Johns substation site. The BSP is supplied by three 33 kV circuits from Penrose GXP. Long-term load forecasts show that planned development in Tāmaki will cause demand on St Johns 33 kV BSP to breach SoSS in long term.

OPTIONS

1. **Do Nothing:** Doing nothing will result in a new 11 kV load in Tāmaki being connected to the existing St Johns ZSS distribution network. This will result in breaches of SoSS requirement at St Johns zone substation on the 33 kV assets in long term. Failure to secure an optimal site at the design stage of the development will result in a higher cost to establish the new substation in future.
2. **Add new 11 kV feeders to Glen Innes zone substation:** Adding new feeders to Glen Innes ZSS will reduce the short-term impact on St Johns ZSS, but it is expected to be more expensive than from St Johns ZSS due to the longer cable route lengths involved.
3. **Early identification and acquisition of a zone substation location within the Tāmaki Regeneration area:** Identify and purchase a site for the location of a future substation in the Tāmaki Regeneration area at an early design stage of the development in about FY28. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly growing development.
4. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in to allow final detailed designs for the new ZSS. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition.

PREFERRED SOLUTION

The preferred option is option 3. Identification and acquisition of land for a new substation in Tāmaki area around FY28. Securing an optimal site at the design stage of the development will avoid a higher cost to establish the new substation at later stage.

10a.9.3 NEWMARKET NEW FEEDERS TO OFF LOAD NEWM K19 AND NEWM K30

NEWMARKET NEW FEEDERS TO OFF LOAD NEWM K19 AND NEWM K30

CONSTRAINT

As a result of 11kV feeder rearrangement after multiple cable failure, feeder LIVE K14 is forecasted to be short of backup capacity under a worst-case scenario of cable fault from 2028. Also, feeders NEWM K19 and NEWM K30 are forecasted to breach capacity and SoSS from 2033.

OPTIONS

1. **Do Nothing:** This option will result in customers losing supply upon contingency conditions. This option is not acceptable.
2. **Install two new 11 kV feeders from Newmarket substation:** connect the new feeders to the existing 11 kV network and rearrange the feeders in the area. This option will off load the heavily loaded feeders as well provide sufficient backup capacity to LIVE K14.
3. **Implement demand side management and non-wires alternative:** This option is expected to have little benefit from an economic and network improvement point of view, due to the high growth rate from Kainga Ora's housing development.

PREFERRED SOLUTION

Option 2 is preferred because it is a cost-efficient solution to solve the problem of capacity and security breach in the three feeders. This project has forecasted spend in the next 12 months.

10a.9.4 SOUTHDOWN ON SITE FUTURE PROOFING DUCTS

SOUTHDOWN ON SITE FUTURE PROOFING DUCTS

CONSTRAINT

Vector has 15 zone substations taking supply from Penrose 33kV GXP. It has been identified to be a risk of common mode failure due to the concentration of large number of ZSSs and magnitude of load. It is proposed to establish a new GXP at Southdown (by Transpower) and divert the load from Penrose GXP to Southdown GXP when the subtransmission cables at Vector's ZSSs in the area are due for replacement. Vector is also to purchase a land to build a new ZSS to off load the existing ZSSs in the area in longer term. Subtransmission and distribution cables will be required to be installed from the GXP site.

OPTIONS

1. **Do Nothing:** Doing nothing will lose the synergy opportunity to install future proofing ducts. It will be costly and disruptive to excavate and install the cables at later stage.
2. **Install future proofing ducts:** This option is to install future proofing ducts at the new GXP site taking advantage of the synergies from the site works.

PREFERRED SOLUTION

Option 2 is preferred because it is a cost-efficient solution to install cables when required at later stage.

10a.10 Pakuranga planning area

10a.10.1 FLAT BUSH 11KV NEW FEEDER - MURPHYS RD

FLAT BUSH 11KV NEW FEEDER - MURPHYS RD

CONSTRAINT

Increasing residential development in the Flat Bush area will lead to a feeder, Flat Bush K05 exceeding capacity in 2028.

OPTIONS

1. **Do nothing:** Accept one feeder at full capacity in 2028 and insufficient capacity for new developments in the area.
2. **Install new feeder:** This option will relieve load on Flat Bush K05 and will add capacity to the area for the new residential developments.
3. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

FLAT BUSH 11KV NEW FEEDER - MURPHYS RD

PREFERRED SOLUTION

Option 2 is the preferred option. This option addresses the feeder constraint and provides additional capacity to the high growth area. This project has forecasted spend in the next 12 months.

10a.10.2 EAST TAMAKI 11KV NEW FEEDER – STONEDON AVE

EAST TAMAKI 11KV NEW FEEDER - STONEDON AVE

CONSTRAINT

As a result of new commercial and industrial growth in East Tamaki area, feeder East Tamaki K20 breaches security of supply in 2028.

OPTIONS

1. **Do nothing:** Accept supply reliability issues from 2028 and insufficient capacity for new developments in the area.
2. **Install new feeder:** This option will relieve load on East Tamaki K20 and will provide backstopping capacity for East Tamaki K20 and other neighbouring heavily loaded feeders.
3. **Implement demand side management and non-wires alternatives:** This area has a large commercial / industrial component and implementation of non-network options will have no benefit from an economic and network improvement point of view.

PREFERRED SOLUTION

Option 2 is the preferred option as it is a cost-effective solution to solve the problem of security breach on feeder East Tamaki K20. This project has forecasted spend in the next 12 months.

10a.10.3 HOWICK 11KV NEW FEEDER – HALF MOON BAY

HOWICK 11KV NEW FEEDER – HALF MOON BAY

CONSTRAINT

As a result of new commercial and residential growth in Howick area, feeder Howick K05 breaches security of supply in 2028.

OPTIONS

1. **Do nothing:** Accept supply reliability issues from 2028 and insufficient capacity for new developments in the area.
2. **Install new feeder:** This option will relieve load Howick K05 and will provide backstopping capacity for neighbouring heavily loaded feeders.
3. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is the preferred option as it is a cost-effective solution to solve the problem of security breach on feeder Howick K05. This project has forecasted spend in the next 12 months.

10a.11 Mangere planning area

10a.11.1 MANGERE SOUTH 11KV SWITCHGEAR AND 33/11KV TRANSFORMERS

MANGERE SOUTH 11KV SWITCHGEAR AND 33/11KV TRANSFORMERS

CONSTRAINT

Significant commercial and industrial developments around the airport area and residential developments in Mangere area will result in Mangere Central substation breaching SoSS.

OPTIONS

1. **Do Nothing:** Existing feeders from Mangere Central and Mangere West substations will become overloaded. Customers supplied from Mangere Central ZSS will increasingly suffer from supply reliability issues and possible equipment failure.

MANGERE SOUTH 11KV SWITCHGEAR AND 33/11KV TRANSFORMERS

2. **Build a new zone substation (11kV switchgear and 33/11kV transformers):** Build a new zone substation at the new 33kV switchroom at Mangere South. This will provide the required 11kV capacity and alleviate constraint at Mangere Central.
3. **Install new 11 kV feeders from alternative ZSS:** There are no spare circuit breakers available at Mangere West and Mangere Central and 1 spare circuit breaker available at Mangere East ZSS. Additionally, this option would be expensive owing to the long cable route lengths to the development area. Planning reviews have also identified this option would be a temporary short-term solution due to the scale of the growth.

PREFERRED SOLUTION

Option 2 is preferred. Building a new Mangere South zone substation will relieve the emerging feeder capacity and SoSS constraints at Mangere Central. This project has forecasted spend in the next 12 months.

10a.11.2 MANGERE CENTRAL K11 11KV FEEDER REINFORCEMENT

MANGERE CENTRAL K11 11KV FEEDER REINFORCEMENT

CONSTRAINT

Increasing commercial and industrial development in Favona area will lead to a feeder, Mangere Central K11 exceeding capacity and breaching SoSS.

OPTIONS

1. **Do nothing:** Accept one feeder at full capacity and insufficient capacity for new developments in the area.
2. **Upgrade a section of under-rated cable on this feeder:** With this option the capacity of the feeder will increase to allow further developments and provide backstopping to this area.
3. **Implement demand side management and non-wires alternatives:** This area has a large commercial / industrial component and implementation of non-network options will have no benefit from an economic and network improvement point of view.

PREFERRED SOLUTION

Option 2 is the preferred option. This option addresses the feeder constraint and provides additional capacity to this area. This project has forecasted spend in the next 12 months.

10a.12 Takanini planning area

10a.12.1 TAKANINI K17 ALFRISTON -ARDMORE OVERHEAD UPGRADE

TAKANINI K17 ALFRISTON-ARDMORE OVERHEAD UPGRADE

CONSTRAINT

New commercial and residential developments in Takanini will lead to a feeder, Takanini K17 breaching SoSS.

OPTIONS

1. **Do Nothing:** Accept the SoSS breaches and thereby risking the loss of customer supplies increasing unreliability. This will result in non-compliance with the SoSS.
2. **Upgrade part of Takanini K17 overhead network:** This option upgrading a small section of the existing Takanini K17 feeder which will increase the capacity of the feeder and address the SoSS constraint.
3. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is the preferred option as it will resolve the backstop shortfall and provide improved network resilience and customer reliability of supply. This project has forecasted spend in the next 12 months.

10a.12.2 MARAETAI K01 FEEDER REINFORCEMENT

MARAETAI K01 FEEDER REINFORCEMENT

CONSTRAINT

As a result of large residential developments, Maraetai K01 and K04 will breach security.

OPTIONS

1. **Do Nothing:** Accept the forecast SoSS breaches and thereby risking the loss of customer supplies increasing unreliability. This will result in non-compliance with the SoSS.
2. **Reinforce the 11kV network:** Install 11kV cable to increase backstopping on both feeders.
3. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is the preferred option as it will resolve the backstop shortfall on both feeders and provides improved network resilience and customer reliability of supply. This project has forecasted spend in the next 12 months.

10a.12.3 MARAETAI 11KV NEW FEEDER – BEACHLANDS RD

MARAETAI 11KV NEW FEEDER – BREACHLANDS RD

CONSTRAINT

As a result of a large residential development in Beachlands, the existing feeder Maraetai K01 will reach capacity.

OPTIONS

1. **Do nothing:** Accept the feeder reaching full capacity. Supply to customers will become increasingly unreliable.
2. **Install a new 11 kV feeder:** Install a new feeder to relieve the load on Maraetai K01 feeder and provide additional capacity from the new feeder during contingency situations.
3. **Implement demand side management and non-wires alternative:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is the preferred option. This option will increase capacity and security to the area and is the most cost-efficient solution to meet the load growth in the area. This project has forecasted spend in the next 12 months.

10a.12.4 MARAETAI 11KV NEW FEEDER – JACK LAUGHLIN DR

MARAETAI 11KV NEW FEEDER – JACK LAUGHLIN DR

CONSTRAINT

As a result of a large residential development in Beachlands, the existing feeder Maraetai K01 will reach capacity.

OPTIONS

2. **Do nothing:** Accept the feeder reaching full capacity. Supply to customers will become increasingly unreliable.
4. **Install a new 11 kV feeder:** Install a new feeder to relieve the load on Maraetai K01 feeder and provide additional capacity from the new feeder during contingency situations.
5. **Implement demand side management and non-wires alternative:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is the preferred option. This option will increase capacity and security to the area and is the most cost-efficient solution to meet the load growth in the area.

10a.12.5 WAIHEKE T1 & T2 TRANSFORMER UPGRADE

WAIHEKE T1 AND T2 UPGRADE

CONSTRAINT

Load growth in Waiheke Island will result in a breach in security of supply at Waiheke ZSS in 2028.

OPTIONS

1. **Do Nothing:** Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies increasing unreliability. This will result in non-compliance with the SoSS.
2. **Replace the Waiheke ZSS transformers with larger units:** This addresses the security of supply at a lower cost than option 2.
3. **Implement demand side management and non-wires alternative:** This area has a large residential component and implementation of a non-wires alternative will be considered and subject to technology development, customer adoption and regulatory settings.

PREFERRED SOLUTION

Option 2 is the preferred option as the more cost-effective solution. This project has forecasted spend in the next 12 months.

10a.12.6 MANUREWA 11 KV NEW FEEDER - ALFRISTON RD

MANUREWA 11KV NEW FEEDER - ALFRISTON RD

CONSTRAINT

As a result of organic growth, two feeders in the area will be constrained. The Manurewa K07 feeder will reach capacity in 2031 and Manurewa K12 feeder have a backstop shortfall in 2032.

OPTIONS

3. **Do nothing:** Accept the feeders reaching full capacity and breaching backstopping from 2031. Supply to customers will become increasingly unreliable.
6. **Install a new 11 kV feeder:** Install a new feeder to relieve the load on Manurewa K07 and K12 feeders and provide additional capacity from the new feeder during contingency situations.
7. **Implement demand side management and non-wires alternative:** This area has a large residential component and implementation of non-wires alternative will be considered and subject to technology development, customer adoption and regulatory settings.

PREFERRED SOLUTION

Option 2 is the preferred option. This option will increase capacity and security to the area and is the most cost-efficient solution to meet the load growth in the area.

10a.12.7 TAKANINI NORTH LAND PURCHASE FOR ZSS

TAKANINI NORTH LAND PURCHASE FOR ZSS

CONSTRAINT

Expansion of large commercial customers along with residential development will result in Papakura substation breaching SoSS in 2035.

OPTIONS

1. **Do Nothing:** Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies increasing unreliability. This will result in non-compliance with the SoSS.
2. **Defer acquisition of land and build of zone substation:** Defer site acquisition until shortly before the location must be locked in to allow final detailed designs for the new ZSS. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition.
3. **Early identification and acquisition of a zone substation location within the southern Takanini/Papakura area:** Identify and acquire a suitable site for the location of a future Takanini South zone substation in reasonable proximity to forecast load growth centres. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly growing development.

TAKANINI NORTH LAND PURCHASE FOR ZSS

PREFERRED SOLUTION

The preferred option is option 3. It is prudent to identify and acquire a suitable ZSS site close to future load centres before suitable sites become unavailable to Vector.

10a.12.8 MILL ROAD FUTURE PROOFIND DUCTS

MILL ROAD FUTURE PROOFING DUCTS

CONSTRAINT

Demand forecast indicates that peak load at Takanini ZSS will exceed capacity beyond the AMP period. .

OPTIONS

1. **Do Nothing:** Doing nothing will lose the synergy opportunity to install future proofing ducts. It will be costly and disruptive to excavate and install cables at a later stage.
2. **Install subtransmission and 11kV future proofing ducts:** This option is to install future proofing ducts taking advantage of the synergies from NZTA works. These ducts will be used for sub-transmission supply for the new Takanini North ZSS.
3. **Undertake civil works later with cable installation:** The civil works will be carried out as part of the cable installation. This will involve re-entering public roads after the NZTA works have been completed.

PREFERRED SOLUTION

The preferred option is option 2. It is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at a later stage. This project has forecasted spend in the next 12 months.

10a.13 Otahuhu planning area

10a.13.1 OTARA SPRINGS ROAD 11KV FEEDER NEW

OTARA SPRINGS ROAD 11KV FEEDER NEW

CONSTRAINT

As a result of organic growth, Otara K15 will have a backstop shortfall in 2032 and reach capacity in 2033.

OPTIONS

4. **Do Nothing:** Accept the feeder reaching full capacity and breaching backstopping. Supply to customers will become increasingly unreliable.
2. **Install a new 11kV feeder:** Install a new 11kV feeder to relieve the load on Otara K15 and provide additional capacity from the new feeder during contingency situations.
3. **Implement demand side management and non-wires alternative:** This area has a commercial and industrial component and implementation of non-wires alternative will be considered and subject to technology development, customer adoption and regulatory settings.

PREFERRED SOLUTION

Option 2 is the preferred option as it will increase capacity and security to the area.

10a.14 Wiri planning area

10a.14.1 CLENDON WEYMOUTH RD 11KV FEEDER NEW

CLENDON WEYMOUTH RD 11KV FEEDER NEW

CONSTRAINT

As a result of organic growth, Manurewa ZSS exceeds transformer capacity.

CLENDON WEYMOUTH RD 11KV FEEDER NEW

OPTIONS

1. **Do Nothing:** Accept Manurewa ZSS reaching full capacity. Supply to customers will become increasingly unreliable.
2. **Install a new 11kV feeder from Clendon ZSS:** Install a new 11kV feeder from Clendon ZSS to relieve the load on Manurewa ZSS and provide additional capacity to this area during contingency situations.
3. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is the preferred option as it will increase capacity to the area and offload Manurewa ZSS. This project has forecasted spend in the next 12 months.

10a.14.2 WEST WIRI PUHINUI RD 11KV FEEDER NEW

WEST WIRI PUHINUI RD 11KV FEEDER NEW

CONSTRAINT

As a result of significant commercial and industrial development on Puhinui Rd, the existing supplying feeder Mangere East K19 reaches capacity and breaches SoSS.

OPTIONS

1. **Do Nothing:** Accept Mangere East K19 reaching full capacity. Supply to customers will become increasingly unreliable.
2. **Install a new 11kV feeder from Clendon ZSS:** Install a new 11kV feeder from West Wiri ZSS to relieve the load on Mangere East K19.
3. **Implement demand side management and non-wires alternatives**: This area has a large commercial and industrial component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is the preferred option as it will increase capacity to the area and offload Mangere East K19. This project has forecasted spend in the next 12 months.



SECTION 11

Reliability, environment, safety and resilience

11 – Reliability, Environment, Safety and Resilience

11.1 Overview

Our customers are increasingly reliant on affordable, reliable energy to support everyday life. As electricity becomes more central to daily needs such as communication and connectivity, working from home, and the electrification of transport, network reliability and resilience are more important than ever. We manage network security through a range of targeted investment portfolios.

This section sets out the investment in both asset replacement and asset reinforcement categories with a specific focus on projects for the improvement and bolstering of network reliability and resilience, including managing the impacts of climate change as well as reducing our asset management carbon footprint.

11.2 Asset management objectives

The asset management objectives that are addressed through our network reliability and resilience investments are set out in the table below:

FOCUS AREA	OBJECTIVES
Safety, environment and network security	• Comply with relevant safety and environmental legislation, regulation and planning requirements. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change).
Customers and stakeholders	• Enable customers' future energy and technology choices. • Ensure the long-term interest of our customers by endeavouring to provide an affordable and equitable network.
Network performance and operations	• Utilise clear business case processes, integrate risk management and complete post investment reviews to inform our decision making and analysis. • Maintain compliance with Security of Supply Standards through risk identification and mitigation. • Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. • Collaborate with teams throughout Vector to leverage different thinking, skillsets and asset management capabilities. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings.
Future energy network	• Prepare the network for future changes that are expected to be driven by: – technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc. – environment: climate disruption and network resilience. – customer: decarbonisation of the economy, electrification of transport, etc. – operations: transition to distribution system operator model and whole-of-system planning. • Embed network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third party flex traders and retailers. • Facilitate customer adoption of new technology while ensuring a resilient and efficient network. • Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network. • Develop digital and data platforms to meet changing customer needs and enable the future network in partnership with new entrants to the energy market. • Improve our visibility of, and ability to control, the LV network including management of the information required. • Collaborate with the industry, partners, thought leaders and subject matter experts to ensure Vector remains at the leading edge of future energy solutions.

TABLE 11-1: ALIGNMENT WITH ASSET MANAGEMENT OBJECTIVES

11.3 Network reliability

11.3.1 STRATEGIC RELIABILITY MANAGEMENT PLAN (SRMP)

Over recent years we have accelerated specific programmes of work that reflect our commitment to quality compliance, and the outcomes customers experience through the regulatory quality compliance framework. Vector's Strategic Reliability Management Plan (SRMP) specifies how we work to comply with quality standards and sustain this performance in future years, while not compromising health and safety outcomes, to meet the expectations of our customers and other stakeholders.

The reliability objectives and reliability strategies within the SRMP are a subset of Vector's broader set of asset management objectives and are governed by Vector's Strategic Management (SRM Reliability) group. The SRMP builds upon the actions taken as part of our response to our reliability performance from RY2016-22, with a heightened focus on initiatives aimed at reducing the length of outages, which has been identified as Vector's key reliability challenge, as well as reducing the number of customers impacted by events. There is an annual review process for the SRMP at the end of regulatory years which assesses all components of unplanned SAIFI and SAIDI performance including contribution by cause and the effectiveness of the initiatives during that year. Following that review process the SRMP is revised and some of the initiatives are embedded into business-as-usual practice while other new initiatives aligned to the reliability strategies are developed for the upcoming year and provided for in the expenditure profile.

We returned to quality compliance in both RY21 and RY22 however the extreme weather events of January and February 2023 resulted in SAIDI breach in RY23. Vector has been compliant in RY24 and RY25. Unplanned SAIDI and SAIFI remains on track to be compliant for RY26 pending any periods of sustained adverse weather conditions. The SRMP and associated reliability management targets a margin below the regulatory limit to allow for the variability in network operating conditions from year to year.

In this section, we describe the ongoing strategies, investment and initiatives underpinning our Strategic Reliability Management Plan.

11.3.2 SRMP GOVERNANCE AND MONITORING OF RELIABILITY PERFORMANCE.

The SRM meeting is held fortnightly and comprises the following actions and objectives;

- Discuss outage events of note for the preceding two weeks to determine operational learnings and any emerging trends affecting reliability performance and customer experience
- Monitor status of most significant HV constraints, subtransmission security of supply risks and Transpower planned outages with potential to impact customers so that contingency plans are in place and any identified risks can be mitigated
- Tracking of reliability performance for year-to-date, including by cause, to monitor progress against year-end internal targets and need to accelerate actions if required
- Monitoring of the SRMP and associated initiatives to ensure actions are completed on time and within allocated budget

11.4 Specific SRMP Initiatives

11.4.1 RISK BASED VEGETATION MANAGEMENT

Vegetation strikes and damage, transient or sustained, are one of the most common causes of outages on Vector's network and with the change in climate this is becoming more prevalent. To manage the impact of vegetation, Vector utilises a risk-based approach to plan and then carry out remediation work. This involves an independent company to scope, plan and package the work using the risk-based approach and also carry out audits of work undertaken, in conjunction with Vector's in house expertise, to provide assurance that work has been undertaken correctly. To deliver this work Vector engages two vegetation management businesses, along with others when required, to achieve this targeted approach and the volumes of work each year.

In 2021 a targeted rate for vegetation was implemented by the Auckland Council on Vector and to fund enhanced maintenance of Auckland Council-owned trees that present a risk to Vector's electricity network. Now that this programme has been in place for over three years, there is a review being undertaken into Vector's vegetation strategy and business rules to increase efficiencies with the Council programme while maintaining the risk-based approach.

Vector continues to advocate for changes to Tree Regulations which have a direct influence on the efficacy of our vegetation management practices and therefore vegetation related outages. This is discussed further in this section and section 8 of this AMP.

Under the Resource Management Act, the new National Policy Statement on Indigenous Biodiversity means we have a limited timeframe of just six months to cut back any trees to assist in the preservation and protection of the habitats of native and protected animals. The focus of our vegetation management approach is to find the right balance, so that we can meet this requirement while maintaining an effective vegetation management programme to deliver better outcomes for customers, given the challenges of planning around suitable weather conditions, the availability of specialist crews and other maintenance activities.

11.4.2 DEPLOYMENT OF NETWORK AUTOMATION

Vector's SRMP strategy includes a programme to continue the deployment of automation and sectionalisation on the network. This programme provides for the automation for remote control of existing 11 kV switches and the rollout of new automated switches for remote control on 11 kV feeders over ten years. The programme was accelerated with the first six years of the deployment completed in 2021. The programme of automation is continuing. Further details on the nature of this initiative are provided further below.

Also included in this initiative is the development of a network automation integration strategy roadmap which will determine the use and further deployment of equipment such as Fault Passage Indicators (FPI) and Distance to Fault Technology (DTF) on the network to assist fault restoration. We are also implementing the use of smart meter technology to automatically detect and report on network outages.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland Network Isolation and Automation	1.91	1.72	1.72	1.54	1.54	1.54	1.54	1.54	1.54	1.54	16.15
Northern Network Isolation and Automation	2.49	2.68	2.68	2.86	2.86	2.86	2.86	2.86	2.86	2.86	27.85
Total	**4.83**	**4.83**	**4.83**	**4.83**	**4.83**	**4.83**	**4.83**	**4.83**	**4.83**	**4.93**	**48.4**

TABLE 11-2: FORECAST EXPENDITURE FPI INSTALLATION

11.4.3 DISTRIBUTION RELIABILITY INITIATIVES

SRMP has provided an allocation of funds which is used for finding and executing reliability projects across the network. These projects can also be opportunistic in nature but are typically planned 1-2 years in advance. The projects typically belong in the following categories:

- Visibility – decreasing the time to locate and isolate faults
- Automation – decreasing the time to re-arrange the network after fault location and isolation.
- Spur links – connecting isolated parts of the network to adjacent feeders for backstopping purposes
- Microgrids – keep customers connected in remote areas where there can be lengthy repair times

FY27 and FY28 allocations have been assigned to the Big Omaha microgrid project (see section 11.5.8).

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland reliability initiatives	$0	$0	$3.2	$3.2	$3.2	$3.2	$3.2	$3.2	$3.2	$3.2	$25.5
Northern reliability initiatives	$0	$0	$1.9	$1.9	$1.9	$1.9	$1.9	$1.9	$1.9	$1.9	$15.2
Total	$0	$0	$5.1	$5.1	$5.1	$5.1	$5.1	$5.1	$5.1	$5.1	$40.7

TABLE 11-3: FORECAST EXPENDITURE DISTRIBUTION RELIABILITY INITIATIVES

11.4.4 CUSTOMER EXPERIENCE IMPROVEMENTS

Through the SRMP, Vector has fast tracked the existing FPI replacement project targeting the feeders with the highest SAIDI impact. Analysis has been carried out to identify the top 19 worst performing feeders and 190 FPI installation locations. They are predominantly very long, overhead distribution feeders. The total fault exposure/coverage of these 19 network feeders being 1,578 km, equates to 20.51% of the current distribution 11kV & 22kV network length. With some caveats, an estimated 5% improvement in CAIDI across these 19 feeders would yield in terms of SAIDI an improvement around 1.1 minutes per annum in magnitude. The project will target the top 135 of the 190 sites identified, delivering an estimated reduction of 0.78 SAIDI minutes per annum.

11.4.5 WAIHEKE ISLAND SUBTRANSMISSION SUPPLY RESILIENCE

The sub-transmission cables to Waiheke Island provide N-1 security, but any damage to the undersea portion of these circuits takes considerable time to repair, leaving the supply to the island dependent on a single circuit and without any backup at distribution level or any significant embedded generation. The two existing submarine cable circuits are located adjacent to each other and do not have mechanical protection. Recent anchor strikes have identified that the risk of outages is higher than thought and needs to be mitigated. To improve resilience and reliability, and to comply with security of supply standards (SoSS), Vector proposes to install a third sub-transmission cable. The new cable will be spatially separated from the existing cables and include mechanical protection to improve resilience to anchor strikes. This project has been scheduled to start in FY31.

11.4.6 CORRECTIVE MAINTENANCE STRATEGY AND IMPROVED INSPECTION TECHNIQUES

To accelerate the delivery of corrective work to reduce high priority condition notifications, resources to specifically focus on this strategy were increased through FY26 and will continue into FY27. This strategy includes improved inspections techniques in the field outlined in the newly developed maintenance standards, and improved tools for the crews in the field, such as GridAware. This strategy also continues a program of works using enhanced LiDAR inspection techniques, tools, and process that focuses on the identification and correction of clearances between overhead lines to ground, structures, buildings, waterways, etc. to act in accordance with statutory requirements, more specifically NZECP34[15] and reduce the risk of harm to the public.

Vector has adopted a comprehensive approach to corrective maintenance, implementing a new condition-based maintenance (CBM) regime for primary and overhead switchgear to supplement existing time-based planned actions. This transition, now embedded in the latest Vector maintenance standards, is supported by dedicated programmes to remediate backlogs and enable priority timelines. Enhanced preventative techniques and advanced analytics, including tools like GridAware and aerial imagery, have improved the ability to assess, prioritise, and plan asset remediation. The clarity provided by updated standards

[15] Code of Practice for Electrical Safety Clearances, NZECP 34

has strengthened collaboration with service providers, facilitating the assembly and execution of work packages that minimise customer outages and maximise reliability. These combined advancements are key to smoother asset management and meeting Vector's performance standards.

11.4.7 MICROGRIDS – GENERATORS AND ENERGY STORAGE

Microgrids are a Flexible Storage Option (as defined in Section 2). These self-sustaining local power systems provide valuable benefits to the communities they serve. Traditionally, outages have been managed by enhancing interconnectivity and backstopping, but this is not economical or practical in certain remote areas on the edge of the distribution network. Microgrids serve a relatively small geographic footprint with their own interconnected resources such as generators or energy storage devices and have the capability to island from the broader distribution network. They can include the use of mobile generation to mitigate the impact of increased planned work on the customer experience, fixed generation as a contingency plan to manage SAIDI on long rural feeders where other options to improve network resilience are not economically viable or, can be large scale batteries colloquially known as BESS systems (battery energy storage systems). Microgrids, where economically feasible, are a helpful solution for assisting remote communities against the impact of climate change.

11.5 Ongoing reliability and safety investments

11.5.1 APPLY SAFETY IN DESIGN

Vector has made Safety in Design (SiD) a mandatory requirement for Vector design and capital projects and SiD is embedded in the review process for the design of capital projects. For this purpose, Vector has developed a formal SiD standard, USH002 Networks Safety in Design, which sets out the minimum requirements to establish safety in design as early as possible in the design and throughout the life cycle of the asset.

This requires all parties to consult, co-operate and co-ordinate to eliminate or otherwise minimise risks in the design to prevent harm throughout the life of the asset being designed, as far as reasonably practicable. Safety in Design is a practice that integrates risk-management techniques into the design process early, to identify, assess and treat health and safety risks to people over the life of the asset being built. The transmission and distribution of high and low voltage electricity involve managing significant electrical hazards, and the Health and Safety at Work Act (HSWA) 2015 now places greater accountability on designers to achieve safe outcomes for the works they design.

Safety in Design means that the integration of control measures early in the design process eliminates, or, if this is not reasonably practicable, minimises the risks to health and safety throughout the life of the structure being designed. Safety in design applies to any plant, substance or structure that is constructed, whether fixed or movable. SiD will evolve to consider the impact of climate change to a much larger degree than in the past.

11.5.2 OVERHEAD REFURBISHMENT

Over recent years we have accelerated specific programmes of work that reflect our commitment to quality compliance and the outcomes that customers experience through the regulatory quality compliance framework.

Vector has over 3,682 km (route length) of distribution overhead conductor circuits, representing 45% of its total network line length. The expected asset life differs for each type of conductor deployed on the network and each type also has a different failure mode which are accounted for in the asset management strategies and plans. The actual life of each conductor type is also affected by environmental factors (corrosive elements and exposure to wind), mechanical loads, electrical loads and number and magnitude of downstream electrical faults. The geographical location of overhead conductor circuits thus plays a major part in its condition and rate of deterioration.

Vector's proactive replacement and refurbishment programmes of work are informed by our CBARM models, incorporating condition assessments and criticality.

This AMP provides for increased baseline resilience investment in our overhead network refurbishment, incorporating conductor replacement and pole top hardware replacement (crossarms, insulators etc.). This uplift is driven largely by the increased use of covered conductor (CCT) and composite crossarms across the CBARM identified refurbishment projects as well as a marginal increase in length of circuits replaced on an annual basis. The adjustment to specifications will assist with improving overhead network resilience to high winds, vegetation and climate challenges.

Additionally, LiDAR inspection (surveying of lines clearance as an ECP34 regulatory requirement) has been brought into this capital investment category. The LiDAR programme, which in addition to lines clearance measurement, includes components of high-resolution aerial photography of asset condition and vegetation risk assessment will offset maintenance related operating expenditure.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Overhead Refurbishment Programs	17.83	11.26	13.66	14.09	15.13	15.11	13.77	14.29	14.06	15.67	144.87
Network LiDAR Survey	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	19.1
Network Line Clearance	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	8.86	88.60
Total	28.6	22.03	24.43	24.86	25.9	25.88	24.54	25.06	24.83	26.44	252.57

TABLE 11-4: FORECAST EXPENDITURE FOR OVERHEAD CONDUCTOR RENEWALS

11.5.3 COPPER CONDUCTOR REPLACEMENT

The replacement of overhead conductors is an important reliability and climate change hardening program of works and focuses on the 11 kV network. This program has evolved to prioritise the areas for conductor replacement, using Vector's CBARM model, as well as SAIFI and SAIDI performance.

In addition, Vector has initiated a 10-year replacement programme specifically targeting 16mm² copper conductors driven by the condition and the high fault rates recorded in recent years. Fundings previously allocated to the crossarm replacement programme has now been re-allocated to the replacement of these copper conductors. Given the large volumes involved, copper conductors with the highest age and the most faults will be prioritised for replacement.

All conductor replacement will by default include the replacement of crossarms with composite crossarms, replacement of class B insulators with class A post type insulators, lightning arrestors and if required, the replacement of pole structures to maintain the mechanical integrity of overhead line support structures. This holistic replacement approach will harden the overhead networks against the impact of increasing winds and storms in general as well as against lightning, all of which are the result of climate change. The replacement of conductors focuses on overhead line portions with small and conductors most at risk of failure.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Overhead Copper Conductor Replacement	5.53	5.13	5.95	6.16	6.16	6.17	6.16	6.16	6.16	6.16	59.74

TABLE 11-5: FORECAST EXPENDITURE FOR CROSSARM REPLACEMENT

11.5.4 11 KV DISTRIBUTION CABLE REPLACEMENT

This reliability focused replacement program of works focuses on the proactive replacement of underground 11 kV cables. Vector's CBARM model for the underground 11 kV cable fleet is fully developed, and this model is used to inform the program for proactive cable replacement. The focus of the program is on the PILC cable fleets that were installed between the 1950s and 1980s. Distribution 11 kV cables have an average fault rate of 0.047 faults/km with most of these faults attributable to PILC cables. Most faults are found to originate from cable joints but the results of some of the pre-commissioning tests upon repair suggest a deterioration of the cable insulation. Auckland CBD is undergoing major and rapid development and the line-item titled Auckland opportunistic cable replacement in the financial table below, makes provision for the proactive replacement of cable assets, where the risk of failure is sufficiently high enough, under major civil works upgrade in the Auckland CBD including the new underground central rail link and underground stations under a dig once, replace once approach to prevent continuous disruption to business owners and the public.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland 11 kV cable replacement	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16	51.60
Northern 11 kV cable replacement	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	5.50
Auckland opportunistic cable replacement	-	-	-	-	3.19	3.19	3.19	3.19	3.19	3.19	31.90
Total	**5.71**	**5.71**	**5.71**	**5.71**	**8.90**	**8.90**	**8.90**	**8.90**	**8.90**	**8.90**	**76.24**

TABLE 11-6: FORECAST EXPENDITURE 11 KV CABLE REPLACEMENT

11.5.5 REPLACEMENT OF 11 KV RING MAIN UNITS (RMU)

This reliability focused program of works focuses on ageing 11 kV oil filled RMUs such as the Long and Crawford population, and the combined population of series 1 Andelect/Astec/ABB SD RMU switchgears. The CBARM model for this asset type is fully developed and is used to inform the replacement program. From RY19 to RY21 this program was delayed to make way for the SRMP automation initiative but this program is now back up to speed and is continually being evaluated against the risk presented by the RMU population. The new RMUs will be automated as and where required and those that are not automated will be able to be retrofitted with automation if such a requirement should arise. This program will not only improve the reliability and resilience of the network but also decrease the risk of oil leaks and failure effects of the oil filled RMUs. The oil filled RMUs presents risk to operators and its replacement will also improve operator and public safety. Even though this programme is more focused on reliability, that focus will also include climate change considerations, especially flooding, so that RMUs are installed in elevated positions or in a different location less prone to flooding.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland RMU Replacement	18.49	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	144.49
Northern RMU Replacement	2.21	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	1.90	19.31
Total	**20.70**	**15.90**	**15.90**	**15.90**	**15.90**	**15.90**	**15.90**	**15.90**	**15.90**	**15.90**	**163.80**

TABLE 11-7: FORECAST EXPENDITURE RMU REPLACEMENT

11.5.6 REPLACEMENT OF DISTRIBUTION TRANSFORMERS

The Vector network utilises a large number of distribution transformers, either pole mounted and ground mounted as best suited to the application. A mature CBARM model is utilised for each of the pole mounted and ground mounted transformer asset classes to determine the asset risk profile and inform the replacement program. For the integrity of this simple but important asset population, distribution transformers, both pole mount and ground mount, will be proactively replaced on a risk-based priority, transformers smaller than 100 kVA do not have a proactive replacement programme and are managed solely through the maintenance programme, being replaced when defects are identified.

The intention is the asset once installed should last its entire nominal life even with the forecast load growth. Hence all current single-phase transformers undergoing replacement shall be upgraded to a standardised 50kVA size and most 100kVA & 200kVA transformers being replaced will be upgraded to 300kVA. Pole mounted distribution transformers will be installed with improved and more robust kingpins that hardens the installation. Pole mounted transformers will include lightning arrestors at locations where repeated lightning strikes occur to harden the network against the impact of lightning over voltages.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland distribution transformers replacement	3.88	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	32.23
Northern distribution transformers replacement	5.51	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	33.50
Total	**9.39**	**6.30**	**6.30**	**6.30**	**6.30**	**6.30**	**6.30**	**6.30**	**6.30**	**6.30**	**66.09**

TABLE 11-8: FORECAST EXPENDITURE DISTRIBUTION TRANSFORMER REPLACEMENT

11.5.7 REPLACEMENT OF OVERHEAD 11 KV SWITCHES

Vector's 11 kV overhead network includes a large number of air-break switches, disconnectors, fuses, isolating links, sectionalisers and reclosers. Vector does not have a CBARM model for its overhead 11 kV switch population, as most of the asset population are drop out fuses which are managed under a condition-based strategy. Population risk is determined by analysis of failure modes, defects and network impact that allows a risk level to be determined and to inform our proactive replacement program. The focus of the proactive replacement program is on the air break switch (ABS) population, and legacy SF6 insulated overhead switchgear due to age and obsolescence. This program will replace like for like but where automation is needed, will replace a manual operated device with an automated device.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland overhead 11 kV switch renewal	1.08	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	8.28
Northern overhead 11 kV switch renewal	1.78	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	15.28
Total	**2.86**	**2.30**	**2.30**	**2.30**	**2.30**	**2.30**	**2.30**	**2.30**	**2.30**	**2.30**	**23.56**

TABLE 11-9: FORECAST EXPENDITURE OVERHEAD 11 KV SWITCH RENEWAL

11.5.8 MICROGRID ROLLOUT

As stated earlier, ensuring reliability in remote areas using traditional network enhancement or backstopping solutions is often costly relative to the number of customers served and, in some instances, simply not practical. We are always looking at smarter and cost-effective ways to meet the requirements of our customers in areas on the edges of our network with modest growth but with inadequate quality of supply performance. This is where employing microgrids can be a viable economic alternative. Most microgrids are network-connected, but they can 'island' themselves during an outage. This means those connected to them can access back-up power, and this cost-effectively improves remote communities' resilience.

Temporary generation was deployed in the rural enclaves of Piha and South Head in 2019, and this generation has proved to be well worth the investment and hugely successful in alleviating SAIDI and improving the customer experience. Customers have been vocal in stating their satisfaction and support for the generation installations. In this AMP period, permanent generation sites will be established at these two remote communities that are reliant on single and lengthy 11 kV supplies.

Both these feeders are in the SAIDI top ten worst performing feeders: backstopping is not available, and a traditional network backstop solution is not economic. The higher capital cost of BESS systems compared to diesel generation has discounted the installation of BESS systems in these enclaves. Apart from the higher installation cost, BESS systems are not suitable as a backup supply for long outages typically associated with for example a car-versus-pole incident which, can typically take up to 8 hours to replace at which time a BESS would have run out of capacity.

The Big Omaha substation will see 2x 2.5MVA diesel gensets installed in the area. One will be located beyond Leigh and the other closer to the Zone substation, serving dual purposes. The first is to improve the performance of the Leigh feeder under contingency, which is currently only backstopped from the extremely long Wellsford K02 feeder. The second is to address the loss of the Warkworth – Big Omaha 33kV circuit. This outage is difficult to deal with at certain times of the year and the addition 5MVA of generation would greatly simplify operation.

Swanson K07 supplies the Bethells township. This feeder is similar to Piha and South head in that it is lengthy and performs poorly from a SAIDI perspective. The ultimate solution has not been finalised, but it will likely include diesel generation after the success of the previous projects.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
South Head permanent standby generation					1.49						1.49
Piha permanent standby generation									0.11	1.81	1.92
Big Omaha Backup Diesel Generators	0.8	2	2.2								5.0
SWAN K07 Bethells 11kV reinforcement, automation and backup supply									2		2
Total	**0.8**	**2**	**2**		**1.49**				**2.11**	**1.81**	**10.21**

TABLE 11-10: FORECAST EXPENDITURE FOR PERMANENT STANDBY GENERATION

11.5.9 THE INCREASED USE OF LIGHTNING ARRESTORS

Climate change has seen increased lightning activity around the network but more specifically in the North-western network. 11 kV lightning arrestors will become part of our standard for overhead installations in areas of high lightning activity. In areas of high lightning activity, lightning arrestors will be retrofitted to the network. This will reduce the risk of overvoltage related damage to plant.

11.5.10 EXPULSION DROP OUT FUSE REPLACEMENT

With climate change there is a risk that hot and dry conditions can occur and perhaps increase which in turn leads to a higher risk of wildfires. The electricity network can contribute to the start of a wildfire if an expulsion drop-out fuse emits/ejects hot particles during operation to clear a fault. To reduce this risk Vector will install current limiting drop out fuses in a number of 11 kV overhead feeders in the Auckland and Northern networks. The performance of these feeders and current limiting fuses will then be closely monitored and if the performance of these new devices is to expectations, they will be rolled out network wide for all extreme and high fire risk areas in the AMP period. These devices will provide reliability, safety and environmental improvements and hardening against climate change.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland expulsion drop out fuses replacement	0.38	0.33	0.33	0.33	0.33	0.40	0.40	0.40	0.40	0.40	3.75
Northern expulsion drop out fuses replacement	0.38	0.33	0.33	0.33	0.33	0.40	0.40	0.40	0.40	0.40	3.75
Total	**0.75**	**0.65**	**0.65**	**0.65**	**0.65**	**0.80**	**0.80**	**0.80**	**0.80**	**0.80**	**7.50**

TABLE 11-11: FORECAST EXPENDITURE FOR EXPULSION DROP OUT FUSE REPLACEMENT

11.6 Financial summary of reliability programmes of work

The investment forecast below provides a financial summary of the programmes of work that are already in progress to address network resilience, reliability, safety, and the environment but also includes our high-level forecast for programmes of work in the DPP4 period that will specifically focus on hardening the network to improve resilience for weather related events.



FIGURE 11-1: FORECAST RELIABILITY IMPROVEMENT AND CLIMATE CHANGE NETWORK HARDENING

11.7 Climate resilience

Changes to the frequency and intensity of climate change remain a challenge to lifeline utilities like Vector. Vector has continued its focus into the resilience of Auckland's electricity system by investing in physical and digital infrastructure as well as maintenance programmes to harden its network and to enable faster recovery in response to significant weather events.

In 2025, Vector conducted a survey of its customers to better understand their needs and expectations around resilience of our network. Some key takeaways of this survey were:

- Customers expect electricity network resilience to mean strong infrastructure that prevents outages where possible, and fast restoration when outages do occur, especially during major storms, alongside clear, timely communication.
- They generally prefer resilience investments that improve restoration speed and reduce storm-related outage frequency.
- Many also see backup options and proactive maintenance (like vegetation management) as part of the overall resilience picture, with storm-impacted customers placing even greater emphasis on storm performance.

The survey findings validate Vector's strategy to invest in a more resilient network. This includes strengthening our understanding of how climate change affects our assets and identifying efficient, targeted solutions to reduce risk. Vector is leveraging in-house expertise and working alongside industry specialists to improve our assessment of physical climate hazards and their potential impacts on the network. We are continually building this evidence base. A summary of the physical effects modelling undertaken to date is summarised below.

Flood risk modelling: Vector models storm-driven coastal inundation (sea level, storm surge and tides), freshwater flooding, and cyclone-induced flooding to understand how flood hazards may change over time and where they intersect with our asset base. Where practicable, we assess both 1:100-year and 1:500-year return periods and, where data supports it, project these hazards across Vector's climate scenarios out to 2100 to inform resilience investment planning.

Landslip modelling: Vector undertakes landslip susceptibility analysis to identify areas where slope instability may increase the likelihood of damage to network assets. This modelling has been applied across overhead electricity assets providing a geospatial basis for identifying hotspots and prioritising targeted mitigation and operational responses.

Hot, dry weather and wildfire modelling: Vector conducts short-term, year-ahead fire assessments to understand seasonal wildfire risk and associated impacts on network operation and public safety. This work informs preparedness and response planning, with a view to extending the approach over time toward longer-term horizons (out to 2100) as methodologies and datasets mature.

Wind speed modelling: Vector has analysed projected changes in wind speeds across the Auckland region to understand potential changes in exposure to wind-driven damage mechanisms. While this provides useful regional insight, a key next step is developing a repeatable methodology to map wind risk geospatially to specific assets, recognising the high spatial and temporal variability of wind.

Cyclone modelling: Vector has commissioned analysis of a severe cyclone scenario comparable to Cyclone Gabrielle to understand plausible impacts if a similar event tracked directly over Auckland. This modelling supports planning for extreme-event exposure and informs both longer-term resilience thinking and near-term readiness, including improving the quality of pre-event impact assessment.

Vector uses the outputs of our physical effects modelling to inform our resilience model and to identify the network areas and assets most vulnerable to high impact, low probability events. This model is a risk-point framework which converts the outputs of our physical climate hazard modelling into a single, comparable measure of network exposure, so we can prioritise resilience investment on a consistent basis. Vector's engineering team applies a risk scoring system that combines climate model results with in-house engineering judgement to assign each climate-related risk on specific assets a score based on customer outage impact, total network load at risk, public safety, and the ability to back-feed and maintain supply. The projects and programmes described below give effect to this approach by targeting the highest-scoring vulnerabilities and strengthening both prevention (hardening/renewal) and recovery capability (restoration speed and contingency readiness) supported by the arrangements in Section 6.4.

In this AMP Vector is investing $393M in projects and programmes of work that improve our climate change resilience. Examples of this include:

11.7.1.1 WAIKAUKAU ZSS 33KV ODID AND 11 KV SWBD REPLACEMENT PROJECT

Waikaukau ZSS sits in a floodplain and is vulnerable to heavy-rain flooding. It flooded in March 2017 and again in January 2023 during Cyclone Gabrielle, forcing a substation shutdown and several days of back-feeding while cleanup occurred. Flooding damaged the DC systems and the lower sections of the 11 kV switchgear, as shown in the photos below.

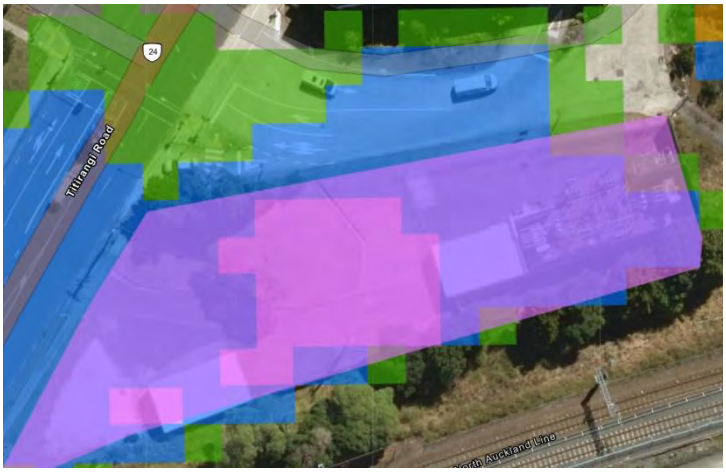




This project will replace the aging 33 kV and 11 kV switchgear by constructing a new combined 33 kV and 11 kV switchroom. It will also mitigate flood risk by siting the new switchroom near the substation road frontage, on ground above the 1:500 ARI flood level. The project is currently under construction and is scheduled for completion in FY29.

11.7.1.2 NEW LYNN ZSS 33KV ODID AND 11 KV SWBD REPLACEMENT PROJECT

Similar to Waikaukau, New Lynn ZSS sits in a floodplain and is vulnerable to heavy-rain flooding. The site flooded in March 2017, resulting in equipment damage. Our flood modelling indicates the 1:500 ARI inundation extent shown below.



This project will replace the aging 33 kV and 11 kV switchgear, including electro-mechanical relays. There is sufficient space within Vector's substation land to construct a new, purpose-built switchgear building elevated above the 1:500 ARI flood level. The building will house new indoor 11 kV and 33 kV switchgear. The project is planned to commence in FY28 and be commissioned by FY30.

Vector has planned for several programmes of work that provide a clear link to resilience against the impacts of climate change but also have benefits towards network 'adequacy' and 'reliability'. Examples of this include some of the projects in the preceding sections such as:

- Deployment of network isolation and automation
- Specific reliability initiative like reinforcement of distribution spur feeders
- Overhead conductor renewals and LiDAR surveys
- Replacement of distribution transformers and switchgear
- Use of composite crossarms
- Microgrid rollout
- Increased use of lightening arrestors
- Expulsion drop out fuse replacement

We have also applied for Innovation and Non-Traditional Solutions Allowance (INTSA) funding to develop a large-capacity dry-type mobile power transformer. If successful, this initiative would materially improve network resilience by significantly reducing transformer deployment and restoration times for both planned and unplanned outages.

Vector is continuing to invest in complementary, non-network solutions to strengthen resilience, including DERMS, ADMS and enhanced vegetation management. We are in the process of assessing our resilience framework using the Resilience Maturity Model Assessment Tool (RMMAT) provided by the Electricity Engineers Association. This will help us benchmark our current capability, support more informed investment and planning decisions, and demonstrate that we are taking a structured approach to resilience improvement.

11.8 Managing carbon footprint

Vector has set a science aligned target to reduce scope 1, and 2 emissions (excluding electricity distribution losses) by 53.5% by 2030 based on a 2020 baseline. The target has been set to meet the External Reporting Board's Climate Related Disclosure standards which Vector is obliged to comply with under the Financial Markets Conduct Act 2013 as a listed entity. Vector is also investigating scope 3 reductions, and is already working with supply chain partners, like our field service providers, on reducing indirect emissions. For more information, please refer to Vector's Greenhouse Gas Inventory Report[16].

11.8.1 TEMPORARY DIESEL GENERATION REDUCTION (STATIONARY COMBUSTION)

The largest lever for decarbonisation of Vector's electricity distribution business is in the reduction of temporary diesel generation during planned construction works or planned maintenance works. Temporary generation is required to maintain supply when the plant to be worked on needs to be de-energized. The present strategy focuses on better management of diesel generators,

[16] https://www.vector.co.nz/investors/reports

and the use of mobile transformers as an alternative to diesel generation. Such initiatives not only reduce emissions but also noise, street pollution, urgency of the shutdown window, and overall cost. Note that the Diesel Generators used as standby generators for outages, such as those in Piha and Southhead represent approximately 0.5% of overall diesel emissions and can therefore be considered negligible.

11.8.2 SF_6

As SF_6 comes under the emission trading scheme (ETS), Vector is obliged to purchase New Zealand Units (NZUs). SF_6 reduction can be achieved through improvements in monitoring and management. Nevertheless, failures will always occur, and the only solution to eliminate SF_6 emissions is through the installation of SF_6 free equipment. However the costs of this SF_6 free switchgear is currently high.

11.8.3 CONSIDER ENVIRONMENTAL IMPACTS

The environmental effects of installing, operating, maintaining and upgrading Vector's network are regulated by a range of legislation and statutory controls - particularly the Resource Management Act 1991, as given effect to by the Auckland Unitary Plan. Vector also maintains ISO14001 Environmental Management certification.



SECTION 12

Our assets

12 – Our assets

Asset replacement and renewal is aimed at ensuring that the assets installed on the network are in serviceable condition and are replaced pro-actively (prior to failure) or reactively (after failure) according to their condition and criticality. Vector takes a whole of life cycle approach to assessing the need for asse replacement to minimize the cost to customers.

The following sections describe:

- an overview of the asset management objectives applicable to replacement and renewal, and strategies to achieve those objectives
- how we manage our asset fleets
- the factors that influence our asset management strategy
- our approach to forecasting and drivers for asset replacements
- a summary of the major investments identified to maintain network performance between 2026 and 2036, further detail on the renewal programmes (including a list of major projects for AMP period) is provided in section 12A

12.1 Renewals objectives and strategy

12.1.1 ASSET MANAGEMENT OBJECTIVES

The asset management objectives that are addressed through the replacement and renewal programme of works and investments are set out in the table below.

FOCUS AREA	OBJECTIVES
Safety, environment and network security	• Comply with relevant safety and environmental legislation, regulation and planning requirements. • Asset management activities align with environmentally responsible and sustainable behaviours, in line with industry best practice, enabling wider emissions reductions. • Minimise the impact on the environment with regards to our assets and work practices. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change).
Customers and stakeholders	• Enable customers' future energy and technology choices. • Ensure the long-term interest of our customers by providing an affordable and equitable network. • Consider the impact of our operational decisions on customers and minimise the disruption of planned outages and unplanned outage response times while providing a high-quality customer experience across all interactions.
Network performance and operations	• Strive to optimise asset lifecycle performance through increased asset standardisation, clear maintenance regimes and the development of fact-based investment profiling. • Utilise clear business case processes, integrate risk management and complete post investment reviews to inform our decision making and analysis. • Maintain compliance with security of supply standards through risk identification and mitigation. • Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings.
Future energy network	• Prepare the network for future changes that will be driven by: – technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc. – environment: climate disruption and network resilience – customer: decarbonisation of the economy, electrification of transport, etc – operations: transition to distribution system operator model and whole of system planning • Embed network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third party flex traders and retailers. • Improve our visibility of, and ability to control, the LV network including management of the information required.

TABLE 12-1: ALIGNMENT TO ASSET MANAGEMENT OBJECTIVES

12.1.2 STRATEGIES TO ACHIEVE THE OBJECTIVES

To meet the asset management objectives, the following strategies are employed by Vector. As electricity networks are complex interconnected systems, each strategy addresses multiple objectives.

12.1.2.1 COMPLY WITH RELEVANT REGULATIONS

Vector will comply with the relevant regulatory obligations, legislative requirements such as the Electricity Safety Regulations and industry standards. The most relevant to network integrity, growth and security are compliance with the Security of Supply Standards, achieving and maintaining compliance with the DPP4 Quality Standards and complying with the Power Quality requirements.

By modelling the condition of our assets, we identify where assets are likely to fail and plan our remedial actions to prioritise the assets with highest criticality through to lowest criticality, hence managing network risk, and ensuring resilience and compliance with regulations.

12.1.2.2 ASSET INFORMATION AND INSIGHTS STRATEGY

Vector has established the Information and Insights Strategy, which is tightly coupled with the Digital Strategy, to focus on improving asset data and condition information required to enable advanced analytics, support Network Operations, and optimise Asset Management decisions. Initiatives under this strategy have included investing in new systems to improve the quality and accuracy of asset data, improve network visibility through smart meter acquisition, analytical solutions, and modernising data platforms to improve data management.

12.1.2.3 RISK BASED ASSET CONDITION FORECASTING METHODS

Vector applies a risk-based approach to forecasting asset condition, and therefore the expected asset volumes and expenditure required for asset replacement. The value and criticality of the asset type determines the complexity of the modelling implemented so that the effort is appropriate for the risk posed to the network. Asset obsolescence, vendor support and/or availability of spare parts are included in the condition assessment of asset types. For example, high value assets such as switchboards are forecasted using condition-based risk models, whereas low value and low criticality assets such as LV distribution equipment, are forecast using historical trend models and condition assessments.

12.1.2.4 MAINTAINING NETWORK SAFETY

Safety of the public and workers is of the highest importance to Vector. Where an asset is identified to pose a risk to safety, we will prioritise remedial actions to remove the risk. Such risks are documented in Vector's risk management system and reviewed on a regular frequency as appropriate by a steering group until the risk is closed out. Vector is required to operate its network in compliance with NZS7901 which details safety management systems for public safety.

12.1.2.5 MANAGING ASSETS TO ENSURE LEAST COST ACROSS THE LIFE CYCLE

At each point in an asset's life cycle, Vector will take the appropriate action to ensure the least cost of owning the asset across its life cycle. Actions may include replacement/retirement if the asset is no longer needed, refurbishment/life extension, or maintenance.

Our approach is to identify possible options to address the need, undertake a cost and benefit analysis for asset replacements of each solution, and to select the solution which has the best benefit-cost ratio. The options analysis considers capital and operational costs, safety, environmental impacts, risks and opportunities from the whole of asset life perspective. For some low value asset classes, a run to failure approach with reactive replacement is applied where deemed more efficient.

12.1.2.6 DEFERRED REPLACEMENTS AND INNVOVATIONS

While the deferral of asset replacements is typically part of our standard operations, we continue to look for opportunities through innovations. For example:

- The use of smart meter data helps to determine loading on each distribution transformer allowing Vector to make decisions when we are evaluating capacity increases. Depending on loading, we can choose to defer transformer replacement if it can absorb the additional load
- Vector has developed an automated maintenance system that monitors circuit breaker operations and automatically generates service requests for field technicians. This innovation optimises maintenance intervals by enabling condition-based rather than time-based servicing helping ensure breakers are maintained when needed and maximising operational life
- Vector uses a VIA Analytics model to provide a fleet-wide view of power transformer condition by drawing on large datasets from other utilities. Using available asset health data as inputs, the model estimates the current condition of the transformer fleet and forecasts future condition under different modelling scenarios. This innovative approach improves the accuracy of predictive insights and helps maximise transformer life while operating within defined risk envelopes

12.2 Forecasting methods

The purpose of forecasting assets renewals is to ensure that an appropriate level of capital and resources are available for Vector to manage network risk at a fleet level and align with our wider Asset Management Objectives (Section 5). Vector uses a number of different methods to forecast asset renewals needed on its network. The type of forecasting approach used is dependent on the asset value, asset criticality, population size, renewal drivers and robustness of available information associated with the asset class.

For high value assets such as power transformers, where inspection and testing provide robust condition information, predictive modelling is undertaken to understand when individual assets are at the end of their serviceable life. For low value high volume assets that are less critical to network operations, such as air-break-switches, the forecasting is done at a portfolio level to identify the expenditure required for the asset fleet while actual replacements are identified based on field inspections.

The rationale and methods Vector uses to inform their capital expenditure forecasts across its asset categories are described below.

12.2.1 RISK BASED MANAGEMENT

Vector has adopted the use of Condition-Based Asset Risk Management (CBARM) to model the condition of selected asset classes from a fleet perspective. This approach is based on the methodology published by the UK regulator Ofgem[17] (Office of Gas and Electricity Markets) and considers asset criticality, asset health data, deterioration rates, and probability of equipment failure. The outcome of this modelling provides a fleet-wide overview of the asset health risk of a particular asset class. It also allows various intervention strategies to be tested by providing a forecast of the asset risk profile in the future. By comparing different intervention strategies Vector is able to assess the scale of replacement required to efficiently manage network risk.

The asset data used as inputs to the models are directly retrieved from SAP PM thereby enabling each model to be updated with the latest information from the field. Vector's focus on improving its asset health information is complementary to the continued improvement in the accuracy of its CBARM models."

In the context of this AMP the output of our CBARM models have been defined using the following risk categories:

- **R1: Minimal risk** – Assets are generally in good condition. Continue to review and monitor using current asset maintenance standards.
- **R2: Moderate risk** – Assets are showing signs of deterioration. Where issues have been identified, these can be addressed through corrective maintenance to ensure the assets remain serviceable.
- **R3: High risk** – Assets have defects that have the potential to cause failure. Remedial planning and specific actions need to be identified and executed.
- **R4: Maximum risk** – Assets are in a poor condition with a heightened risk of failure. Requires immediate remedial actions.

12.2.2 CONDITION BASED ASSESSMENT

In instances where asset criticality information is not available, the asset fleet condition is based on various health indicators such as age, type, known defects and results of routine testing. This differs from CBARM as it produces a condition score rather than risk score, that is the criticality of the asset is not assessed. An example of this the power transformer asset class where the condition score is based on the results of tests on the oil and insulation in addition to age and type, to arrive at a combined condition score. The asset fleet health indicators are described using the criteria below:

- **H1: Negligible risk of failure** – Assets are generally in good condition. Continue to review and monitor using current asset maintenance standards.
- **H2: Moderate risk of failure** – Assets are showing signs of deterioration. Where issues have been identified, these can be addressed through corrective maintenance to ensure the assets remain serviceable.
- **H3: Increasing risk of failure** – Assets have defects that have the potential to cause failure. Remedial planning and specific actions need to be identified and executed.
- **H4: Material risk of failure** – Assets are in a poor condition with a heighted risk of failure. Requires immediate remedial actions.

This assessment approach is compared against historical records to validate any anomalies in modelling outputs.

12.2.3 AGE AND TYPE

For some asset classes it is appropriate to use deterministic factors such as age and type information to predict asset replacement needs. In particular, where it is not efficient or possible to gather sufficient condition information to assess the health of individual assets or develop a CBARM model.

An example is digital devices, such as modern protection relays, which are generally managed to a specific age as it is not possible to assess the condition of the integrated circuits and/or software and firmware upgrades are not available anymore.

Also note in some sections we discuss systemic issues leading to the premature replacement of assets or parts of assets. For example, in section 12.5.13 we note that while the current versions of XLPE cables are very robust, the early generations of XLPE had manufacturing defects which could result in premature failures of the cable. Vector has experienced several repeat failures on the early generations of XLPE, resulting in the establishment of a proactive replacement programme for the population.

12.2.4 HISTORICAL TRENDS

In asset classes where there is insufficient asset information available to support the use of the methods above, the number of assets replaced on an annual basis can be predicted by referring to historical trends. The historical trend rates can also be extrapolated or adjusted to account for changes in age across the fleet. This is typically applied to high volume, low value and low criticality asset types.

17 DNO Common Network Asset Indices Methodology

A high-level summary of renewal forecasting methods and renewal drives by asset class is provided below in Table 12-2:

FLEET	RENEWAL DRIVER	PRIMARY FORECASTING METHODS
Primary switchgear	Obsolescence, condition, age, safety, reliability, criticality	CBARM and Condition based assessment
Power transformers	Obsolescence, condition, age, safety, reliability, criticality	VIA analytics model
Underground cables	Condition, age, safety, reliability, environmental	CBARM, Historical for LV
Overhead lines	Condition, age, safety, reliability, environmental	CBARM and Condition based assessment
Support structures	Condition, age, safety	Condition based assessment
MV Distribution equipment	Condition, age, safety, reliability	CBARM
Distribution transformer	Condition, age, safety, reliability, environmental	CBARM
LV Distribution equipment	Obsolescence, condition, age, safety, reliability	Historical and Condition based assessment for some assets
Protection and controls	Obsolescence, age, availability of spares, functionality	Type and age
Auxiliary systems	Obsolescence, age, reliability	Type and age, Historical
Generation and energy systems	Condition, age	Historical
Infrastructure and facilities	Condition, safety	Historical

TABLE 12-2: RENEWAL DRIVERS AND FORECASTING METHODS

The asset classes listed in table 12-2 cover the categories set out in the Report on Forecast Capital Expenditure in Schedule 11a(iii). This schedule can be found in appendix 7 of this document.

12.2.5 ALIGNMENT WITH SYSTEM GROWTH

All assets identified for replacement are overlaid with future demand and customer requirements (e.g. DER impact) to ensure that replacements meet the long-term system growth needs. Section 10 covers the system growth methodology and process such as load forecasting and capacity constraint modelling.

12.3 Primary switchgear

The purpose of primary switchgear is to provide protection of the network and primary assets such as underground cables, overhead lines and power transformers, as well as a point of control and isolation of primary circuits.

Primary switchgear is used to provide a means to safely disconnect a faulted section of the network and to provide a point of control or isolation needed for network control or planned maintenance activities.

This Section describes our primary switchgear fleet and provides a summary of our associated asset management practices.
The primary switchgear fleet consists of the following three subcategories:

- Indoor and outdoor 110 kV switchgear
- Indoor 33 kV, 22 kV and 11 kV switchgear
- Outdoor 33 kV switchgear

12.3.1 110 KV SUBTRANSMISSION SWITCHGEAR

12.3.1.1 FLEET OVERVIEW

Three sites on Vector's network house 110 kV switchgear. Liverpool and Hobson Zone Substations both have indoor GIS switchboards and Lichfield GXP has two outdoor circuit breakers. All of Vector's 110 kV switchgear are SF_6 insulated and use SF_6 gas puffer circuit breaking technology.

12.3.1.2 POPULATION AND AGE

The two outdoor 110 kV GIS circuit breakers at Lichfield GXP are 30 years old. The 110 kV GIS switchboards at Liverpool and Hobson zone substations are 28 and 14 years old, respectively. The Liverpool switchboard was extended in 2021 with the installation of three new circuit breaker bays.

12.3.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Vector's indoor GIS assets have been performing well with no notable failures since commissioning. Although not an issue at this time as more than half of the fleet is under 12 years old, assets of this type are vulnerable to obsolescence as more modern designs become available and the original equipment manufacturer (OEM) no longer provides support or can make readily available parts. To mitigate this risk, Vector has secured strategic spares and vendor support for these assets.

The circuit breaker hydraulic drives on the GIS switchboard at Liverpool substation due to age and reliability concerns were considered for mid-life refurbishment and upgrade. To mitigate the increasing risk of drive-mechanism failure presented by the existing hydraulic system, Vector engaged in a program of complete hydraulic systems renewal with extended monitoring and control functionality. This major 20-year mid-life refit program was completed in FY23.

There are known issues associated with the SF_6 gas seals on the outdoor circuit breakers installed at Lichfield GXP (a spare pole is held on site) as well as the ability to maintain a supply of serviceable spares. Due to obsolescence and the availability of spare parts, these circuit breakers are scheduled for replacement in 2028 (refer to Appendix 12 for details).

12.3.1.4 CONDITION AND HEALTH

Provided there are no major failures, indoor GIS switchboards technically have no end of life if proper maintenance is undertaken and there is a supply of spare part. The Merlin Gerin type D-TH7 switchboard installed at Liverpool zone substation is no longer in production but is still supported by the OEM factory in Grenoble France (MasterGrid) for parts and service. Some of its components are vulnerable due to age related deterioration such as gaskets, “O” rings and polycarbonate materials which have been historically difficult to acquire. Vector has recently repaired known SF_6 leaks with new seals and component renewals and has further procured a contingent of spare parts to minimise any future repair time. A project to install gas loss trending equipment to monitor the leak rate of any compartment has also been completed which will act as an early warning system to investigate any future leaks faster. A project to investigate abnormalities in contact resistance in the primary apparatus has been scheduled for FY26. As part of this project, Vector has invested in mass flow meters to accurately record the SF_6 losses incurred during repair or maintenance works for all its SF6 switchgear.

As the Lichfield 110 kV circuit breakers are located outdoors, they are prone to the typical issues associated with outdoor switchgear such as corrosion, pollution, or animal interference. These circuit breakers have performed in line with expectations, but their age and risk of obsolescence mean that they are approaching end of life.

12.3.1.5 MANAGEMENT STRATEGY

Subtransmission GIS switchgear is procured to align with site specific functional and performance requirements.

The maintenance for the 110 kV indoor GIS is detailed in Vector’s maintenance standard ESM102 and the outdoor breakers at Lichfield zone substation are covered under Vector’s maintenance standard ESM103. Planned maintenance activities consist of inspection and testing with specialist work contracted to the OEM. Routine inspections are undertaken by Vector’s FSPs every two months. Specific OEM service works are conducted at a frequency of between one and eight years depending on the level of service, make and model of the switchgear as determined by the OEM. The replacement of this asset class is driven primarily by obsolescence, lack of vendor support or availability of spare parts and is conducted on a proactive basis.

The outdoor circuit breakers installed at Lichfield zone substation are planned to be replaced in FY28 due to obsolescence, reliability, and risk of supply.

12.3.2 INDOOR PRIMARY SWITCHGEAR

12.3.2.1 FLEET OVERVIEW

Indoor primary switchgear on Vector’s network operates at 11 kV, 22 kV or 33 kV depending on the topology of the network. The 33 kV and 22 kV switchgear are used for subtransmission, and 22 kV is used for distribution in certain areas of higher density load such as the CBD and Highbrook Industrial Park. Indoor switchgear comprises modular panels containing integrated devices such as circuit breakers, disconnectors, earth switches, instrument transformers and protection relays. A series of modular panels connected together makes up a switchboard which is housed in a purpose-built building with temperature and humidity control. This switchgear is generally more reliable than its outdoor equivalents because it does not incur as many issues associated with corrosion, pollution and other environmental factors.

The indoor switchgear on Vector’s network includes both conventional and fixed pattern types. The conventional switchgear fleet uses oil, vacuum or SF_6 for its interrupter mediums whilst modern fixed pattern switchgear uses vacuum interrupter technology only. The composition of this fleet according to build type, interrupter type and voltage level is provided in Table 12-3 below.

TYPE	110KV FIXED PATTERN	110KV CONVENTIONAL	33 KV FIXED PATTERN	33 KV CONVENTIONAL	22 KV FIXED PATTERN	22 KV CONVENTIONAL	11 KV FIXED PATTERN	11 KV CONVENTIONAL
Oil				2				274
Vacuum			213	7	93		613	399
SF_6	22		2	15		29	10	127

TABLE 12-3: INDOOR SWITCHGEAR

12.3.2.2 POPULATION AND AGE

The population and age profile for both the conventional and fixed pattern indoor switchgear types is shown below in Figure 12-1 for each voltage level.

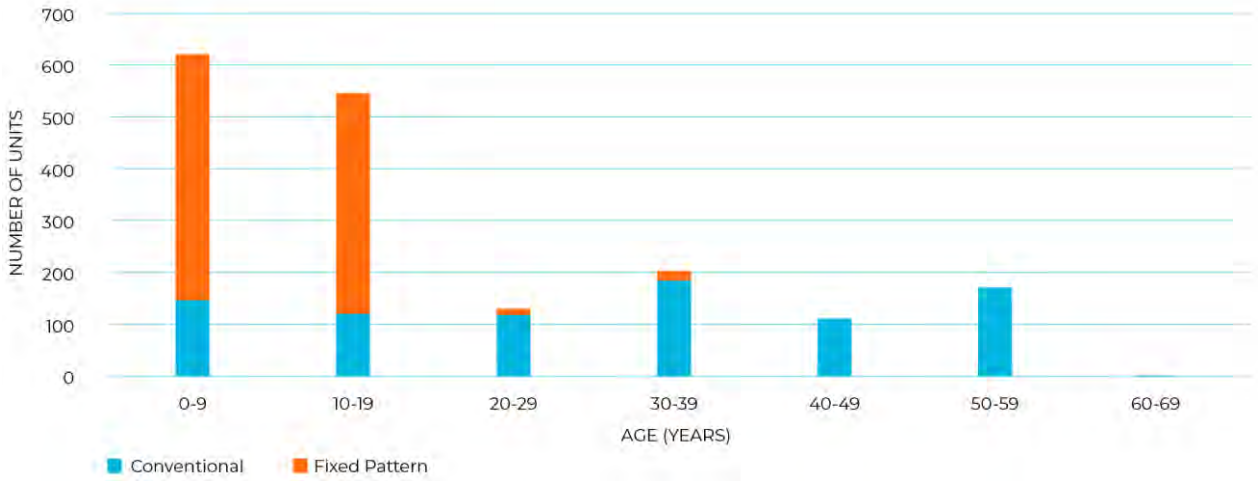


FIGURE 12-1: INDOOR SWITCHGEAR FLEET AGE PROFILE

12.3.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Indoor switchgear of conventional design has several known failure modes, including mechanical failure, insulation breakdown, and secondary circuit malfunctions. By comparison, the issues identified with indoor fixed pattern switchgear have been relatively minor. Fixed pattern switchgear has generally demonstrated good reliability and performance, with the main exception being cable bushing failures that were limited to a specific bushing type that Vector no longer procures. An operational restriction applied to a particular switchgear type has required a targeted remediation programme, which Vector is undertaking in collaboration with the manufacturer to mitigate the associated risks and impacts.

12.3.2.4 CONDITION AND HEALTH

Vector has recently developed a CBARM model to assist to inform the replacement programme for indoor switchboards. This model is based on age, condition and criticality. The present (RY26) risk level for the indoor switchboard fleet is shown below in in Figure 12-2.

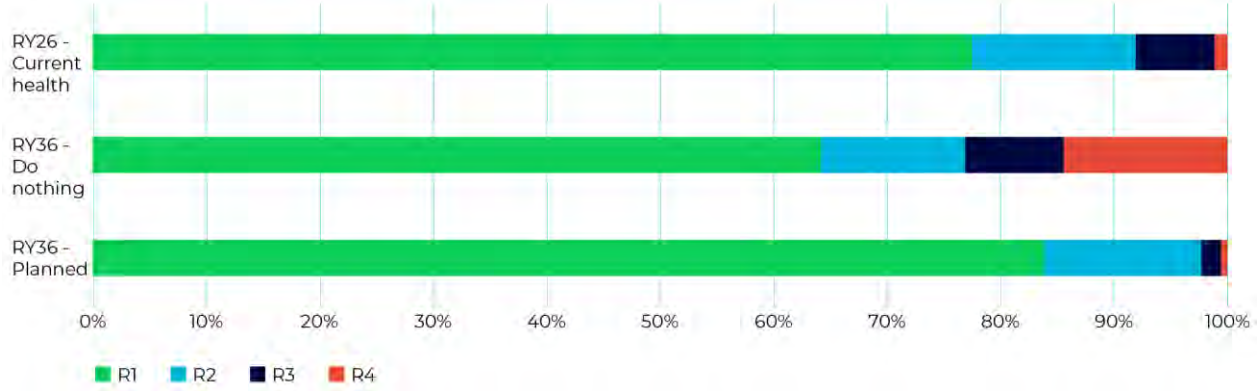


FIGURE 12-2: INDOOR SWITCHBOARD FLEET RISK PROFILE

This indicates that the indoor switchboard fleet is in good condition and Vector's investment programme will maintain the risk profile at approximately present levels. Full details of this programme are provided in Section 12 Appendix.

12.3.2.5 MANAGEMENT STRATEGY

The management strategy for indoor switchboards is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.3.2.6 DESIGN AND CONSTRUCT

Vector has adopted fixed pattern switchgear as a standard given its safety, reliability, and performance benefits as well as reduced maintenance needs over conventional switchgear. As such, conventional switchgear is procured by exception and considers cost and safety trade-offs. Examples of this include extensions to existing switchgear and oil to vacuum breaker conversions. Generally,

fixed pattern switchgear is used for all new installations and is procured using Vector's specification ENS-0005. Conventional switchgear is procured based on specific site performance and functional requirements.

12.3.2.7 OPERATE AND MAINTAIN

Vector's maintenance standard ESM103 for conventional switchgear apparatus is a culmination of best practice as per AS/NZ 2467 standard and manufacturer specific maintenance regimes. In addition, Vector has recently purchased a magnetron atmospheric condition tester to better determine the condition and serviceability for vacuum circuit breakers (where it is physically possible to be used). Vector has a separate maintenance standard ESM101 specifically for fixed pattern switchgear.

Typical planned maintenance activities are shown below in Table 12-4.

ACTIVITY DETAIL	Visual inspections	Thermovision inspections	Partial discharge testing	Kelman (timing) testing
FREQUENCY	2 Months	1 Year	2 Years	2 Years

TABLE 12-4: PLANNED MAINTENANCE ACTIVITIES FOR INDOOR AND OUTDOOR SWITCHGEAR

Vector has developed an automated maintenance system that monitors circuit breaker operations and automatically issues service requests to field service technicians. This innovation optimises maintenance intervals by ensuring that circuit breakers are serviced when needed as opposed to time based servicing. In addition, specific OEM service works are conducted at a frequency of between two and sixteen years depending on the level of service, make and model of the switchgear as recommended by the vendor. Investigations, programs of repair, inspection and modifications have been initiated where systemic issues are identified. For example, the cable terminations on Schneider switchgear incomer CBs were changed from socket type outer cone terminations to inner cone terminations to reduce the risk of torsional forces on 33 kV bushings leading to premature failure.

12.3.3 OUTDOOR PRIMARY SWITCHGEAR

12.3.3.1 FLEET OVERVIEW

Conventional outdoor switchgear is a general classification for 33 kV outdoor circuit breakers[18], associated bus works, support structures, disconnectors, and instrumentation. Their deployment is limited to the Northern region, and this class of switchgear is used exclusively for subtransmission in the Vector network.

Vector's outdoor 33 kV switchgear fleet includes both conventional and GIS types as shown in Table 12-5.

TYPE	33 KV GIS – OUTDOOR	33 KV CONVENTIONAL – OUTDOOR
Oil		58
Vacuum	20	8
SF_6		3

TABLE 12-5: OUTDOOR SWITCHGEAR

12.3.3.2 POPULATION AND AGE

Vector has 89 outdoor circuit breakers in service across its network including three that are installed with a GXP. The population and age profile for these outdoor circuit breakers is presented below in Figure 12-3.

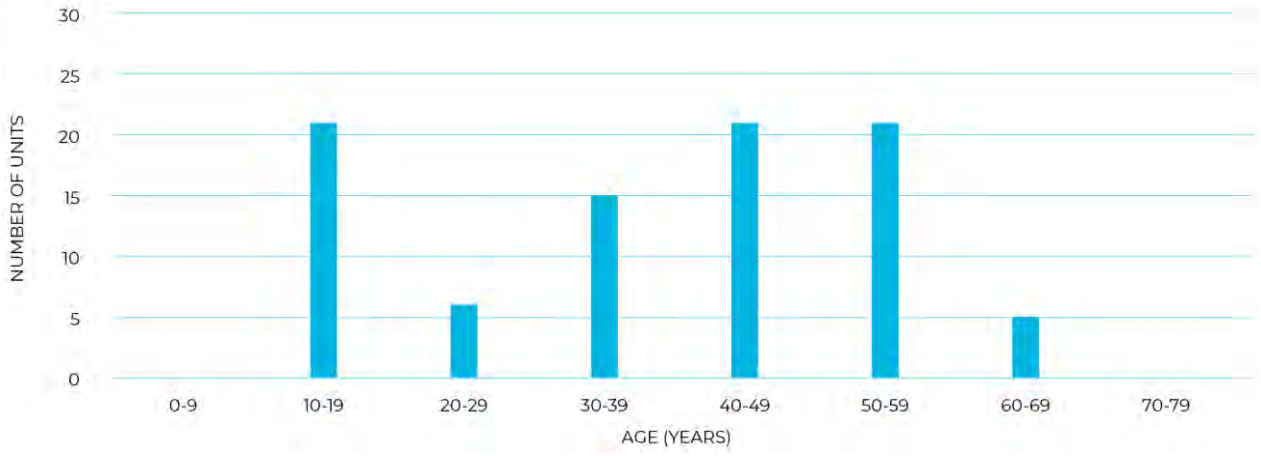


FIGURE 12-3: OUTDOOR 33 KV SWITCHGEAR FLEET AGE PROFILE

18 Note that 'outdoor circuit breakers' excludes the 110 kV circuit breakers at Lichfield GXP

12.3.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

In 2013, a Vector owned 33 kV oil-filled circuit breaker failed at Transpower's Hepburn Road GXP resulting in collateral equipment damage in the switchyard and a prolonged outage. This is an inherent risk of all outdoor switchyards containing oil-filled circuit breakers with porcelain bushings, which have the potential to fail catastrophically resulting in damage to surrounding equipment. The risk of failure for these types of circuit breakers increases as they get older.

12.3.3.4 CONDITION AND HEALTH

This asset class is aging with the average age being 38 years. The reliable working age for this asset type is 40 years and therefore approximately 69% of the fleet requires remediation or replacement within the next ten years. There have been two failures of this asset type, namely at Milford zone substation in 2007 and as stated above, at Hepburn GXP in 2013. In both cases, complete replacements were undertaken.

12.3.3.5 MANAGEMENT STRATEGY

Typical planned maintenance activities are shown in Table 12-4. Vector is managing the risk of failure of outdoor circuit breakers by progressively replacing those circuit breakers that have been identified to pose a risk on the network with indoor fixed pattern type in larger ODID conversions and selected replacement where warranted. However, there are instances where a complete conversion to indoor fixed pattern switchgear is not economical in which case new outdoor circuit breakers will be deployed. Vector's specification ENS0106 covers the requirements for new outdoor circuit breakers should they be required as one-off replacements or extension projects should strategic stock be unavailable.

There is no planned like-for-like asset replacement programme for individual outdoor circuit breakers with the intention being to replace them with modern indoor fixed pattern switchgear where possible. This equipment has improved safety, spatial, maintenance and economic benefits and eliminates the risk of catastrophic failures associated with bulk oil circuit breakers with porcelain bushings.

In addition to Vector's internal replacement program of this type, Vector has also worked with Transpower to replace similar 33 kV outdoor circuit breakers at GXPs under a so-called outdoor to indoor conversion programme colloquially known as the 'ODID' programme. This programme has made good progress with only two GXPs remaining.

12.3.4 REPLACE, RENEW AND DISPOSE

Renewal and refurbishment of primary switchgear assets is undertaken to ensure continued reliable and safe operation of the assets well into the future. Our switchgear assets need to be considered against the cost of continued maintenance, obsolescence, vendor support and the availability of spares. The aforementioned as well as the asset health and criticality drives our switchgear replacement programme.

In addition to the above, environmental factors and climate change such as a risk of flooding as an example, will also drive the need and timing for replacement of primary switchgear out of harm's way. The programme of works for primary switchgear replacement consists of either a complete replacement of switchgear, or partial replacement or retrofit of oil circuit breakers with vacuum circuit breakers as the case may require.

When primary switchgear is replaced, components are carefully selected and retained to serve as strategic spares for similar equipment that remain in service. Carcasses are then scrapped as per Vector's contractual agreements with scrap metal companies.

12.3.5 FORECAST SPEND

The forecast capex graph shown in Figure 12-4 provides a summary of the overall capital investment for this asset header class for the 10-year AMP forecast period. The replacement and refurbishment programme for primary switchgear is described in detail in Section 12 Appendix and includes the proposed investment for each individual project.



FIGURE 12-4: FORECAST CAPEX – PRIMARY SWITCHGEAR

12.4 Power transformers

This Section describes our Power Transformer fleet and provides a summary of our associated asset management practices within the following three subcategories:

- Power Transformers
- Power Transformer Tap Changers
- Power Transformer Ancillaries

12.4.1 POWER TRANSFORMERS

Power transformers are static devices that are used to transform electrical energy from a higher voltage to a lower voltage. They are critical and capital-intensive assets for utilities. Power transformers come in various sizes, phase arrangements and voltages. Performance of the power transformer is critical to maintaining supply to customers.

Power transformers are robust with very good reliability, requiring relatively low maintenance. However, the on-load tap changers are prone to wear and tear which can lead to premature failure if not monitored and not regularly maintained. The internal health of a transformer is not easily observed and therefore it is highly important for transformers to be regularly monitored and tested to ensure the overall health of the asset is within acceptable parameters and limits. Failures of power transformers are rare but if they do occur, they are often sudden and can have a severe impact including considerable collateral damage to other equipment, lost revenue, extended network outages, and in rare instances injury or death to persons.

12.4.1.1 POPULATION AND AGE

Vector currently has 232 power transformers in service ranging from 5 MVA to 80 MVA. They take supply from the Transpower network at 110 kV, 33 kV and 22 kV to step the voltage down to 22 kV or 11 kV for network distribution. The transformer fleet is composed of 20 different manufacturers encompassing 21 different models. Since the year 2000, Vector has standardised on a small number of manufacturers and power transformer models which has reduced the type and number of spare parts required. The average age of our power transformers is 31 years. 57 power transformers are 50 years and older with the oldest being 70 years of age.

Table 12-6 provides a summary of the population of our power transformers by voltage category. Most of our power transformers (approximately 73%) are 33/11 kV units.

CATEGORY	110/11 KV TRANSFORMER	110/22/11 KV TRANSFORMER	110/33 KV TRANSFORMER	110/22 KV TRANSFORMER	33-22/11 KV TRANSFORMER	33/11 KV TRANSFORMER	22/11 KV TRANSFORMER
Population	2	2	5	8	5	170	40

TABLE 12-6: POWER TRANSFORMER POPULATION

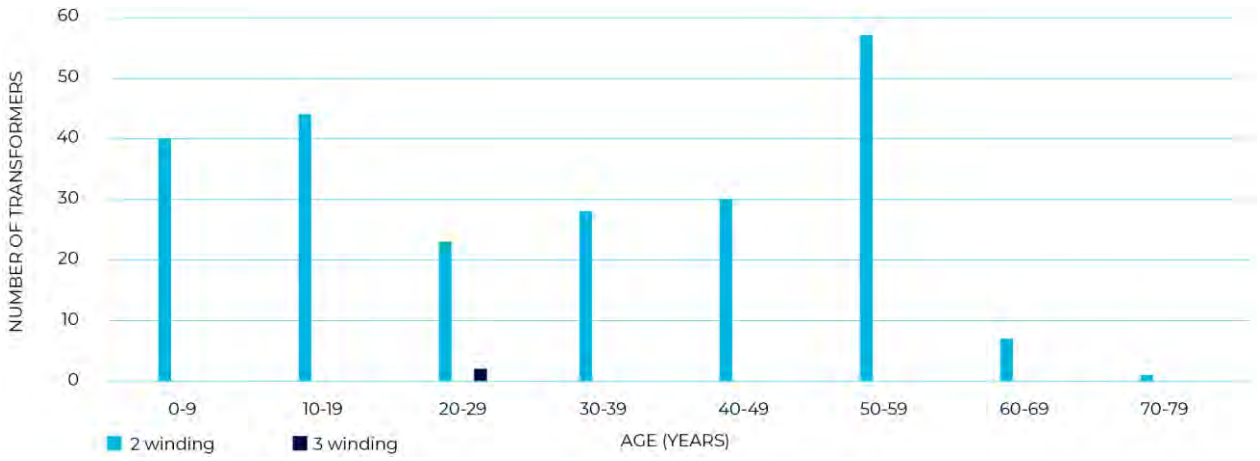


FIGURE 12-5: POWER TRANSFORMER FLEET AGE PROFILE

12.4.1.2 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector relies on Dissolved Gas Analysis (DGA) of the insulating oil in the form of Transformer Condition Assessment (TCA) of the main tank and Tap Changer Activity Signature Analysis (TASA) for its tap changers. This type of oil testing identifies the presence of different gases and by-products of internal insulation degradation and trending over time, allowing Vector to trend and determine the health of the internal condition of the power transformer fleet.

In addition to the TCA, power transformers are monitored using Reg-DA voltage regulating relays and protection relays. These protection relays monitor inputs from current transformers, instrument transformers, temperature sensors, oil level sensors and Buchholz devices (which detect internal faults resulting in rapid gas accumulation and surges inside transformers). Incipient faults trigger alarms via ADMS which then elicits a response by field crews to undertake detailed investigations.

Over the last 20 years, there have been very few power transformer faults resulting in complete loss or long-term outages. These faults were mainly due to close in through faults or tap changer failure. in most cases the power transformers were able to be

repaired. However, in rare cases, the power transformer had to be replaced: details of power transformer failures can be found in Vector's asset strategy for this header class. Overall, the performance of Vector's transformer fleet has been very good.

12.4.1.3 CONDITION AND HEALTH

Vector is actively monitoring the health and condition of the power transformer fleet to ensure we get the optimum life from this fleet. We carefully manage our power transformers so that they are not subject to excessive or prolonged high electrical loading, and we ensure they undergo regular testing in accordance with our maintenance regime.

Vector utilises a VIA analytics model to provide a fleet-wide overview of the condition of its power transformers by leveraging large data sets from other utilities. Using the available asset health data as input, this innovative model is able to estimate the current health of the transformer fleet, as well as forecast the future health levels in response to different modelling scenarios. The output of this model is used to inform which unit(s) should be refurbished or replaced. Vector's strategy is to progressively replace the population of power transformers that have the worst asset health and are the most likely to suffer major failures.

The present (RY26) condition level for the power transformer fleet is shown in Figure 12-6.

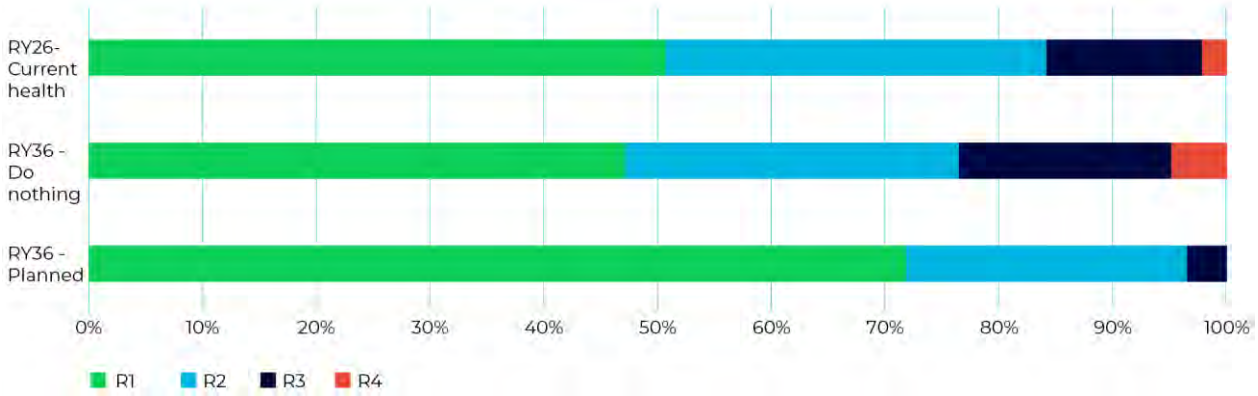


FIGURE 12-6: POWER TRANSFORMER FLEET CONDITION PROFILE

This indicates that Vector's power transformer fleet is in good condition and approximately 10% of the fleet will approach end of life within the next 10 years. Vector's investment programme will ensure that the risk profile of this asset fleet is appropriately managed.

12.4.1.4 MANAGEMENT STRATEGY

The optimal life cycle investment considers the balance between asset renewal requiring capital expenditure and the combination of reactive, preventive, and corrective operational expenditure. The strategies for each of the stages of a transformer lifecycle have been established to address the fleet condition and performance.

Vector has agreed with Transpower to add an additional 220/33 kV interconnecting grid transformer to supplement the existing T7 interconnecting grid transformer at Transpower's Wairau GXP adjacent to Vector's Wairau bulk supply substation. The Vector owned 110/33 kV transformers at Wairau zone substation will be retired in a staged decommissioning program after the second 220/33 kV grid transformer is commissioned into service.

The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.4.1.5 DESIGN AND CONSTRUCT

Vector has two main standards for the specification of new power transformers:

- ESS-0200 - Specification for two winding power transformers (33 kV/11 kV); and
- ESS-0201 – Specification for 110 kV/22 kV two-winding power transformers

These two Vector standards reference IEC standards and form the basis on which all new power transformers are procured. More recently, Vector has standardised its fleet on 24/34 MVA ONAN/ONAF transformers to meet future network requirements, optimise whole-of-life costs, and support efficient strategic spares management. Where site-specific constraints apply, Vector may continue to specify legacy designs.

12.4.1.6 OPERATE AND MAINTAIN

Power transformers have very long in service life expectations and can operate at full load continuously. However, continuous use at full rating will result in the insulation life of the paper being exhausted and failure will become imminent at around 25 years. However, Vector, like most utilities worldwide, designs its network with N-1 contingency and as a result the loading on our power transformers is rarely greater than 50% of its nameplate rating for most of its operating life. At this level of loading, we can expect service life to exceed 50 years.

The insulation of power transformers comprises mineral oil, paper and pressboard that has a finite life even under ideal operating conditions. Aging of the paper insulation depends primarily on the operating temperature of the oil and the time in operation at high oil temperatures. Moisture and the presence of oxygen are other factors that will accelerate the ageing of the insulation. Another factor in the life expectancy of a power transformer is the number of downstream faults to which a transformer has been subjected. High magnitude through faults may cause winding and core deformation that will lead to unintentional short-circuits

across the insulation, of which a high percentage are irreparable. Depending on the condition of power transformer, mid-life refurbishment is an option to extend the life of a transformer.

Oil tests are conducted on an annual basis, supplemented with TCA and Furan analysis every third year. This program of testing was implemented approximately twenty years ago as a means of lowering operating cost and reducing faults caused by incorrect maintenance on tap changers using time and operations-based intervals.

Vector's maintenance standard ESM201 details the planned, corrective, and reactive maintenance requirements for its power transformer fleet. The planned maintenance regime for our power transformer assets is summarised below in Table 12-7.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Inspection on Power transformer	2 Months
Thermovision Inspection	Infrared Thermographic Survey (IRT) Inspection on Power transformer	1 Year
Partial Discharge Inspection	Partial Discharge and Ultrasonic Inspection on Power transformer	2 Years
Testing	Testing on Oil auto-transformer tank (TCA)	2 Years
Testing	Testing on Oil power transformer tank (TCA)	1 Year
Testing	Testing on Oil power transformer Furan (Furan)	3 Years
Testing	Testing on Power transformer protection	4 Years
Electrical Testing	Testing on Power transformer PI and insulation resistance	5 Years
Electrical Testing	Testing on Power transformer bushing power factor	5 Years
Electrical Testing	Testing on Power transformer winding power factor	5 Years
Electrical Testing	Testing on Power transformer winding resistance and OLTC verification	5 Years
Electrical Testing	Testing on Power transformer excitation current	5 Years
Electrical Testing	Testing on Power transformer turn ratio	5 Years
Electrical Testing	Testing on Power transformer short circuit impedance	5 Years
Electrical Testing	Testing on Power transformers – SFRA (Sweep Frequency Response Analysis)	5 Years

TABLE 12-7: PLANNED MAINTENANCE ACTIVITIES FOR POWER TRANSFORMERS

Corrective maintenance is a task carried out to further diagnose or restore a network asset to its serviceable condition and involves further testing, repairing or replacement of parts to ensure that the unit is functioning effectively. Vector's maintenance standard ESM201, Section 4 details the requirements of specific corrective maintenance activities for power transformers.

Reactive maintenance work for power transformers involves returning a power transformer to service, usually after an unplanned outage due to an unforeseen event such as close-in through faults. For every unplanned outage, we undertake post event root cause analysis to ensure that any valuable information as a result of the fault is captured and data is available to identify any trends.

12.4.2 POWER TRANSFORMER TAP CHANGERS

The purpose of a tap changer is to regulate the output voltage of a transformer so that it can be maintained within the required voltage range. Tap changers have preconfigured 'steps' with typical changes to the output voltage of 1.25% per step to +5% and down to -15%. Tap changers can be fitted to either the primary (HV) or secondary (LV) winding but the majority are fitted to taps on the HV winding due to the lower current and easy access to the outer HV winding.

12.4.2.1 POPULATION AND AGE

Power transformers for Vector's network are procured complete with a tap changer. Tap changers are intended to match the entire life of a power transformer subject to good maintenance practices. It is rare that a tap changer is replaced in its entirety and can generally be considered as fit for life. As such, asset health modelling is focused on the power transformer as described in the previous section instead of considering tap changers separately.

There are two types of tap changers in use: on and off load. Most of Vector's power transformers are equipped with oil type on-load type tap changers because they can be operated while the transformer is energised. Since 2009, Vector has procured power transformers with vacuum interrupter type on-load tap changers. The off-load types require the transformer to be de-energised and isolated so are only used where automatic voltage regulation is not required. Only two of Vector's power transformers are fitted with off-load tap changers.

Currently, Vector has tap changers in service from eight different manufacturers with Ferranti, Fuller and Reinhausen being the most prevalent. Since 2000, Vector has standardised its fleet to use only Reinhausen tap changers.

12.4.2.2 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Due to age and uncommon types of tap changers used on some of the transformers, there is a risk of obsolescence and unavailability of spare parts. Vector has partnered with local manufacturers to custom manufacture parts as needed.

Secondary system components such as tap-changer drive/control mechanisms are complex and prone to faults as the equipment ages. This type of failure does not often result in a permanent loss but can contribute to power quality issues.

12.4.2.3 CONDITION AND HEALTH

Vector uses the results of TASA (Tap Change Activity Signature Analysis) oil tests results to trigger maintenance activities. TASA oil tests assume a certain number of operations over the entire range of the tap changer positions, rather than the actual range. Because of Vectors excellent voltage stability, tap changers seldom transition more than three taps either side of the nominal position. With a similar number of tap change operations, oil test results from the tap changer cycling through all 17 tap positions vs. a tap changer cycling through only six positions would show similar results, but the contacts of the latter would show significantly less deterioration.

While TASA oil tests have proven to reduce costs as compared to traditional time-based methods, they are not perfect. Vector has recently experienced issues with tap changers not picked up by this test method. To overcome this issue, a new time and operations-based inspection and maintenance activity has been introduced to the maintenance programme on an initial five-year basis. This new activity will coincide with the new time-based electrical benchmark testing activity being introduced for power transformers.

12.4.3 POWER TRANSFORMER ANCILLARIES

In addition to the main tank and tap changer, there are small but important components fitted to a power transformer. These ancillary components include:

- Bushings - Every power transformer is fitted with LV and HV bushings. Nearly all Vector power transformers are fitted with solid porcelain bushings. Older outdoor power transformers are fitted with solid porcelain oil filled type bushings. These are reliable having no systemic issues other than periodic leaks of a gasket, which are usually minor in nature and repairable.
- Protection Equipment - Protection, control and monitoring of power transformer comprises either legacy analogue, solid state or fully digital systems. The preferred digital platform is the REG-DA (A-Eberle) system for voltage control and transformer monitoring.
- Neutral Earthing - Neutral earthing resistors act to reduce the fault current during phase to earth faults. They are effective to reduce damage to network equipment and require little to no maintenance and are co-located with the power transformer.
- Cooling Systems - There are two systems used on Vector's transformers: bulk oil cooling and heat exchanger systems. The oil radiator system is by far the most common in use and is also an uncomplicated system. The heat exchanger system relies on the continuous operation of pumps and is rarely used due to its complexity.
- Oil Preservation - All of Vector's power transformers are either of a free breathing or atmoseal (bladder) type preservation systems. The free breathing type are not sealed from the atmosphere. As the unit heats and cools through normal operation, the changes in the oil volume are taken up in the headspace of the conservator tank.

12.4.3.1 CONDITION AND HEALTH

Transformer ancillaries are almost always acquired at the same time as the power transformer and are covered by the same specifications. Transformer ancillaries are expected to last the life of the power transformer. Vector maintains a stock of spare parts and ensures contractor capabilities to carryout timely repairs.

12.4.3.2 MANAGEMENT STRATEGY

Maintenance of ancillary components is carried out during periodic inspections or by test regimes as indicated by Vector's maintenance standards.

If required, some component parts are replaced or repaired as necessary under corrective works. However, the ancillary components are generally replaced when the power transformer is replaced.

12.4.4 REPLACE, RENEW AND DISPOSE

The key drivers for replacement are asset health and criticality to ensure the continued reliability of zone substations. Operationally, most of Vector's fleet of power transformers have been loaded well below their design rating thus ensuring oil and winding temperatures have been kept low through most of their operating life thus prolonging the life of the paper (cellulose) insulation. This often enables 30–40-year-old units to have what is commonly called a 'midlife refurbishment' in which the transformer is taken off-site and is completely stripped down, dried out and all badly worn parts replaced before being re-assembled and taken back to site.

The refurbishment is undertaken in accordance with Vector's standard ENS-0164 with the objective to extend the life of the transformer by 25 years. Candidates for refurbishing are reviewed on a case-by-case basis, triggered by condition, criticality, and future value to the network. The economics of the option to refurbish vs replacement are also considered.

The availability of spare parts, especially for tap changers, will impact our decision on whether to refurbish or to replace a power transformer. Notwithstanding our maintenance and testing regime, the asset health of our oldest power transformers has now reached a stage where 'midlife refurbishment' is unlikely to be an economic option.

Power transformers that require replacement are scrapped but parts will be salvaged and placed in strategic stock to be utilised as a source of spares for similar transformers in the fleet that remain in service.

Some of Vector's older substations use power transformers with off-tank radiators to optimise limited space on site. In these locations, replacing them with the current standard on-tank radiator rectangular footprint design would trigger costly bay demolition and civil rebuild works. To avoid these costs and retain existing building enclosures, Vector procures transformers with compatible off-tank radiator configurations for such sites.

Tap changers are integrated components of transformers so are typically replaced when the associated transformer reaches end of life. However, if and where required, a tap changer will be replaced as a separate entity if a transformer is still in good asset health. Vector has only replaced a few tap changers during refurbishment.

As described in the previous section, the availability of spare parts for tap changers guides our decision on whether to refurbish or to replace a power transformer. Replacement parts for certain older generation tap changers are almost impossible to source and decommissioned tap changers are used for spare parts where possible.

12.4.5 FORECAST SPEND

Figure 12-7 below shows our forecast capital spend for the complete replacement programme of power transformers as well as provision for refurbishment in the AMP period. Full details of the individual transformer replacements are given in Section 12 Appendix.

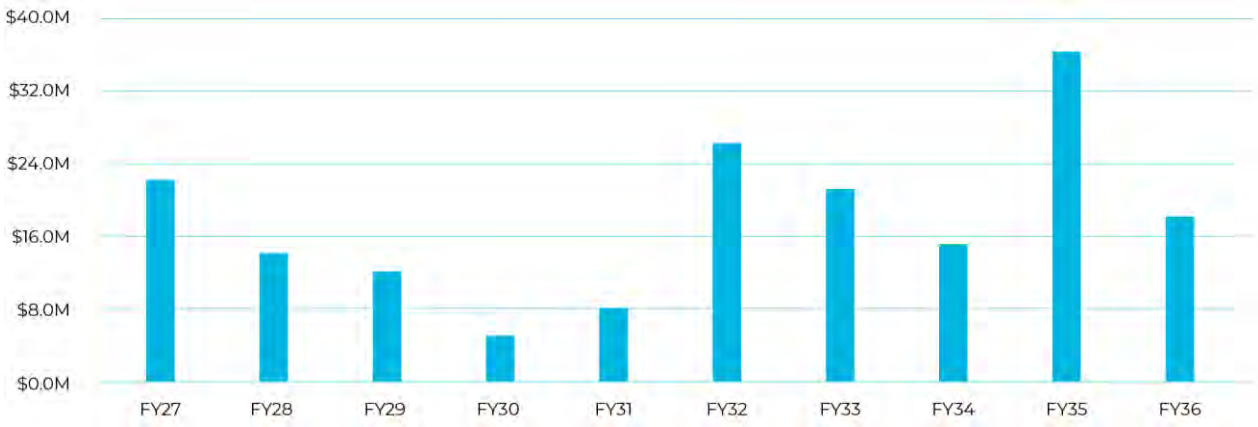


FIGURE 12-7: FORECAST CAPEX – POWER TRANSFORMERS

12.5 Underground cables

This section describes our cable fleet and provides a summary of our associated asset management practices. The cable fleet comprises of:

- Subtransmission (includes submarine cables)
- Distribution
- Low Voltage (LV)
- Joints and terminations

12.5.1 SUBTRANSMISSION

The subtransmission cable network transports electricity from Transpower GXPs to Vector's bulk supply substations and zone substations. Vector's subtransmission cable network operates at 110 kV, 33 kV and 22 kV.

The 110 kV subtransmission network originates from Transpower 110 kV GXPs and connects to Vector's bulk supply substations in the Auckland CBD, Kingsland and Wairau Valley on the North Shore. The 110 kV subtransmission network includes the cables installed within the Penrose to CBD tunnel as well as cables buried underground directly or in ducts. The 33 kV and 22 kV subtransmission circuits run from Vector's bulk supply substations and Transpower GXPs to Vector's zone substations and are installed in underground buried directly or in ducts and in some instances in Vector's tunnels.

12.5.1.1 FLEET OVERVIEW

Key statistics of the 110, 33 and 22 kV subtransmission cable assets are shown in Table 12-8.

CATEGORY	NUMBER OF 110 KV UNDERGROUND SUBTRANSMISSION CIRCUITS	110 KV UNDERGROUND SUBTRANSMISSION CIRCUITS ROUTE LENGTH	110 KV UNDERGROUND SUBTRANSMISSION CIRCUITS IN TUNNELS ROUTE LENGTH	NUMBER OF 33 KV AND 22 KV UNDERGROUND SUBTRANSMISSION CIRCUITS	33 KV AND 22 KV UNDERGROUND SUBTRANSMISSION CIRCUITS ROUTE LENGTH	33 KV AND 22 KV SUBMARINE SUBTRANSMISSION CIRCUITS ROUTE LENGTH
Population	15	28 km	21 km	307	582 km	12 km

TABLE 12-8: SUBTRANSMISSION CABLES FLEET OVERVIEW

The total number of circuits for 110,33 and 22kV circuits has decreased since last year due to consolidated data. This data excludes internal cables circuits between zone substation transformers and switchgear (internal cabling).

12.5.1.2 POPULATION AND AGE

The expected life for subtransmission cables is indicated below in Table 12-9:

CATEGORY	22 KV, 33 KV OIL CABLES	22 KV, 33 KV PILC	22 KV, 33 KV PRIOR TO MID 1980'S XLPE	22 KV, 33 KV PRESENT GENERATION XLPE	22 KV, 33 KV SUBMARINE CABLE - XLPE	22 KV, 33 KV SUBMARINE CABLE - PILC	22 KV, 33 KV SUBMARINE CABLE – OIL CABLES	110 KV XLPE
Onset of unreliability	70 years	60 years	30 years	60 years	60 years	60 years	70 years	70 years
Maximum practical life	100 years	90 years	45 years	80 years	60 years	60 years	70 years	90 years

TABLE 12-9: EXPECTED LIFE OF SUBTRANSMISSION CABLES

The figures above are based on EEA Asset Health Indicator (Guide) 2019 and ODV. However, some projections of the lifespans have been amended based on Vector's experience. A very small portion, circa 1% of Vectors Subtransmission fleet is housed on third party land.

Figure 12-8 below summarises the population and age of our 110 kV, 33 kV and 22 kV subtransmission cable fleets.

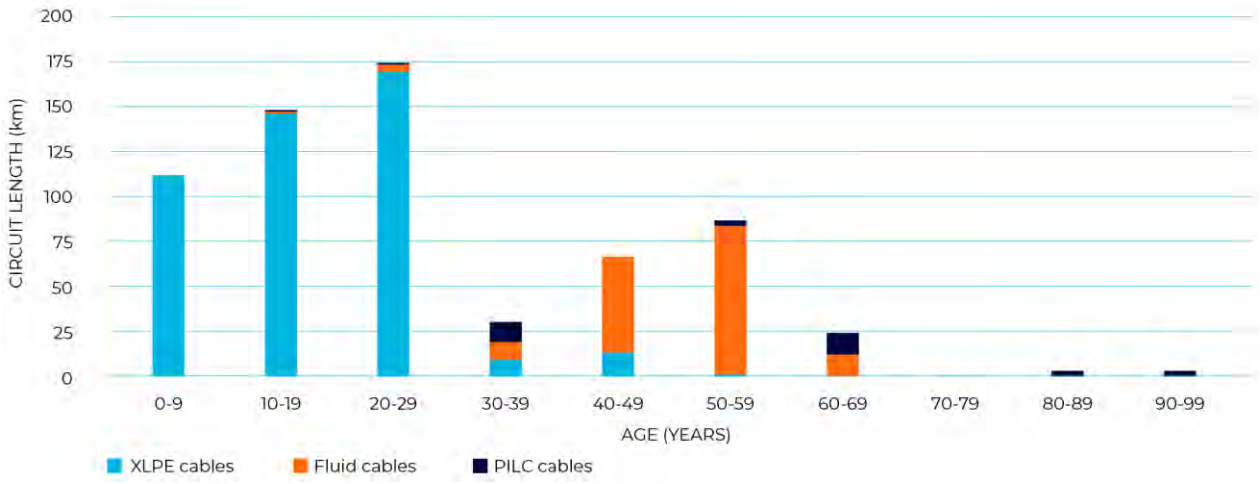


FIGURE 12-8: SUBTRANSMISSION CABLE FLEET AGE PROFILE

12.5.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

General:

Figure 12-9 shows the SAIFI interruptions contributed by subtransmission cables system assets and the number of unplanned events between regulatory years 2016-1025.

Just under half of the total number of unplanned events have the cause recorded as cable, however most of these are likely attributed to joint or termination failures due to records not being updated once the root cause is discovered.

Because the subtransmission network normally operate at an N-1 security level, unplanned events often result in no loss of supply and no SAIDI or SAIFI. For example, in 2017 there were six unplanned events caused by subtransmission cable assets but zero SAIDI and SAIFI was contributed. However, when there is a loss of a circuit, it leads to reduced security of supply and can impact a much greater SAIFI.

110 kV cables: The oldest 110 kV cables in Vector's fleet are the two cables from Mt Roskill GXP to Kingsland zone substation which have been in service since 1965 (57 years old). The 110 kV cables to Pacific Steel were installed in 1982 and the remainder of the fleet after that. The maximum practical life of 110 kV cables and their accessories is projected to be approximately 90 years and we do not expect any material deterioration of these assets over the next 10 years.

22 kV/33 kV PILC cables: We have identified that for some 33 kV and 22 kV PILC cables in our fleet, there is an increasing contribution to SAIDI, but others are performing well. This specific population is viewed as the type at highest risk and is therefore being closely monitored.

22 kV/33 kV fluid filled cables:

While these cables are currently only midway through their expected lifespan, there is an industry-wide risk arising from a shrinking resource pool for the repair and maintenance of fluid-filled cables. This challenge coincides with an increasing need to manage this type of asset fleet as it ages. To mitigate this risk, Vector is working closely with its Field Service Providers (FSPs) to maintain the necessary skills and resourcing. In addition, Vector plans to initiate a proactive replacement programme for fluid-filled cables from FY30, with prioritisation based on asset condition and risk

22 kV/33 kV XLPE cables: While the current versions of this cable are very robust, the early generations of XLPE (between 1970-1990) had manufacturing defects which could result in premature failures of the cable. Vector has experienced several repeat failures on the early generations of XLPE, resulting in the establishment of a proactive replacement programme for the population.

Submarine cables Vector operates several submarine cables for distribution and subtransmission. These have higher risks of anchor damage and insulation failure, though most can be replaced via directional drilling, reducing reliance on specialised vessels. Onshore transitions at beaches are particularly vulnerable, with cables exposed at low tide. Recent works include installing protection shells in coastal areas such as Kawau Island.

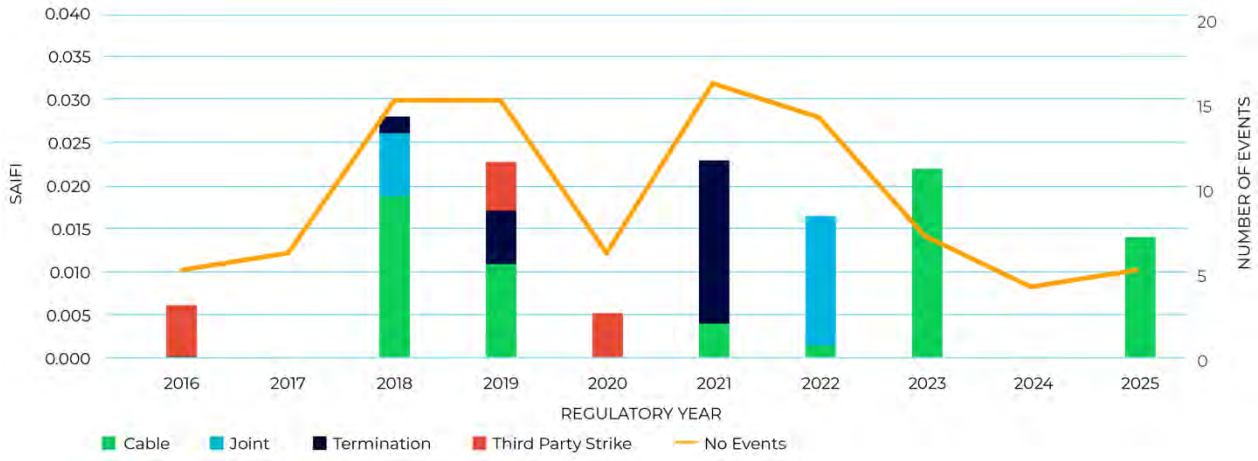


FIGURE 12-9: SUBTRANSMISSION CABLE SYSTEM ASSET PERFORMANCE

12.5.1.4 CONDITION AND HEALTH

Vector has recently developed a CBARM model to assist to inform the replacement programme for subtransmission cables. This model is based on age, condition and criticality. The present (RY24) risk level for the subtransmission cables fleet is shown below in Figure 12-10.



FIGURE 12-10: SUBTRANSMISSION CABLE FLEET RISK LEVEL

The above indicates that the subtransmission fleet is in good condition. However, without intervention from Vector's investment programme, we expect that a small portion of the assets will be reaching an extremely high-risk category (R4 category) and a larger portion reaching a high-risk category (R3 category) within the next 10 years. Vector's investment programme will ensure that the risk profile is maintained at current levels or better. The risk profile for FY25 has changed since the last iteration due to improvement in the input data and recalibration of criticality factors within the CBARM model.

12.5.1.5 MANAGEMENT STRATEGY

The management strategy for subtransmission cables is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers and close scrutiny by the Vector Asset Management team. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.5.1.6 DESIGN AND CONSTRUCT

New cable circuits generally comprise three-core or single core cables with XLPE insulation, copper wire screen, PE or PVC outer sheaths with a water blocking layer. Cables sizes and types are standardised across the network to reduce the required types of spares and accessories and simplify the procurement and maintenance activities.

New major cable circuits are generally installed in ducts utilising directional drilling techniques. Cables sizes and types are standardised across the network to reduce the required types of the spares and accessories and simplify the procurement and maintenance activities.

Vector standards, ENS-0191 and EN-0032 detail the technical requirements for the procurement of subtransmission underground cables. Vector balances the benefits in economies of using a single cable manufacturer against the risks of not having supply chain redundancy and reduced standardization and potential costs.

Vector utilises CYMCAP cable thermal rating software to model the installation details and ensure optimum ratings for a cable circuit(s). This model considers the physical cable installation environment, prospective future load profiles and other external factors such as heat sources from other cables. The CYMCAP software is also used to determine the ampacity of subtransmission circuits and the impact of adjacent cable circuits.

Vector has design standards (refer to Appendix 2 in Section 17) in place that ensures that cables are installed in a consistent, cost-effective manner and in accordance with best practice to ensure that asset life is maximised.

12.5.1.7 OPERATE AND MAINTAIN

Subtransmission cables are operated within rating limits established by CYMCAP cable rating modelling for summer, winter, and contingency conditions. These limits undergo:

- Partial reviews every two years; and
- Full reviews every five years.

Vector manages seasonal cable ratings dynamically through ADMS, using soil moisture data provided by NIWA and Vector-owned weather stations.

- Winter ratings apply from December to April.
- Thresholds are set to identify potential dry summer conditions, where soil moisture levels indicate a need to further reduce cable ratings to maintain safe operation.

Vector's maintenance requirements for subtransmission cables are defined in **ESM301,** which has recently undergone complete review and rewrite. **ESM301** covers:

- Planned maintenance
- Corrective maintenance
- Reactive maintenance

Planned maintenance activities for subtransmission cables primarily focus on preventing third-party damage through proactive patrolling and inspection of construction and subdivision sites. This approach is necessary, as underground cables are not accessible for physical inspection once installed.

Where visual inspection is possible (e.g., within zone substations or at overhead connections), subtransmission cable assets are monitored for visible signs of distress. Accessible joints and terminations are routinely inspected.

To mitigate fire risks:

- Existing joints located in air, and cables near flammable materials within zone substations and grid exit points, are painted with intumescent paint.
- While most joints have already been identified and treated, some may have been missed or may require recoating due to paint degradation.
- These joints and surrounding cables/fluid materials will be painted in accordance with ESE302, with inspections conducted in line with ESM301.

The fluid-filled cable fleet is maintained by trained oil mechanics, with condition assessments carried out by engineering specialists. Fluid pressure is continuously monitored via ADMS and alarmed to the Electricity Operations Centre (EOC) if

Reactive maintenance involves repairing subtransmission cables to restore service following unplanned outages, such as faults caused by third-party interference.

For each unplanned outage, Vector undertakes a post-event root cause analysis to identify trends, recurring issues, or material-specific vulnerabilities.

Diagnostic testing methods, including Partial Discharge (PD) and Tan/Delta (TD), are applied to XLPE circuits where issues are suspected. Testing is conducted selectively, as it can accelerate deterioration in older assets with known condition concerns.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Patrol of Sub-transmission Cables	1 Week
Inspection	Drone & Full inspection of Cable Riser & Terminations (To be completed with overhead activity 410106)	5 Years
Inspection	Pole top inspection of Cable Terminations (To be completed with overhead activity 410107)	5 Years
Inspection	Acoustic and Thermal Testing of Cable Riser & Terminations (completed with overhead activity 410109)	5 Years
Inspection	Inspection of Strategic Spares	6 Months
Inspection	Inspection on oil truck & trailer inspection	6 Months
Inspection	Inspection on Major Tunnel cables and their support structures	1 Year
Inspection	Inspection on Minor Tunnel cables and their support structures	2 years
Inspection	Inspection on 110 kV Cable Terminations	3 Years
Inspection	Inspection on ZSS Cables, Joints and Terminations	3 Years
Inspection	Inspection of Cable Waterway Crossings - Land based	5 Years

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Inspection of Cable Waterway Crossings - Land based	5 Years
Inspection	ZSS Sub-transmission Cable Termination Inspection & Thermographic survey	1 Year
Servicing	Servicing on cable equipment kiosk/pit maintenance	6 Months
Servicing	Servicing on cross link bonding boxes	2 Years
Testing	Testing on all alarm settings and operating function on gauges and transducers	6 Months
Testing	Test, check and calibrate all cable oil pressure alarm gauges and transducers	2 Years
Testing	Serving Testing on Sub-transmission cables	2 Years
Testing	Testing on cable cover protection unit (SVLs) (Oil and solid cable)	5 Years

TABLE 12-10: PLANNED MAINTENANCE ACTIVITIES FOR SUBTRANSMISSION CABLES

12.5.2 DISTRIBUTION

Distribution cables connect zone substations to distribution switchgear or transformers and connect between distribution transformers and switchgear. Vector's distribution cables are predominantly XLPE and PILC 11 kV cables. However, we also have population of 22 kV distribution cables in the Highbrook, Roskill, Kingsland and CBD supply areas of the network to cater for high density energy needs.

12.5.2.1 FLEET OVERVIEW

Key statistics of Vector's distribution cables assets are shown in Table 12-11.

NUMBER OF 11 KV AND 22 KV UNDERGROUND DISTRIBUTION CIRCUITS	948
LENGTH OF 11 KV AND 22 KV UNDERGROUND DISTRIBUTION CIRCUITS (KM)	3998

TABLE 12-11: DISTRIBUTION CABLES FLEET OVERVIEW

12.5.2.2 POPULATION AND AGE

The expected life for distribution cables is indicated below in Table 12-12:

CATEGORY	ONSET OF UNRELIABILITY	MAXIMUM PRACTICAL LIFE
11 kV PILC	60 years	80 years
Pre 1985 XLPE	20 years	40 years
11 kV, 22 kV present generation XLPE	60 years	80 years

TABLE 12-12: EXPECTED ASSET LIFE FOR DISTRIBUTION CABLES

The figures above are based on the EEA Asset Health Indicator (Guide) 2019 and ODV. However, some projections of the lifespans have been amended based on Vector's experience.

Figure 12-11 summarises the population and age of our 11 kV and 22 kV distribution cables.

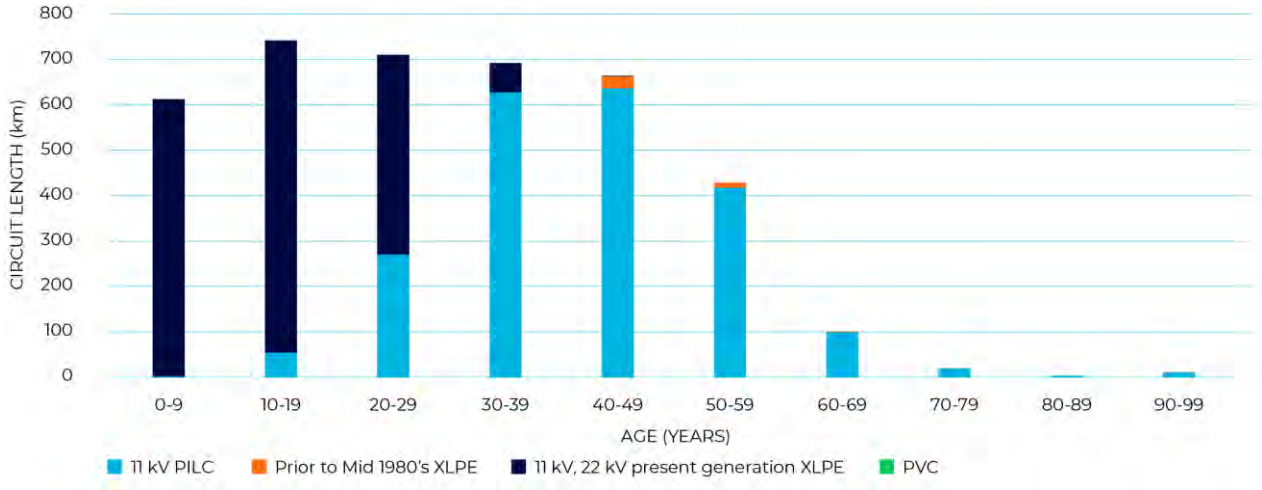


FIGURE 12-11: DISTRIBUTION CABLES FLEET AGE PROFILE

12.5.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector's distribution XLPE cables are performing well with most cables being less than 20 years old and therefore in the early part of their operational life span. The exception to this is our polyloom cables and XLPE cables manufactured and installed prior to 1990. These have exhibited poor reliability due to the integrity issues on the outer sheath. However, our population of polyloom cable is relatively small and the impact on network performance has been minor. Vector has a significant portion of distribution installed between 1950 and 1980 and are approaching the end of their reliable working life. A proactive programme of replacement has been on-going and is continuing to replace 11 kV and 22 kV cables most at risk or in areas of high criticality.

Distribution cables have an average fault rating of 0.047 faults/km with most of these faults attributable to PILC cables.

Most failures are associated with cable joints or terminations. Despite the ageing profile of the network, both the number of faults and the associated SAIFI impact have remained stable over the past five years, reflecting the effectiveness of Vector's replacement and maintenance strategies in containing fault levels.

Vector has identified that the trend of increasing frequency of sustained high temperatures over the summer months presents a risk of accelerated degradation to all underground cables when it coincides with low soil moisture content and increased cyclic loading. Vector mitigates this risk by modelling cable circuits approaching ampacity limits.

Figure 12-12 shows the SAIFI contribution from distribution cable system assets and the total number of unplanned events between regulatory years 2014-2023. Most events attributed to cables are likely caused by joints and terminations in both subtransmission and distribution cable systems. Third party is a major contributor to cable faults however we expect to see a reduction of this with more modern cables being installed in ducts at greater depths.

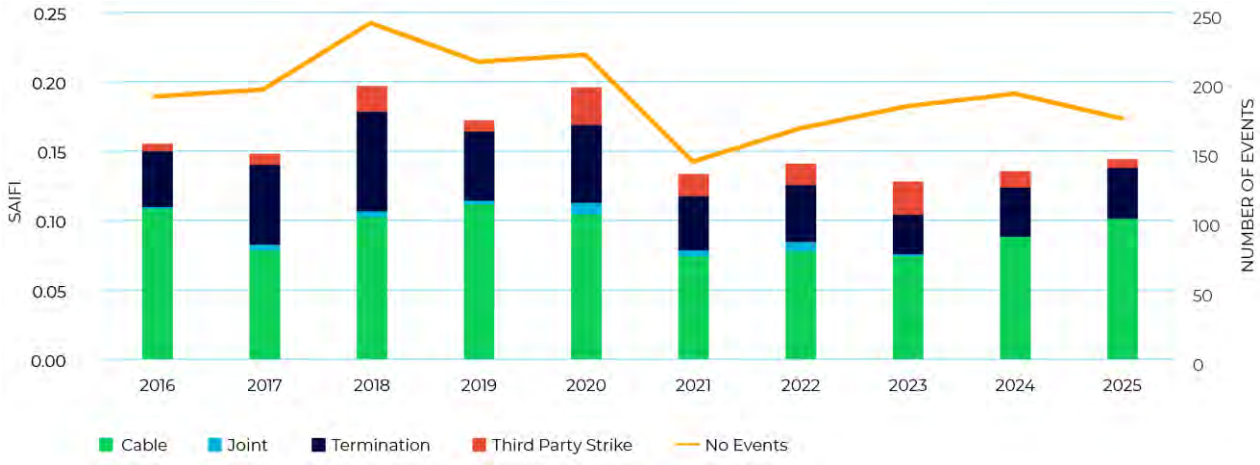


FIGURE 12-12: DISTRIBUTION CABLE SYSTEM ASSET PERFORMANCE

12.5.2.4 CONDITION AND HEALTH

Our CBARM model for distribution cables is based on age, condition and criticality. The present (RY23) risk level for the distribution cables fleet is shown in Figure 12-13.

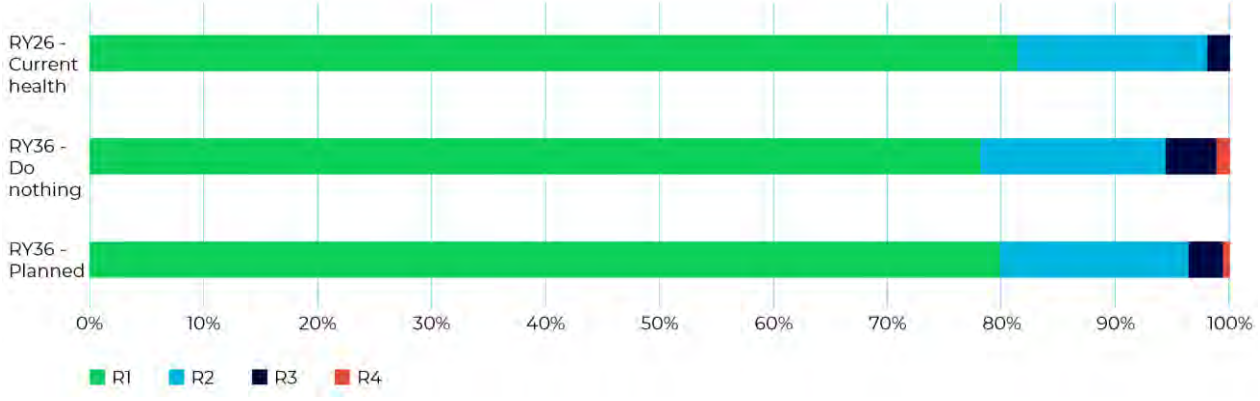


FIGURE 12-13: DISTRIBUTION CABLES RISK PROFILE

The risk profile indicates that the distribution cable fleet is aging. This is predominately due to the PILC cable fleet which has an average age of 40 years. Our analysis shows that approximately 1% of the fleet will approach end of life within the next 10 years. Due to this, it is possible that number of cable faults occurring on the 11kV network may increase from present levels. In the past 3 years, we have conducted tan delta and PD testing on approximately 200 main sections of the feeders to capture further condition insights. While we have found PD can be inconclusive especially with PILC cables, it is a tool to provide a condition score for the cables and not a sole reason for replacement. Vector's investment programme will ensure that the risk profile of this asset fleet will be maintained at approximately present levels.

The risk profile for FY24 has changed since the last iteration due to improvement in the input data and recalibration of criticality factors within the CBARM model.

12.5.2.5 MANAGEMENT STRATEGY

The management strategy for distribution cables is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.5.2.6 DESIGN AND CONSTRUCT

Vector has standardised the type of cables used in its distribution network to reduce the stockholding of many types (and accessories, simplify procurement and maintenance activities and reduce stockholding costs. Generally, new cables are specified to be three-core or single core cables with XLPE insulation, copper wire screen, PE or PVC outer sheaths with a water blocking layer.

Vector's procurement standard ENS-0127 details the requirements for distribution underground cables. The distribution network uses predominantly 11 kV cables, but 22 kV XLPE cables are used in high-density load areas.

Vector maintains a strategic stockpile of the standard range of cable types and sizes used by Vector to ensure that critical spares are available for contingencies.

Vector has design and installation standards ESE301, ESE302 and ESE303 in place which ensures that cables are installed in a consistent and cost-effective manner and in accordance with best practice to ensure that asset life is maximized (see Appendix 2, Section 17 for the list of design standards). Construction of new cables for the distribution network is like that for subtransmission network and are exclusively XLPE.

12.5.2.7 OPERATE AND MAINTAIN

Vector's maintenance standard ESM301 details the planned, corrective and reactive maintenance requirements for its distribution cable fleet. The planned maintenance regime for distribution cable involves a visual condition assessment inspection on externally visible cable systems (cables, terminations, joints) every five years.

Corrective maintenance activities for distribution cables are carried out to further diagnose or restore a network asset to its serviceable condition. This typically involves sheath integrity testing for distribution cables identified with a high risk of failure.

Reactive maintenance for distribution cables involves work needed to return a cable to service, usually after an unplanned outage due to an unforeseen event such as a fault due to third party interference. For every major unplanned outage, we undertake post event root cause analysis to ensure that any valuable information relating to the fault is recorded and data is available to identify any trends.

12.5.3 LOW VOLTAGE

Low voltage cables are used for distribution and connection from ground or pole mounted transformers to the customer.

Figure 12-14 shows the current known populations of low voltage distribution cables with the recorded installation decade. Values are in kilometres with a data error rate of approximately 6%.

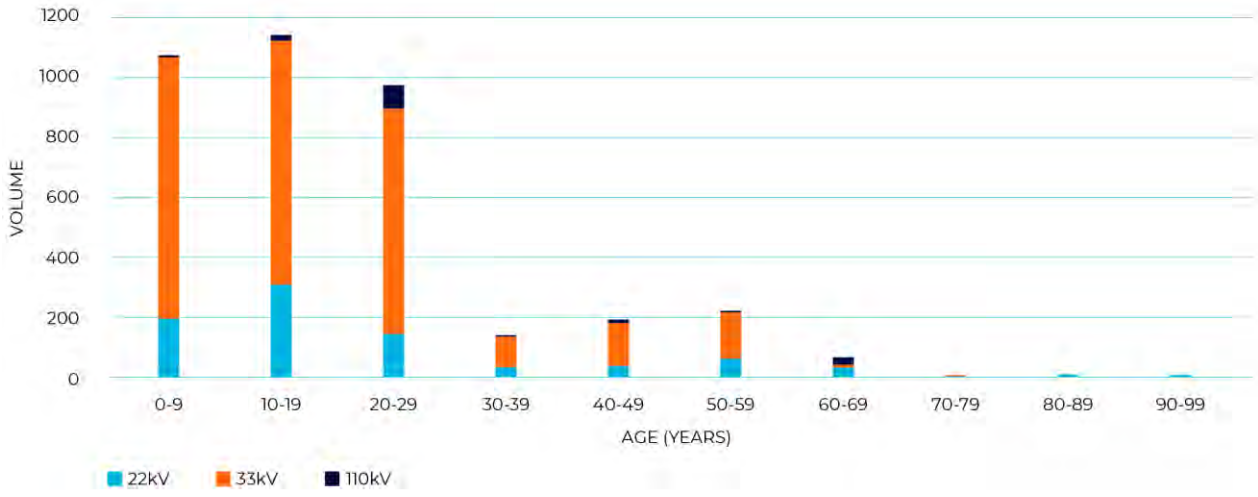


FIGURE 12-14: LV DISTRIBUTION CABLE AGE PROFILE

The average age of the LV cable fleet is 28 years. PILC cables have a design life of 70 to 80 years. Early implementation of XLPE and PVC cables were expected to last 40 to 50 years. With cable technology advancing, the design life of XLPE and PVC has increased up to 60 years. Temperature and the cable's installation environment have the largest impact on cable asset life.

12.5.3.1 FLEET OVERVIEW

Key statistics for the low voltage cable assets are shown in Table 12-13.

CIRCUIT LENGTH OF LV UNDERGROUND CABLE DISTRIBUTION FEEDERS (KM) – AUCKLAND NETWORK	4082
CIRCUIT LENGTH OF LV UNDERGROUND CABLE DISTRIBUTION FEEDERS (KM) – NORTHERN NETWORK	2837

TABLE 12-13: LOW VOLTAGE CABLES FLEET OVERVIEW

12.5.3.2 POPULATION AND AGE

Approximately 65% of the LV network in the Auckland region is undergrounded. In some areas, the underground network has been in service for over 60 years. Pockets of underground LV networks exist in the Northern region, but the underground network in the Northern region are generally of lower age. Due to population growth in the Northern region, the underground LV network is expanding.

12.5.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

We are not experiencing any systemic network failure modes in our LV underground network but are seeing a slight increase in faults in older parts of the LV underground network. The biggest threat and cause of faults in the LV underground cable network is damage by third party excavations and vehicle strikes on above ground pillar boxes.

12.5.3.4 CONDITION AND HEALTH

For legacy reasons, data deficiencies exist for much of the existing LV underground network and hence Vector does not presently have robust data with regards to condition and health for this asset class. Vector is improving its data accuracy for LV cables by recording asset information for all new installations and replacement work.

12.5.3.5 MANAGEMENT STRATEGY

The low voltage cable fleet is not replaced as part of a proactive programme of works but is dealt with on a reactive replacement basis given its relatively localised impact on the network due to the low numbers of customers impacted by these failures. These circuits are however replaced as part of larger scale works, initiated by Vector or third parties, when required.

Vector considers the improvement of existing data records as a top priority for this asset class as it is a critical pre-requisite before the establishment of a proactive asset management strategy. The ESM505 maintenance standard defines the procedure for data capture and system updates carried out by Vector's field service providers. It also prescribes preventive maintenance requirements, frequency of inspections, and how to treat defects identified either through corrective maintenance or asset replacement processes.

Cable terminations and joints are used to join cable sections together or transitioning the cable to busbars or overhead lines. They are a critical component of the cable system for subtransmission, distribution and low voltage cable systems but are often the points of failure.

12.5.3.6 FLEET OVERVIEW

Key statistics of the cable ancillary assets are shown in Table 12-14. The transformer cable termination component of the statistics (as well as the population chart in Figure 12-12) is inferred from the population of our distribution and power transformers due to data unavailability.

TYPE	UNITS
110 kV subtransmission cable joints & terminations	149
33 kV subtransmission cable joints & terminations	2824
22 kV subtransmission cable joints & terminations	814
22 kV distribution cable joints & terminations	1593
11 kV distribution cable joints & terminations	71,381

TABLE 12-14: DISTRIBUTION CABLE JOINT & TERMINATION FLEET OVERVIEW

12.5.3.7 POPULATION AND AGE

The expected life for cables joints and terminations are indicated below in Table 12-15.

CATEGORY	ONSET OF UNRELIABILITY	MAXIMUM DESIGN LIFE
Subtransmission cable oil filled cable joints and terminations	40 years	60 years
Subtransmission solid cable joints and terminations	40 years	65 years
Distribution joints and terminations	40 years	65 years

TABLE 12-15: EXPECTED LIFE OF CABLE ACCESSORIES

The figures above are based on the EEA Asset Health Indicator (Guide) 2019 and ODV. However, some projections of the lifespans have been amended based on Vector's experience. The graphs below summarise the population and age of our cable joints and terminations.

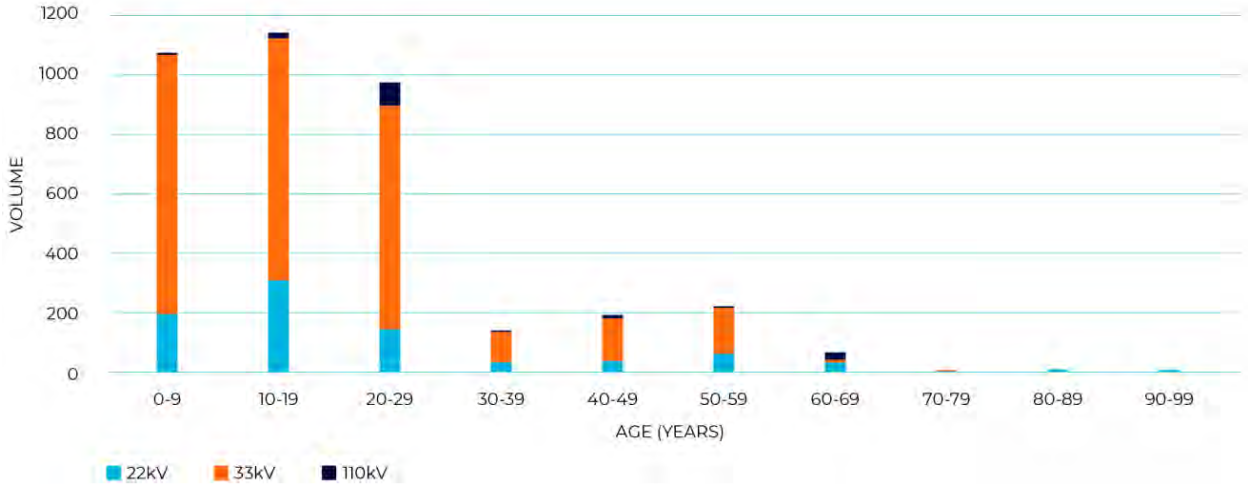


FIGURE 12-15: SUBTRANSMISSION CABLE JOINT AND TERMINATION FLEET AGE PROFILE

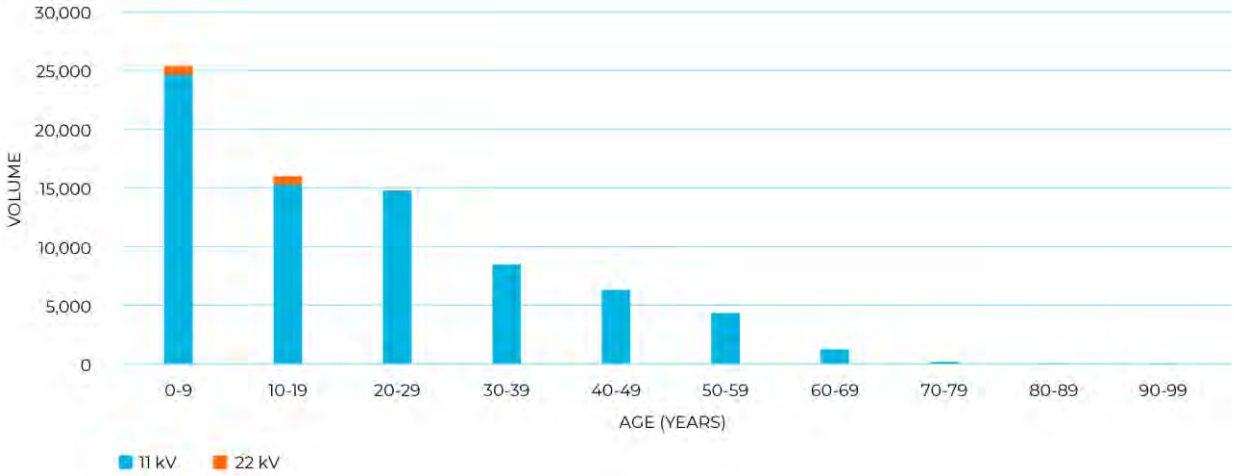


FIGURE 12-16: DISTRIBUTION CABLE JOINT AND TERMINATION FLEET AGE PROFILE

12.5.3.8 CONDITION AND HEALTH

The routine condition assessment of cable joints can be impractical as they are predominately installed underground and require the cable to be offline to undertake testing. As such, aside from specific known issues or established trends, the condition of cable joints and terminations mirrors that of its associated cable.

12.5.3.9 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector has identified several trends associated with specific types of joints and terminations. There are some known issues associated with the twelve Pirelli (Prysmian) outdoor terminations installed in 1998. The issues concern the internal oil sealing mechanism which can be unreliable. Vector actively monitors these terminations to identify any issues that may lead to premature failure and takes remediation action where necessary. These have also been listed for replacement in FY27 as a proactive measure.

For the Medium Voltage category 11-33kV, early XLPE cable joints presented risks. Connectors used compression technology, which required a high level of skill and workmanship to install correctly. Inconsistent installation standards in the past resulted in many compression joints failing prematurely, often becoming points of high electrical resistance.

The highest-risk joints have already been addressed through targeted replacement programmes. Where a failure occurs on one joint, other joints in the vicinity are typically replaced at the same time to optimise shared civil costs.

Modern XLPE joints now use shear-bolt technology, which is simpler to install and significantly reduces the likelihood of installation errors. Cast metal pothead cable terminators on the 33 and 11 kV overhead network have degraded over time. The degradation of this type of termination can allow moisture ingress which has the potential to lead to failure. In FY21, Vector undertook the replacement of degraded 11 kV pothead terminations. Their failure risk stemmed from water ingress and arcing, with the potential for explosive shattering. Most have now been replaced. Vector has experienced termination failures inside ABB SafeLink ring main units, often after a switchgear replacement job where the existing PILC cable termination is reused. Partial discharge caused by re-orientated cables crossing over, or a misalignment between the termination and bushing are thought to

be predominate causes of these failures. Apart from exceptional circumstances, Vector standards no longer allow existing PILC cable terminations to be reused in switchgear replacements.

Failures have also recently been observed in smaller PILC cables with HDPE sheaths (typically 16 mm²), particularly those installed between 1985 and 1999. Most failures occurred at pole-top and ground-mounted terminations, in some cases damaging adjacent switches or transformers. Vector will proactively replace these terminations beginning in FY26, with priority on overhead terminations and those within oil-filled RMUs.

12.5.3.10 MANAGEMENT STRATEGY

The management strategy for subtransmission and distribution cable joints and terminations is based on asset health, network criticality and safety. It is informed by asset health data where it is available and is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.5.3.11 DESIGN AND CONSTRUCT

For the procurement of new cable joints and terminations, Vector uses its standards ENS-0191 and ENS-0032. Vector uses the relevant AS/NZS or IEC standard for testing and quality assurance of the cable accessories used on its network. New products go through a well-defined and rigid trial and evaluation process prior to asset introduction.

Joint and termination kits for solid cables are readily available therefore not stocked as strategic stock. However, for oil filled, 110 kV XLPE and submarine cables, straight, stop and transition joints have a lead time for up to six months and therefore Vector maintains strategic spares for these assets.

12.5.3.12 OPERATE AND MAINTAIN

Vector's standard ESM301 details the maintenance requirements for cable joints and terminations. Aside from instances where specific issues and requirements are identified (such as with 110 kV terminations), Vector's typical routine maintenance practices involve the following:

- Externally visible joints and cable terminations in a zone substation and tunnels are inspected for any signs of deterioration on an annual basis.
- Overhead cable equipment visual inspection including thermographic and acoustic imaging are undertaken every five years.
- On-line partial discharge tests are undertaken in accordance with a scheduled programme.

12.5.4 REPLACE, RENEW AND DISPOSE

Vector uses its CBARM tool as a risk-based approach to assist to forecast the need for cable replacements. The CBARM model considers asset health, probability of failure and criticality to forecast the need to replace or retire specific subtransmission or distribution cables. Before committing to a decision to replace a cable, Vector validates the output of the CBARM model against test results taken in the field and historical records to ensure the model is providing accurate guidance. Using the outcomes of this analysis Vector has identified the programme of subtransmission cable replacements listed in the Section 12 Appendix to be undertaken within the next 10-year period.

For distribution cables Vector also uses a targeted risk-based approach for replacement. This focuses on replacing the cable sections with a higher-than-average rate of cable faults and the cable sections where the cable is approaching or has reached the end of its reliable service life. The decision for the replacement of a cable circuit is checked against field test results and historical records.

As LV cables have a low impact on network performance the strategy for the replacement of this asset class is to renew the asset on a reactive basis, at end of functional life or when they pose a public health and safety risk.

Vector will replace its cable joints and terminations on an 'as needed' basis. This usually means that the replacement of cable joints and terminations will coincide with cable circuit replacement or repair. The exceptions to this are when targeted programmes of work designed to address specific risks, are undertaken.

12.5.5 FORECAST SPEND

The forecast capex graph shown in Figure 12-17 provides a summary of the overall capital investment for this asset header class for the 10-year AMP forecast period. The replacement and refurbishment programme for underground cables is described in detail in Section 12 Appendix and includes the proposed investment for each individual project.



FIGURE 12-17: FORECAST CAPEX – UNDERGROUND CABLES

12.6 Overhead lines

12.6.1 SUBTRANSMISSION

12.6.1.1 FLEET OVERVIEW

Vector's overhead subtransmission circuits transfer electricity from GXPs to bulk supply substations and zone substations and typically operate at 33 kV or above. Vector owns and operates three 110 kV rated subtransmission overhead circuits and 89 circuits operating at 33 kV.

In many instances, multiple subtransmission, distribution and/or low voltage circuits are installed on the same support structures.

12.6.1.2 POPULATION AND AGE

The overhead 110 kV subtransmission network comprises three circuits that run between Transpower's Albany GXP and Vector's Wairau zone substation. All three circuits were constructed in the 1970's with upgrades in 2011 and 2012. The circuits are of the AAC conductor type. The overhead 33 kV subtransmission overhead line network is spread across Vector's network and comprises a mix of copper, ACSR and AAC conductors mostly installed on concrete poles. Most of this network was built between 1970 and 1995.

Table 12-16 summarises the expected lives of the different conductor types. The actual life is affected by environmental factors (corrosive elements and exposure to wind), mechanical loads, electrical loads and the number/magnitude of downstream electrical faults.

Vector utilizes a variety of different conductor types depending on the amount of energy to be transferred and voltage regulation requirements. Each type of conductor has different expected ages and failure modes that are accounted for in the asset management strategies and plans.

TYPE	DESIGN LIFE (YEARS)	LENGTH (KM)	
		110 KV	33 KV
All Aluminium Alloy Conductor (AAAC)	60	0	9
Aluminium Alloy Conductor (AAC)	60	27	323
Aluminium Conductor Steel Reinforced (ACSR) >100mm2	55	0	28
Copper (Cu) > 60mm^2	70	0	6
Total		**27**	**361**

TABLE 12-16: ASSET FLEET TYPE COMPOSITION AND EXPECTED LIFE

The age profile of the asset fleet in Figure 12-18 shows that nearly 10% of the asset fleet is up to 60 years old. Approximately 10% of this asset fleet has exceeded it's expected design life and the end of this AMP period it will increase to 35%.

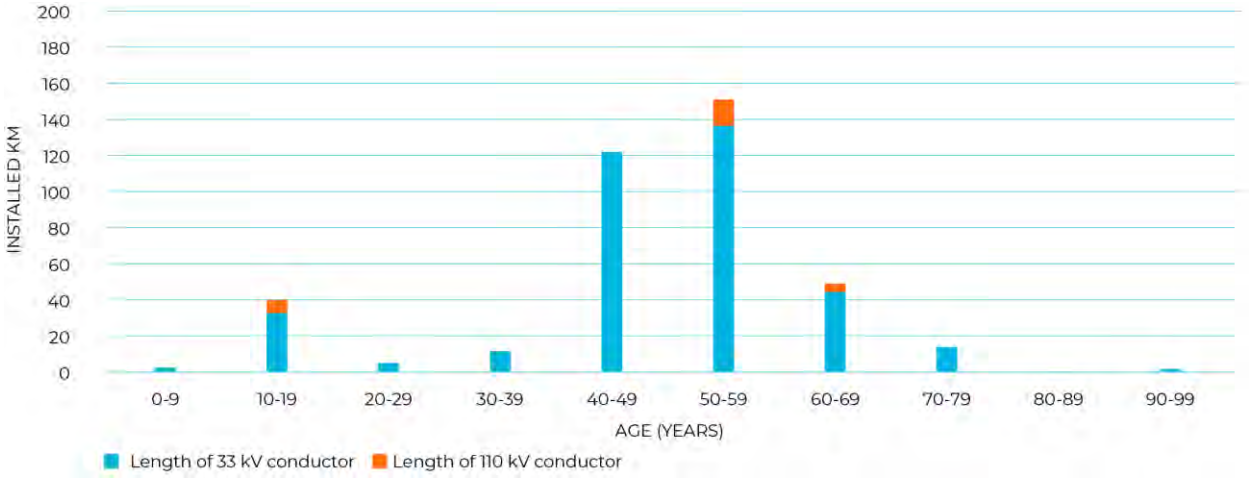


FIGURE 12-18: SUBTRANSMISSION CONDUCTOR FLEET AGE PROFILE

12.6.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

The expected life of each conductor is related to the type of conductor, operating conditions and environmental factors. Conductor diameter is also a factor on life expectancy because smaller conductors are inherently weaker and are less able to withstand shock impacts from external forces such as vegetation and vehicle impacts. Once they have broken, they are repaired with additional joints. Joints are known to be a likely point of failure, especially under fault conditions where secondary failures can occur. As conductors deteriorate and have increasing numbers of joints installed due to repairs, their reliability is expected to decrease.

Figure 12-19 shows the performance of the subtransmission lines as fault rate per 100km. Subtransmission lines are maintained to have a high level of reliability and have redundancy. A fault on a subtransmission line does not necessarily result in a power outage to customers.



FIGURE 12-19: SUBTRANSMISSION OVERHEAD LINE PERFORMANCE (FAULT RATE)

Other causes of faults and emerging risks identified for this asset fleet that are contributing to its performance are:

- The failure of components of overhead lines, in particular joints
- Vegetation in the proximity of overhead power lines causing transient faults or damage through physical contact. These types of outages are more likely during storms and high winds. This can cause power outages and damage to the conductors that can result in immediate or delayed failure.

Vector has established management strategies to address these issues and ensure the subtransmission network reliability is maintained to comply with the Quality Standards.

12.6.1.4 CONDITION AND HEALTH

The condition of the subtransmission overhead fleet is modelled using CBARM. This model is reasonably well developed and is used to point out network areas that are at risk. Figure 12-20 shows that there is a strong trend of increasing risk if no action is taken. This aligns with the expected increase in the age of the asset fleet and the percentage of the fleet that will be exceeding its expected life by the end of the 10-year forecast.

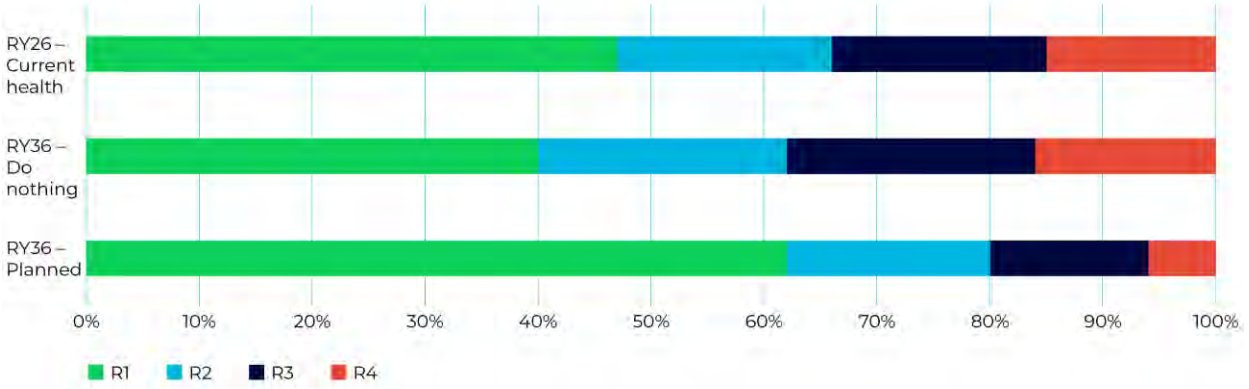


FIGURE 12-20: SUBTRANSMISSION OVERHEAD FLEET RISK PROFILE

12.6.1.5 MANAGEMENT STRATEGY

The optimal lifecycle investment considers the balance between asset renewal requiring capital expenditure and the combination of preventive, corrective and reactive operational maintenance expenditure.

Vector proactive replacement and refurbishment programmes of work are informed by our CBARM models, condition assessments and criticality. Projects or programmes are initiated to address gaps in service level targets that are either already apparent or are forecast in the next 5-10 years. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.6.1.6 DESIGN AND CONSTRUCT

The design of the replacement of overhead subtransmission lines are undertaken by Vector with assistance from specialist engineering consultancies and input from the FSPs. The design and performance characteristics are prescribed in Vector's Standard ENS-0153: Specification for overhead conductors. The completed designs are issued to the FSPs for construction and commissioning according to Vector's standards. The design for replacement or refurbishment will also be cognizant of the impact of climate change, significantly storm events, and how to improve the design to harden against the impact of these events. Routes will also be carefully selected to not build in flood prone areas or along routes where there is a risk of ground slips.

12.6.1.7 OPERATE AND MAINTAIN

Vector implements a wide range of routine and operational tasks covering asset inspections, condition-based testing and maintenance. The tasks and timeframes for overhead inspections have been reviewed and updated to include latest technology and inspections tools such as GridAware and the Neera program. These improvements are set out in our newly revised and updated maintenance standard ESM401. The preventive tasks are designed to uncover non-compliant or serviceability defects which are then treated as corrective maintenance actions or an asset renewal action depending on the extent and level of risk to performance and safety.

Most defects are identified through aerial, acoustic, and thermographic inspections. Under the current inspection cycle, conductors are inspected every two years, and any defects are recorded against the nearest pole as it has a point location and unique identifier in GIS. Key tasks carried out during inspections include:

- Inspection of ground clearances.
- Conductor separation and proximity to structures are assessed for adequate clearance.
- Assessment of clearance from vegetation.
- Spans checked for balanced sags.
- Conductors free from broken strands, corrosion and (vegetation or conductor) clash burn marks.
- CCT high voltage conductors are free from insulation damage.
- Joints in conductors are visually secure and not showing signs of overheating.
- Inspection of support structures e.g. crossarms, insulators, foundations, straps etc.
- Acoustic inspection of infrastructure

Vector has also implemented the use of LiDAR technology as a tool to assess the conductor clearance from the ground, roads, buildings, and vegetation in compliance with ECP34 requirements. In parallel, high-resolution photographs are taken from the helicopter, enabling desktop pole-top assessment of defects on the overhead conductors and components. In parallel, high-resolution photographs are taken from the helicopter, enabling desktop pole-top assessment of defects on the overhead conductors and components. The defects identified are processed into SAP and are being addressed on a risk prioritised basis. Routine LiDAR and Pole top assessment surveys will continue to be conducted across the network ensuring that clearance and network risks are effectively managed, and compliance breaches are identified

In addition, drone inspections are being utilised as a primary method to capture detailed high-quality images of overhead assets since FY25. This inspection focuses on detecting conditions such as broken strands, corrosion, burn marks and joints overheating. All captured images are uploaded in SAP and GridAware, where an annotation process is undertaken to identify overhead asset defects. This process also contributes to ongoing AI model training, developing automated defect detection and analysis capabilities over time.

12.6.2 DISTRIBUTION

12.6.2.1 FLEET OVERVIEW

A distribution overhead circuit is defined as an electrical line that transfers electrical energy from a zone substation to a distribution transformer where it is converted to low voltage. The distribution voltages used by Vector are 22 kV and 11 kV. In many instances, multiple subtransmission, distribution and/or low voltage circuits are installed on the same support structures.

Unlike overhead subtransmission lines, not all distribution feeders have redundancy, and a fault will result in an outage to consumers that can only be rectified with corrective repairs.

12.6.2.2 POPULATION AND AGE

Vector has over 3,707 km (route length) of distribution overhead conductor circuits, representing 45% of its total network line length. Table 12-17 summarises the typical expected lives of the different conductor types along with the length at each voltage level. There is a short length of 11 kV aerial bundled conductor on Vector's distribution network in the Clendon area.

The expected asset life differs for each type of conductor, and each type also has a different failure mode which are accounted for in the asset management strategies and plans. The actual life of each conductor type is also affected by environmental factors (corrosive elements and exposure to wind), mechanical loads, electrical loads and number and magnitude of downstream electrical faults. The geographical location of overhead conductor circuits thus plays a major part in its condition and rate of deterioration.

TYPE	DESIGN LIFE (YEARS)	LENGTH (KM)	
		22 KV	11 KV
All Aluminium Alloy Conductor (AAAC)	60	2	115
Aluminium Alloy Conductor (AAC)	60	0	972
Aluminium Conductor Steel Reinforced (ACSR) >100mm2	55	0	116
Aluminium Conductor Steel Reinforced (ACSR) <100mm2	50	0	1505
Copper (Cu) > 60mm2	70	0	219
Copper (Cu) < 60mm2	55	0	751
Unknown type	55	0	0
Total		**2**	**3,678**

TABLE 12-17: ASSET FLEET TYPE COMPOSITION AND EXPECTED LIFE

The age profile of the asset fleet in Figure 12-21: distribution conductor age profile shows that 75% of the asset fleet is between 30 and 60 years old. Approximately 17% of this fleet has exceeded its design serviceable life

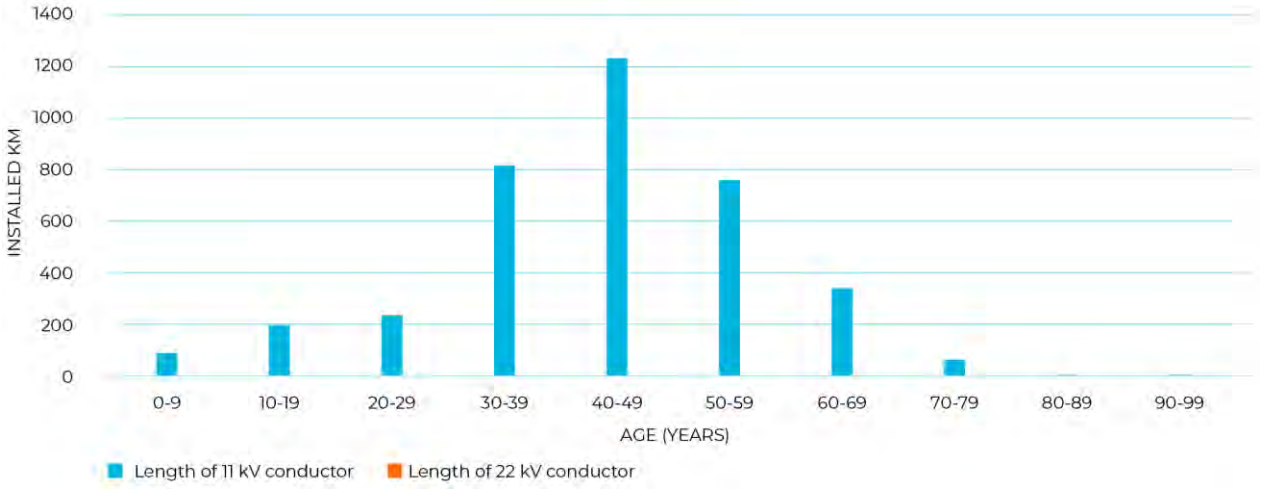


FIGURE 12-21: DISTRIBUTION CONDUCTOR AGE PROFILE

12.6.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Over the last decade, approximately 20% more conductors have been removed (185km) from the network than has been installed (84km). As a result, the length of overhead line is reducing, with an average annual decrease of approximately 6km per year. This reduction is the result of overhead to underground conversions that are driven by Vector, customers and new development in areas where Auckland Council require undergrounding of existing overhead reticulation. This trend is expected to continue for the planning horizon of this AMP.

Conductor diameter affects life expectancy as smaller conductors are inherently weaker and are less able to withstand shock impacts from external forces such as vegetation and vehicle impacts.

As shown in Figure 12-21, there has been a long-term trend of increasing faults on the overhead distribution network. Analysis of the data showed that vegetation impacts and the proximity to marine environments are significant contributors to the fault rate. The following are some of the failure modes:

- Vegetation in the proximity of our overhead power lines is a major factor in network outages especially during storms and high winds. In most instances the impacting vegetation is within the growth limit zone but falling trees from outside the zone can also have a significant impact. The power outages and damage to the conductors can either result in an immediate or delayed failure.
- Overhead conductors harden over time (anneal) due to wind induced vibration, movement and thermal cycling, resulting in becoming brittle and a reduction of its tensile strength, eventually leading to failure.
- The marine environment is more corrosive due to salt in the air and is generally a windier environment and this contributes to the deterioration rate of conductors. All of Vector's network is less than 15 km from the nearest shoreline, and approximately 50% is within 3 km of the shoreline. Hence, these factors are an important driver of asset condition.
- The failure of components of overhead lines (other than the conductor itself) contribute significantly to interruptions on distribution feeders.
- We are starting to see the impact of climate change. This became especially poignant during the Jan-Feb 2023 cyclone where ground slips put portions of the overhead distribution network at risk.

By then end of this planning period, 38% of the distribution overhead conductor population is expected to exceed its serviceable life and in the past four years Vector has embarked on an accelerated proactive refurbishment programme for this fleet to ensure high impact areas are addressed.



FIGURE 12-22: DISTRIBUTION OVERHEAD CONDUCTOR FAILURE RATE PER 100KM

12.6.2.4 CONDITION AND HEALTH

The condition of the distribution conductor fleet is modelled using CBARM, output shown in Figure 12-23 below This model is well developed and is used to point out network areas that are at risk. The forecast risk of the network is used to develop an intervention strategy and inform the programme of works that will manage the risk to within acceptable compliance limits.

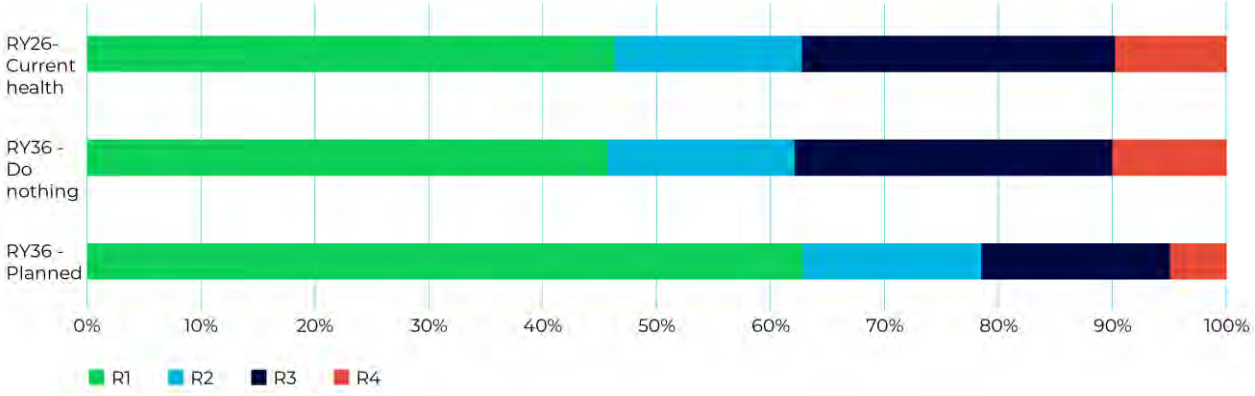


FIGURE 12-23: DISTRIBUTION OVERHEAD CONDUCTOR FLEET RISK PROFILE

12.6.2.5 MANAGEMENT STRATEGY

The optimal lifecycle investment considers the balance between asset renewal requiring capital expenditure and the combination of preventive, corrective and reactive operational maintenance expenditure.

The life of the conductor is determined by its ability to maintain operating tensions developed by static (gravity) and dynamic (wind) forces. These in turn are influenced by conductor type, size, span length, sag and environmental factors (corrosive elements and exposure to wind).

Vector proactive replacement and refurbishment programmes of work are informed by our CBARM models, condition assessments and criticality. Programmes of work are initiated to address gaps in service level targets that are either already apparent or are forecast in the AMP period. From FY27, Vector will begin a targeted replacement programme for old 16mm² copper conductors, selected and prioritized using network performance data to ensure highest risk are addressed. The completion of our replacement and refurbishment programmes during this AMP period is expected to improve the overall resilience and reliability of our overhead network and accordingly reduce our overhead conductor failure rate.

The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.6.2.6 DESIGN AND CONSTRUCT

Vector uses specialist overhead network design consultancies together with practical input from our FSPs to design the refurbishment of overhead lines. The design and performance characteristics of overhead conductors are prescribed in Vector Standard ENS-0153: Specification for overhead conductors. Design requirements are stated in ESE401, overhead line design requirements and ESE402, overhead design standard design applications. The completed designs are issued to the FSPs for construction and commissioning according to Vector's standards. The full suite of standards has been reviewed through the first quarter of 2024 with recommendations implemented.

The impact of climate change will also be considered in the design of routes for rebuilds and refurbishment and methods to harden construction against the impact of climate change will be added to our standards.

Increased use of lightning arrestors will be implemented on our overhead networks to harden the network against the impact of lightning surges.

12.6.2.7 OPERATE AND MAINTAIN

Vector implements a wide range of routine and operational tasks covering asset inspections, condition-based testing and maintenance. The tasks and timeframes are set out in our standard ESM401. The preventive tasks are designed to uncover non-compliant or serviceability defects which are then treated as corrective maintenance actions or an asset renewal action depending on the extent and risk to performance and safety.

Most defects are identified through aerial inspection and acoustic and thermovision inspection. Under the newly implemented inspection cycles, conductors are inspected twice in a five-year period, and any defects are recorded against the nearest pole as it has a point location and unique identifier in GIS. The key tasks carried out during inspections are similar to those detailed in Section 12.6.1.

Vector has also implemented the use of LiDAR technology as a tool to carry out height measurements and assessing clearance from vegetation and from the ground. The intrusions identified through the latest LiDAR survey are now processed into SAP and a corrective program of work has been initiated to remediate them on a risk prioritised basis.

12.6.3 LOW VOLTAGE

12.6.3.1 FLEET OVERVIEW

A low voltage overhead circuit is defined as an electrical line that transports electricity from a distribution transformer from which connections are then taken to customer's premises. The low voltage network operates at 400 V and excludes conductors associated with load control and streetlight systems. The low voltage network is generally a three-phase network i.e. comprises four wires: three phases and a neutral. In many instances, subtransmission, distribution and low voltage circuits are installed on the same support structures.

12.6.3.2 POPULATION AND AGE

Vector has over 4,120km (route length) of low voltage overhead conductor circuits, which is 50% of its total overhead network fleet length. Table 12-18 shows a summary of the types of LV conductor in the fleet with typical expected asset lives along with the installed route length for each type. Each of these types of conductors have different expected asset lives and failure modes, however the actual life of each conductor type is also affected by environmental factors (corrosive elements and exposure to wind), mechanical loads, electrical loads and number and magnitude of downstream electrical faults.

TYPE	DESIGN LIFE (YEARS)	LENGTH (KM)
All Aluminium Alloy Conductor (AAAC)	60	6
Aluminium Alloy Conductor (AAC)	60	1,164
Aluminium Conductor Steel Reinforced (ACSR) >100mm2	50	1
Aluminium Conductor Steel Reinforced (ACSR) <100mm2	50	445
Copper (Cu) > 60mm2	70	268
Copper (Cu) < 60mm2	55	1,525
Aerial Bundled Cable (ABC)	30	237
Unknown type	55	440
Total		**4,088**

TABLE 12-18: ASSET FLEET TYPE COMPOSITION AND EXPECTED LIFE

The age profile of the asset fleet is shown in Figure 12-24. It shows that 75% of the assets are between 30 and 60 years old and that approximately 15% of assets have exceeded their asset design life. During the planning period of this AMP, an additional 21% of LV conductor is expected to exceed its expected asset design life. As the condition of a conductor is determined by factors other than age, the asset management strategy for conductors is to utilise an inspection-based maintenance regime to determine risk and prioritise replacement. Due to historical data deficiencies for this fleet, an analytical approach was undertaken to allocate an age to each conductor based on its material type, size, age of the development in which overhead LV lines are located, age of associated assets and information gathered from the field. Values are in kilometres with a data error rate of approximately 1%.

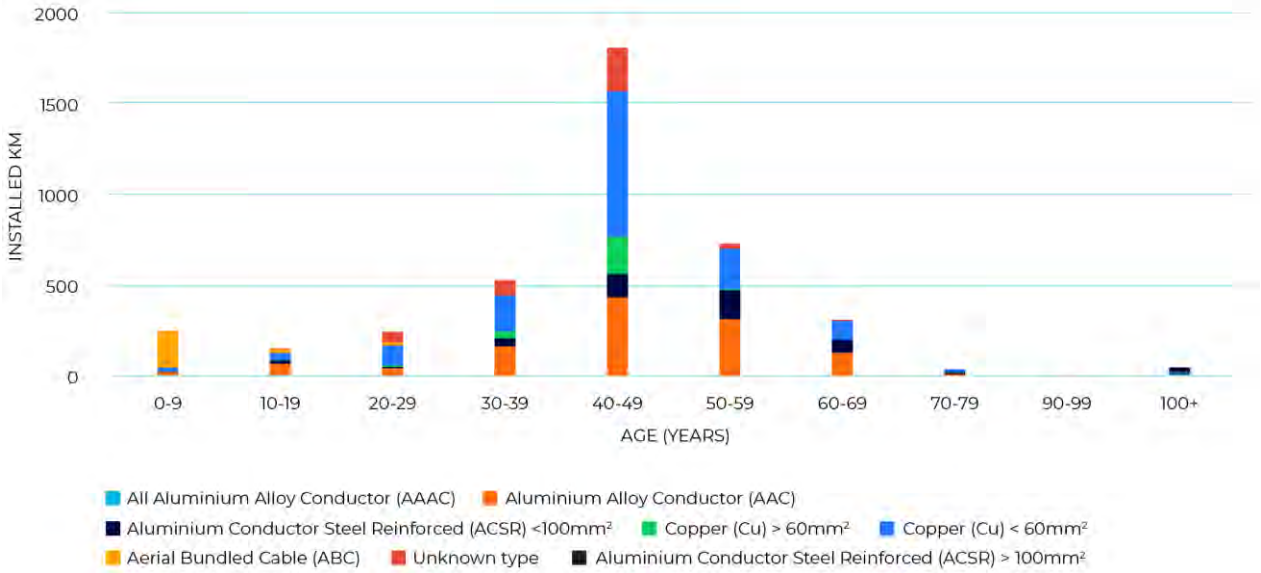


FIGURE 12-24: LOW VOLTAGE OVERHEAD CONDUCTOR FLEET AGE PROFILE

12.6.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Similar to conductors operating at higher voltages, the life of each conductor varies significantly and is related to conductor type, operating conditions and environmental factors. As most of the observed failure modes for conductors are not driven by age, the expected life based on age is an indication only. Conductor diameter is also a factor on life expectancy as smaller conductors are inherently weaker and are less able to withstand shock impacts from external forces such as vegetation and vehicle impacts. If a conductor fails, it is repaired with additional joints being introduced into the network. Joints are known to be likely points of failure, especially under fault conditions where secondary failures can occur. As conductors deteriorate and an increasing number of joints are installed under repairs, the reliability of such a circuit is likely to decrease.

Analysis of outage data showed that vegetation is a significant cause of faults. Proximity to marine environments also impacts conductor life considerably, observed failure modes are detailed below:

- Vegetation has proved to be major contributor to faults, especially during storms and high winds and thus a major contributor to a reduction in the reliability indices and customer service levels. Our increasing use of fully covered ABC conductor is assisting to mitigate this risk.
- Overhead conductors harden over time due to wind induced vibration, movement (strain hardening) and thermal cycling, resulting in becoming brittle and a reduction of its tensile strength, eventually leading to failure.
- Proximity to the ocean creates a more corrosive environment due to salt in the air and is generally a windier environment increasing the deterioration rate of conductors. All of Vector's network is less than 15 km from the nearest shoreline, and approximately 50% is within 3 km of the shoreline. Hence, these factors are an important driver of asset condition.
- The failure of components of overhead lines (other than the conductor itself) contribute significantly to interruptions on distribution feeders.
- Reporting of low lines by the public result in disconnection of the supply by Vector to take a no-risk approach to public safety until the situation has been made safe or repaired.
- The impact of climate change was very evident during the Jan-Feb 2023 cyclone when a significant number of outages occurred because of airborne debris and trees undermined by slips falling on conductors.

12.6.3.4 CONDITION AND HEALTH

We are not experiencing any systemic network failure modes in our LV network apart from the impact of vegetation during storms, which impact other parts of the overhead network as well. However, the LV network is experiencing the failure of aging hardware components such as neutral conductor clamps and crossarms and this has impacted customer service levels. The increasing frequency and severity of climate change events emphasis the need to design and construct a more reliable and resilient overhead LV network.

12.6.3.5 MANAGEMENT STRATEGY

The optimal lifecycle investment considers the balance between asset renewal requiring capital expenditure and the combination of preventive, corrective and reactive operational maintenance expenditure.

In order to deliver network opportunities aligned with our Symphony modelling, our focus on the visibility of our LV network and dynamic management of the LV network will increase. We will continue to maintain, refurbish and upgrade the LV network in line with our Asset Management Objectives.

This includes enhancing our capability to model and analyse the behaviour of our LV network, and the customer energy demands placed on it particularly where DER and transport electrification is becoming pronounced. We have defined the use cases to improve visibility of the LV network using modern and cost-effective monitoring devices to measure energy flows in the LV network and trial sites are being evaluated. Data from smart meters and advanced metering infrastructure are key enablers of our LV network visibility strategy.

Vector proactive replacement and refurbishment programmes of work are informed by our condition assessments and criticality projects or programmes are initiated to address gaps in service level targets that are either already apparent or are forecast in the next 5-10 years. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.6.3.6 DESIGN AND CONSTRUCT

The design of new or replacement distribution lines is undertaken by Vector with input from the FSPs and pole engineering specialists as required. The design and performance requirements are defined in Vector Standard ENS0153: Specification for overhead Conductors. The completed designs are issued to the FSPs for construction and commissioning.

For LV service line replacements, Vector has standardised the use of LV ABC instead of like-for-like conductor replacements. This approach enhances public safety, reduces the risk of contact incidents and eliminates the need for service crossarms.

12.6.3.7 OPERATE AND MAINTAIN

Vector undertakes a wide range of routine and operational tasks covering asset inspections, condition-based testing and maintenance as detailed in our standard ESM401. The preventive tasks are designed to uncover non-compliant or serviceability defects which are then treated as corrective maintenance actions or an asset renewal action depending on the extent and risk to performance and safety.

Most defects are identified through aerial inspection and acoustic & thermovision inspection. Under the current inspection cycle, conductors are inspected twice every five years, and any defects are recorded against the nearest pole as it has a point location and unique identifier in GIS. The key tasks carried out during inspections are similar to those detailed in Section 12.6.1.

Any identified defects that render a potentially unsafe situation to the public or property are repaired, replaced or isolated immediately. Remediation timeframes are based on likelihood of failure creating an unsafe situation and interruption to consumers. Vector has also implemented the use of LiDAR technology as a tool to assess the conductor clearance from the ground, roads, buildings, and vegetation in compliance with ECP34 requirements. In parallel, high-resolution photographs are taken from the helicopter, enabling desktop pole-top assessment of defects on the overhead conductors and components. The defects identified are processed into SAP and are being addressed on a risk prioritised basis. Routine LiDAR surveys and pole-top assessment will continue to be conducted across the network ensuring that clearance risks and network performance risks are effectively managed, and compliance breaches are identified.

In addition, drone inspections are being utilised as a primary method to capture detailed high-quality images of overhead assets since FY25. This inspection focuses on detecting conditions such as broken strands, corrosion, burn marks and joints overheating. All captured images are uploaded in SAP and GridAware, where an annotation process is undertaken to identify overhead asset defects. This process also contributes to ongoing AI model training, developing automated defect detection and analysis capabilities over time.

12.6.4 SUPPORT STRUCTURES

12.6.4.1 FLEET OVERVIEW

Overhead support structures include towers, poles, crossarms and associated pole and conductor hardware. These are designed to carry overhead conductors of all voltages under a wide variety of configurations. The support structures must be able to withstand design loads that are generated by the equipment fixed to the pole for the expected lifetime of the asset. Vector has a variety of concrete (reinforced and pre-stressed), wood (hardwood and softwood) and composite (fiberglass) poles, as well as steel monopoles and lattice towers.

12.6.4.2 POPULATION AND AGE

Overhead supports are described by the highest voltage conductor that is attached to the structure, that is - HV (110 kV), MV (33 kV, 22 kV or 11 kV) and LV (400 V or 230 V). It is common for supports to have conductors of two or more voltages installed on them.

As shown in Table 12-19, approximately 92% of Vector's fleet of 126,438 poles are concrete poles. Approximately 4% are wood and the remaining 4% are either steel (predominantly on the subtransmission network), composite materials or unknown material.

MATERIAL	LIFE EXPECTANCY (YEARS)	VOLUME NORTHERN			VOLUME AUCKLAND			TOTAL
		HV	MV	LV	HV	MV	LV	
Wood – Softwood	40		393	1,393		75	2,117	3,720
Wood – Australian Hardwood	60	61	133	44		546	357	1,141
Steel – Lattice Tower	100	45	57					102
Steel – Monopole	100	16	7	3			3	29
Composite	80		292	820		84	427	1,623

MATERIAL	LIFE EXPECTANCY (YEARS)	VOLUME NORTHERN			VOLUME AUCKLAND			TOTAL
		HV	MV	LV	HV	MV	LV	
Concrete – Prestressed	80	25	10,808	7,316		22,080	25,036	65,265
Concrete – Reinforced	80	34	35455	12,383		1,769	1,548	51,189
Unclassified			1,413	1,386		59	250	3,111

TABLE 12-19: POLE FLEET COMPOSITION BY NETWORK REGION

Figure 12-25 below shows that approximately 13% of poles currently exceed their expected life and during the next 10-year planning period, this will increase by an additional 3%. However, these assets are assessed annually for condition and replaced if required. Vector notes that due to incomplete pole age data, this data is considered to be circa 87% accurate.

Prior to 1990, reinforced concrete poles were the preferred type. These were often produced locally and consist of reinforcing bar with concrete poured onto it in a cast. Modern concrete poles comprise a prestressed steel core and spun concrete that results in less concrete being used (lighter) but retains the structural strength as required.

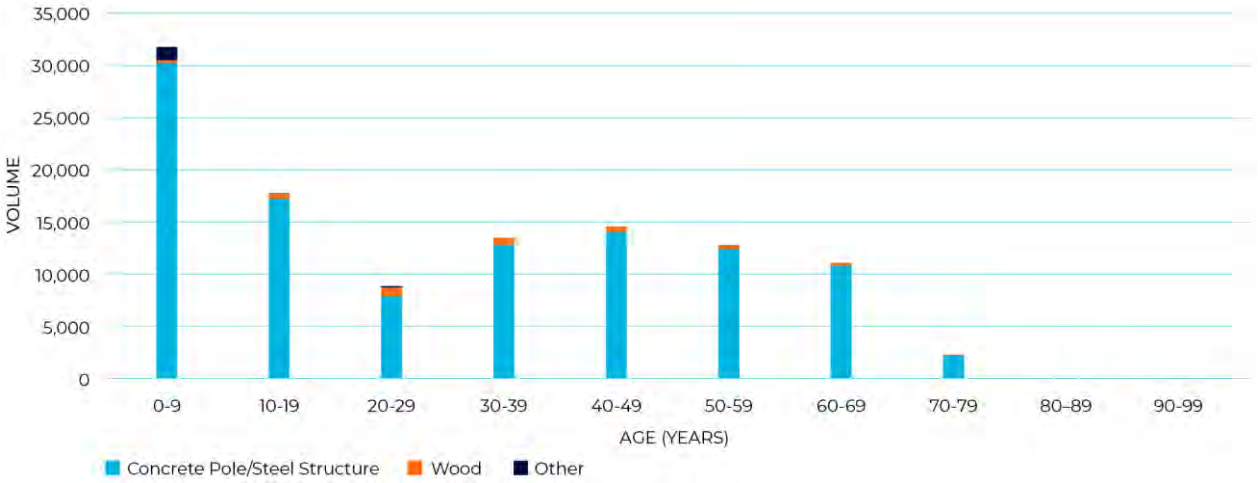


FIGURE 12-25: POLES FLEET AGE PROFILE BY MATERIAL TYPE

12.6.4.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Although the events shown in Figure 12-26 below have been recorded in our outage recording system as being a 'Pole' failure, investigations have found that an external factor is often the cause of the outage. For example, if a car hit a pole, it is recorded as 'Pole' in the system. Vector has recently improved the way it categorises pole failures which is reflected in the low number of events recorded since 2020.

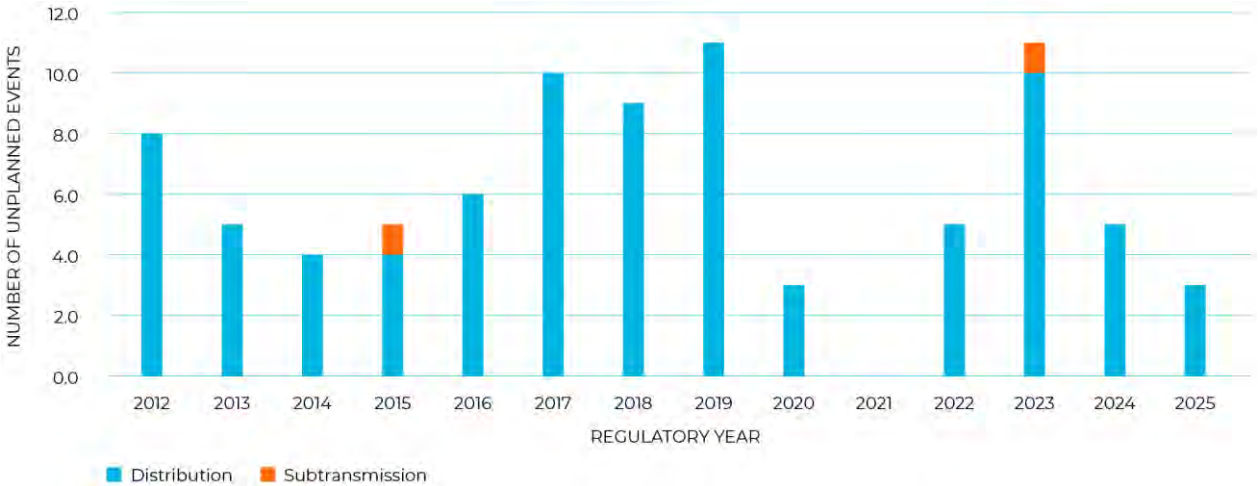


FIGURE 12-26: POLE FAILURES RECORDED ON THE NETWORK

The failure modes and expected life of poles are determined by their material type and environmental factors. As poles age and deteriorate, they lose their mechanical strength and will eventually fail due to the load of the assets installed on them. High winds increase the load on poles. Environmental factors such as moisture and proximity to the ocean accelerate deterioration.

Concrete poles can fail due to 'concrete cancer' where moisture penetrates and causes the reinforcing steel to corrode and crack the concrete. Many of Vector's concrete poles are the 'Vierendeel' poles which are the prestressed type cast into a mould, which are susceptible to the concrete cancer failure mode. This poses a risk to field crews. Prior to any Vierendeel No. 1 concrete pole being climbed, it is inspected and if showing signs of stress, is not climbed unsupported.

KNOWN ISSUE	HOW IT WAS DISCOVERED	HOW IT IS BEING ADDRESSED
Weak Firth Vierendeel poles (especially No. 1 type poles)	Historic design	Work practice (do not climb unsupported, replace when changing the load)
Poles with unknown ownership	GIS legacy data	GIS updated as and when these situations are found
Wooden Poles failing within inspection frequency	Pole Failure	The long-term goal is to remove wooden poles from the network but in the meantime the following has been implemented: • Reduced the timeframes for testing from 5 and 10 years to 2.5 and 5 years based on testing results • Reduced the SI/Remaining strength limit for additional replacement • Removed the installation of wooden poles from standards, all future new installs will be either composite or concrete • Budget for the proactive replacement of wooden poles
Pole with customer ownership not being adequately maintained	Observed failure trend	Proactive right of way survey and pole replacement
Poles owned by other utilities with different asset management capabilities	Observed failure modes	Work practices – do not climb

TABLE 12-20: KNOWN ISSUES AND RESOLUTION FOR POLES

12.6.4.4 CONDITION AND HEALTH

In the absence of a developed CBARM model, Vector uses an aged-based assessment to describe the condition of its pole fleet. Figure 12-27 shows that there is a trend of deteriorating condition if no action is taken. This aligns with the expected increase in the age of the asset fleet and the percentage of the fleet that will be exceeding its expected life at the end of the 10-year forecast.

Vector has developed an intervention strategy to replace at risk overhead supports during the current AMP period. These supports will be replaced with increasingly more reliable infrastructure that has a longer life and is more robust

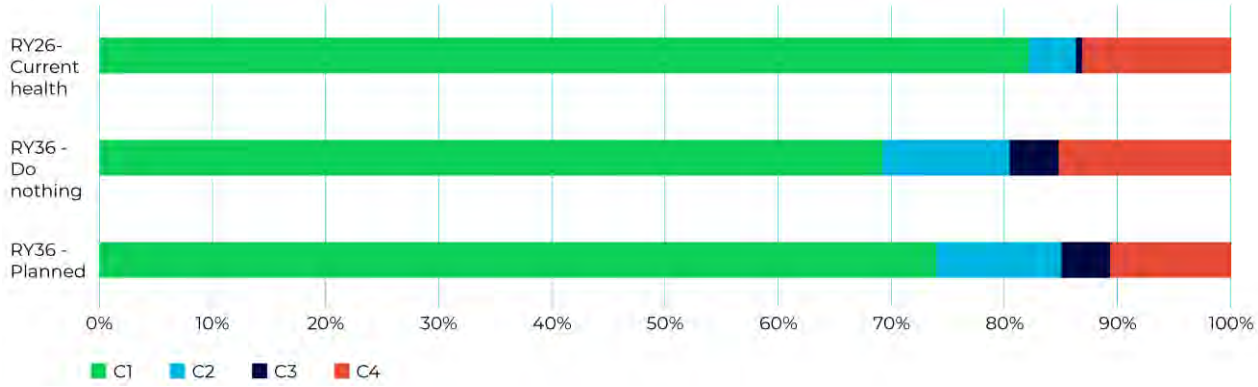


FIGURE 12-27: POLE FLEET CONDITION PROFILE

12.6.4.5 MANAGEMENT STRATEGY

Vector uses a condition-based approach that considers asset health and safety to identify the need to replace or retire specific poles. The remaining life of a pole is difficult to predict accurately because it is dependent upon several factors. These include the pole material and construction, natural environment, public exposure, access and the load that is being supported. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.6.4.6 DESIGN AND CONSTRUCT

Vector has approved for use in the network a number of pole designs, made of concrete, steel or composite materials. Vector's FSPs are responsible for purchasing these poles from the approved suppliers directly, and manage the pole stocks on Vector's behalf, except for the composite poles Vector retain the responsibility of its procurement and stock management in Vector's own warehouse. A rationalisation exercise has been carried out with the aim of reducing the number of different sizes of concrete poles. This will ensure the stock levels are optimised.

Poles on the 110 kV line and some 33 kV tower routes require bespoke solutions, e.g., specifically sized monopoles, and replacements may take several months to procure.

Where overhead supports are replaced, it is Vector's preference that prestressed concrete poles be used. For specialist applications (height or strength requirements), steel monopoles are used. As composite poles are light weight, they can be used in remote locations without vehicle access because they are easier and safer to transport.

When designs are being undertaken, the locations of poles and selecting the use of structures the impact of climate change will become an important consideration. For example, areas that are prone to ground slips must be avoided as far as practicable and routes in areas that are flood prone must also receive special consideration.

Vector has stopped the installation of new wood poles in the network, because unlike the other pole types, timber requires regular specialist assessment in the remaining strength of the timber through a wood pole's life cycle.

12.6.4.7 OPERATE AND MAINTAIN

Most defects are identified through visual inspection. Under the current inspection cycle, each pole and its associated pole top hardware are inspected twice every five years and wood poles are subject to additional testing every two and a half years or five years dependent on the previous SI results. This test is conducted at just below ground level where decay occurs. All equipment defects are recorded in SAP PM. A tagging system is used during visual indications to tag poles that require replacement. Different colour tags define the timeframe in which remedial action is required.

The routine inspection, maintenance and testing requirements for Vector's overhead structures are currently prescribed in Vector Standard ESM401.

12.6.5 REPLACE, RENEW AND DISPOSE

12.6.5.1 CONDUCTORS

Vector decides on replacement of its overhead subtransmission, and distribution lines based on condition observed during field inspections and from the output of the conductor CBARM model. When the condition of part or all of an assembly meets the replacement criteria, the entire assembly is assessed to test for the cost efficiency of replacing just the component or the entire assembly.

A conductor testing regime has also been introduced to improve the assessment of the condition of conductors where visual observation shows suspect conductors. Furthermore, whenever a conductor fails a sample is retrieved and tested for tensile strength and ductility. These properties provide better indication of the condition of a conductor and its need for replacement.

For the overhead distribution network fleet, a targeted program has been established to replace over 197km of overhead conductors for which there is a trend of increasing failure rates. A significant portion of the small conductor fleet is also expected to reach its standard asset life. The key types targeted for replacement are 16mm² Copper conductors and other older conductors. Due to these conductors also being in areas with higher population densities, they pose an increased safety hazard to the public as well as a reliability risk. In line with the requirements of the Auckland Unitary Plan, replacement of LV conductor will either be with aerial bundled conductor or with underground cable.

Vector is also validating conductor clearance defects captured through the 2019 LiDAR survey, with a particular focus on high priority ground clearance defects. A large portion of clearance defects have been validated and addressed through corrective maintenance activities. Further validation will be resolved using data from the new LiDAR provider engaged since FY25, which employs enhanced LiDAR survey methodologies and improved modelling analysis.

In addition, a targeted program will be initiated to eliminate all P1 overhead line defects, planned for completion across FY26 and FY27, with priority given to those associated with other urgent condition-based overhead line defects.

12.6.5.2 SUPPORT STRUCTURES

Vector applies a condition-based approach in managing the pole populations. Each pole structure is inspected on a periodic basis, or if a potential issue is reported, against assessment criteria established in the maintenance standards. The decision to repair or replace is based on the outcome of the inspection and condition assessment. In addition, poles may also be replaced when new assets attached to the pole are added or removed. This is contingent on an engineering assessment being carried out on the existing pole and in accordance with the design standard.

Pole replacements identified for replacement under the tagged inspection regime are forecast as part of the corrective maintenance programme. However, where a proactive overhead line refurbishment project is undertaken each pole in the route will be assessed for replacement and if required, its replacement will be undertaken as part of the overhead refurbishment scope of works. Pole replacement includes the replacement of the hardware.

A proactive wooden pole replacement programme has been initiated since FY26, targeting poles that have not yet failed but are in the poorest condition. Due to variations in timber seasoning and environmental exposure, the remaining serviceable life of wooden poles can be difficult to predict, and this programme aims to address those poles most at risk of failure.

12.6.6 FORECAST SPEND

The replacement and refurbishment programme for overhead lines is described in detail in Section 11 and includes the proposed investment for each individual project.

12.7 Distribution equipment

This section describes our distribution equipment fleet and provides a summary of our associated asset management practices. The distribution equipment fleet consists of the following six subcategories:

- 11-22 kV overhead switchgear
- Pole mounted distribution transformers
- 11-22 kV Ground mounted switchgear
- Ground mounted distribution transformers

- Voltage Regulators
- LV Distribution system (non-overhead)

12.7.1 11-22 KV OVERHEAD SWITCHGEAR

In the distribution network, overhead switchgear comprising of circuit breakers, load break switches and isolating links are used to control, protect and isolate the network. The function of the switchgear is to provide protection, by interrupting short circuit and overload fault currents, or isolation, by providing a clear open point, while maintaining service to unaffected circuits.

The circuit breakers in the overhead distribution network are typically epoxy insulated reclosers with vacuum interrupters capable of manual operation and remote operation where required. Older designs consist of SF_6 gas insulation, installation of which ceased in 2000.

Load break switches in our network use either epoxy resin, SF_6 gas or air as an insulation medium. These switches are capable of breaking loads and use various methods of extinguishing the resultant arc. We have recently introduced the epoxy resin insulated load break switch (LBS) as a trial to compare performance against the extensively used SF_6 insulated LBS.

Isolating links refer to drop out fuses, knife links and sectionalisers. Drop out fuses and knife links require manual operation to achieve isolation whereas sectionalisers use logic to determine when to operate, based on defined settings. Sectionalisers are used to isolate larger network portions during a fault. Drop out fuses are used to protect transformers, short sections of overhead line and underground cable sections to transformers. Load break switches are used to provide safety isolation to personnel and to reduce the number of customers affected by a planned or unplanned outage.

12.7.1.1 FLEET OVERVIEW

Key statistics of the overhead switchgear assets are shown in Table 12-21.

EQUIPMENT TYPE	POPULATION
ABS/ABI (air break switch/air break isolator)	853
Drop out fuses	10,861
SF_6 gas switch	562
Solid and sectionalising links	536
Reclosers with vacuum interrupters	228
Automated switch with vacuum interrupters	52

TABLE 12-21: KEY STATISTICS

12.7.1.2 POPULATION AND AGE

The expected life for the overhead switchgear fleet is indicated in Table 12-22

CATEGORY	DESIGN LIFE SPAN
ABS/ABI	30 years
SF_6 gas switch	30 years
Circuit breaker (reclosers and automated switches with vacuum interrupter technology)	30 years
Drop out fuse holder	20 years
Drop out fuse	Single use
Solid and sectionalising links	20 years

TABLE 12-22: EXPECTED RELIABLE OPERATING LIFE FOR OVERHEAD SWITCHGEAR

The table above shows the design life of the overhead switchgear assets. However, this is often not the driving factor for replacing the asset. The longevity of each piece of equipment is influenced by other factors including the operating environment, the number of operations completed, and maintenance completed throughout the life of the equipment. This results in the retention of equipment within our network beyond their design life if the asset is serviceable and can be operated safely.

Figure 12-28 summarises the population and age of our overhead switchgear (Vector notes the level of data error is approximately 10% and the population data consistency is being continually refined).

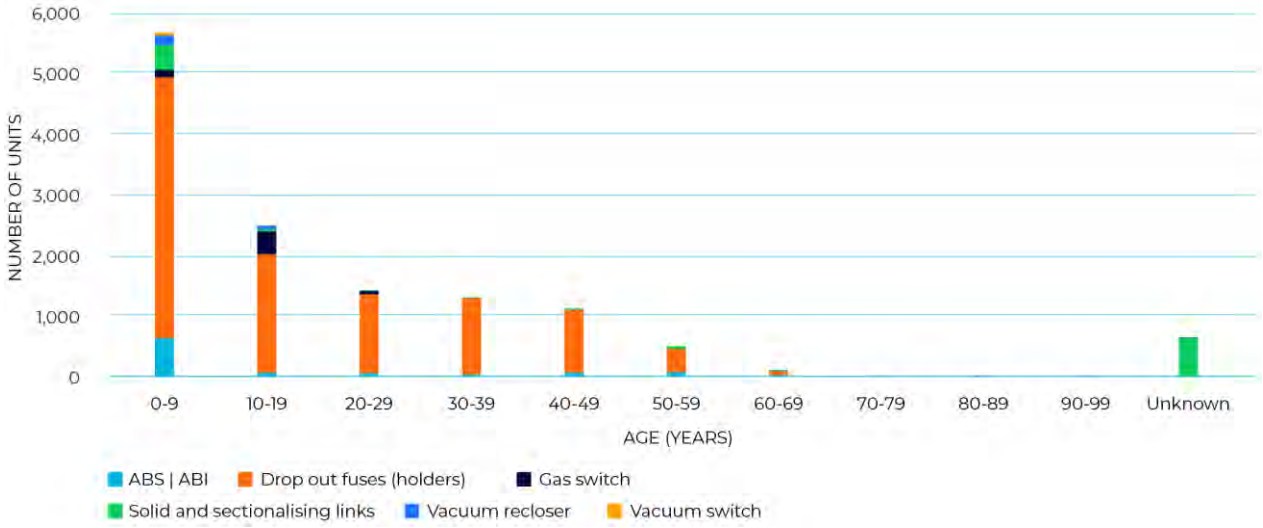


FIGURE 12-28: DISTRIBUTION SWITCHGEARS FLEET AGE PROFILE

12.7.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

With proper maintenance on the exterior of a switch to ensure its integrity as well as maintenance on external connections, the gas and vacuum switch fleet can continue to provide satisfactory operation beyond the stated design life. Vector started using gas and vacuum switchgear technologies in the early 2000s which means that the oldest units in the network are only halfway through their stated design life.

Vector has experienced gas leakages from the tanks of gas insulated switchgear. This has led to the re-introduction of air-break switches with arc limiting chutes, to replace earlier than expected failed gas switches. Since this is not a whole of population problem, we will continue to maintain the existing gas insulated switchgear and monitor for additional failures through routine maintenance activities for as long as practicable.

There are approximately 130 ABS/ABI units of pre-1980s vintage. Although these older switches may still be able to perform their intended functions through periodic inspection and maintenance, the maintenance being performed is designed to maintain the basic operational proficiency of the equipment to ensure it can last until its life expectancy. Maintenance alone should not be considered as a life-extending mechanism to prolong the service life of the equipment indefinitely. Therefore, the performance of this older population shall be monitored closely to help identify any upwards trend in the equipment's failure rate.

There has been a considerable growth in the number of transformers in the network over the past ten years due to the growth of Auckland's population. This in turn resulted in an increase of the drop out fuse fleet because fuses remain the preferred method of protection for distribution transformers and spur lines due to their simplistic design, effective operation mode and their economic cost.

Prior to the 2000's there was limited deployment of SF_6 gas switches in the overhead distribution network and use was limited to specific network applications only. From 2003 Vector adopted the use of pole mounted gas switches with the intent for it to be a standard type of overhead equipment to replace air-break switches. Together with the uptake of gas switchgear additional reclosers were installed in critical locations of the overhead network driven by an initiative to improve the network SAIDI performance. Due to regular occurrences of gas leakage in the gas switch fleet there has been an increase in the usage of ABS's since 2015. Vector has recently introduced a vacuum operated gas switch that will be utilised in locations where remote-controlled switching is required.

Due to the age and condition of Vectors ABI overhead switch fleet, live operations using these devices are only permitted if the load on the network at the time of operation is 20 amps or less.

The Vector maintenance standard defines periodic maintenance activities to identify defects or signs of deterioration in the overhead switchgear fleet. The maintenance standard also prescribes corresponding remedial actions to address any identified defects to ensure the risk of equipment failure is managed appropriately.

12.7.1.4 CONDITION AND HEALTH

Vector uses an age and condition determined from identified defects as a method to determine likelihood of asset failure of its overhead switchgear fleet. The majority of the overhead switchgear population are drop out fuses that are managed by replacement on condition. As such the risk profile is significantly skewed positively by this subset of the population as it is a simple asset that presents low risk through life. To better present the risk profile that is driving the asset replacement program for overhead switchgear, the risk from the 853 ABS/ABI switches are presented in Figure 12-29. This shows that there is a trend of deteriorating condition if no action is taken. This aligns with the expected increase in the age of the asset fleet and the percentage of the fleet that will be exceeding it expected life by the end of the 10-year forecast.

Vector has developed an intervention strategy to ensure the condition of the fleet is maintained at current health levels.

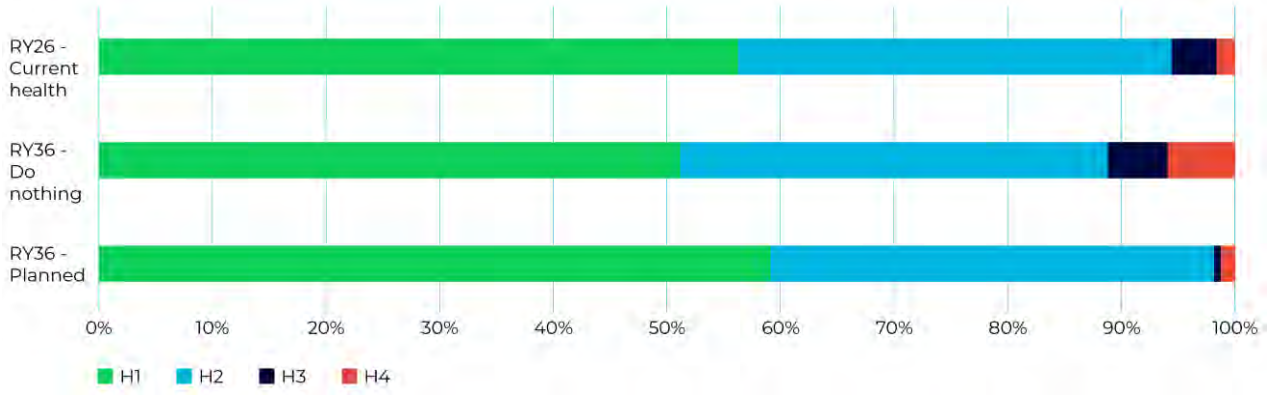


FIGURE 12-29: OVERHEAD SWITCHGEAR (ABS/ABI) FLEET CONDITION PROFILE

12.7.1.5 MANAGEMENT STRATEGY

To ensure optimal performance in MV overhead switchgear, all condition assessment and maintenance are performed by following Vector's maintenance standard ESM501: Maintenance of Overhead Switchgear. Each switchgear shall be inspected against assessment criteria established in maintenance standard. The decision to repair or replace shall be based on the outcome of a condition assessment.

Integrating automation and alternative assets into the distribution network is identified as a significant aspect of Vector's long-term strategy for improving SAIDI.

If major off-site maintenance is required to be carried out on a legacy ABS, Vector's present practice is to replace the switch with a new modern equivalent. The old switch will be scrapped because of outdated designs or obsolescence and because they generally require a higher level of maintenance compared with modern equivalents.

12.7.1.6 DESIGN AND CONSTRUCT

Drop-out fuse links and solid links are procured by the FSPs in accordance with Vector standards. All other types of overhead switchgear are directly purchased by Vector and released to Vector's FSPs on request as free-issue equipment or as part of proactive works projects.

Vector has prioritised the identification and onboarding of at least two switchgear designs for each network function, to avoid reliance on a single supplier for overhead switchgear.

Vector has developed a comprehensive suite of in-house design standards and drawings that define the installation requirements for different overhead switchgear types. All installations must conform to these standards, but Vector can give permission for deviations through a change control process.

12.7.1.7 OPERATE AND MAINTAIN

The Vector maintenance standard prescribes preventive maintenance requirements, frequency of inspections, and method of treatment of defects identified either through corrective maintenance or asset replacement processes. The standard also defines the procedure for data capture and system updates carried out by Vector's field service providers.

Vector implements a wide range of routine and operational tasks covering asset inspections, condition-based testing and maintenance. The tasks and timeframes are set out in our standard ESM501. The preventive tasks are designed to uncover non-compliant or serviceability defects which are then treated as corrective maintenance actions or an asset renewal action depending on the extent and risk to performance and safety.

Most defects are identified through aerial inspection and acoustic & thermovision inspection. Under the newly implemented inspection cycles, assets are inspected twice in a five-year period.

If major off-site maintenance is required to be carried out on a legacy ABS, Vector's current practice is to replace the switch with a new modern equivalent. As such, there is currently no asset refurbishment needed for overhead switchgear other than performing a few simple onsite maintenance activities on the legacy ABSs and ABIs, such as greasing the moving parts or replacing arc horns to maintain their operational efficiency.

Vector's maintenance standard ESM501 details the requirements for the distribution overhead switchgear fleet. Table 12-23 summarises the planned maintenance regime for this asset subclass.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Full Drone, Acoustic and Thermal Inspections	5 years
Inspection	Acoustic Survey and Thermovision Inspection	5 years
Inspection	Thermal Inspections on air break switches within Zone substation	1 year
Servicing	Servicing on Air break switches and air break isolators	3 years
Servicing	Servicing on air break switches within Zone substation (in switch bay area only)	4 year
Servicing	Servicing on Sectionalisers & automated gas switches	10 years

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Servicing	Servicing on Reclosers	10 years
Functional Test	Function Testing on Omni-Rupter ABS, Allied insulator ABS and Manually Operated Fully Enclosed switchgears	3 years

TABLE 12-23: PLANNED MAINTENANCE ACTIVITIES FOR OVERHEAD SWITCHGEAR

Vector does not carry out any electrical testing on its overhead switchgear unless there is a specific issue that needs to be investigated and resolved. Thermal imaging and testing for partial discharge (PD) can be included as part of the testing regime once a decision to test is made.

Vector incorporates risk elements in the overall maintenance approach, such that the treatment of an identified defect is also heavily influenced by consequence and hazard likelihood. For example, assets that have low impact on network performance, such as fuses supplying individual dwellings, are allowed to run to failure because it is more cost effective to replace the failed units rather than inspecting them on a regular basis.

12.7.2 POLE MOUNTED DISTRIBUTION TRANSFORMERS

Pole mounted distribution transformers are essential components in the distribution network that transform the higher voltages down to consumer usable voltages. These are similar to the larger power transformers but are limited to 300 kVA due to their installation on a pole. Pole mount transformer installations in overhead networks are an economical way to locate the equipment close to the point of supply.

12.7.2.1 FLEET OVERVIEW

Vector has approximately 7,530 pole mounted distribution transformers ranging from 1 kVA to 300 kVA. Vector uses a combination of 11 kV/400 V 3 phase, 11 kV/230 V single phase transformers to step the voltage down to 400 V or 230 V for customer use. Transformers up to 100 kVA are 'hung' on poles and larger transformers are mounted on an elevated platform.

12.7.2.2 POPULATION AND AGE

Table 12-24 provides a summary of the population of our pole mounted distribution transformers by size.

CATEGORY (SIZE)	POPULATION
1 kVA	2
5 kVA	1
7.5 kVA	9
10 kVA	36
15 kVA	1160
20 kVA	40
25 kVA	76
30 kVA	2826
50 kVA	2178
75 kVA	1
100 kVA	226
150 kVA	26
200 kVA	237
250 kVA	1
300 kVA	701

TABLE 12-24: POLE MOUNTED DISTRIBUTION TRANSFORMER POPULATION

Figure 12-30 illustrates the age profile of our pole top distribution transformers. The average age of pole top transformers is 21.9 years. Our pole top transformer fleet is considered young compared to the typical 30 to 40-year design life.

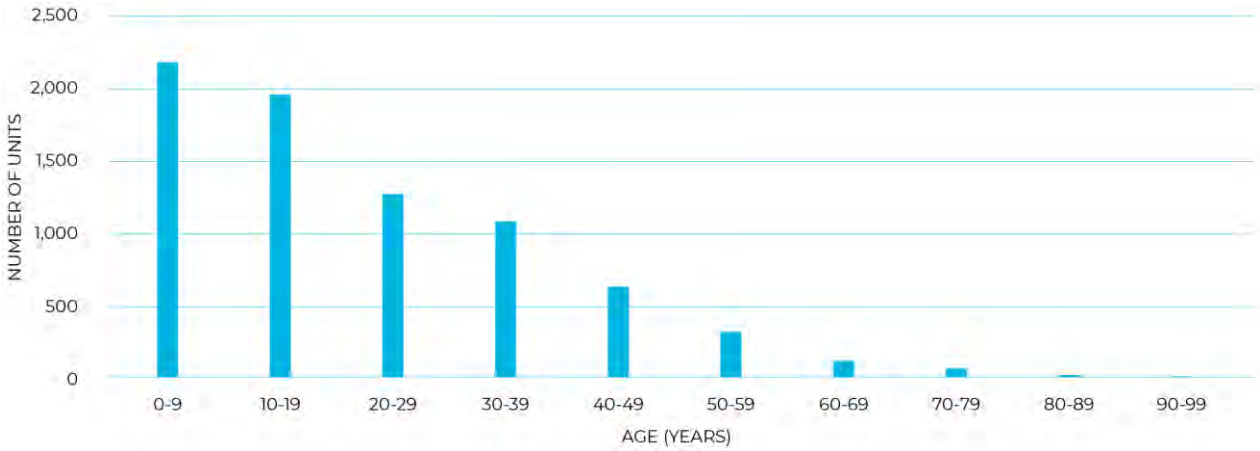


FIGURE 12-30: POLE TOP DISTRIBUTION TRANSFORMER FLEET AGE PROFILE

12.7.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector relies on visual inspections to determine the condition of the transformer fleet but is also informed by the CBARM model. The transformer life depends on loading and operating conditions. If loaded beyond rated capacity for prolonged periods, the expected lifespan is shortened. Typically, these transformers are not operated above nameplate and therefore are not unduly stressed, leading to a low count of replacements due to fatigue.

12.7.2.4 CONDITION AND HEALTH

Our CBARM model for pole top transformers is based on age, condition and criticality. The present (RY24) risk level for the pole top transformer fleet is shown below in Figure 12-31.

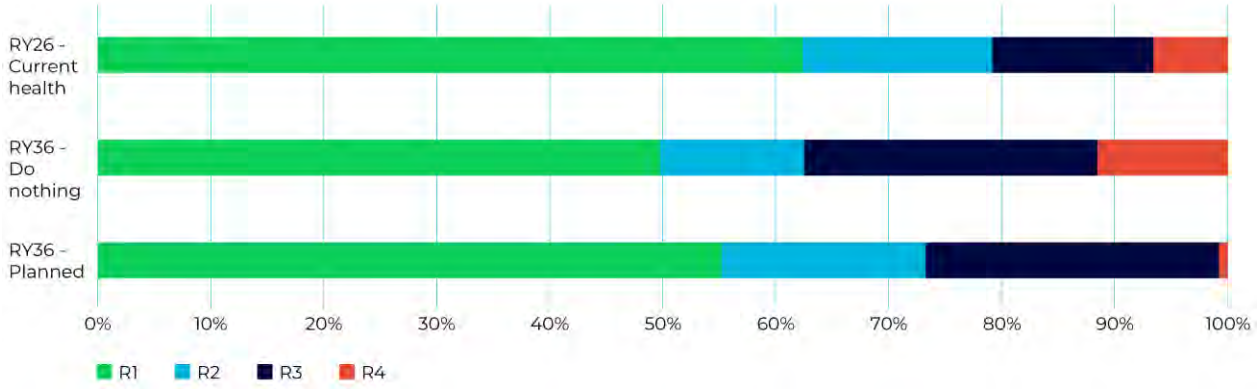


FIGURE 12-31: POLE TOP TRANSFORMER FLEET RISK PROFILE

The risk profile indicates that the pole top transformer fleet is in good condition with less than 11% of the fleet approaching end of life within the next 10 years. Vector's investment programme will significantly reduce the number of pole top transformers within the highest risk category in the upcoming AMP period.

12.7.2.5 MANAGEMENT STRATEGY

The management strategy for pole mounted transformers is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.7.2.6 DESIGN AND CONSTRUCT

All new pole mounted distribution transformers are manufactured to Vector's equipment specification ENS-0093. Vector has developed a suite of design standards and drawings that define the installation requirements for pole mounted distribution transformers.

To ensure diversity of supply Vector currently has two approved suppliers for this asset class.

12.7.2.7 OPERATE AND MAINTAIN

Vector implements a wide range of routine and operational tasks covering asset inspections, condition-based testing and maintenance. Preventive tasks are designed to uncover non-compliant or serviceability defects which are then treated as corrective maintenance actions or an asset renewal action depending on the extent and risk to performance and safety.

Most defects are identified through aerial inspection and acoustic & thermovision inspection. Under the newly implemented inspection cycles, assets are inspected twice in a five-year period. Visual inspections are used to check external components because the internal components are sealed and inaccessible for on-site inspections.

The planned maintenance regime for our distribution transformer assets is summarised below in Table 12-25.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Drone inspection, acoustic and thermovision inspection on Overhead Distribution Transformers	5 Years
Inspection	Acoustic and thermovision Inspection on Overhead Distribution Transformers	5 Years

TABLE 12-25: PLANNED MAINTENANCE ACTIVITIES FOR DISTRIBUTION TRANSFORMERS

12.7.3 11-22 KV GROUND MOUNTED SWITCHGEAR

In the Vector distribution network, ground mounted distribution switchgear is commonly known as Ring Main Units (RMUs) whose function is to connect underground cables to form a meshed network feeder. RMUs are found inside buildings, on private properties or installed in enclosures on the road reserves.

RMUs provide multiple functions – load break switch, circuit breaker and fuse switching. Circuit breaker and load break switching is incorporated in the main connection of the network and the fuse switch is typically used to feed a downstream distribution transformer directly.

12.7.3.1 FLEET OVERVIEW

The fleet of RMUs is made up of oil filled, SF_6 gas filled and epoxy resin insulated equipment of varying ages and manufacturers. The arc-quenching medium used is natural mineral oil, SF_6 gas and air, respectively. The majority of the older RMUs are oil filled due to the industry widely using this method of insulation up until late 2011. Since 2012 SF_6 gas insulated equipment has been the new standard. A small number of epoxy resin insulated RMUs were installed in the 1980s, however this ceased due to safety concerns.

Most of the RMUs in the network are rated at 12 kV and installed in the 11 kV network. There are a small number of 24 kV rated units in the 22 kV network which are all SF_6 gas insulated. The number of installed RMUs is shown in Table 12-26.

EQUIPMENT TYPE	POPULATION
Resin	69
SF_6 gas	4,125
Oil	5,215

TABLE 12-26: NUMBER OF RMUS INSTALLED

12.7.3.2 POPULATION AND AGE

The expected/design life of the differing insulation categories for RMUs is shown in Table 12-27.

CATEGORY	DESIGN LIFE SPAN
Resin	40 years
SF_6 gas	30 years
Oil	40 years

TABLE 12-27: DESIGN LIFESPAN OF RMUS

Figure 12-32 illustrates the age profile of our RMUs. The average age of the RMUs installed in the Auckland region is 26.5 years, while the average age of the RMUs installed in the Northern region is 15 years. The older equipment in the fleet is predominantly oil insulated, and as discussed above, this is progressively being replaced with SF_6 insulated equipment.

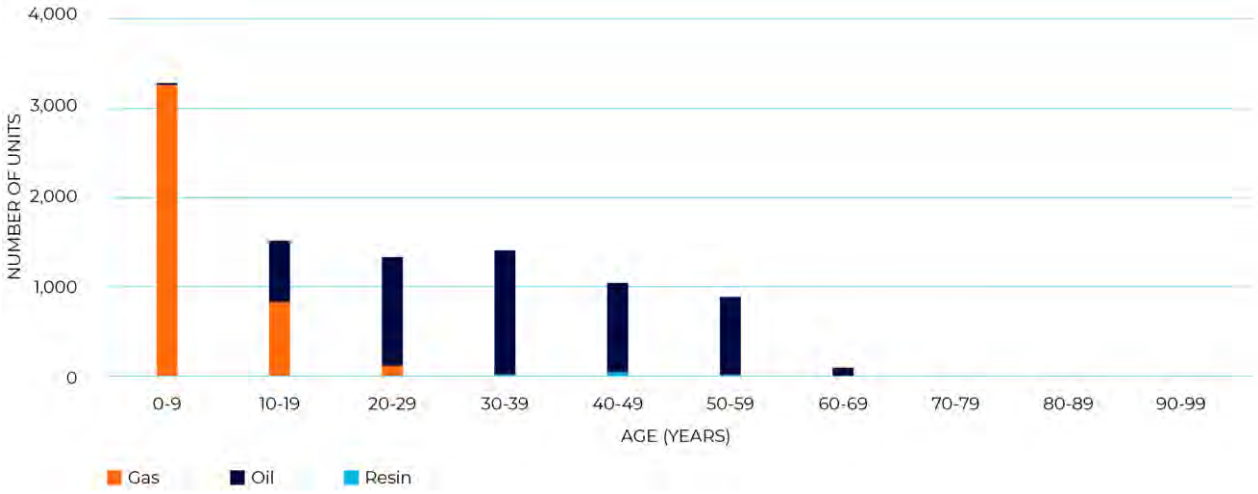


FIGURE 12-32: RMU FLEET AGE PROFILE

12.7.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

RMU service life is a function of the number of duty cycles that the switches experience, the volume and magnitude of through faults, and the RMU's installation environment. Aggressive environmental conditions such as heavy pollution or corrosive atmospheric conditions can have a detrimental effect on the service life of a switch. These operating conditions affect the steel and the protective coatings that protect the switch. A key factor is the effect on the corrosion of steel, which directly affects the integrity of the sealed gas tank and thus its ability to maintain the required pressure of the SF_6 insulating gas for safe switching operations.

For oil-filled switchgear, deterioration in the tank condition or compromised seals in the tank penetrations could result in a loss of the insulating oil and/ or exposing the switching assembly housed inside the tank to external interference, such as moisture or other contaminants. These defects can lead to internal failure in the tank and shortening the life of the equipment.

Accessibility can also affect the longevity of ground mounted switchgear. Vector typically installs distribution RMUs in public spaces, such as footpaths and road reserves where they are more exposed to external damage such as vandalism or vehicle impact.

In 2017, an oil filled Long & Crawford RMU failed catastrophically which has resulted in Vector targeting this make of switchgear for further investigations to ensure the continued safe operation of this type. Vector, in line with other utility operators, is performing ongoing assessment of the arc flash risk at the distribution sites across the network. New installations contain arc quenching capability; so, will comply with safety standards. However, all oil and resin, as well as any SF_6 gas RMUs installed prior to the 2000s, were designed before the arc fault containment standard and will need to be monitored, maintained and prioritised for replacement to ensure appropriate measures are in place to limit the risk to workers and the public.

12.7.3.4 CONDITION AND HEALTH

Our CBARM model for RMU's is based on age, condition and criticality. The present (RY24) risk level for the RMUs is shown in Figure 12-33.

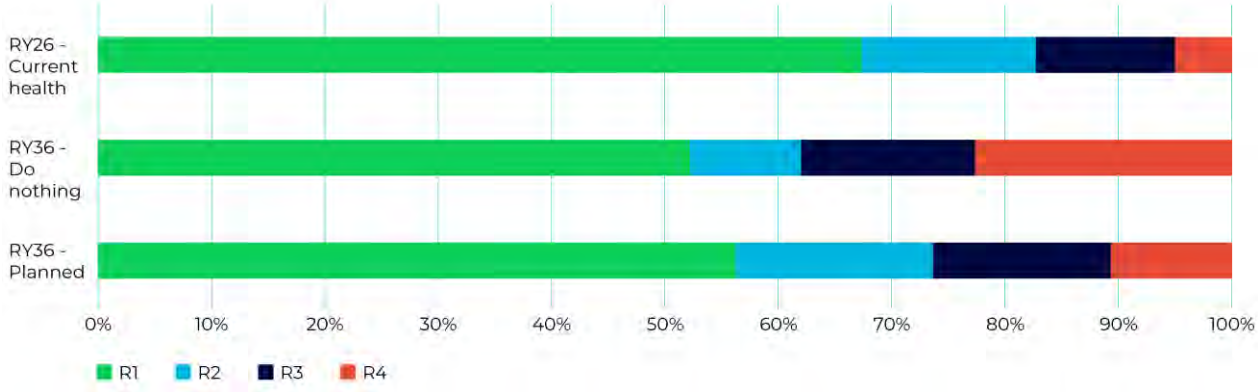


FIGURE 12-33: RMU FLEET RISK PROFILE

The risk profile indicates that the RMU fleet is currently in good condition but with an increasing average age, without intervention from Vector's investment programme, an increasing percentage of the asset fleet will be approaching end of life within the next 10 years. Vector's investment programme will ensure that all R4 risks are removed, and the remaining risk profile of this asset fleet will be maintained at approximately present levels.

12.7.3.5 MANAGEMENT STRATEGY

The management strategy for RMU's is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The replacement of RMUs is an important part of our program to improve network reliability as described in Section 11.

12.7.3.6 DESIGN AND CONSTRUCT

There are a wide range of switchgear models and makes operating in the Vector network. New RMU's are supplied in compliance with Vector's equipment specification standard ENS-0103. In 2017, to standardise the network design and minimise the required capital investment and operating costs Vector rationalised to two switchgear models from ABB and Siemens to be used for the foreseeable future.

The ABB SafeLink 2 is rated at 12 kV and is used for 11 kV applications. The Siemens 8DJH is rated at 24 kV and is used for both 11 kV and 22 kV applications.

12.7.3.7 OPERATE AND MAINTAIN

Vector's maintenance standard ESM503 details the maintenance requirements for its RMU fleet. The planned maintenance regime for our RMU assets is summarised below in Table 12-28.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Safety Inspection	All 11 kV and 22 kV ground mounted distribution switchgear in distribution substations	4 years
Full Inspection		4 years
Thermovision Inspection		4 years
Partial discharge inspection		4 years
Servicing	Servicing on all 11 kV and 22 kV oil filled ground mounted distribution switchgear	10 years
Servicing	Servicing on all 11 kV and 22 kV cast resin ground mounted distribution switchgear	10 years

TABLE 12-28: PLANNED MAINTENANCE ACTIVITIES FOR RMU'S

Due to the decision to move away from oil and resin insulated switchgear, these items will continue to be operated until maintenance requirements require removal from the network, at which point they will be scrapped. Given the relatively young age of the gas-filled switchgear population, any unit removed from the network is returned to the supplier's depot for assessment and servicing. The refurbished unit will then be re-issued back into Vector's distribution equipment stock pool for further use.

12.7.4 GROUND MOUNTED DISTRIBUTION TRANSFORMERS

Like the pole mounted distribution transformer fleet, ground mounted distribution transformers are essential components of the distribution network that transform the higher voltages down to consumer usable voltages. Vector uses transformer ratings from 100 kVA to 1500 kVA, with smaller exceptions in remote areas and larger exceptions related to higher load requirements.

Vector maintains a combination of 11 kV/400 V and 22 kV/400 V 3 phase transformers installed with one of three designs – cabinet, cubicle and package.

12.7.4.1 FLEET OVERVIEW

Vector maintains approximately 15,000 ground mounted distribution transformers, predominantly at 11 kV/400 V. The 22 kV/400V population makes up less than 2% of the entire population. Vector records show 23 different transformer ratings ranging from 10 kVA to 1.5 MVA. Table 12-29 shows a breakdown of the populations by kVA rating.

TRANSFORMER SIZE	POPULATION
<100	804
100	4075
150	554
200	2477
250	96
300	3679
325 to 450	15
500	2126
750	814
1000	717
1250 to 1500	143

TABLE 12-29: GROUND MOUNTED DISTRIBUTION TRANSFORMER POPULATIONS BY TRANSFORMER RATING

Table 12-29 illustrates the age profile of our ground mounted distribution transformers. The average age of ground mounted transformers is 24.6 years.

12.7.4.2 POPULATION AND AGE

The average age of the ground mounted distribution transformer fleet is 24.6 years as presented in Figure 12-34.

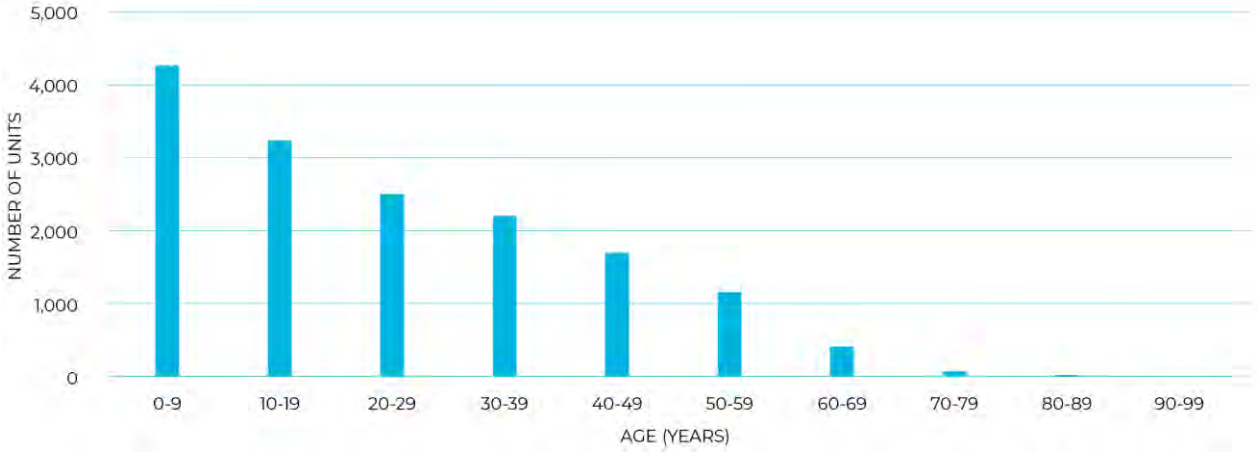


FIGURE 12-34: GROUND MOUNTED DISTRIBUTION TRANSFORMER AGE PROFILE

12.7.4.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

The contribution of ground mounted transformers to the overall SAIDI target is considered small mainly due to a small number of transformers being involved with an outage in any one year.

As shown in Table 12-29, there are a large range of transformer kVA sizes currently installed. Vector has rationalised the range of kVA sizes to8 simplify inventory management and optimise the number of spares to be held.

A considerable number of ground mounted transformers are currently connected as a daisy-chain through the practice known as “group fusing”, in which a single set of protection fuses is used to provide protection for a chain of distribution transformers. This network design has the advantage of reducing the development cost as the network continues to grow. However, it has a disadvantage of not being able to detect individual transformer faults, especially in detecting faults on the LV terminal bushings - thus driving up fault response time and we also lose the ability to isolate individual transformers if needed. Group fusing is now only permitted in rural subdivisions with two transformers of matching capacity that are both 100kVA and under in rating. Due to the size of the fuse required to maintain load condition stability, low level faults may remain undetected until the fault develops into a fault significant enough to operate the fuse. Vector has recognised that this poses a high threat to people and property in close proximity and has significantly restricted the criteria for new group fused installations and developed an extensive mitigation strategy for existing group fuse installations, this is outlined in ESE806 - Protection distribution substations.

Occasionally, a customer with a large load demand may require two or more transformers in parallel. A fault on the HV winding side will trigger the HV protection and isolate the faulted transformer on the HV side. A risk of undetected earth fault exists in the HV delta winding if the faulted transformer is back fed via the LV side from the un-faulted transformer in parallel. Vector’s Multiple Transformer Configuration Guide (EGP501) stipulate controls for various installation configurations requiring multiple transformers.

Fire-related events involving distribution transformers are often caused by a combination of high loads and loose connections in congested LV frames. To counteract this Vector has compiled a detailed design standard for ground mounted transformers that clearly describe the maximum number of LV cables and fuse ways allowed to be installed. Visual inspections including thermal imaging helps identify this hazard before thermal runaway develops and eventuates as a transformer fire.

12.7.4.4 CONDITION AND HEALTH

Our CBARM model for ground mounted distribution transformers considers age, condition and criticality. The present (RY24) risk level for the ground mounted transformer fleet is shown below in Figure 12-35.

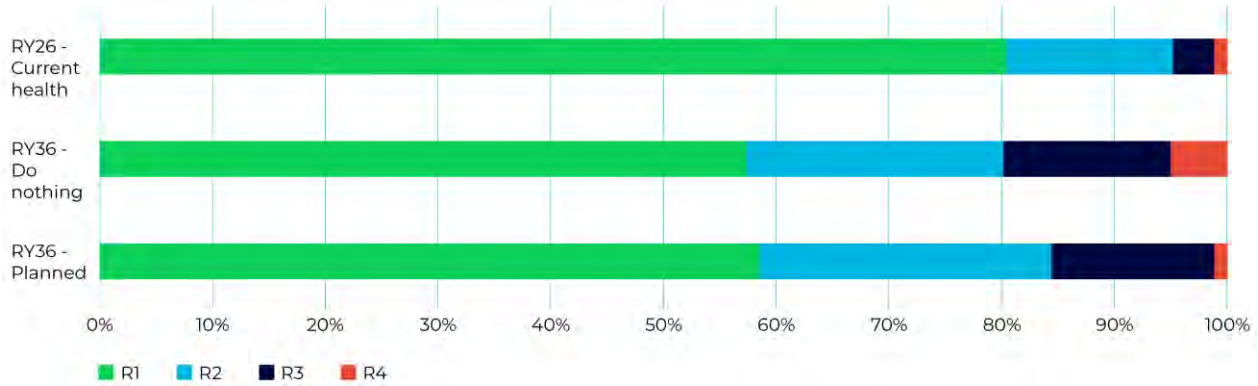


FIGURE 12-35: GROUND MOUNTED DISTRIBUTION TRANSFORMERS RISK PROFILE

The risk profile indicates that the ground mounted distribution transformer fleet is currently in good condition and approximately 10% of the fleet will approach end of life within the next 10 years. Vector's investment programme will ensure that the risk profile of this asset fleet will be maintained at approximately present levels.

12.7.4.5 MANAGEMENT STRATEGY

The management strategy for ground mounted transformers is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.7.4.6 DESIGN AND CONSTRUCT

All new ground mounted distribution transformers are supplied in compliance with Vector's equipment specification standard ENS-0093: Specification for fluid filled distribution transformers. This standard applies to both 22 kV/400 V and 11 kV/400 V transformers.

To ensure diversity in the supply chain Vector currently has three approved suppliers for this asset class. One of these suppliers has also been contracted to provide a refurbishment service for the inspection and repair if practicable, of faulted distribution transformers. Refurbished transformers are released back into the general equipment stocks for re-use on the network.

Vector has developed a suite of design standards and drawings that define the installation requirements for ground mounted distribution transformers. The design documents pertaining to ground mounted distribution transformer are listed in Section 17, Appendix 2.

12.7.4.7 OPERATE AND MAINTAIN

Vector's maintenance standard details our maintenance requirements, including the frequency of inspections, and treatment of defects identified through either the corrective maintenance or asset replacement processes. The planned maintenance regime for our ground mounted transformer assets is summarised below in Table 12-30.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Safety Inspection	All 11 kV and 22 kV ground mounted distribution transformers in distribution substations	4 years
Full Inspection		4 years
Thermovision Inspection		4 years
Partial discharge inspection		4 years

TABLE 12-30: PLANNED MAINTENANCE ACTIVITIES FOR GROUND MOUNTED DISTRIBUTION TRANSFORMERS

Planned maintenance inspections as listed above ensures that faults are detected early and minor repairs such as replacement of holding down bolts, repair of minor oil leaks, minor rust treatment and paint repairs are undertaken on site.

12.7.5 VOLTAGE REGULATOR

A voltage regulator is a device that automatically produces a regulated output voltage from a varying input voltage. The purpose is to hold the line voltage within predetermined limits and to ensure compliance with voltage regulatory requirements at customer points of supply. The regulators in Vector's network are step-voltage regulators, fitted with on-load tap changers to achieve the desired line voltage.

12.7.5.1 FLEET OVERVIEW

Voltage regulators have been deployed at three sites in the Auckland region and four sites in the Northern region to ensure voltage is within permitted limits. Vector uses two types of voltage regulators: the Siemens JFR single phase and the ABB three phase at Puhoi. The three-phase regulator at Puhoi is rated to 417 kVA; the remainder are the Siemens models rated at either 165 kVA or 220 kVA.

Single phase regulators are connected in either open delta or closed delta arrangements. A closed delta connection uses three separate single-phase voltage regulators whereas an open delta connection uses two separate single-phase voltage regulators. The difference in range of voltage regulation between the two configurations is the deciding factor in how they are implemented in the network.

12.7.5.2 POPULATION AND AGE

The average age of the regulator fleet is 10 years and considering the 25-year minimum lifespan of the asset, this is a young fleet. Figure 12-36 shows the age profile of the installed voltage regulators.

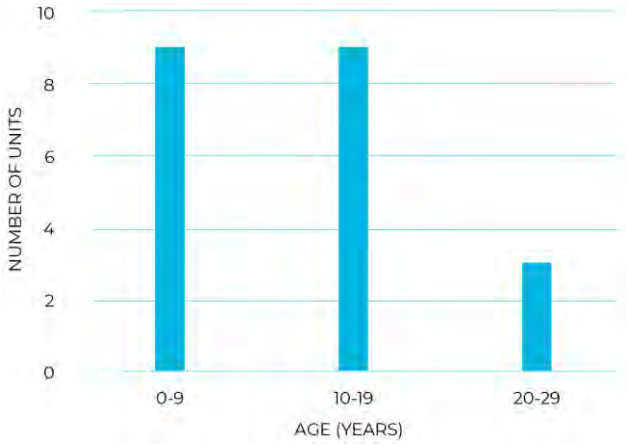


FIGURE 12-36: VOLTAGE REGULATOR FLEET AGE PROFILE

12.7.5.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

There are no recorded network events attributed to voltage regulators. The small population does not allow any meaningful trend analysis. Similarly, there are no risks recorded in Vector's risk management system, attributed to distribution voltage regulators.

12.7.5.4 CONDITION AND HEALTH

The environment in which the regulators in the Auckland region operate is relatively hostile because they are situated very close to the coast. This results in an elevated level of marine induced corrosion occurring on the regulator tanks and mild steel controller enclosures (the mild steel has a low resistance to corrosion). Electrically they are in good condition and provides reliable service, however the condition-based maintenance regime will identify and resolve defects to the enclosures and tanks as the units age.

12.7.5.5 MANAGEMENT STRATEGY

The management strategy for voltage regulators is based on asset health, reliability and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.7.5.6 DESIGN AND CONSTRUCT

The existing fleet of Siemens JFR regulators were procured on the basis that they offered the same performance ratings and characteristics as the legacy regulators installed in the network. Vector has identified a need to develop an equipment specification to document Vector's procurement and product requirements for its MV voltage regulators.

12.7.5.7 OPERATE AND MAINTAIN

ESM504 is Vector's maintenance standards for Voltage Regulators. It prescribes preventive maintenance requirements, frequency of inspections, and how to treat defects identified either through corrective maintenance or asset replacement processes. Vector's approach is to assess the condition of these assets during aerial or visual inspections, and to devise appropriate remedial action(s) based on the results of the condition assessment.

Table 12-31 lists the planned maintenance activities and the interval at which they are to be completed.

ACTIVITY TYPE		FREQUENCY
Safety Inspection	Safety inspection on all ground mounted voltage regulators	4 years
Full Inspection	Full inspection on all ground mounted voltage regulators	4 years
Thermovision Inspection	Thermovision inspection on all voltage regulators	4 years
Partial Discharge Inspection	Partial discharge on all voltage regulators	4 years
Servicing	Servicing on all voltage regulators	10 years
Acoustic Survey and Thermal Inspections	Acoustic and thermovision Inspection on overhead distribution voltage regulators	5 years

TABLE 12-31: PLANNED MAINTENANCE FREQUENCY FOR VOLTAGE REGULATORS

12.7.6 LV DISTRIBUTION SYSTEM (NON-OVERHEAD)

Vector's low voltage distribution network is the part of the network that conveys electricity from a large network of inter-connected distribution substations to the end users at either 400 V (three phase) or 230 V (single phase).

The ground mounted LV distribution network consists of several key equipment types:

- LV switchboard, commonly referred to as LV frame
- LV switchgear
- Pillars
- Pits

LV frames can be either free-standing or wall-mounted with 3-phase galvanised aluminium or copper busbar arrangement onto which cables and switchgear are terminated or mounted. Its primary function is to distribute power from the incoming main LV incomer to the outgoing distribution cables supplying individual customers or LV feeders.

LV switchgear is designed to perform two main network functions: firstly, to provide overcurrent protection against excess currents due to overloads, short circuit or ground faults and secondly to provide an isolation point. LV switchgear consists of fuses, circuit breakers and visible isolating disconnector units. These devices are mounted in LV frames, pillars, pits and network boxes as required.

Pillars are commonly referred to as an enclosure or a cabinet mounted above ground in which network connections are housed for distribution purposes. Pits serve the same purpose as the pillars, except that the connections are contained in a casing or container buried in the ground. Functionally, there are two types of pillars and pits: link pillars and link pits are used for connecting main LV distribution cables and to facilitate the extension of Vector's LV distribution network when required; service pillars and service pits are used for connecting individual customers onto the LV distribution network.

12.7.6.1 FLEET OVERVIEW

The majority of the 3,500 LV frames on the Northern Network have been installed after 2000, and the total now is almost double the number on the Auckland Network. Due to historical data legacy issues the asset information on LV switchgear is poor and initiatives have been put in place to update data to assist with LV switchgear faults.

There are approximately 200,000 known pillars and pits across the Vector network with 67% installed on the Auckland network. This is made up substantially of service pillars and pits with 10,949 link pillars and 155 link pits.

12.7.6.2 POPULATION, AGE AND CONDITION

Our fleet of LV frames has an average age of 19 years and an expected life of 30 years. Figure 12-37 below shows the age profile of the LV frame fleet. (Vector notes the level of data error is approximately 12%).

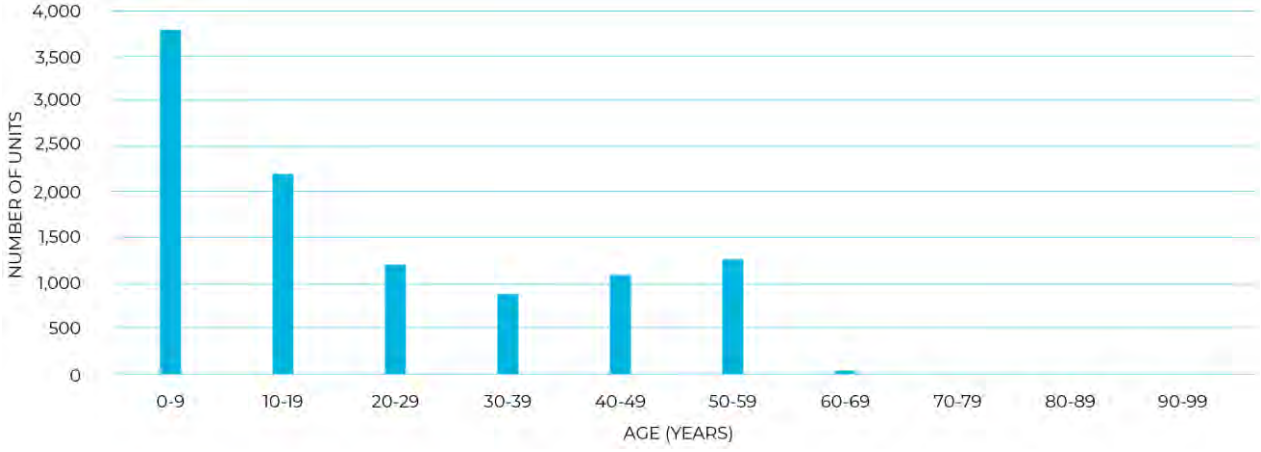


FIGURE 12-37: LV FRAME FLEET AGE PROFILE

Vector maintains approximately 163,000 LV pits and pillars with the majority installed in the Auckland region. Figure 12-38 shows the age profile of the combined pillar and pit populations as these two asset types are not recorded separately (Vector notes the level of data error is approximately 5%).

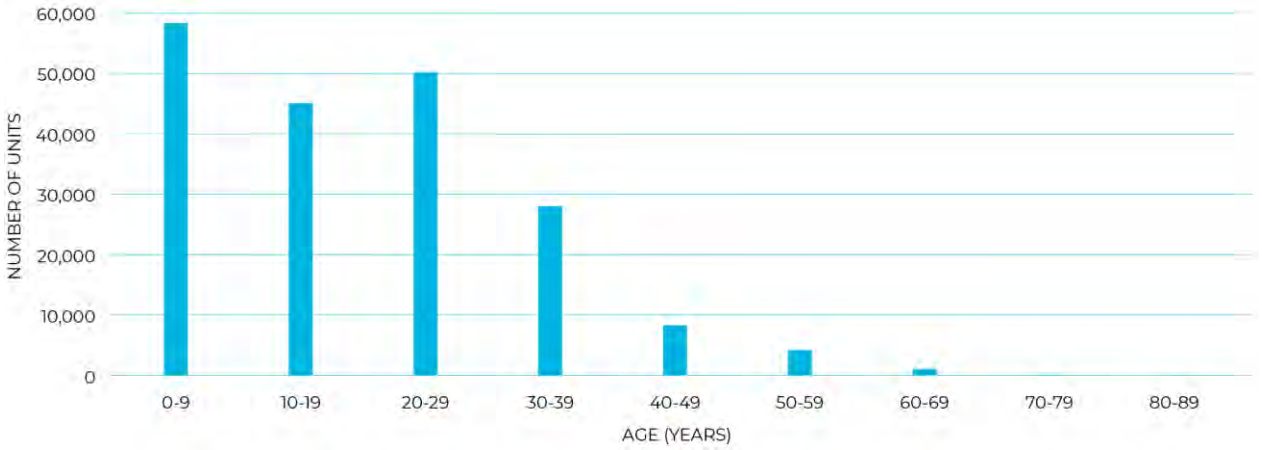


FIGURE 12-38: PILLAR AND PIT FLEET AGE PROFILE

Early generations of pillars were made of cast metal. While larger link pillars have continued to be constructed from aluminium, service pillars have been primarily constructed from plastic since the 1980s. Plastic pillars and pits are expected to last 30 years. Metal pillars are expected to last between 30 and 40 years.

12.7.6.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Since the 2000s we have preferred the installation of underground pits over above ground pillars because of the visual amenity with less equipment visible on kerbs. This is also public preference.

There are several issues which we are closely monitoring in this asset class and includes the following:

- Exposed busbars in LV frames
- Failing J Wedge fuse holders
- Failure of neutral connections at customer connections
- Inadequate earthing of metal low voltage service pillars
- Incorrect lugs, loose cable connections causing hot spots
- Building removals without LV isolation confirmed

12.7.6.4 MANAGEMENT STRATEGY

The condition and health of underground LV cables, service pillars and pits are presently monitored on a limited basis. The condition of LV frames is monitored as part of the maintenance programme for ground mounted transformers. The following sections describe how Vector is managing this asset class through the key lifecycle phases. The LV network strategy is currently being reviewed and updated to determine how greater automation and data gathering capabilities can be utilised to better understand the LV network, as well as identify and manage risk.

12.7.6.5 DESIGN AND CONSTRUCT

Vector controls the procurement of LV equipment through the following equipment specifications:

- ENS-0078 Specification for 400 V underground cable
- ENS-0154 Specification for LV service pits
- ENS-0155 Specification for IPPCs for LV distribution pits.

Vector has supply agreements in place with a pool of approved manufacturers and suppliers for each LV equipment category but does not procure directly from them. LV equipment is procured by the FSPs who have their own commercial arrangements with the approved suppliers.

12.7.6.6 OPERATE AND MAINTAIN

Our maintenance standard ESM505 details maintenance requirements, frequency of inspections, and how to treat defects identified either through corrective maintenance or asset replacement processes. It also defines the procedure for data capture and system updates carried out by Vector's field service providers.

The maintenance of the LV distribution system is achieved through periodic visual inspections of the accessible elements of the network (pits, pillars and LV switchgear). Neither invasive maintenance nor electrical testing is carried out unless there is a specific issue that needs to be investigated and resolved.

Thermal imaging is carried out on LV frames mounted inside ground mounted distribution transformers and distribution substations as part of the inspection requirements specified in Vector's standard ESM503.

Onsite maintenance for LV assets is minimal, and we generally operate these assets on a "run to failure" philosophy unless they pose a health and safety risk. The planned maintenance for this asset sub class is shown in Table 12-32 below.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Detailed inspection of service pits and service pillars.	4 Years
Inspection	Detailed inspection of link pillars and network boxes (underground link boxes).	4 Years
Inspection	Detailed inspection of LV switchgear in distribution substations [all Vector enclosures and third-party buildings, and excluding HV customer substations]	4 Years
Inspection	Detailed Inspection of LV switchgear in HV customer substations	4 Years
Infrared Thermography (IRT)	IRT on LV switchgear in distribution substations [all Vector enclosures and Third-party buildings, and excluding HV customer substations]	4 Years
Infrared Thermography (IRT)	IRT Inspection on LV switchgear in HV customer substations	4 Years
Infrared Thermography (IRT)	IRT Inspection on link boxes (underground distribution pits)	4 Years

TABLE 12-32: PLANNED MAINTENANCE ACTIVITIES

12.7.7 REPLACE, RENEW AND DISPOSE

12.7.7.1 OVERHEAD SWITCHGEAR

Vector's approach to replacement of MV overhead switchgear is condition-based. The age of the asset may be reflected through the condition along with other factors, such as environment, loading, duty cycles, maintenance history etc., but it is not used as a primary determining factor in Vector's asset replacement consideration.

Generally, the replacement of an MV overhead switchgear is dependent on the condition assessment resulting from the inspections of the assets in accordance with Vector's maintenance standard. Defect(s) identified during these inspections are evaluated to determine if the identified condition had exceeded the threshold for replacement. In addition to this approach particular equipment designs that have demonstrated poor reliability or short service lives, those designs are prioritised for replacement.

In the absence of a condition-based asset risk management (CBARM) model for this asset class, the remediation of defects is prioritised through the same risk-based prioritisation methodology described for the treatment of the maintenance defects.

12.7.7.2 GROUND MOUNTED SWITCHGEAR

Given the disparity in condition and age among Vector's ground mounted distribution switchgear (ring main unit) population, we have chosen to approach the management of equipment renewal both on a condition based and age-related basis.

For relatively new equipment, condition-based replacement is the most appropriate measure used to maintain the serviceability of this portion of the RMU population. This includes all SF_6 gas insulated switchgear, some of the oil-filled switchgears (namely the ABB SD Series 2 and Lucy models) and all epoxy resin installed switchgear.

Aging equipment such as the older models among the Long & Crawford switchgear population, and the combined population of Andelect/Astec/ABB SD Series 1 switchgear are being renewed through a more proactive replacement approach with an aim to progressively remove this equipment from Vector's network. This programme is scoped to remove all older oil insulted switchgear at the end of its service life of 40 years and prioritised by the CBARM model analysis of equipment condition and risk.

Under the condition-based replacements, the most common cause for an RMU replacement is expected to be significant degradation in the physical condition due to corrosion or leaks. Other general causes are expected to be due to vehicle damage and network growth.

The proactive replacement program uses the assessments from field service providers, and population data in the CBARM framework to identify assets for replacement in a yearly rolling program. Figure 12-32: RMU FLEET RISK PROFILE shows a comparison between the RY33 risk level with and without a proactive replacement programme. Without a proactive replacement program the other drivers for equipment replacement will not replace all of the legacy oil filled switchgear by the end of the service life within the population and the health of this asset fleet will steadily decline.

12.7.7.3 TRANSFORMERS

The most common cause for a transformer replacement is a significant degradation in its physical condition due to corrosion or leaks, with less common causes being due to vehicle damage and network growth. Historically, 100 kVA, 200 kVA and 300 kVA transformers are replaced most frequently which aligns with these being the predominant populations of transformers.

Since their introduction in the 2000s there have been two 22 kV/400 V transformer replacement based on reactive maintenance. This low rate is expected considering the low overall age of this equipment.

In 2018 Vector developed a condition-based asset risk management (CBARM) framework to inform its programme for the renewal of distribution transformers. Vector now has a proactive distribution transformer replacement programme in place, however pole mount transformers with a rating under 100kVA are replaced only on reactive basis.

12.7.7.4 VOLTAGE REGULATORS

Vector's approach to replacement of voltage regulators is condition-based. Presently the replacement programme is aligned to the maintenance programme for the scheduled overhaul of current fleet of voltage regulators. It is expected that the existing installations will continue to operate in the network for the foreseeable future.

12.7.7.5 LV NON-OVERHEAD ASSETS

LV assets are typically replaced when they have reached the end of functional life or pose a public health and safety risk, this strategy presents a balanced approach to remove risk while allowing maintenance resources to be prioritised for the higher consequence assets in the distribution and HV parts of the network. The LV frame and associated switchgear are usually replaced in conjunction with the replacement of a distribution transformer.

Programmes to remove specific asset types have occurred in the past, such as the replacement of mushroom pillars and letterbox pillars. We may adopt the same approach in the future for other types of assets as the need arises, such as the cast iron link boxes. Replacement forecasting for this asset class is undertaken on a historical basis.

12.7.8 FORECAST SPEND

The focus on improving the reliability of the network, means that the proposed capital investment in overhead switches, RMUs and distribution transformers are included in Section 11, Reliability. Below provides a summary of the overall capital investment for the LV distribution class for the 10-year AMP forecast period.

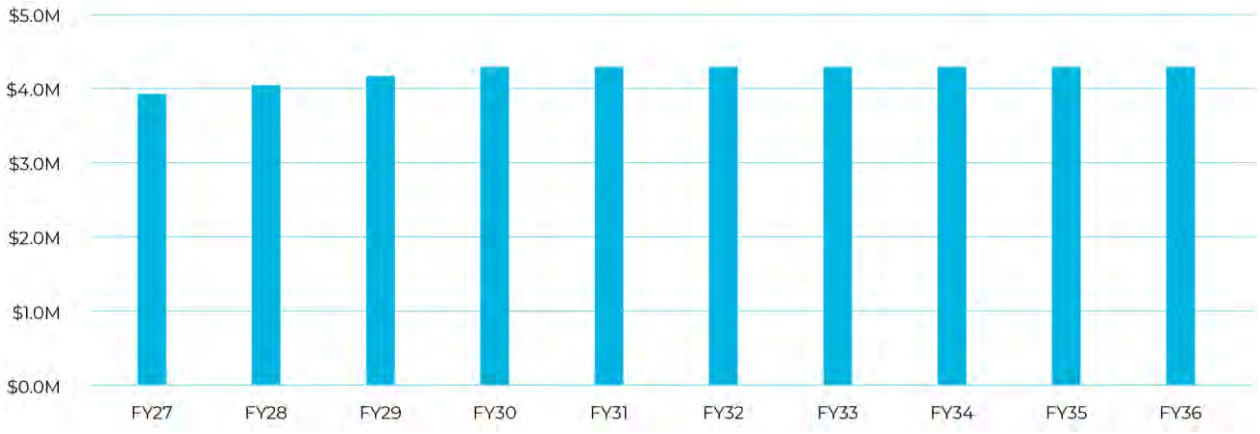


FIGURE 12-39: FORECAST CAPEX – DISTRIBUTION SYSTEMS

12.8 Protection and Operational Technology

This section describes the protection and operational technology fleet and summarises the associated asset management practices. These assets predominantly supply data into the ADMS SCADA system for network visibility and remote operation, enabling real-time monitoring, protection, automation, and control of the electricity network. Collectively, they underpin safe and reliable network operation by supporting fault detection, isolation and restoration, remote switching, asset condition monitoring, and operational decision-making.

- The protection and operational technology fleet is grouped into five sub-categories based on their primary functional role within the network control and protection environment:
- Protection systems, which detect abnormal network conditions and initiate protective actions to safeguard assets and public safety
- Transformer management systems, which monitor transformer condition and performance to support operational decisions and asset health management
- Communications systems, which provide the secure and reliable data pathways required for real-time control, protection signalling, and telemetry
- Automation systems, which enable automated switching, fault response, and restoration functions to improve reliability and response times
- Data acquisition systems, which collect and transmit operational and condition data from field devices into ADMS SCADA and related enterprise systems

12.8.1 PROTECTION SYSTEMS

Protection relays are devices that form a major part of the protection system. These are crucial for the safe and reliable operation of the electrical network. The protection relays detect faults and isolate the faulted network parts from the electrical network whilst retaining the healthy part of the network in service. This allows Vector to minimise the number and extent of power outages to customers.

Vector uses a variety or protection relays as discussed in the sections that follow. Failures of protection relays are rare, but they have a shorter design life than the primary equipment they protect. Additionally, the legacy electro-mechanical relays within the network are at risk of obsolescence, with limited manufacturer support and spare parts availability. The failure of protection relays in detecting and clearing faults can potentially result in catastrophic plant damage, cascade network damage and in rare

instances, injury or death to persons. As such, the effective monitoring of asset health and flexible designs to allow for asset replacement, is highly important for this asset class.

12.8.1.1 FLEET OVERVIEW

Vector has 3,982 protection relays in service within the network. They are installed within GXPs, zone substations, and distribution assets to isolate and clear faults that could otherwise damage network assets or cause harm to the public. 196 protection relays are installed within a GXP. Vector uses three types of relays:

- Electromechanical
- Numerical
- Static

Table 12-33 provides a summary of the relay types in the fleet. This shows that the majority of protection relays in Vector's network are numerical relays.

ELECTROMECHANICAL	STATIC	NUMERICAL
499	44	3,439

TABLE 12-33: SUMMARY OF RELAY TYPE COMPOSITION

12.8.1.2 POPULATION AND AGE

The population and age profile for electro-mechanical, numerical and static relays are provided in Figure 12-40 below.

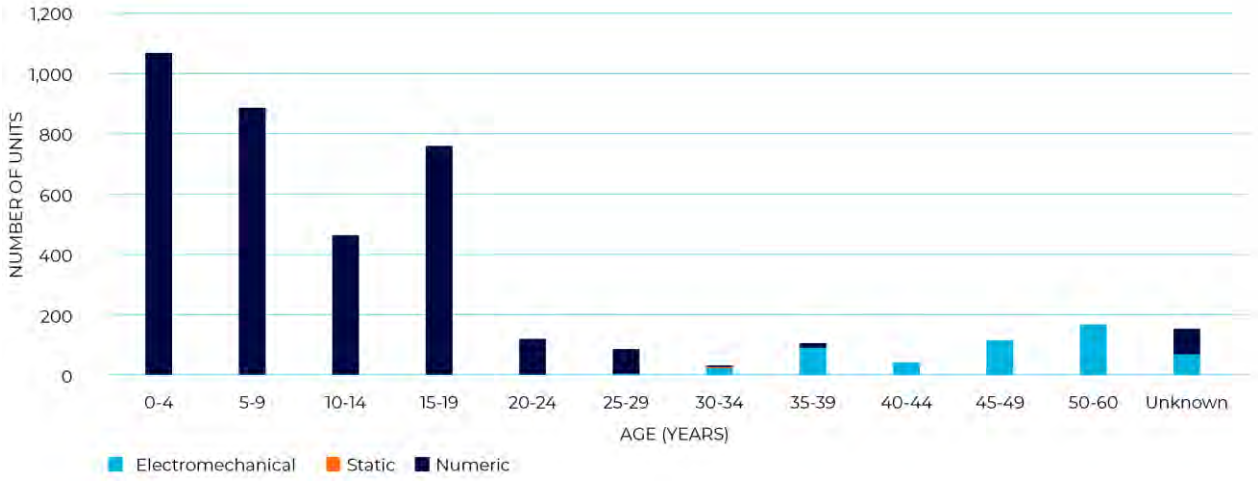


FIGURE 12-40: PROTECTION RELAY FLEET AGE PROFILE BY TYPE

12.8.1.3 CONDITION AND HEALTH

As protection relays reach their design life, their failure rate is expected to increase. Most relay failures on Vector's network since 2013 have been due to failure of an aging asset. Vector has programmes of work in place to replace existing electromechanical, static and first-generation numerical relays with modern numerical relays.

Electromechanical relays are reliable but is an aging legacy protection technology at risk of obsolescence and with only basic functional settings and data storage capability which prohibits fault and event analysis. They also have no relay supervision functionality. It is becoming increasingly costly to obtain spare parts and retain the skills required to maintain and operate this fleet. Approximately 13% of the relays are electromechanical. The oldest are 50 to 60 years old.

Static relays are solid state devices with no moving parts, are easy to configure and more flexible compared with electro-mechanical relays. However, they are limited in their functionality when compared with numerical relays and lack event recording facilities. Static relays are also becoming obsolete, spare parts are becoming harder to source and more expensive; there are also reliability issues associated with this type of relay. The static type relays on Vector's network are 30 years old.

Numerical relays are extremely flexible as they are programmable and can be configured to perform a wide range of protection functions. They can store data and be used for post fault event analysis. They are also equipped with digital communication functionality and can be integrated with the ADMS. The disadvantages of these relays include a relatively short 20-year design life as they use microprocessor-based technology and the need to manage firmware versions and compatibility requirements. To date, failures of numerical relays have been rare.

12.8.1.4 MANAGEMENT STRATEGY

51% of all relays will require replacement over the next 10 years. Vector's asset management strategy for protection relays is to phase out static electromagnetic and first-generation numerical relays then replace numerical relays as they exceed the 20-year design life of the relay. The new replacement strategy is based on a) relay age and b) switchgear replacement. The relays will be replaced as a standalone project only if there is no plan to replace the switchgear in the next 10 years or so. This is to ensure ultimate utilisation of resources.

The risk of relays will be reassessed annually, and the replacement activities are prioritised as required.

The superior monitoring and control capabilities provided by the modern numerical relays provide better visibility and control to the network. This will allow Vector's network to deliver higher reliability and resilience.

The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.1.5 DESIGN AND CONSTRUCT

All new relays on Vector's network will be the numerical type and will take into consideration the relay being replaced at least once during the switchboard design life. This replacement must be seamless through flexibilities allowed during the design stage. Vector has rationalised to two relay manufacturers: Siemens and SEL (Schweitzer Engineering Laboratories). This standardised approach reduces the number of relay variants and the number of spares held and introduces familiarity with the programmable logic used in the relays, the firmware and setting software. The standardised relay approach combined with standardised wiring designs decreases the duration of network outages for installations.

12.8.1.6 OPERATE AND MAINTAIN

Vector's maintenance requirements for protection relays are detailed in ESM801. FSPs undertake the following general inspection and maintenance activities:

- Investigate and repair or replace any faulty devices and associated systems showing signs of imminent failure or damage.
- Fix any wiring or mounting of the device that is unsecured or damaged that poses electrical failure risks and safety hazards.
- Maintain general cleanliness of the devices due to build-up of dust or grime.
- Investigate and remediate a device that has powered down or indicates abnormal alarms.
- Arrange a replacement of a relay that has failed the self-test.

12.8.1.7 REPLACE, RENEW AND DISPOSE

Replacement prioritisation for Vectors investment programme includes the following considerations:

- Imminent relay or protection system failure.
- Risk of large-scale failure of numerical relays when reaching end of life.
- Relay spares availability
- Reliability concerns (based on performance of particular models)
- Data storage and fault recording capability, grading limitations and type of connected load.
- Feeder automation program
- Live line works implementation (Health and Safety)
- Switchgear replacement program

12.8.2 TRANSFORMER MANAGEMENT SYSTEMS

Vector employs Transformer Management Systems (TMS) to monitor zone substation power transformers, manage their performance and predict failure. TMS systems are used to monitor supply voltage quality to ensure compliance with regulatory standards. TMS within Vector's network range from legacy electromechanical relays, to modern numerical relays. A failure of TMS relay could potentially result in Vector's primary assets operational integrity being compromised, its performance to deteriorate, or creating undue risk to equipment.

12.8.2.1 FLEET OVERVIEW

Vector has 213 TMS relays in service. These devices can be grouped into three major types as listed below:

- Numerical TMS relays
- Static TMS relays
- Electromechanical TMS relays

Table 12-34 below provides a summary of TMS fleet. This shows approximately 83% of the TMS fleet are modern numerical types.

ELECTROMECHANICAL	STATIC	NUMERICAL
13	23	177

TABLE 12-34: TMS RELAY FLEET COMPOSITION

12.8.2.2 POPULATION AND AGE

The population and age profile for electro-mechanical, numerical and static TMS relays are provided in Figure 12-41.

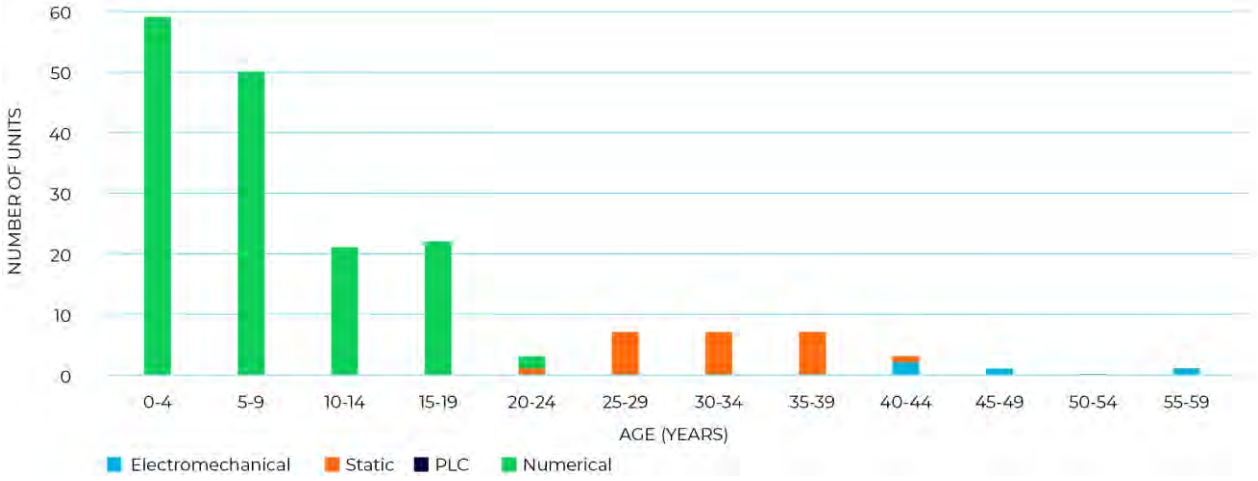


FIGURE 12-41: TMS RELAY FLEET AGE PROFILE BY TYPE

12.8.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

The majority of the modern numerical TMS relays on the network are within their design life of 20 years, hence failures are rare.

The age of the electromechanical TMS relays range between 28 and 51 years. While most are still functioning satisfactorily, they are at risk of obsolescence with limited spare parts and technical support available from manufacturers. They also require regular calibration that adds cost and consumes technician resources. All remaining electro-mechanical TMS systems with high failure rate have been replaced with modern numerical systems. The remaining static and electro-mechanical TMS systems will be replaced as part of the power transformer or switchgear replacement.

12.8.2.4 CONDITION AND HEALTH

Over the past 7 years, the use of modern numerical TMS relays on Vector's network has increased from 63% to 83%. Modern numerical relays within Vector's network are well within their design life of 20 years hence are considered to be highly reliable and in good working condition.

12.8.2.5 MANAGEMENT STRATEGY

The management strategy for TMS is based on asset age, risk of obsolescence and reliability. It is informed by asset health data being collected from ADMS and supplemented with information gathered by our field service providers and industry peers such as other utilities.

The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.2.6 DESIGN AND CONSTRUCT

The replacement of the TMS units will reuse existing control wiring as well as the enclosures (cabinets) where practicable. Vector has standardised on two types of TMS relays: REGSys and Schweitzer. New switchboards will incorporate REG-DA relays from REGSys, while retrofit projects will have either REG-DA or SEL-2414 Schweitzer relays.

12.8.2.7 OPERATE AND MAINTAIN

Vector's maintenance requirements for protection relays are detailed in ESM801. The Field Service Providers undertake general inspections of the relays as follows:

- Investigate and repair or replace any faulty devices and associated systems that is mal-operating or has physical damage.
- Fix any wiring or mounting of the device that is unsecured or damaged that poses electrical failure risks and safety hazards.
- Maintain general cleanliness of the devices due to build-up of dust or grime.
- Investigate and remediate a device that has powered down or indicating abnormal alarms.
- Arrange a replacement of the TMS or relay that has failed the self-test.

12.8.3 COMMUNICATIONS SYSTEMS

Vector uses communication systems to enable real time control, monitoring, management and restoration of the power network. The communications systems consist of backhaul communications networks and onsite communications networks. The backhaul network known as the Operational Technology Wide Area Network (OT WAN) links the remote sites to centralised control and monitoring systems. The onsite communications typically substation local area networks (LANs) interface the intelligent electronic devices (IEDs) within the remote sites to each other and to the OT WAN.

12.8.3.1 FLEET OVERVIEW

The backhaul communication network consists of:

- The Vector Fibre network used for connectivity to 116 zone substations and GXP's which is over 80% of the network.
- The Wireless Plus cellular network using dual SIM 4G routers to provide communications to 842 predominantly automated distribution sites.
- Fibre and ADSL networks provided by third parties that are used when the Vector Fibre network is unavailable.
- Radio networks including Digital Microwave Radio (DMR), Very High Frequency (VHF) and Ultra High Frequency (UHF) radio systems used where fibre connectivity is unavailable.

The on-site communication systems consists of:

- Substation Routers
- Ethernet Switches
- Media Converters

The key communications equipment are the substation routers, ethernet switches and cellular routers. Table 12-35 provides a summary of the fleet. 53 communications devices are installed within a GXP.

SUBSTATION ROUTERS	ETHERNET SWITCH	CELLULAR ROUTERS
170	451	842

TABLE 12-35: NUMBERS OF ROUTERS AND SWITCHES

12.8.3.2 POPULATION AND AGE

The population and age profile for substation routers are provided in Figure 12-42:

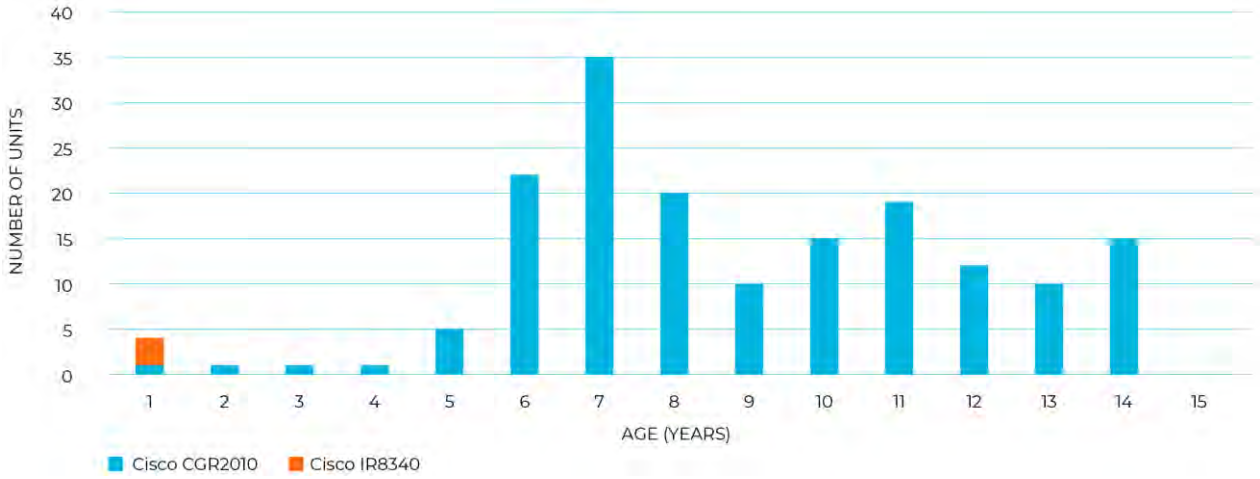


FIGURE 12-42: SUBSTATION ROUTER FLEET AGE PROFILE

The population and age profile for ethernet switches are provided in Figure 12-43:

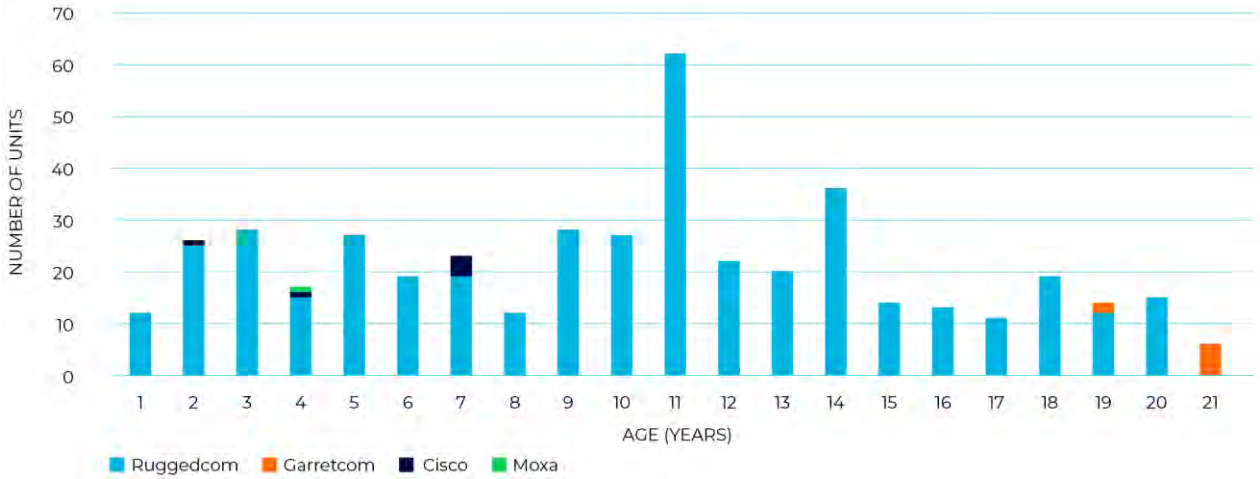


FIGURE 12-43: ETHERNET SWITCH FLEET AGE PROFILE

The population and age profile for cellular routers are provided in Figure 12-44 below.

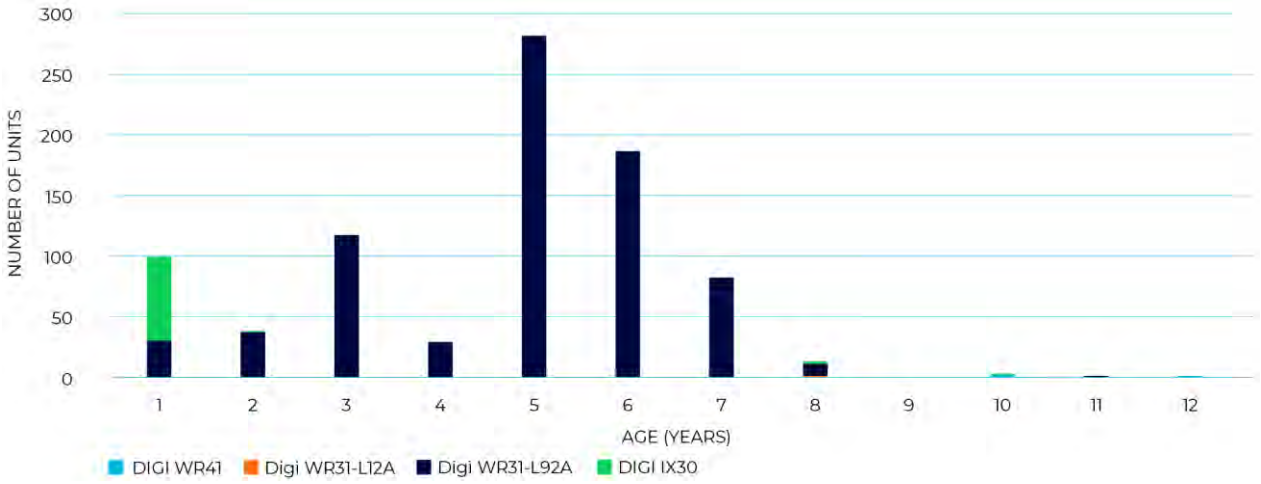


FIGURE 12-44: CELLULAR ROUTER AGE FLEET PROFILE

12.8.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

For fibre infrastructure the system availability figure for the last year has been above the 99.95% availability target. The fibre outages experienced are predominantly caused by third party strikes on the network. The fibre network is fit for purpose, has been extensively expanded over the years and will continue as required. The available bandwidth on the fibre network is sufficient for future expansion. To accommodate increasing bandwidth requirements between data centres and to enhance network resilience, a high-capacity Dense Wavelength Division Multiplexing (DWDM) fibre ring which was completed in March 25 has been established to interconnect data centres with key zone substations.

The overall device availability for the cellular network for the last year has been above the 95% target. The risk of failure in the third-party infrastructure (e.g., cell tower) could cause loss of communications to multiple distribution automation devices and there is no guaranteed quality of service so if usage of a cell site is high, this impacts the signal strength to one or multiple sites resulting in loss of communications. Dual sim and dual antenna routers with connections to two cellular providers provides some mitigation of these risks.

The performance of the radio systems are not actively monitored. Real time remote monitoring functionality will be implemented in the future to provide performance information. The key risks associated with radio are environmental and third-party damage.

Availability of substation routers and ethernet switches is above the 99.95% target over the past year.

12.8.3.4 CONDITION AND HEALTH

The asset condition and health of the fibre infrastructure, cellular network,.3rd party fibre connections and DMR network for backhaul communications is good. Onsite communications asset health is also good. Aging systems being replaced include the VHF radio system, the copper pilot wire connections and 3rd party ADSL connections.

12.8.3.5 MANAGEMENT STRATEGY

When assessing communications options to sites fibre is the preferred backhaul communications interface for zone substations, GXP and critical distribution sites. In certain remote areas, especially the far northern regions of the network, the cost of fibre installations is prohibitive, and this is where 3rd party fibre and/or radio solutions are implemented.

The radio system provides a network that is highly available and has sufficient spare capacity for future expansion. This system is expected to be in operation for the foreseeable future.

The CGR2010 router is no longer available and will be out of support in 2028. New installations now utilise the Cisco IR8340 and the replacement program will replace the CGR2010 routers.

The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.3.6 DESIGN AND CONSTRUCT

For the backhaul communications network, the following must be considered when designing and constructing new infrastructure:

- Provide a secure, highly available communication link to remote sites like zone substations and GXP's.
- Ensure that a failure of a single communications node does not impact multiple sites.
- Provide the infrastructure for real time monitoring and control capabilities to manage Vector's electricity network.

On site network equipment is standardised as much as possible to reduce the number of spares required to be kept.

The Cisco Grid Series routers and Ruggedcom ethernet switches are Vector's standard devices across all substations and strategic spares are kept for zone substations.

12.8.3.7 OPERATE AND MAINTAIN

The fibre infrastructure for the Operational Technology network is managed by Vector Fibre, and a support agreement is in place for the cellular routers, substation routers and ethernet switches.

The maintenance requirements for the radio systems are defined in Vector's standard ESM805. These include:

- Annual off-site inspection (remote monitoring) with corrective follow-up on remedial actions as required.
- Annual on-site inspection with corrective follow-up on remedial actions as required.
- Two yearly on-site testing with corrective follow-up on remedial actions as required.

Where maintenance of radio equipment is required, site specific maintenance standards are developed (ESM805 Maintenance of Radio Equipment, ESM709 Penrose – Hobson Tunnel Radio Systems and ESM712 Penrose – Hobson Tunnel Radio Systems.)

12.8.4 AUTOMATION SYSTEMS

Vector employs network automation systems, comprising substation remote terminal units (RTUs) and distribution controllers, to provide real-time remote presence at locations throughout the network and enable automation of key processes such as monitoring plant status and service restoration. Vector has adopted an internationally recognised open communications architecture standard that allows different devices located within the zone substations to integrate seamlessly and communicate with the ADMS system through the communications network.

12.8.4.1 FLEET OVERVIEW

Vector has 763 RTU devices from a variety of suppliers within its network. 20 RTU are installed within a GXP. Table 12-36 below provides a summary of distribution automation devices type composition.

TYPE	NUMBERS
SEL	414
ABB	235
Foxboro	58
Siemens	16
GTP Plessey	8
Abbey Systems	7
Fuji Electric	5
Advantech	1
Leeds & Northrup	1
Linak	1
Mitsubishi Electric	1
Unknown	16

TABLE 12-36: RTU FLEET COMPOSITION

12.8.4.2 POPULATION AND AGE

The majority of automation devices range in age from new to over 20 years, with the odd exceptions that were installed in 1988.

The population and age profile of Vector's fleet of automation devices are provided in Figure 12-45 below (Vector notes this data has an error rate of approximately 18%):

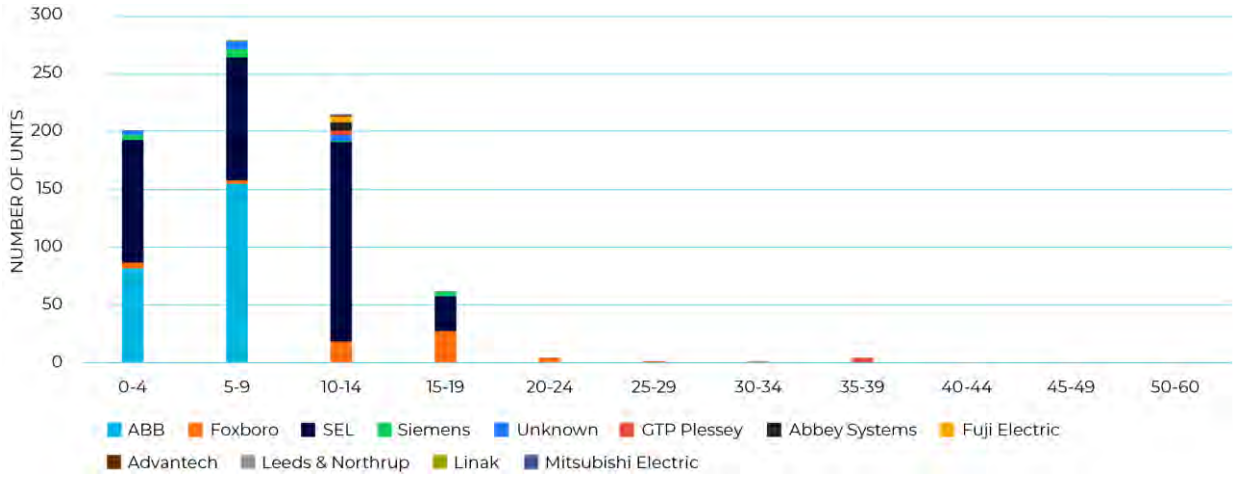


FIGURE 12-45: NETWORK AUTOMATION SYSTEM AGE PROFILE

12.8.4.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

The introduction of distribution automation infrastructure has clearly demonstrated the benefits of network visibility afforded by these systems. Reliable and accurate visibility of our network is critical when making real time operational decisions and responding to outages. In addition, the implementation of automation systems allows hands-off operation of the network and reducing the need for crews to travel, with its associated hazards and time to navigate congested roads, to remote destinations.

Whilst the loss of an RTU may not be an immediate issue under healthy network conditions, the loss of visibility under abnormal or fault conditions can result in overloaded networks, delayed fault restoration and, most importantly, lack of response to potential high-risk events.

Vector maintains its capability to operate and maintain RTU's and distribution automation devices across multiple generations of underlying hardware platforms. The current core capability of Vector's distribution automation system is sufficient to operate the network, but it is evident that additional capability and performance will be required as the industry develops, and Vector needs to adapt to the customer expectations.

12.8.4.4 CONDITION AND HEALTH

Due to the age of Vector's legacy RTU equipment, some of the components within the RTU are no longer manufactured and/or supported by the OEM. Therefore, a portion of the RTUs within Vector's fleet, especially those installed over 20 years ago, are obsolete. In addition, better technology is required to ensure the network can accommodate higher levels of volatile generation and unpredictable loads. The technology used by the old generation of RTUs cannot cope with new demands. Vector systematically replaces legacy devices as part of switchgear and protection replacement projects and as stand-alone RTU replacement projects.

In general, the modern RTU devices within Vector's network have been operating reliably and improves safety by providing network visibility and control that allows remote operation.

12.8.4.5 MANAGEMENT STRATEGY

Replacement of RTU devices in Vector's network is based on the level of functionality, the technology and the availability of spare components rather than measurable condition parameters.

The existing infrastructure has been architected so it can expand to accommodate the anticipated service, traffic and interface growth. The following strategy is adopted by Vector for RTUs:

- Replace on failure – cut spending to a minimum and accept a progressive decline in performance and increasing risk
- Upgrading to current standard automation equipment when major site-works are carried out such as switchboard, transformer or protection relay replacements
- Removing obsolete plant that is still in service but presenting progressively higher risk with dedicated RTU replacement programs

The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.4.6 DESIGN AND CONSTRUCT

The automation infrastructure provides operational services to the ADMS. The infrastructure needs to be designed with the following in mind:

- Provide a secure environment in which the automation equipment can operate
- Provide infrastructure which allows efficient development of data acquisition and control services
- Utilise robust infrastructure installations to support high service performance
- Provide robust DC systems with adequate backup supply suitable for the prolonged loss of AC mains
- Provide adequate capacity for present and future needs

Vector has standardised RTU designs that use devices from approved manufacturers to reduce the number of spares required thereby minimising the total cost of ownership.

12.8.4.7 OPERATE AND MAINTAIN

Vector's maintenance requirements for RTUs are specified within ESM801.

FSPs will undertake the following general inspections of RTUs:

- Investigate and repair or replace any faulty devices and associated systems or damaged units
- Fix any wiring or mounting of the device that is unsecured or damaged that poses electrical failure risks and safety hazards
- Maintain general cleanliness of the devices due to build-up of dust or grime
- Investigate and remediate a device that has powered down or indicating abnormal alarms
- Arrange a replacement of the RTU or relay that has failed the self-test

12.8.5 DATA ACQUISITION SYSTEMS

Vector utilises several data acquisition systems these include power quality meters (PQMs), smart overhead fault passage indicators (FPI), LV transformer monitoring and weather stations. Unlike protection or automation systems they do not have network control capabilities. Data is used for network visibility, analysis and regulatory requirements.

Vector's most significate data acquisition system is the power quality meters (PQMs). These are intelligent revenue class devices that provide power quality analysis coupled with revenue class accuracy. They are deployed at key distribution points such as GXPs and zone substations. These meters communicate to the metering central server over an IP communication network. Power quality information and energy consumption metrics are required to make informed decisions that best meet the business objectives as well as to meet legal and regulatory requirements. At the GXP level PQMs provide the function of "check meter" to compare electricity consumption against revenue metering measurements. Their event data storage functionality is also used for post fault analysis and power quality excursions.

12.8.5.1 FLEET OVERVIEW

Vector has 166 power quality meters commissioned on its sub-transmission and distribution networks. Vector uses two types of PQM spanning multiple generations:

- Advanced functionality PQM: ION 7600, ION 7650, ION 9000
- Intermediate: functionality PQM: ION 7330, PM 8000, ION 7400

Advanced PQM's are typically deployed at Transpower GXP's and zone substations, while intermediate PQM's are deployed on distribution feeders. 24 PQM are installed within GXP's.

Table 12-38 summarises the PQM fleet.

TYPE	NUMBERS
ION 7650	113
ION 9000	14
ION 7400	6
ION 7330	4
ION 7350	4
ION 7600	3
PM8000	2
Other	20

TABLE 12-37: PQM TYPE COMPOSITION

12.8.5.2 POPULATION AND AGE

The population and age profile for PQMs are provided in Figure 12-46 below:

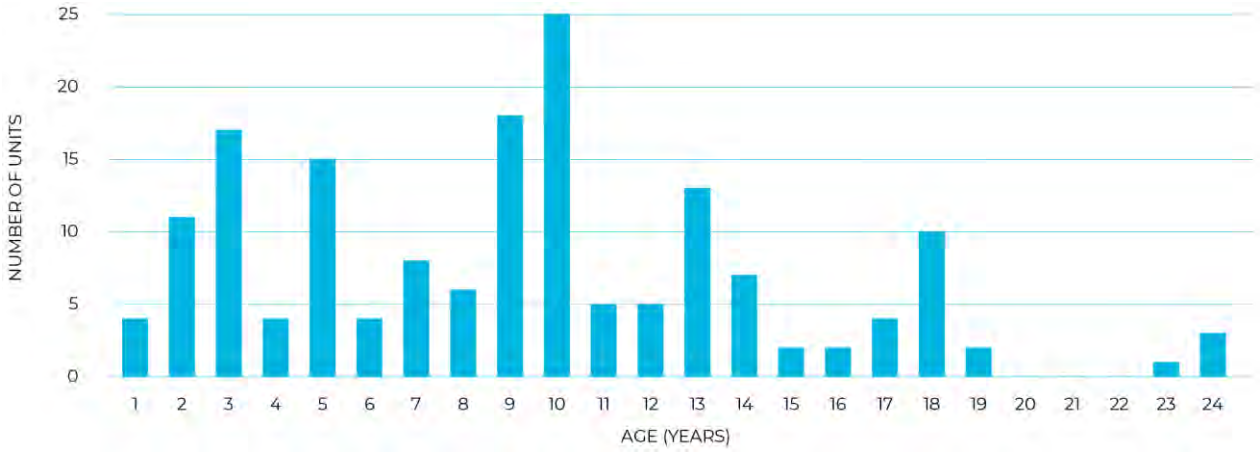


FIGURE 12-46: PQM FLEET AGE PROFILE

12.8.5.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

The PQM's currently in service are in good health, despite the age of some devices. All PQM's within the network are equipped with self-monitoring capabilities. However, older versions of devices are running on unsupported software and devices that are getting close to or exceed their design life of 15 years will be included in the replacement programme.

Key risks involving PQM devices are communications and hardware failure. The PQM field devices have a 30-day data storage capability that mitigates the risk of data loss. Further, the communications to all zone substations have dual redundancy which provides a high level of reliability.

12.8.5.4 CONDITION AND HEALTH

The power quality metering devices in service operate reliably even though some of these devices are reaching the end of their design lives. These devices have in built self-supervision functionality and provide remote monitoring and recording functionality for post event analysis. Replacement devices are obtainable from Vectors New Zealand based vendor.

12.8.5.5 MANAGEMENT STRATEGY

Vector is progressively replacing older (15 years or over) models of the PQM fleet to ensure a fleet is in place that will have technical support of the hardware as well as software support from the vendor. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.5.6 DESIGN AND CONSTRUCT

The PQM system must be designed with the following considerations:

- Utilise robust infrastructure installations to support high service performance
- Provide adequate capacity for present and future needs
- Provide infrastructure which allows efficient development of communications services

12.8.5.7 OPERATE AND MAINTAIN

The PQM hardware is digital and has no field serviceable parts and does not require physical maintenance. The PQM software and hardware are monitored and supported by Vector's service representative as part of a support agreement.

12.8.6 REPLACE, RENEW AND DISPOSE

12.8.6.1 PROTECTIONS SYSTEMS

The electromechanical, static and first-generation numerical relays within Vector's network are coming to the end of their expected service lives. Many will remain in operation but are planned to be replaced with numerical relays within the next 10 years. The replacement of relays will be prioritised based on the following risks:

- Imminent relay or protection system failure
- Spares availability
- Reliability concerns, i.e., increasing failure of relays of a particular model
- Fault record capability, grading limitation and type of connected load

12.8.6.2 TRANSFORMER MANAGEMENT SYSTEMS

The main drivers for the replacement of transformer management systems are age, risk of obsolescence and reliability. Vector's approach is to replace the static TMS relays followed by electromechanical TMS relays and other TMS devices that are more than 20 years old. The replacement projects are prioritised as follows:

- Replacement of failing static devices (within 5 years)
- Replacement of all electromechanical devices (within 10 years)

12.8.6.3 COMMUNICATIONS SYSTEMS

The main drivers for the replacement of Vector's communications systems are age, risk of obsolescence and reliability. Vector is in the process of replacing communications network components that remains in service but no longer has manufacturers' support.

12.8.6.4 AUTOMATION SYSTEMS

The main drivers for the replacement Vector's automation systems are age, risk of obsolescence and reliability. The specific criteria for RTU replacement are:

- Substation primary equipment, such as the switchboard, is being replaced with modern equipment. The RTU will be replaced with either an IED or modern RTU to enable improved facilities, such as Ethernet connection and remote engineering connection to equipment, and to reduce the small wiring required to install the switchboard and therefore reduce installation costs.
- Lack of strategic spares available for ongoing maintenance of the remaining RTUs.
- To support improved functionality such as for IEC61850.

12.8.6.5 DATA ACQUISITION SYSTEMS

The main drivers for the replacement of PQMs are obsolescence and lack of ability to upgrade software on older models. The availability of spares will help prolong the asset life of existing PQMs although not indefinitely as both the PQMs and spares are already in an aged condition and is not compatible with software updates. Where practicable, PQMs are replaced as part of other capital projects such as switchgear replacement.

12.8.7 FORECAST SPEND

The forecast capex graph shown in Figure 12-47 provides a summary of the overall capital investment for this asset header class for the 10-year AMP forecast period. The replacement and refurbishment programme for protection system assets is described in detail in Section 12 Appendix and includes the proposed investment for each individual project.



FIGURE 12-47: FORECAST CAPEX - PROTECTION AND OPERATIONAL TECHNOLOGY

12.9 Auxiliary systems

This section describes our auxiliary systems fleet and provides a summary of our associated asset management practices within the following subcategories:

- Power supply systems
- Load control systems
- Capacitor banks
- Security and access systems
- Fire protection systems
- Earthing systems

12.9.1 POWER SUPPLY SYSTEMS

Auxiliary power supply systems provide power to secondary systems in zone substations and GXPs including protection, control, automation, metering, and communications equipment. Typically, this equipment operates at 110, 48, 24 or 30 V DC and is critical for the safe and reliable operation of a zone substation and its primary function of customer power supply. DC battery banks are charged by LV AC chargers and ensure that in the event of a LV AC system failure, the DC battery bank supplies these critical secondary systems for a period sufficient to re-establish LV AC supply. At zone substation critical sites, DC systems are fully redundant to provide resilience and minimise operational disruption when maintenance activities are undertaken.

12.9.1.1 FLEET OVERVIEW

Key statistics of the DC charger assets are shown in Table 12-39.

TYPE	NUMBERS
240V DC chargers	2
110 V DC chargers	386
48 V DC chargers	1
30 V DC chargers	29
24 V DC chargers	70
12 V DC chargers	3

TABLE 12-38: DC CHARGER FLEET OVERVIEW

The 110 V DC systems are used to provide power to protection relays and DC secondary systems within switchgear. The 48 V DC and 24 V DC systems are used to supply power to the communications and digital radio systems respectively. The 30 V DC systems exist in zone substations with legacy communications equipment and legacy circuit breakers with 30 V equipment. These legacy DC systems are being progressively replaced with 110 V DC and 48 V DC systems as part of a wider risk-based legacy switchboard replacement strategy. Approximately 40 of these DC chargers are located within GXP sites.

12.9.1.2 POPULATION AND AGE

Based on Vector's experience, the expected age of reliable operation for a DC charger is around 15-20 years. The age distribution for each voltage type of DC charger is shown in the chart below. Due to incomplete installation date records, Vector notes this data has an error rate of approximately 30%.

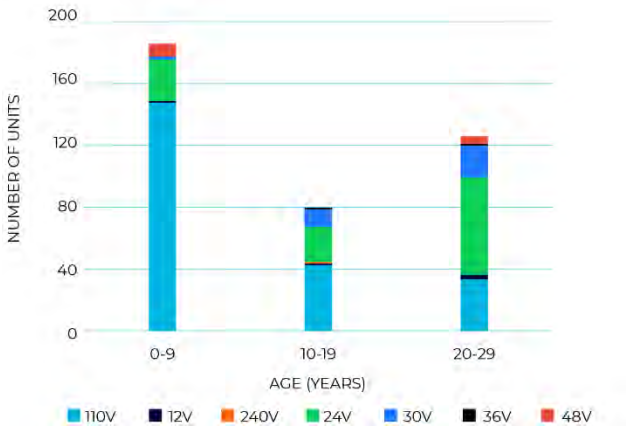


FIGURE 12-48: DC CHARGER FLEET AGE PROFILE

12.9.1.3 ASSET PERFORMANCE, EMERGING TRENDS, AND RISKS

A large, planned programme to replace legacy DC chargers over the last few years has ensured that Vector's DC systems are continuing to perform in line with expectations and there have been no recent failures leading to an unplanned loss of supply.

12.9.1.4 CONDITION AND AGE

Age can be used as a proxy for the condition of DC systems. The average asset age of our DC systems is 15-20 years. Vector manages the condition of its DC systems using its inspection and testing regimes. Our 110 V DC systems also employ a PowerShield Sentinel monitoring system which provides real-time monitoring on each discrete battery (monobloc): temperature, impedance and voltage. This approach has proven successful in replacing assets prior to systemic failure.

12.9.1.5 MANAGEMENT STRATEGY

The management strategy for auxiliary systems is based on asset health, risk of obsolescence, reliability, and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.9.1.6 DESIGN AND CONSTRUCT

Vector has standardised its secondary systems on its switchgear to be powered using 110 V DC across all zone substation sites. Some sites still have legacy 24V DC and 30 V DC and are being progressively replaced due to condition or through planned site upgrades. Vector continues to monitor the benefits of new technologies such as the use of Lithium-Ion batteries.

For the procurement of new DC systems, Vector utilises its specifications ESE-601 and END-6001.

12.9.1.7 OPERATE AND MAINTAIN

For real time visibility and monitoring of our DC systems, Vector has installed a PowerShield Sentinel monitoring system at each of its zone substations. This provides real-time measurements and alarms to the engineering team to then generate any fault-correction response required by our FSP's.

Vector's maintenance standards for DC systems are outlined in the ESM601 maintenance standard. Planned maintenance activities are summarised below in Table 12-40.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Inspection on AC circuitry, fittings, main boards, network LV supply, auto changer over panel, meter panel, UPS	2 Months
Inspection	Thermovision inspection on all electrical equipment	1 Year
Functional Testing	Functional DC system testing on batteries, battery chargers, DC circuitry, UPS, fittings	4 Months
Inspection	Full DC system performance discharge testing on batteries, battery chargers, DC circuitry, UPS, fittings and convertors	2 Years

TABLE 12-39: PLANNED MAINTENANCE ACTIVITIES FOR DC SYSTEMS

Vector follows internationally recognised standards such as AS2676, IEC 60050 and IEEE 1188 for the testing of its DC systems to ensure that best practice are adhered to in the management of its DC systems. Inspection and test results are uploaded to the SAP planned maintenance module by the FSP.

Minor items are addressed as corrective maintenance. Defects unable to be addressed as corrective maintenance are recorded within Vector's Active Risk Management system (ARM), along with assigned controls and action plans for a project-based resolution.

12.9.1.8 REPLACE, RENEW AND DISPOSE

DC systems assets are replaced when they reach their end of functional life, or pose a non-performance or health and safety risk, as detected during routine planned maintenance activities. Generally, the replacement timeframe is based on risk, age, identification of any systematic issues or findings from routine maintenance activities.

New DC charger installations achieve an N-2 level of security to ensure that contingency remains in the system while a charger is out of service during testing, maintenance, or replacement.

12.9.2 LOAD MANAGEMENT SYSTEMS

12.9.2.1 FLEET OVERVIEW

Vector uses demand-side load management systems on its distribution network to offer non-instantaneous system capacity reserve to the wholesale electricity market, and to respond to national grid emergencies. The following sections relate to customer hot water heating load management.

Due to the separate legacy power board network philosophies at the time of installation, four types of signalling systems exist: 'ripple injection' over power lines in the Auckland network, and parts of the Northern network as 'ripple injection', 'pilot wire', 'rotary' or Cyclo' systems. Customers in the Auckland network can sign up to a 'controlled' (lesser cost) time of use (TOU) tariff. This allows signalling of these customer's hot water cylinders to switch on or off, shifting Vector's network demand peaks for up to three hours continuously within a 24-hour period.

The number of ICPs per type of hot water load control system is provided in Table 12-41.

ASSET SUBCLASS	NUMBER OF ICPS	SYSTEM STATUS
Ripple	329,489	Active load management in Auckland region only
Pilot wire	139,108	No active load management
Rotary	38,625	No active load management
Cyclo	10,948	No active load management

TABLE 12-40: NUMBER OF CUSTOMERS PER HOT WATER CONTROL TYPE

12.9.2.2 POPULATION, AGE AND CONDITION

Vector's fleet of 22 ripple plant units are installed across twelve zone substations or GXP sites. The replacement of two new plants in 2021 has brought down the average age from 36 years to 24 years. Apart from the 2021 replacements, Vector fleet of ripple plants are approaching end of life.

12.9.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector has experienced a number of failures on its ripple plant controllers in recent years. Although these plants have been successfully returned to service, these events are typical symptoms of an ageing ripple plant fleet. Bespoke repairs are required due to no OEM support and like-for-like spares availability for this legacy equipment.

Although Vector's ripple plants are suspectable to age related failure modes, they are still considered to be performing adequately at this time. This is a benefit of ripple load management system architecture which can tolerate the loss of a ripple plant without the loss of customer hot water supply.

12.9.2.4 MANAGEMENT STRATEGY

The new Transpower Pricing Methodology (TPM) that takes into effect from 1 April 2023 replaces interconnection and HVDC charges with benefit-based charge and residual charges. This will effectively remove the economic incentive to manage regional coincident peak demand (RCPD) under the current TPM. In the past, hot water load control has played a pivotal role in managing the RCPD.

Vector has reviewed the viability of their hot water (ripple) load management system under the new TPS and have decided to maintain the existing equipment with strategically selected compatible spare components. As smart meter penetration increases, these meters will gradually assume the hot water load control function. Consequently, Vector's load control capability will decline over time in a stepped manner, aligned with the level of smart meter adoption.

12.9.2.5 REPLACE, RENEW AND DISPOSE

Vector will maintain but not replace its ripple plant systems.

12.9.3 CAPACITOR BANKS

12.9.3.1 FLEET OVERVIEW

Vector uses pole-top capacitor banks to maintain voltage stability and power quality across the network. Vector's strategy is to progressively replace these assets depending on their condition.

12.9.3.2 POPULATION, AGE AND CONDITION

The average age of Vector's capacitor banks is 20 years, achieving their performance targets against an expected operating life of around 20 years. This was aided by capacitor banks installed in an indoor environment typically remaining in better condition than their outdoor equivalents as they are not prone to environmental issues such as corrosion and pollution.

12.9.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Since the introduction of overhead capacitors in 1999, the Vector network has not experienced catastrophic failures related to this asset class. However, with most units now operating beyond their intended life span of over 20 years, many have shown signs of enclosure deterioration due to corrosion from prolonged environmental exposure. Maintenance, repairs, and replacements of these assets have been conducted in accordance with Vector's maintenance standard.

12.9.3.4 MANAGEMENT STRATEGY

The remaining lifespan of pole-mounted capacitors is challenging to estimate accurately, as it depends on multiple factors including age, environmental conditions, electrical loads, and the magnitude of fault currents encountered during their operation. Consequently, Vector will continue to apply a condition-based approach when managing this asset group.

To ensure optimal performance of medium voltage (MV) overhead capacitors, all assessments and maintenance activities are conducted in accordance with Vector's maintenance standard. Each unit is inspected based on assessment criteria defined within the maintenance standard. Decisions regarding repair or replacement are determined by the results of the condition assessment.

12.9.3.5 REPLACE, RENEW AND DISPOSE

Vector employs a condition-based methodology for the replacement of MV overhead capacitors. This approach evaluates factors such as asset age, environmental conditions, loading, life cycles, and maintenance history during condition assessments. Overhead capacitors have traditionally been procured on a made-to-order basis in response to asset failures or identified condition defects. Solutions are prioritised according to customer and network requirements. Currently, assets that have reached the end of their service life and are deemed unnecessary are decommissioned and disposed of.

Initially, the revision of Overhead Capacitor Strategy 2020 proposed no replacement programme for the current overhead capacitor fleet and anticipated the complete removal of all overhead capacitors from the network by 2023. However, further analysis showed that the rural section of the network continues to require the use of overhead capacitors within the Vector network.

12.9.4 SECURITY AND ACCESS SYSTEMS

12.9.4.1 FLEET OVERVIEW

Vector's security and access systems at facilities consist of keyed and electromagnetic locks, door hardware, electric and perimeter fencing and access and monitoring systems. Proximity card readers are used for access and monitoring and are installed across all zone substation sites and other critical sites such as Transpower GXPs and the Vector Penrose-Hobson cable tunnel.

Vector EOC remotely monitors, via ADMS, the entrance and egress of facilities via the card reader. Motion detectors are fitted to detect intruders in switch room and enclosed transformer buildings. If an unauthorised entry event alarm occurs, the EOC contacts the FSP to investigate. If required, the Police are contacted.

12.9.4.2 POPULATION, AGE AND CONDITION

There are approximately 164 security and access controllers installed across the electricity network sites.

12.9.4.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

There have been no recorded failures in this asset class, nor have there been any unauthorised building intrusions across Vector's zone substation sites. Proximity card access systems have proven to be robust and are performing in line with expectations with a product replacement pathway. The vendor has notified Vector that hardware support for its devices will be discontinued within the next ten years as it has reached the end of its product lifecycle.

12.9.4.4 MANAGEMENT STRATEGY

Vector's acquisition strategy will be to continue to procure security and access systems from its current accredited supplier using procurement standard ESE603. Ordering is by the contractor directly with the NZ based vendor. A project has been stood up to progressively replace card readers on the network

Asset maintenance is in accordance with Vector's maintenance standard ESM603 and is undertaken at regular planned intervals by Vector's field service providers and where required, asset-specific specialists. Planned maintenance activities include visual inspections and self-diagnostic tests which can be conducted remotely from site.

12.9.4.5 REPLACE, RENEW AND DISPOSE

Vector has a programme of works in place to progressively replace with its proximity card access systems with modern equivalents within DPP4.

12.9.5 FIRE PROTECTION SYSTEMS

12.9.5.1 FLEET OVERVIEW

Vector's fire protection systems can be separated into two categories.

- Passive - preventative systems such as flame traps, hypoxic, smoke/heat detection, intumescent products
- Active - automated extinguishing systems such as sprinklers, Inergen gas flood, foam, fire ventilation shutters

Fire protection passive and active control is determined by risk assessment associated with the criticality of a substation's connected customers and asset value. Vector's risk evaluation procedures, guides and standards are used for risk assessment.

Vector requires zone substations either within the Auckland CBD, supplying critical customer load, or supplying downstream zone substations as a bulk point of supply, to have both passive preventative and active automated extinguishing fire protection systems. All other zone substation sites have passive preventative systems only unless otherwise determined as part of a risk-based assessment.

A local indoor fire panel installed at all zone substation sites provides collation and communication of system status and fire heat and/or smoke detection alarms to the local security panel and integrated to ADMS for alarms to EOC. This enables the EOC to contact FENZ to request a responder for the alarmed site in the appropriate circumstance.

CBD zone substations also signal in parallel to EOC a fire event to a FENZ approved aggregator to achieve a FENZ callout response.

12.9.5.2 POPULATION, CONDITION AND AGE

The age of individual fire protection systems is not currently recorded. It is reasonable to assume that the age of this asset class to be aligned with the age of the building it is installed in.

12.9.5.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

There has been a deliberate increased focus on fire protection of assets due to the safety, asset, and customer supply continuity risk that fire poses.

Fire protection evaluation and implementation use AS2067, the NZ Fire Code, the NZ Building Act, Vector's standards, site specific fire engineer reports, and known appropriate industry practice. Fire protection is also guided by the lessons of the 5 October 2015 Penrose GXP fire within Vector's 33 kV cable trench and the 400 V a.c. local service supply fire within Takanini zone substation in 2016. At Takanini its standard 2-hour fire resistance rating (FRR) prevented damage to the substation itself.

Site specific hazard reviews have found the following risks along with resolving these:

- Legacy internal doors between adjacent transformer bay fire cells continue to be removed where this does not impact twin emergency egress. Auto-closers will be fitted to those that provide a second egress between the fire cells.
- Fire doors and fire dampers are now installed within naturally ventilated power transformer buildings where appropriate to their distance to other buildings and neighbouring boundaries.
- The Penrose-Hobson Tunnel Penrose, Liverpool and Hobson vertical cable riser shafts will have their 25-year-old cable-wrap fire suppression system replaced, commencing in FY25. The 9.1 km tunnel sprinkler head replacement programme will be completed in 2027.
- Targeted investment on the establishment of firewalls at substation sites. Where possible this is combined with planned transformer replacement or upgrade projects.

The fire protection asset class originated in the 1960s, with systems progressively replaced as technologies reached the end of their technical or service life. These updates have been carried out in consultation with registered fire engineers and in compliance with relevant fire standards and codes.

12.9.5.4 MANAGEMENT STRATEGY

The fire protection asset classes have inspection and testing regimes in accordance with ESM603 which aligns with AS/NZS 4512 - fire detection and alarm systems in buildings. Fire engineer studies are commissioned and implemented for all new buildings and major renewals. Assets are replaced when they reach their end of functional life, or pose a non-performance or health and safety risk, as detected during routine planned maintenance activities. On-site assessment is by visual and thermographic inspection, and test condition, in accordance with the afore-mentioned maintenance standard.

12.9.5.5 REPLACE, RENEW AND DISPOSE

Vector has a programme of works in place to progressively replace its active and passive fire protection systems, prioritised by age and condition.

12.9.6 EARTHING SYSTEMS

Earthing systems are required to protect people and equipment from the risk of harm of electricity due to abnormal network operation, inadvertent contact to live conductors, interaction with third party infrastructure and environmental effects such as lightning strikes. Earthing systems also ensure that protection systems operate as intended and are specifically designed to meet established performance criteria.

Every zone substation has an earth system, commonly a combination of buried earth conductors, earth rods and the building reinforcing. All asset installations with conductive equipment have their own independent earthing systems. In general, the earthing systems comprise a set or sets of pins (electrodes) driven into the earth connected using bare copper conductor. Copper

is both an excellent electrical conductor and mechanically resistant to in-ground corrosion but has a risk of theft as described below.

The nature of the surrounding soil and surface covering play an integral part in the performance of the earthing system. The effects of local soil electrical resistance, localised site surface covering (e.g., metal chip and asphalt) and transferred voltage potentials from the site are included in the overall analysis of earth system step and touch voltage performance within regulatory limits.

12.9.6.1 CONDITION, EMERGING TRENDS AND RISKS

An earthing system is usually aligned with the age of the equipment or buildings it serves. As such it is difficult to establish an accurate age profile of the different components of an earthing system. The condition and health of earthing systems are essentially determined by visual inspection and testing.

Copper theft remains an ongoing issue. Both passive and active security measures are used as a preventative tool. Vector uses regular site security and asset inspections as part of planned maintenance regimes as a preventative measure. Raising awareness of the issue to FSPs also assists in ensuring that issues are identified and remediated as soon as practicality possible. Construction works in existing zone substation sites also runs the risk of damage to earth grids and theft.

To minimise harm to personnel and the public in an operational electricity substation site, damage to earthing must be minimised and immediately repaired. Earthing consists of typically copper conductor which is susceptible to corrosion in contaminated soils, by galvanic action with dissimilar metals and hazardous substances. ESE704, ESE506 and ESM607 activities control this risk.

12.9.6.2 MANAGEMENT STRATEGY

Earthing systems for zone and distribution substations are installed in accordance with Vector engineering standards ESE704 and ESE506 respectively. Earthing design incorporates a risk-based approach for safety of nearby public and Vector's own personnel including control to safe touch and step voltage levels. Fault levels are controlled to 13.1 kA for distribution network equipment and 26.0 kA for zone substation equipment. Zone substations and distribution earthing systems are subject to a thorough testing regime that is performed every five years as detailed in Vector maintenance standard ESM607. Earthing studies are commissioned and implemented for all new sites and primary transformer equipment capacity upgrades and additions. The latter as customer electricity supply increases require two-transformer sites to become three-transformer sites.

Vector's earthing related standards reference the EEA (NZ) Guide to Power Systems Earthing Practice and the Safety Manual – Electricity Industry (SM-EI). Independent audits completed in accordance with NZS 7901 are undertaken annually to assess public safety adjacent to the zone substation property. These audits and Vector's planned maintenance regime ensures corrective actions are undertaken to maintain the design safety performance of its earthing systems.

Special care is required for cable power supply connections to traction rail systems such as KiwiRail and City Rail Link to avoid directing connection of cable screens and the hazard of traction earthing neutral (TEN) current return paths raising fault current levels on the Vector public multiple earth neutral system (thereby avoiding raised fault levels being superimposed on the MEN) system. Specialist design, installation and maintenance practices are undertaken to control these risks. Vector's asset strategy for earthing systems is described in strategy report EAA600 Auxiliary Systems.

12.9.6.3 REPLACE, RENEW AND DISPOSE

Assets are replaced when they reach the end of their functional life or present non-performance or health and safety risks identified during routine planned maintenance, with associated costs captured under OPEX. New and replacement zone substation builds incorporate upgraded earthing systems based on site-specific earth testing and designs that comply with Vector standards, including the EEA (NZ) Power System Earthing Practice Guide and IEEE 80/81. To address compliance gaps, a zone substation earth grid renewal program will commence in FY27 for systems identified through five-yearly testing as not meeting current standards. Programs of work are triggered by new standards or regulatory requirements, systemic environmental changes, asset failures, or end-of-life conditions, with solutions determined in alignment with customer and business needs and developed in collaboration with asset vendors and recognized industry bodies.

12.9.7 FORECAST SPEND

The forecast capex graph shown in Figure 12-49: FORECAST CAPEX – AUXILIARY SYSTEMS provides a summary of the overall capital investment for this asset header class for the 10-year AMP forecast period.



FIGURE 12-49: FORECAST CAPEX – AUXILIARY SYSTEMS

12.10 Generation and energy storage

12.10.1 UTILITY BATTERY ENERGY STORAGE SYSTEMS (BESS)

12.10.1.1 FLEET OVERVIEW

The Utility Battery Energy Storage Systems (BESS) installed in Vector's network are connected to the 22 kV and 11 kV networks. The BESS are designed to perform multiple functions applicable to the entire electricity system. The BESS installed at zone substations perform peak shaving and voltage control functions and assists with resolving the sub-transmission network security deficiencies. The BESS installed at remote ends of the 11 kV feeders improve the feeders' reliability and voltage quality. They are also able to supply electricity to customers during outages by forming microgrids.

Vector considers BESS within a suite of options when deciding on capital investment solutions to enhance the electricity network's resilience, quality of supply or network capacity expansion. BESS are installed where it is determined to be a more economical solution to address network capacity expansion in comparison to traditional primary systems investments or to defer investment in primary systems.

Most operational BESS are of the Tesla Powerpack type except for Tapora (which is a hybrid site made up of Hitachi and Samsung equipment). The Tesla Powerpacks are of modular and scalable construction that can be relocated within the network. They have also been tested and proven to comply with the safety requirements of current international standards. The BESS can be repurposed or relocated once the functions they perform at the installed location are no longer needed.

12.10.1.2 POPULATION AND AGE

We have a total of seven operational BESS, with our first 1 MW/2.3 MWh BESS at Glen Innes zone substation being in service since October 2016. Our second and third BESS were commissioned at Warkworth South and Snells Beach zone substations in 2018 and have successfully assisted in deferring network capacity expansion investment. The BESS at Kawakawa Bay and at Hobsonville Point were commissioned in February 2020 and November 2020 respectively. The BESS at Kawakawa Bay is installed at the end of a long rural feeder to improve voltage quality and feeder reliability. It also enables a segment of the feeder supplying Kawakawa Bay customers to operate as a microgrid.

The construction of the 1.14 MW / 1.254 MWh BESS at Tapora was completed in 2022. Unlike previously installed BESS on the Vector network which are Tesla Powerpack battery systems, the Tapora BESS consists of an ABB Power Conversion System and Samsung Battery System. The BESS is to improve reliability and voltage quality and support operation of a microgrid.

The BESS and a solar energy PV system installed as part of Vector Lights initiative provides renewable energy for Vector Lights on Auckland Harbour Bridge. The current BESS fleet uses Tesla Powerpack battery systems.

Key information of the BESS assets are shown in table 12-41.

LOCATION	RATINGS	AGE
Zone Substation Glen Innes	1.0 MW / 2.3 MWh	9 years
Zone Substation Warkworth South	2.0 MW / 4.8 MWh	8 years
Zone Substation Snells Beach	2.5 MW / 6 MWh	8 years
22 kV Feeder - Vector Lights	0.25 MW/0.475 MWh	7 years
11 kV Feeder - Kawakawa Bay	1 MW / 1.7 MWh	5 years
Zone Substation Hobsonville Point	1 MW/2.0 MWh	5 years
11 kV Feeder - Tapora	1.14 MW / 1.254 MWh	3 years

TABLE 12-41: KEY INFORMATION FOR BATTERY ENERGY STORAGE SYSTEMS

12.10.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

As most of our Tesla Powerpack are first generation, the availability of spares and equipment obsolescence is a point of discussion with Tesla to increase parts availability and decrease time to supply spares.

There have been several instances of hardware and software issues affecting BESS remote control operations and indications at Tapora where localised system resets have been required to restore communications, and this issue is being investigated by Hitachi.

12.10.1.4 CONDITION AND HEALTH

The Tesla Powerpack systems come with a 10-year warranty. Each Tesla Powerpack system is connected to the Tesla Remote Management (RM) System that enables remote monitoring, diagnostics, configuration managing and upgrading. The expected operational life of the batteries depends on aggregated energy throughput and functionality implemented. Apart from some deterioration of outdoor battery enclosures, the BESS population is in good health and condition.

Tesla is holding spares for replacement during the warranty period. A requirement and quantity of the spares to be purchased after warranty expires is to be discussed with Tesla closer to 2026.

For the Hitachi Powerstore BESS Vector has purchased spare equipment and quantity as recommended by Hitachi. The spares are also to be used in conjunction with Hitachi SLA agreement.

12.10.1.5 MANAGEMENT STRATEGY

Preventative maintenance on BESS are carried out by FSP In line with the Vector maintenance standard which requires yearly, 5-yearly and 10-yearly inspections and servicing.

Corrective maintenance of Tesla Powerpack BESS is carried out with Tesla as part of its product warranty.

Any further investment in new BESS, improving the functionality of the existing BESS will be based on a cost-benefit analysis, considering functional requirements and network planning considerations.

12.10.1.6 DESIGN AND CONSTRUCT

At present, on a utility scale and for functionality required for the operation of distribution and the electricity system, lithium-ion battery-based energy storage systems are the technology of choice due to their energy density and lowest cost. We have deployed our lithium-ion BESS to understand the technology, defer investment in network capacity expansion, and improve supply quality.

As part of the installation of the first BESS at Glen Innes substation, detailed BESS requirements document including technical specifications were developed. Based on the system requirements and standardised system architecture, a design have been produced, which has been used to realise subsequent BESS installation.

IEC has been working on the standard set under IEC 62933 Electrical energy storage (EES) systems. The technical requirements as defined in IEC 62933 standard set, in addition to previously defined IEC/IEEE/ISO standards, will be used for future BESS acquisition.

12.10.2 DIESEL GENERATION

12.10.2.1 FLEET OVERVIEW

Vector has Diesel generating sets (genset) at the end of lengthy 11 kV feeders at Piha and South Head. The function of both generator sites is to improve the network reliability to these two remote communities. The generators are only operated as required during planned or unplanned network outages. The gensets are connected to the 11 kV feeders supplying the area via interconnection equipment.

Presently the diesel gensets and interfacing equipment are fixed installations on leased land with land extension agreements in place on a year-by-year basis. Vector plans to attain land in South Head (FY31) and Piha (FY36) to establish a permanent generation station site. The intention is to use Vector owned generating sets and step-up transformers.

For small portable petrol generator sets, a process is in place to manage engagement with customers and the qualification of customers to supply electricity from the portable petrol gensets during outages. The field management of the portable generators is carried out by our field service providers.

12.10.2.2 POPULATION AND AGE

The Piha site has two generators, which are owned by Vector whilst the interconnection equipment is leased. At the South Head location two 1.25 MVA diesel generators and interconnection equipment are presently leased. The Vector owned diesel gensets installed at Piha are around 3 years old and are infrequently used (i.e., used only during outages). This implies very low wear and carbon emissions.

12.10.2.3 CONDITION AND HEALTH

The gensets are in good condition and are maintained as part of an agreement with a generator service provider.

12.10.2.4 EXPENDITURE FORECAST

Because of its focus on network reliability, the capex forecast for permanent generation sites at Piha and South Head are shown in Section 11, Network Reliability.

12.10.3 RESIDENTIAL PHOTOVOLTAIC (PV) AND BATTERY ENERGY STORAGE SYSTEMS (BESS)

12.10.3.1 FLEET OVERVIEW

Vector owns and maintains residential PV and BESS systems supplied to customers starting in 2013. Initially, Sunverge and SunGenie BESS with rated energy capacity of 10.7 kWh were installed. The SunGenie BESS has been decommissioned in 2024 as a result of Sunverge liquidation and cessation of product support.

Tesla Powerwall BESS have also been installed. Tesla Powerwall generation 1 has 2 kW rated power and 6.4 kWh rated energy capacity. The latest Tesla Powerwalls (generation 2) have a rated power of 5 kW and rated energy capacity 13.5 kWh,

12.10.3.2 POPULATION AND AGE

Table 12-42 summarises our population of installed combined residential solar PV energy and battery energy storage systems, and stand-alone residential battery energy storage systems.

ASSET	QUANTITY
Solar Photovoltaic combined with Battery Energy Storage Systems	165
Residential Battery Energy Systems (no solar)	180

TABLE 12-42: KEY INFORMATION FOR SOLAR/BATTERY AND STAND-ALONE BATTERY SYSTEM INSTALLATIONS

Figure 12-50 and Figure 12-51 shows the age profiles for solar/battery installations and stand-alone battery installations, respectively.

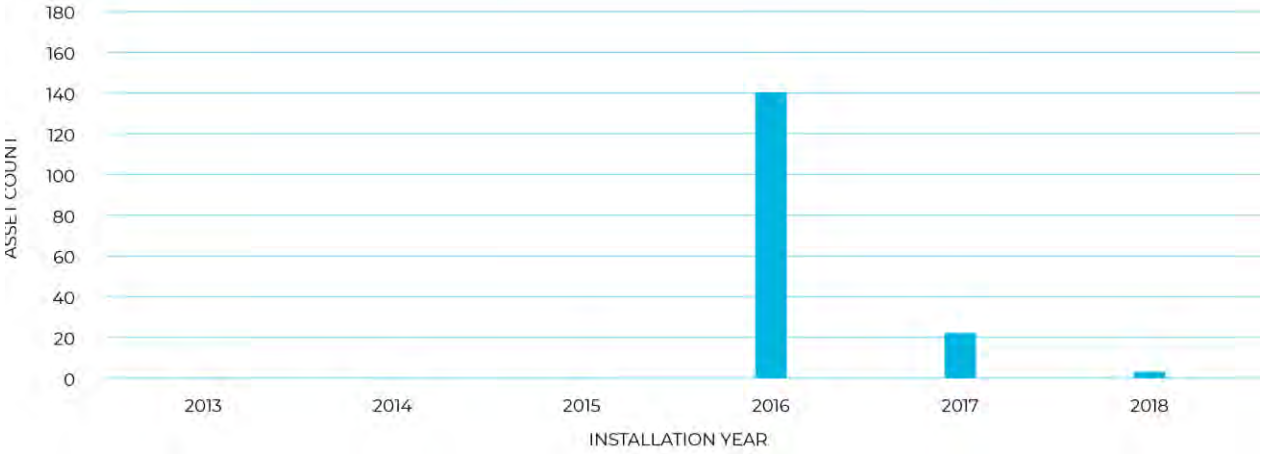


FIGURE 12-50: AGE PROFILE FOR SOLAR PV AND BATTERY ENERGY STORAGE SYSTEM INSTALLATIONS

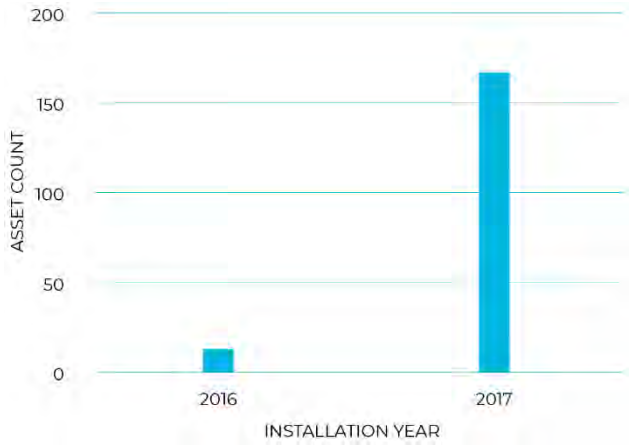


FIGURE 12-51: AGE PROFILE FOR BATTERY ENERGY STORAGE SYSTEM INSTALLATIONS

12.10.3.3 CONDITION AND HEALTH

Solar panels and battery installations form part of our maintenance regime for which provision is made in our OPEX budget. The solar panel and battery populations are relatively young, and apart from teething issues with operating software, we have not experienced systemic failures in our solar panel or battery fleets.

12.10.4 FORECAST SPEND

There is no further planned CAPEX investment in residential PV or BESS systems.

12.10.5 MOBILE SUBSTATIONS

Vector does not currently own any mobile substations, emergency supply is provided by BESS microgrids and diesel generators. Vector does own a mobile 11 kV switchboard which is used to mitigate risk during planned and unplanned outages.

12.11 Infrastructure and facilities

Infrastructure and facilities reside across the Vector network. The purpose of these assets is to provide a means of siting and housing primary and secondary zone substation equipment, digital microwave radio systems and customer hot water load management infrastructure, for the following reasons:

1. Security and safety for the public

2. Security and safety for Vector personnel
3. Operational security plus environmental and performance safety for electricity network assets

This Section describes our Infrastructure and Facilities fleet and provides a summary of our associated asset management practices. The fleet consists of two subcategories:

1. Buildings and Grounds
2. Cable Tunnels

12.11.1 BUILDINGS AND GROUNDS

Vector's buildings and grounds portfolio includes zone substation buildings housing protection, communications, indoor and outdoor switchgear, transformers, and structures, and ripple injection plant. The portfolio is located on Vector property or co-located at Transpower grid exit point (GXP) sites. Site grounds are secured from entry by boundary fences, and contain access driveways, potable, storm and wastewater infrastructure, security systems, and gated access ways. The degree of security is risk-based determined by customer and network asset importance, location, and risk of unobserved intrusion. Vegetation, asset screening and property fencing management are key to site security and for personnel, public and asset safety. Property frontages use palisade security fences that allow street visibility into the site to deter trespass, and closed board shiplap fences to customer facing boundaries for their privacy.

12.11.1.1 FLEET OVERVIEW

Buildings are constructed of various materials including reinforced steel cast in-situ or masonry block, light timber frame, since 2008 precast tilt slab concrete, and since circa 2010 sandwich insulated panel (SIP). Unreinforced masonry brick infill panels between reinforced concrete pilasters and bond beams are typical of pre-1960's era construction, with this construction having the highest risk of seismic failure. Key statistics of the buildings and grounds assets are shown in table 12-43.

TYPE	ASSET QUANTITY
Zone Substation Buildings and Grounds	116
Substation Buildings	216

TABLE 12-43: BUILDINGS AND GROUNDS FLEET OVERVIEW

12.11.1.2 POPULATION AND AGE

The expected life for the building fleet is 80 to 100 years with an onset of unreliability between 40 to 60 years. Figure 12-52 illustrates the age profile of Vector zone substation buildings. Their average age is 36 years.

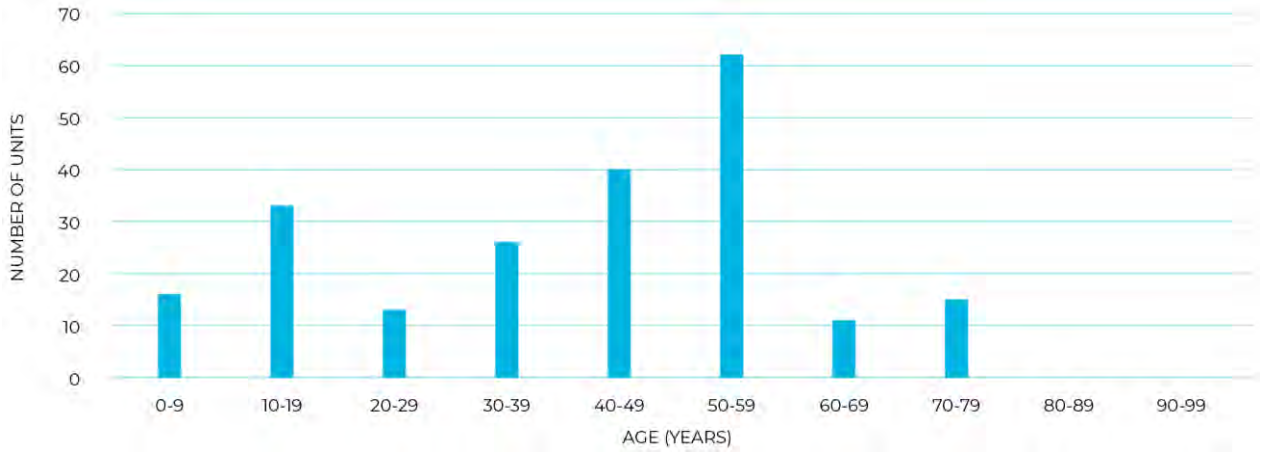


FIGURE 12-52: POPULATION AND AGE PROFIILE FOR SUBSTATION BUILDINGS

12.11.1.3 CONDITION AND HEALTH

The Vector buildings and grounds fleet is ageing in accordance with expected industry trends, and we are actively monitoring their health and condition to ensure we achieve the optimum life from the fleet. We manage our buildings in perpetuity, except for where substation primary electricity asset renewal requires a rebuild for additional space than the existing building allows.

12.11.1.4 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Due to our regular planned maintenance programme with corrective and planned actions our building performance is in a good state. The current drivers for our programme of work are property perimeter fencing, roofing replacements due to age or asbestos control, extreme weather events and seismic performance. We have assessed the higher risk category of zone substation buildings against the New Zealand Society of Earthquake Engineering (NZSEE) grades using engineering specialists also experienced in setting the NZ IEECP and the Christchurch earthquake re-build.

Multi-storey buildings of circa 1990 to 2010 are of variable performance within the NZ building sector due to that era's building standards, for which Vector's planned maintenance inspections target evidence of issues, as for all other buildings. A recent

example is Sandringham zone substation's partial rebuild that is now achieving 100% NBS performance for its 1990's building extension that had leaky building issues that appeared outside its 15-year Council code-compliance performance.

NZS7901 annual external assessor audits provide a risk-based independent assessment of zone substation property perimeter safety to the public, with their recommendations and observations corrected on site, and where required the updating of standards, and knowledge sharing with designer and planned maintenance practices. We also monitor sites with SMF with the intention that if deemed in the future to be a H&S hazard we have the necessary testing, records and proactive actions in place to mitigate risks.

There are substation buildings in low lying ground that are prone to flooding, which was highlighted more than ever during the 2022, 2023 and 2025 cyclone events and, these form part of capital projects to either harden against the impact of climate change, rebuild on higher ground, or other network solutions as described in Section 12 Appendix.

We have assessed flood hazards and their mitigation for zone substations since 2012 inclusive of reference to Auckland Council hydrology records. Third party specialists in climate change and extreme weather impact now also inform our planning for new zone substation builds and rebuilds of existing sites required by replacement of primary equipment and/or seismic condition. Sites most likely to be operationally affected by flooding also form our rebuild programme. Analysis includes industry norms of a 1:100 return event, and for 2024 onwards 1:500 events due to apparent increasing 24-hour rainfall intensity volumes and durations.

12.11.1.5 MANAGEMENT STRATEGY

The management strategy for the buildings and grounds fleet is based on safety and asset condition, including as important considerations the impact of climate change and how to harden facilities against such impacts. This is informed by condition data which is being continuously improved with information gathered by our field service providers during planned maintenance inspections to ESM701.

12.11.1.6 DESIGN AND CONSTRUCT

Vector as part of its conceptual development of new substation buildings and grounds, integrates the design within the surrounding environment and in conjunction with the Auckland unitary plan. In urban and rural areas, we make our sites as unobtrusive as practicable, with aesthetics incorporating architectural and open landscape treatment sensitive to the surrounding neighbourhood. When we renew existing substation buildings, we consider changing demographics and where practicable adapt the substation appearance to align with these trends. As stated above, the impact of climate change is considered and incorporated in our new builds and replacements.

Specification standards for the design and construction of new buildings and grounds are design standards ESE701, ESE702 and AS2067. Although electricity utility operator sites are not within the NZ Building Act: 2004 and our buildings are classed as unoccupied, for prudency our standards incorporate the requirements of the NZ Building Code, the Auckland unitary plan, and electrical industry Standards inclusive of AS2067.

12.11.1.7 OPERATE AND MAINTAIN

Vector routinely inspect its buildings and grounds fleet through the use of appropriately qualified personnel to ensure they remain fit for purpose. Remedial work is scheduled based on personnel and asset safety, and asset performance condition and functional importance. Vector's maintenance standard ESM701 comprehensively details the planned, corrective, and reactive maintenance requirements.

12.11.2 CABLE TUNNELS

Vector cable tunnels are installed where there is no other practical cost-effective means to install and maintain electricity cables. These satisfy the requirements of motorway crossings or mass cable runs within congested and difficult to access routes such as in the CBD.

The tunnel fleet houses extra high voltage power cables connected to Transpower grid exit point supply substations and between Vector zone substations.

All the tunnels are defined as confined spaces and are restricted to entry by personnel trained in those safety procedures.

This asset class includes the tunnel's structure and access security, ground water drainage pumps, active fire suppression where warranted and small power electrical circuits.

The 9.2km long Penrose-Hobson Tunnel at between 20 and 60 m underground as the land lies has added infrastructure of dual 375kW ventilation fans, five 37kW ground water pumps, an industrial lift for equipment and personnel, a light rail system for expedient access, tunnel fire sprinkler and cable shaft deluge active fire protection, permanent gas sensors for personnel protection, and a digital radio personnel communication system, all with remote systems status to the Vector electricity operations centre.

The Penrose-Hobson Tunnel safety systems are in addition to the confined space personal protective equipment (PPE) specified by Vector's HSEMS work type competency (WTC) requirements for all entrants to tunnels.

The Penrose-Hobson Tunnel train, rail and safety systems are assessed 18-monthly by Waka Kotahi NZTA for compliance with the Railways Act and the Health and Safety at Work Act. Vector also completes an annual independent assessment by KiwiRail certified rail engineers for the performance of tunnel train, rail, and safety systems and the delivery of these by our operations and maintenance provider Northpower.

12.11.2.1 FLEET OVERVIEW

Vector has one major (9,200m) and six minor (total length 762m) cable tunnels.

12.11.2.2 POPULATION AND AGE

The expected life for cable tunnel structures is between 80 to 100 years with an onset of unreliability between 60 and 80 years. The electrical and mechanical, secondary and process systems within the tunnels have a typical replacement lifecycle of 15 to 20 years.

12.11.2.3 CONDITION AND HEALTH

The cable tunnel fleet is ageing against industry norm expectations. We are actively monitoring and maintaining their health and condition within our Planned Maintenance regime (ESM708 and ESM709) to ensure we achieve optimum fleet safety and life.

12.11.2.4 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector completes five-yearly structural and seismic surveys using certified structural engineers of proven experience in tunnel design and construction for tunnels. The survey results continue to show good asset performance. A seismic event will result in a structural survey after the event has safely subsided to ensure asset integrity and that entry is safe for personnel.

HILP risk for all Vector cable tunnels is loss of hazard warning and personnel communication systems, impaired ventilation, atmospheric gas ingress, fire, or ground water flood. Vector uses a risk process safety approach to assess tunnel hazards and their controls, with the electricity operation and planned maintenance standards providing the method and frequency for their performance inspection and correction.

Emerging trends and risks are for tunnel ancillary and process systems as these approach 15 to 20 years of age within high moisture environments. Our maintenance and replacement program addresses this.

With the Penrose-Hobson Tunnel now 28 years old, to ensure its continued safe operation and expected longevity the 9.2 km rail system is undergoing a major refit, along with replacement of the tunnel control systems, active fire suppression, and the 60 m main access vertical lift at the Newmarket portal at the tunnel's midpoint.

12.11.2.5 MANAGEMENT STRATEGY

The management strategy for the cable tunnel fleet is based on safety and asset condition. It is informed by condition data which is being continuously improved with information gathered by our field service providers.

12.11.2.6 DESIGN AND CONSTRUCT

Tunnels and their systems are designed, certified, and constructed as a professionally engineered specific design since cable tunnels do not fall within the NZ Building Code. Vector does not have specification standards for the design and construction of new cable tunnels and utilises industry-leading tunnel expertise alongside international tunnel standards that would apply at the time, plus IEC and AS/NZS standards including health and safety.

12.11.2.7 OPERATE AND MAINTAIN

Vector routinely inspects its cable tunnels to ensure they remain fit for purpose. Remedial work is scheduled based on personnel and asset safety, and asset performance condition and functional importance. Vector's maintenance standard ESM701, ESM708 and ESM709 comprehensively details these planned, corrective and reactive maintenance requirements for its tunnels and their associated above ground "portal" buildings fleet.

12.11.2.8 BUILDINGS AND GROUNDS

Buildings and grounds renewals and disposal programmes are driven by personnel or asset safety risk, seismic upgrades, mitigation from flood plain and overland flow path hazards, additional primary equipment (switchgear and/or power transformers), or network growth replacements and building performance to meet its intended function. Climate change and hardening against the impact of climate change extreme weather events is an important consideration. Buildings found to not meet the current standard for seismic compliance then become part of a seismic strengthening programme, or if it is uneconomical to do so they are replaced in conjunction with primary equipment replacement requirements.

Approximately 50% of the pre-2000 zone substation population has materials containing embedded or encapsulated asbestos. To manage the risk of asbestos contamination occurring and exposure to personnel a proactive fleet-wide assessment by industry certified specialists is undertaken for buildings and grounds. This is delivered by a proactive risk-based programme of monitoring, cleaning, removal and air monitoring to regulatory standards. Regular air monitoring has provided no evidence of excursion outside the regulatory limit of 0.1 fibres per m^3.

The outcome of this programme allows continued safe entry for personnel for asset inspections and equipment maintenance. Hazard assessment and control procedures are enforced if 'free' asbestos is apparent, and prior to any invasive works for maintenance or asset renewal works. Buildings are also assessed for disposal in association with their asbestos risk.

Each building and grounds site that requires asset replacement is inspected to ascertain the scope of works and site constraints. Planned maintenance findings, predicted lifecycle costs and primary equipment updates are further inputs. This information is used to build a cost-benefit risk-based NPV estimate for forecast expenditure. As part of any building replacement or program, the new facility must meet current standards, codes of practice and legislative requirements.

12.11.2.9 CABLE TUNNELS

In an unlikely event a Vector tunnel is no longer required for cable routes, provided it is structurally sound, then it will be sealed from access and left in-situ. If not structurally sound, then pressure injected concrete infill is one method used to provide its required ongoing safety performance. Tunnel ancillary systems are renewed as required and the end-of-life equipment disposed of at environmentally certified facilities.

Tunnel ancillary's asset replacement ascertains the scope of work including site constraints, planned maintenance findings and predicted lifecycle costs. This information is used to build a cost-benefit risk-based NPV estimate for forecast expenditure. New equipment and systems must meet current standards, codes of practice and legislative requirements.

12.11.3 FORECAST SPEND

Detailed and individual programme forecasts for infrastructure and facilities as well as cable tunnel programmes of work are included in Section 12, Appendix. The forecast chart below is a summary of all the capex for infrastructure and facilities as well as cables. The only exception is the potential future replacement of the personnel egress ladder in the tunnel shaft at Newmarket substation. The replacement of this ladder is driven by safety, and while annual maintenance inspections show no degradation, a nominal allowance is prudently included in the forecast capex in Section 11, Network Reliability.

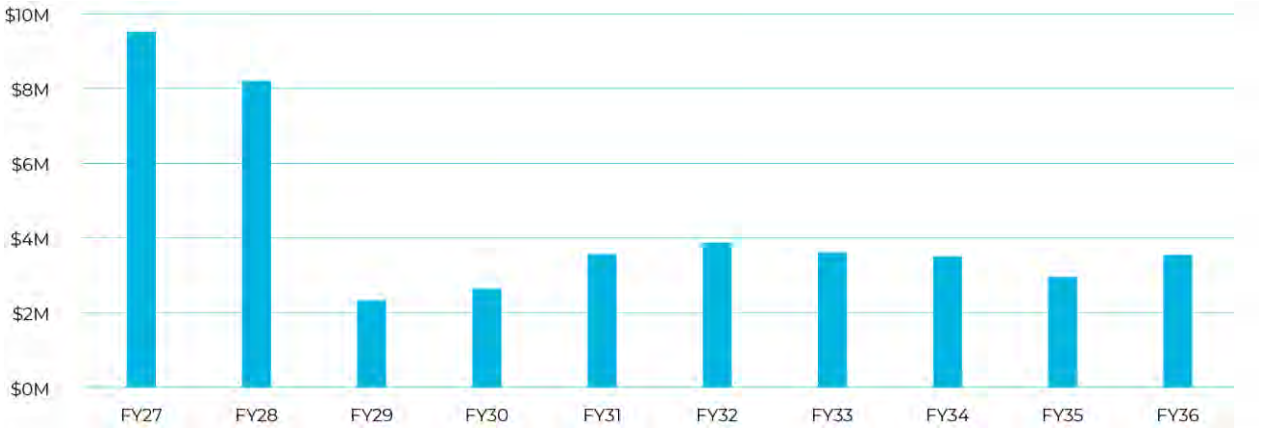


FIGURE 12-53: FORECAST CAPEX – INFRASTRUCTURE AND FACILITIES



SECTION 12A

Appendix: Asset replacement and renewal

12a – Asset replacement and renewal

12a.1 Overview

This section provides details for significant asset replacement and renewal projects that have costs of $1m and over and the timing of these investments covering the next 12 months, the following 4 years and the remainder of the AMP period. All dollar values are nominal and include inflation. For easy reference, the programmes of work are also shown.

12a.2 Primary switchgear

12a.2.1 HENDERSON VALLEY 11KV SWITCHBOARD REPLACE

The Henderson Valley 11 kV switchboard consists of 15 Reyrolle oil filled CBs: a mix of 1968 vintage LMT type 23T CBs and LMT X6 CBs. The existing protection relays are Reyrolle type TJV electro-mechanical overcurrent and earth fault relays with no relay supervision, no fault recording or fault location analysis capability and no capability for remote access to check and change protection settings or to access data in the relays. They also do not have the ability for definite time settings. Bay control on this old suite of CBs is via RTUs. The asset health and criticality of this switchgear is such that it is scheduled for replacement before the conversion of the 33 kV outdoor switchgear at Henderson Valley i.e. 33kV ODID project. The 33 kV ODID project is currently being considered, and its timing will be confirmed within the next 12 months. The accommodation for the new fixed pattern 11 kV switchgear will be designed and constructed to make provision for the 33 kV outdoor to indoor conversion works described separately and that will follow the completion of this project. This zone substation is in a low-lying area, and its design will consider flood levels taking cognizance of the Jan-Feb 2023 cyclone and its impacts.

The implementation of protection relays with definite time settings will allow much improved coordination with the large number of downstream reclosers and sectionalisers on the extensive Piha rural network.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Henderson Valley 11kV SWBD replace	7.03	1.87									8.90

12a.2.2 HOBSONVILLE 11KV SWITCHBOARD REPLACE

The 11kV switchgear in Hobsonville ZSS is of the South Wales C4X oil filled type installed in 1975 and is fitted with electro-mechanical relays. A staged in-situ 11 kV switchgear replacement is not practical because of the limited space in the switchroom and a new switchroom will be installed. This switchroom will be designed and constructed with sufficient room for a future 33 kV replacement of the outdoor switchgear with indoor switchgear.

The new 11kV switchboard will make provision for future additional 11 kV feeders and include all ancillary works and balance of plant e.g. DC system, SCADA panel, control and instrumentation.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Hobsonville 11kV SWBD replacement	2.05	5.05									7.11

12a.2.3 ROCKFIELD 11KV SWITCHBOARD REPLACE

The 11 kV switchgear at Rockfield ZSS is a combination of 1978 vintage Reyrolle UK LMT oil-filled CBs with CDG electro-mechanical relays, and two RPS LMVP vacuum CBSs installed in 1998 and 2005 respectively. Although the Reyrolle oil-filled CB's can be retrofitted with modern vacuum CB's, pressure from expected demand growth on Rockfield ZSS along with the benefits of having the switchboard of the same vintage has prompted a complete switchboard replacement. The scope will include the installation of modern numerical protection relays, replacement of the transformer management system, and the existing VT supplied rectifier units will be replaced with a Vector standard 110 V DC system.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Rockfield 11kV SWBD replacement	4.53	0.01									4.54

12a.2.4 ROSEBANK 11KV SWITCHBOARD REPLACE

Rosebank ZSS supplies the whole of the Rosebank peninsula and parts of Waterview that includes a large base of small and medium enterprises and industrial/commercial customers as well as 4,345 residential customers. The 11 kV switchgear consists of twelve Reyrolle UK LMT oil-filled CBs with electro-mechanical protection relays installed in 1970 and four Reyrolle LMVP vacuum CBs with Siemens numerical protection relays installed in 2007. The oil filled switchgear and the protection relays are not vendor

supported and the substation has a history of faults on VTs and CTs. The output from the switchgear CBARM model categorises this switchboard as having a R4 rating (maximum risk).

Theoretically, this 1970s Reyrolle switchgear could be retrofitted with vacuum CB trucks, but the general condition of the switchgear, cable termination boxes and secondary cabinets is such that the cost of retrofitting versus the benefit and asset life extension is not worthwhile. It will be more beneficial from a safety, operational and asset life point of view to replace the entire switchboard. The new switchgear will be fitted with Vector standard numerical protection relays and the 1970s vintage Reyrolle switchgear suite will be scrapped but selected parts will be retained as strategic spares for similar switches in service. The existing Long and Crawford 11 kV local supply substation RMU will be replaced.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Rosebank 11kV SWBD replacement	2.79										2.79

12a.2.5 SABULITE 33KV OUTDOOR TO INDOOR SWITCHBOARD CONVERSION

Sabulite ZSS is the distribution node for Kelston, Glendene South and North, Glen Eden East and New Lynn West in the Auckland Waitekere region and supplies 8,271 residential customers, 740 small and medium enterprises and 44 industrial customers. In 2012 the then existing South Wales 11 kV type C4/C8 X series of switchgear was replaced with a Schneider GHA fixed pattern switchboard in a Portacom style building that was designed with sufficient space for a 33 kV switchboard to be installed. The 33 kV outdoor CBs at Sabulite consist of five Nissin KOR type oil filled CBs installed in 1966 and one GEC VOX SF_6 outdoor live tank type CB installed in 2008. The protection relays for the 33kV CBs were upgraded in 2008 to Siemens numerical devices.

The Nissin KOR oil filled CBs have been identified as presenting a network risk because if and when they fail, they tend to do so spectacularly with a risk of collateral damage. The 33kV outdoor switchgear will be replaced with indoor fixed pattern switchgear in the AMP 2023 planning period. The works will include cutting, joining and turning new XLPE 33kV tails to the indoor switchgear and civil and structural works under the existing Portacom to make appropriate space for the 33kV cable tails. Replacement of the numerical relays will be required at the remote end 33kV zone substations connected to Sabulite.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Sabulite 33kV SWBD ODID	0.23										0.23

12a.2.6 WAIKAUKAU 33KV ODID AND 11KV SWITCHBOARD REPLACE

33kV outdoor to indoor conversion

The 33 kV substation at Waikaukau ZSS consists of an extensive outdoor switchyard on a combination of concrete and timber support structures with 70s vintage porcelain insulators and rocking type disconnectors/air break switches. There are ten outdoor 33 kV CBs and eight bus disconnectors in the overhead bus structure but no remote-controlled bus coupler CB: any bus fault means a manual operation of bus disconnectors on site with prolonged outage time.

The 33 kV CBs are a mix of Nissin KOR-22 and Takaoka 3ORO oil filled types that have been identified as a risk to operating personnel because the failure of these type of CBs has resulted in explosions and collateral damage. A 1986 installed Inoue outdoor oil CB exists and an Areva VOX SF_6 outdoor CB replaced an oil filled CB in 2008. Protection relays are a mix of Siemens and SEL previous generation numerical relays in indoor protection panels in the relay building on site.

This ZSS is in a floodplain and at risk during heavy downpours. In March 2017 and again in January 2023 the substation was shut down due to flooding and had to be back-fed while a clean-up operation was undertaken.



FIGURE 12A-1: WAIKAUKAU ZSS DURING FLOOD JANUARY 2023

The extensive size of the outdoor switchyard also makes it prone to outages by bird and vermin. A failure mode of cracking of insulators in the rocking disconnectors have been observed and resulted in a total outage of the 33 kV switchyard in January 2019. Apart from the inconvenience to customers this also resulted in undue SAIDI.

The 33 kV outdoor switchyard and CBs will be replaced with modern fixed pattern switchgear. For this purpose, a combined 33 kV/11 kV switchroom building will be constructed towards the front of the property that sits at a higher elevation (the 11 kV switchgear replacement will be undertaken separately in a subsequent year and is described further below). The switchroom will be designed with a floor height that takes into consideration the Unitary Plan flood plain modelling to prevent water from reaching the substation floor level.

Many 33 kV overhead lines enter the substation and as part of the works, this will be tidied up and replaced with underground cable portions into the new switchgear from cable risers. The transformers will also be relocated under the project to purpose built enclosures at a location on site with a higher elevation.

By the time this project will be delivered the existing numerical protection relays would have reached the end of life and the new fixed pattern switchgear will be delivered with generation 5 numerical relays and relays at the remote ZSS ends supplied from Waikaukau will also be replaced with generation 5 relays.

11kV Switchboard replace

The 11 kV switchboard in Waikaukau ZSS is a 1975 vintage South Wales suite that consists of five oil filled CBs: a mixture of D8 and C4X1 types fitted with CDG electro-mechanical protection relays. The South Wales oil filled switchgear is not supported by vendors and has been identified in Vector's asset strategy for replacement.

The 11 kV switchboard will be replaced with fixed pattern low maintenance switchgear and numerical protection relays in a switchgear room installed in a prior year as part of the 33 kV outdoor switchyard replacement.

The switchgear room height will consider the flood plain height as experienced in the Jan-Feb 2023 cyclone to mitigate the risk of flooding and harden this zone substation for the impact of climate change

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Waikaukau 33kV ODID & 11kV SWBD replace	4.08	0.45									4.54

12a.2.7 QUAY STREET 22KV SWITCHBOARD REPLACE

The Quay Street 22 kV Switchboard Replacement project responds to a clear problem at Quay Zone Substation in Auckland's CBD. The existing Calor-Emag switchgear is old and no longer well suited to modern safety, reliability, or security of supply expectations. At the same time, electricity demand in the CBD is growing, driven in part by Auckland Transport's planned e-ferry charging at the ferry terminal and the University of Auckland's decarbonisation plans. Without targeted investment, the current equipment and cable arrangements will struggle to support these new loads while maintaining a reliable supply.

The solution is to replace the existing switchboard with a modern 22 kV switchboard and associated equipment that can safely and reliably support future growth and coordinated with other planned upgrades at the site. This includes new transformers and circuit breakers, a new switchroom with improved fire and security systems, and building upgrades such as seismic strengthening and asbestos remediation. The project also involves upgrading the cable connection to Hobson substation to create a more robust supply route. Together, these works will increase capacity, improve resilience, and support key electrification initiatives in Auckland's city centre, with completion targeted by June 2029.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Quay Street 22kV SWBD replace	0.66	6.82	2.26								9.74

12a.2.8 HILLCREST 11KV SWITCHBOARD OCB TO VCB RETROFIT

Hillcrest ZSS has a 13-panel 11kV switchboard supplied from two 12/24 MVA transformers. Two of the CBs are Reyrolle Pacific LMVP vacuum CBs installed in 2008. The remaining 11 CBs are Reyrolle Pacific LMT2 and ZMT2 oil filled CBs installed in 1990. The first-generation numerical protection relays (GEC MCGG Micom) were replaced under an earlier PAC program of work.

An OCB to VCB retrofit project is scheduled to commence and be delivered within FY28.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Hillcrest 11kV SWBD retrofit		5.20									5.20

12a.2.9 KINGSLAND 11KV SWITCHBOARD REPLACE

Kingsland ZSS is one of the larger distribution centres in Auckland's network and it is supplied from Mt Roskill GXP onto two 110 kV/22 kV transformers that supply a 22 kV switchboard. A large (20 panel) 11 kV switchboard is supplied from the 22 kV switchboard via two 22 kV/11 kV transformers. The 11 kV switchboard is a Reyrolle Pacific switchboard installed in 1990. Although the feeder CBs all have vacuum interrupters, the three incomer CBs and two bus coupler CBs are oil filled Reyrolle Pacific LMT2 CBs. The scope of this project was originally to retrofit the oil CBs with vacuum interrupter CBs, however this was reconsidered in favour of a complete replacement in order to standardise and modernise every component of the switchboard. Circuit breaker replacement alone does not mitigate all risk with this type of switchgear; considering fluid filled cable box conversion, VT and CT replacement and related upgrades it is more cost effective and future proofing to replace the apparatus in its entirety.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Kingsland 11kV SWBD replacement		5.20									5.20

12a.2.10 LICHFIELD 110 KV OUTDOOR CB REPLACE

The two 110 kV CBs at Lichfield ZSS are AEG type S1-145 F1 outdoor single pole encapsulated live tank SF_6 CBs commissioned in the mid-1990s. These CBs have had systemic issues with leaking SF_6 but diligent maintenance and refurbishment have kept them running. ABB still provides some technical support and spare part inventory for this type, but these CBs need to be replaced in this AMP period.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Lichfield 110 kV OD CBs replacement		0.60									0.60

12a.2.11 NEW LYNN 33KV ODID AND 11KV SWITCHBOARD REPLACE

12a.2.11.1 33KV OUTDOOR TO INDOOR CONVERSION

The 33 kV outdoor switchgear in New Lynn ZSS consists of a variety of Siemens India oil filled CBs installed in the mid-eighties and a Vox SF_6 CB installed in 2007. The asset health and criticality of the 33 kV outdoor switchgear is such that it will be retained in service until after the 11 kV switchgear has been replaced. Accommodation for the 33 kV switchgear will be designed and constructed as part of the 11 kV switchgear project.

12a.2.11.2 11KV SWITCHBOARD REPLACE

The New Lynn 11 kV switchboard consists of a mixture of South Wales D4XD 1954 vintage switchgear, three C8X 1954 vintage CBs and three South Wales HG12 SF_6 CBs installed in 1987. All protection relays are electro-mechanical. Based on asset health and criticality the oil filled CBs need to be replaced but the complete suite including the three later model South Wales SF_6 CBs will also be replaced because a partial replacement will be physically challenging and costly to achieve. The three recovered SF_6 CBs will be retained as a source of spares.

The existing 11 kV switchroom does not have any space for a staged 11 kV switchboard replacement regardless that the building achieves 90% seismic compliance of NBS. There is sufficient space in Vector's designated substation land to construct a new switchgear building. It will be designed and constructed to house new indoor 33 kV switchgear that will be undertaken after the

11 kV replacement. The site is within a flood plain and the substation building design will consider this. The works will include the required balance of plant installation, e.g. 110 V Vector standard DC panel, SCADA panel and communications panel

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
New Lynn 33kV ODID & 11kV SWBD replace		5.26	9.99								15.24

12a.2.12 QUAY ST 11KV SWITCHBOARD REPLACE

Quay St ZSS is the bulk supply zone substation that supplies the lower eastern Auckland CBD including Ports of Auckland via a 22 kV and 11 kV network. It also supplies Parnell ZSS via two 22 kV subtransmission underground cables. The 22 kV ABB Calor Emag SF_6 1991 vintage installed double bus switchgear at Quay St recently (FY20/21) underwent a mid-life refurbishment which added ~20 to 30 years to its asset life. No capital works are required on this switchgear in the AMP planning period.

The 11 kV switchgear in Quay St ZSS is a double bus switchgear suite that consists of:

- 9 x Reyrolle 2LMT/MO oil filled CBs with CDG electro-mechanical protection relays installed in 1972. The switchgear has a short circuit rating of 350 MVA for 3 s;
- 17 x Yorkshire YS/L 13.8 kV rated SF_6 CBs with Siemens numerical protection relays installed in 1993. The switchgear has a short circuit rating of 476 MVA for 3 s.

The lack of vendor support, asset age, no fault analysing or data storage capability in the protection relays and high criticality of Quay St ZSS drives a replacement of the Reyrolle 2LMT oil filled CBs later in the AMP 2023 planning period. An in-situ replacement in place of the existing switchgear is simply not practical, but the substation has real estate in which to install the new switchgear and undertake a staged transfer of 11 kV circuits. The Yorkshire SF_6 switchgear is still in good condition and although out of production, Vector has a repository of spares for this type to enable its retainment beyond the AMP 2023 planning period. However, the existing Siemens Siprotec 3 generation protection relays in the Yorkshire switchgear will need replacement later in the present planning period with Siprotec 5 generation numerical relays.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Quay St 11kV SWBD replacement			1.29	4.92							6.20

12a.2.13 ST HELIERS 11KV SWITCHBOARD REPLACE

St Heliers ZSS is equipped with thirteen Reyrolle England 1970s vintage CBs that is a mixture of LMT 36T and LMT X8 types; electro-mechanical protection relays are fitted. According to the CBARM model, the risk category of this switchboard is expected to regress into the R4 category towards the end of the AMP period.

Lighting will be replaced with Vector standard LED lights and emergency lighting, and to reduce solar heat gain the windows will have a covering applied. The 1974 vintage Long and Crawford oil filled RMU in the local supply substation will be replaced with a modern equivalent under the works. The fire protection system will also be upgraded.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
St Heliers 11kV SWBD replacement		2.34	7.02								9.36

12a.2.14 TE PAPAPA 11KV SWITCHBOARD REPLACE

Te Papapa ZSS is supplied from Penrose GXP to two 15 MVA transformers that feed a 13-panel Reyrolle England 11 kV switchboard with oil filled CBs installed in 1975. The line differential protection relays on the two 11 kV incomer CBs were modernized in 2020 to numerical protection relays that operate on a fibre optic signalling cable due to an ageing and failing copper pilot cable.

The oil filled switchgear and electro-mechanical relays are not vendor supported and will be replaced in line with Vector's asset strategy for primary switchgear. The existing substation building has structural issues and although there is space in the 11 kV switchroom for a staged in situ replacement, a new building is the preferred option to house new fixed pattern low maintenance replacement switchgear. The two numerical relays in the existing incomers will be retained as strategic spares at the time of the works. The forecast cost below is based on a new switchgear room constructed on site.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Te Papapa 11kV SWBD replacement				1.38	2.76	2.76					6.90

12a.2.15 SANDRINGHAM 11KV SWITCHBOARD REPLACE

Sandringham ZSS is fitted with a mixture of Brush Q16/2 and Brush R4/2 oil filled CBs installed in 1967; twelve CBs in total. The switchgear is fitted with electro-mechanical protection relays. Neither the switchgear nor protection relays are vendor supported and the switchgear is of the type that has been identified in Vector's asset strategy for primary switchgear, as a type to be replaced. Its ranking in the switchgear condition-based risk model calls it out for replacement in the current AMP planning period.

The existing switchroom building is a remnant of the leaky building period but extensive capital has been invested in recent years, including guttering, roofing and concrete paving to control soil erosion and seasonal swelling/shrinking around the building. The existing substation land is constrained and there is insufficient space to undertake an in-situ replacement inside the existing 11 kV switchroom, and the existing building will most likely have to be extended to create space for a new 11 kV switchboard. This will require extensive geotech investigations to ensure the mass of any building additions does not impact the stability of existing buildings on site. Furthermore, the existing building foundations may require seismic upgrade, and the building addition will likely have some separation so the buildings will have separate mass responses: details to be confirmed at the time of design.

The allowance in the AMP forecast estimate for this switchgear replacement is thus provisional and not firm until the afore-mentioned detailed investigations have been undertaken. This will happen closer to the time but ahead of works delivery. As part of this project, the existing PILC 11 kV incomer cables will be replaced. It is also planned to replace the existing Long and Crawford and LV distribution panel in the local supply substation at this ZSS. If necessary, Vector will deploy its mobile trailer (container) mounted 11 kV switchboard to facilitate the new switchgear installation.

The peak demand in Sandringham in the 2022 winter was 19.6 MVA and is forecasted to reach 37.0 MVA by the end of the AMP planning period. The new design and switchgear installation will make provision for easy extension of an additional 11 kV CB on either side of the bus in the future: a requirement for a new 11 kV feeder is a high likelihood.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Sandringham 11kV SWBD replacement				0.66	5.91						6.58

12a.2.16 MANLY 11KV SWITCHBOARD REPLACE

Manly ZSS supplies suburbs located on the Whangaparaoa peninsula including Whangaparaoa, Manly and Stanmore Bay. Vector's substation switchgear CBARM model has identified the Manly 11kV switchboard as becoming high risk towards the end of the current AMP period and requiring replacement. The 11kV switchgear consists of 11 GEC BVP17 oil filled CBs installed in 1972 with English Electric CDG36 electro-mechanical relays. The new switchboard will be fitted with modern numerical relays and auxiliary systems will be replaced to meet the current Vector standard.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Manly 11kV SWBD replacement					1.46	4.87					6.33

12a.2.17 SUNSET RD 11KV SWITCHBOARD REPLACE

Sunset Rd ZSS in the North Shore supplies the Sunnynook area, parts of Unsworth Heights, northern parts of Wairau Valley and the extensive Constellation Rd and Upper Harbour commercial areas. It includes the North Shore police headquarters in the supply area. The 11 kV switchgear consists of 11 GEC BVP17 oil filled CBs installed in 1972. The protection relays are GEC CDG36 electro-mechanical relays of the same vintage as the switchgear. An in-situ replacement in the existing 11 kV switchroom is unlikely due to limited space and a new switchroom will likely be utilized for fixed pattern low maintenance switchgear.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Sunset Rd 11kV SWBD replacement				1.46	4.87						6.33

12a.2.18 SUNSET RD 33KV OUTDOOR TO INDOOR CONVERSION

The 33kV switchgear at Sunset Rd ZSS consists of seven outdoor CBs: five Takaoka 3OKO oil filled CBs, one Inoue 3OTEO oil filled CB all installed between 1978 and 1980 and one Siemens India vacuum outdoor CB installed in 2005. The oil filled CBs are of a type that has been identified as a risk and will be replaced. Numerical relays were installed on the incoming 33 kV feeder CBs in 2019 and will be returned to stock as strategic spares at the time of the replacement because the new fixed pattern switchgear will come fitted with new protection relays. The existing 11 kV switchroom (see above) will most likely be repurposed for the new 33 kV switchgear.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Sunset Rd 33kV ODID				0.62	4.78						5.40

12a.2.19 WOODFORD 11KV SWITCHBOARD REPLACE

Woodford ZSS is a single transformer substation that supplies a mixture of residential and commercial load. The 11kV switchboard is presently fitted with mid-1970's Reyrolle UK oil filled 11kV switchgear along with English Electric CDG36 electro-mechanical relays of the same vintage. There is sufficient space in the 11kV switchroom to undertake an in-situ 11kV replacement and no remedial work on the switchroom building is required to make this building comply with the Seismic Provisions of the Building Act.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Woodford 11kV SWBD replacement								1.46	2.45		3.91

12a.2.20 HOBSONVILLE 33KV OUTDOOR TO INDOOR CONVERSION

The outdoor 33kV switchyard consists of common copper bus on concrete and steel structures with Canterbury engineering ABS. The circuit breakers consist of 4 Takaoka type 3OKO bulk oil breakers and 2 Areva/ Schnieder type VOX SF6 insulated vacuum interrupter circuit breakers.

The 11kV Switchboard renewal is currently in the deign process. A new combined 11kV and 33kV switchroom will be established as part of this program of works. It is anticipated that the new switchroom will be established at rear portion of the 33kV outdoor switchyard. For this to occur it is proposed a 33kV RMU be commissioned as enabling works to make room for the new construct. The 36kV rated RMU will be recovered as part of the wider 33kV ODID program of work.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Hobsonville 33kV ODID					0.62	4.78					5.40

12a.2.21 MCLEOD 11KV SWITCHBOARD REPLACE

The 11kV switchgear in McLeod ZSS is of the South Wales C4X oil filled type installed in 1975 and is fitted with electro-mechanical relays. Neither the switchgear nor protection relays have any vendor support and the equipment is nearing the end of life. A review into integrity of the switchroom building will be required to determine if a replacement is required or if it is economical to maintain for the lifetime of the new switchboard. Fixed pattern switchgear will be installed in the existing switchroom if practicable, otherwise a new switchroom will be constructed.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
McLeod 11kV SWBD replacement					5.20						5.20

12a.2.22 EAST COAST RD 11KV SWITCHBOARD REPLACE

East Coast ZSS has a nine panel 11kV switchboard supplied from a single 12/24 MVA transformer. Three of the CBs are Reyrolle Pacific LMVP vacuum CBs installed in 2006. The remaining six CBs are Reyrolle Pacific LMT2 oil filled CBs installed in 1989. The oil CBs are fitted with first-generation numerical protection relays (GEC MCGG Micom) while the vacuum CBs are fitted with later generation Siemens numerical relay.

Vectors substation switchgear CBARM has identified the East Coast 11kV switchboard oil CB's as being highly critical assets with their health deteriorating towards the end of the AMP period. The switchboard will be replaced and modern numerical protection relays will be installed with the new switchboard.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
East Coast Rd 11kV SWBD replacement					5.20						5.20

12a.2.23 HAURAKI 11KV SWITCHBOARD REPLACE

The Hauraki 11kV Switchboard Replacement project is part of the broader Asset Renewal and Risk Mitigation strategy aimed at improving network reliability and safety. This initiative addresses aging indoor switchgear at the Hauraki Zone Substation, which has reached end-of-life and poses operational and resilience risks. The scope includes replacing the existing 11kV switchboard with modern vacuum circuit breaker technology, upgrading associated protection systems, and ensuring compliance with current standards.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Hauraki 11kV SWBD replacement						5.20					5.20

12a.2.24 LAINGHOLM 11KV SWITCHBOARD REPLACE

The 11kV Switchboard at Laingholm consists of 9 panel South Wales type C4X oil circuit breakers circa 1969 fluid filled cable boxes and cast resin CT and a single late model HG12 SF6 addition circa 1987. '

Due to the limited ceiling height of the existing 11kV switchroom; a staged in situ replacement with similar demountable circuit breaker form factor as in the RPS LMVP A-FL variant is the likely replacement solution for this site

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Laingholm 11kV SWBD replacement						5.20					5.20

12a.2.25 NEWTON 11KV SWITCHBOARD REPLACE

Newton ZSS supplies the large commercial area in Newton, Eden Terrace and a part of Mt Eden. The 11kV switchboard is a double bus GEC NZ type BTVP suite with oil filled CBs and GEC CDG electro-mechanical protection relays installed in 1980. The risk category of this switchboard according to the CBARM model is expected to regress into the high-risk category towards the end of the AMP period

There is no space in the switchroom for an in-situ staged replacement and insufficient space to build a new switchroom. To replace the switchboard will most likely require a major construction project to build a second level over and above the existing switchroom for new fixed pattern switchgear. This zone substation is close to a cliff in which small landslips occurred during the Jan-Feb 2023 cyclone, and this will be considered in the design of this upgrade.

The investment forecast is provisional as this project requires extensive planning and investigations to select a viable option.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Newton 11kV SWBD replacement						2.34	7.02				9.36

12a.2.26 MT ALBERT 11KV SWITCHBOARD REPLACE

Mt Albert 11kV switchboard consists of 5 panels 1969 vintage oil type Reyrolle England LMT switchboard. In 2023, a new transformer bay was constructed, and the previous bay was removed. A new switchroom is planned for the area where the former transformer bay stood, while the current 11kV switchroom will be dismantled. If necessary, the space created by removing the old switchroom may be used to accommodate a second transformer bay.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Mt Albert 11kV SWBD replacement				1.05	2.10	2.10					5.25

12a.2.27 TORBAY 11KV SWITCHBOARD REPLACE

The Torbay 11kV Switchboard Replacement forms part of a wider asset renewal and risk mitigation strategy at the Torbay Zone Substation to improve NETWORK reliability, safety and resilience. The existing switchboard will be replaced with six modern 11kV panels within the current switchroom, ensuring compliance with current standards and supporting enhanced operational reliability.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Torbay 11kV SWBD replacement						5.20					5.20

12a.2.28 MCLEOD ROAD 33KV OUTDOOR TO INDOOR CONVERSION

McLeod Rd ZSS is a single transformer substation on the northern network with a single subtransmission supply for TP Hepburn. From McLeod Road there is s subtransmission circuit to Te Atatu ZSS. The 11kV switchboard consist of a 1973 vintage 5-panel South Wales OCB switchboard. The 33kV yard consists of a mix of omnirupter switches, abs disconnectors and OCBs. This station is best placed for an OD to OD conversion with a view to replace the outdoor 33kV infrastructure with a 33kV RMU solution.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
McLeod Road 33kV ODOD						0.62	4.78				5.40

12a.2.29 TORBAY 33KV OUTDOOR TO INDOOR CONVERSION

McLeod Rd ZSS is a single transformer substation on the northern network with a single subtransmission supply for TP Hepburn. From MCLEOD Road there is s subtransmission circuit to Te Atatu ZSS. The 11kV switchboard consist of a 1973 vintage 5-panel South Wales OCB switchboard. The 33kV yard consists of a mix of omnirupter switches, abs disconnectors and OCBS. This station is best placed for an OD to OD conversion with a view to replace the outdoor 33kV infrastructure with a 33kV RMU solution.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Torbay 33kV ODOD						0.62	4.78				5.40

12a.2.30 WAIMAUKU 11KV SWITCHBOARD REPLACE

The Waimauku ZSS 11kV switchboard consists of a 1983 GEC BVP17 unit connected to a 2012 RPS LMVP extension via a custom joggle chamber. The GEC switchboard is obsolete with no OEM parts, and spare parts from previous project work are unavailable. Replacing the GEC panels will modem compatible equivalents will support continued operation of the remaining equipment.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Waimauku 11kV SWBD replacement				1.48	4.04						5.52

12a.2.31 MANLY 33KV OUTDOOR TO INDOOR CONVERSION

Manly 33kV subtransmission is supplied via two circuits from Transpower Silverdale. Circuit 1 is a direct connection whereas Circuit 2 has a midpoint tie via S&C VISTSA ground mounted switchgear connection to Gulf Harbour ZSS. The majority outdoor facilities consist of four 1985 vintage Magrini Galileo minimum oil circuit breakers, overhead copper bus and Canterbury engineering ABS atop concrete support structures. The yard was extended in 2007 with steel support structures, copper bus bar and a single Areva VOX 2007 (P864) providing connection to Gulf Harbour substation. Replacement with modern equivalent indoor switchgear is recommended.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Manly 33kV ODID						3.27	2.18				5.46

12a.2.32 SWITCHBOARD REPLACEMENTS IN THE LATTER PART OF THE AMP PERIOD

The forecast below is for switchboard replacements in the latter part of the AMP period that have been assessed based on asset health and criticality. Depending on the performance of the equipment as well as load growth, the priorities for these replacements might change.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Simpson Road 11kV SWBD replace							5.20				5.20
Laingholm 33kV SWBD ODID replace							0.62	4.78			5.40
Northcote 11kV SWBD replace								5.20			5.20
Orewa 33kV SWBD ODID replace								0.62	4.78		5.40
Snells Beach 11kV SWBD replace									5.20		5.20
Victoria Street 11kV SWBD replace									5.20		5.20
Warkworth 33kV SWBD ODOD replace						1.05	2.10	2.10			5.26
Simpson Road 33kV SWBD ODID replace									1.09	4.37	5.46
Remuera 11kV SWBD replace									1.05	4.21	5.26
Snells Beach 33kV SWBD ODID replace										0.60	0.60
Woodford 33kV SWBD ODID replace									1.09	4.37	5.46
Litchfield 11kV SWBD replace									1.05	4.21	5.26

12a.3 Zone substation power transformers

12a.3.1 MANUREWA REPLACE TRANSFORMER T3

Manurewa ZSS is a three transformer ZSS that feeds a 22-panel fixed pattern 11 kV switchboard installed in 2018. All three transformers are 16 MVA (ONAN) Bonar Long units. T1 and T2 were installed in 1968 and T3 was installed in 1976. Manurewa ZSS supplies 17,271 residential customers, 1,1159 small and medium enterprises and 96 industrial customers. The peak demand in 2022 was 50.6 MVA and is forecast to reach a peak of 68.6 MVA by 2033.

DGA sampling in December 2022 showed a high-level of moisture and high acid content which shows that fluid oxidation is advancing and the interfacial tension in the oil has reduced. The estimated DP value of this transformer has degraded from 346

calculated in July 2020 to 309 in the latest test, and the GDAC platform point-in-time condition-based rating of this transformer is at poorest rating on their scale.

The old 11kV switchroom will be demolished and the first of 3 new Transformer bays will be established in the area formerly

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Manurewa 33/11 kV TX Replace T3	3.03										3.03

12a.3.2 HANS ZSS REPLACE TRANSFORMERS T1

1978 Bonar Long 15/20 MVA ONAN/ONAF transformers at Hans ZSS have DP values that require these two transformers to be replaced within the AMP period. T52 was commissioned into service in December 2023 under FY24programs of works and T1 replacement is currently being planned. The existing transformers are off-tank radiator transformers in transformer enclosures to suit the existing off-tank radiator designs. The winter 2022 peak demand is 23.1 MVA and is forecast to reach 34.3 MVA in 2033. Similar pattern, i.e. off tank radiator, replacement transformers rated 20 MVA (30 MVA 2-hour rating) will be procured, and these will be delivered complete with Reg-DA transformer management systems as per Vector's standards.

Because similar footprint transformers, to suit the existing transformer rooms, will be procured, the civil works will include modification of the transformer and radiator pads to suit the new design as well as core drilling of duct routes to suit termination boxes. Because of previous overheating issues, larger louvres will likely be installed, or the roof raised to improve airflow in the transformer enclosure to optimise heat dissipation for the replacement transformers – this will be determined as part of the detail design. The DC system is compliant with Vector's latest standard. The 33 kV oil filled cables that presently terminate directly on to the existing transformers will be terminated to oil-to-XLPE trifurcating stop joints and XLPE tails installed to the new transformer 33 kV termination enclosure.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Hans 33/11 kV TX Replace T1	3.77										3.77

12a.3.3 MCNAB ZSS REPLACE TRANSFORMERS T2 AND T3

McNab ZSS is a highly loaded and critical zone substation that supplies a large commercial and industrial customer base (1,269) as well as 5,062 residential customers. The large Illinois Glass recycling plant counts amongst the industrial customers connected to this ZSS. The deteriorating estimated DP values of the 1966 vintage transformers mean that they need to be replaced to ensure the continued reliability of the supply. McNab T1 has been replaced with a new transformer commissioned in Aug 2024. Replacement of T2 and T3 is planned for completion in FY27 and FY29 respectively.

The peak demand in 2022 was 37.8 MVA and forecast growth is expected to reach a peak demand of 60.6 MVA in 2033. In line with this forecast peak demand, the project will replace the existing 20 MVA transformers with similarly sized 20/28 MVA (30 MVA 2-hour emergency rating) transformers. However new large industrial customers might require larger transformers to be installed at the time.

The 11 kV switchgear at this ZSS is relatively young and meets Vector's load and short circuit requirements and will remain in service but the transformer impedance has been selected to keep fault levels at the appropriate level as stated in Vector standards. The 33 kV supply cables from Penrose GXP as well as the 11 kV 1-core 630 Al XLPE incomer cables will be retained. The transformers will be delivered with on-board A-Eberle Reg-DA transformer management systems as per Vector design standards. The transformers will be replaced in sequence so as not to compromise the security of supply at this important commercial and industrial hub. Transformer neutral CTs will be replaced and protection settings revised for improved earth fault protection. Secondary cabling will be replaced as required and full details will be determined as part of the detailed design.

The transformer foundations will be modified to suit the footprint of the new transformers and new masonry reinforced concrete bunds will be installed to oil volume requirements. The transformer bays will be equalized: this will involve a new blast wall between transformers T1 and T2 and replacement of the existing blast wall between T2 and T3. The existing rain shields will most likely be replaced with Vector standard Osbourne rain/ventilation louvres. New primary cable supports will be installed. Existing NERs are fit for purpose and will remain. A second 110 V battery bank will be added to bring this ZSS to Vector standards for high importance zone substations.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
McNab 33/11 kV TX Replace T2	2.37	3.15									5.51
McNab 33/11 kV TX Replace T3		0.69	3.15								3.84

12a.3.4 LAINGHOLM REPLACE T1 TRANSFORMER

The Laingholm T1 unit is one of the oldest assets on Vector's network, having been first commissioned in 1953. Recent electrical testing indicates elevated moisture levels in its solid insulation. This project leverages the opportunity to reuse a transformer from the soon-to-be-decommissioned Ngataringa Bay site, which is a suitable candidate to replace the aging Laingholm unit. The plan involves refurbishing the Ngataringa Bay transformer and redeploying it to Laingholm. Once the replacement is complete, the existing Laingholm T1 unit will be decommissioned and scrapped.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Laingholm 33/11 kV TX Replace T1	0.70										0.70

12a.3.5 MT WELLINGTON ZSS REPLACE TRANSFORMERS T1 AND T2

Mt Wellington ZSS supplies the large commercial and industrial hub of Mt Wellington. This ZSS is equipped with two 15/20 MVA rated Wilson transformers installed in 1963. Both these transformers are showing a decline in the degree of polymerization. As an interim measure both these transformers underwent Fullers treatment in 2021 to help maintain their integrity and reliability until their replacement.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Mt Wellington 33/11 kV TX Replace T1	2.25	1.03									3.28
Mt Wellington 33/11 kV TX Replace T2	2.25	1.03									3.28

12a.3.6 NEWTON ZSS REPLACE TRANSFORMER T1 AND T2

Newton ZSS is supplied from the Liverpool ZSS 22 kV bus via two 3-core Aluminium PICAS PVC oil-filled cables that terminate directly onto two Turnbull and Jones 12/16 (ONAN/ONAF) MVA 22/11 kV transformers manufactured in 1978. Newton ZSS supplies the south-western corner of Auckland's CBD and has backstop 11 kV circuits to Kingsland and Newmarket zone substations. Newton has a winter peak that reached 18.2 MVA in 2022 and is forecasted to reach 31.0 MVA by 2032.

The existing transformers at Newton are off-tank radiator configured transformers. Replacement transformers will be 20 MVA ONAN (30 MVA 2-hour) rated units and will be of a similar off-tank radiator design to suit the layout of the existing enclosures. The two oil-filled cables will be terminated into oil-to-XLPE trifurcating stop joints and XLPE tails terminated in the new transformer 33 kV cable termination enclosures. The 11 kV PILC incomer cables will be replaced with new XLPE (cu) tails as per Vector's standards.

Currently the replacement of T1 is in the AMP for completion in FY27, but further analysis using the GDAC platform shows that Newton T2 is also a high-risk transformer and has been scheduled for replacement in FY28.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Newton 22/11 kV TX Replace T1	3.99										3.99
Newton 22/11kV Tx Replace T2	0.69	3.99									4.68

12a.3.7 OTARA ZSS REPLACE TRANSFORMERS T1 AND T2

Otara ZSS supplies the commercial and residential community in the southwest of East Tamaki. Otara is T3 Power Transformer configured substation. T1 and T2 are 22/11kV 15 MVA ONAN rated AEI manufactured transformers commissioned in 1964. T3 is a as new Pauwels 20MVA ONAN transformer commissioned in 2009.

Both T1 and T2 transformers are showing a decline in the estimated degree of polymerization. At last measure (2023) the E.DP of T1 and T2 was 462 and 440 respectively. Indicating more than 40% of the tensile strength in the paper has been depleted. As the E. DP is an average measure, the actual DP can vary greatly where vulnerable areas of the transformers insulation below DP 350 are likely.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Otara 22/11 kV TX Replace T1	0.69	2.63									3.32
Otara 22/11 kV TX Replace T2		0.69	2.63								3.32

12a.3.8 THE DRIVE REPLACE TRANSFORMER T1 AND T2

The Drive ZSS supplies a largely residential and retail area of Mount Eden Epsom and One Tree Hill. The Drive is a twin transformer supply station. T1 and T2 are circa 1972 YET (Yorkshire Electric Transformer) 15/20MVA ONAN/ONAF 33/11kV units.

Both T1 and T2 transformers are showing a decline in the estimated degree of polymerization to critical levels. At last measure (2023) the E.DP of T1 and T2 was 510 and 336 respectively. T2 E.DP indicates more than 65% of the tensile strength in the paper has been depleted. As the E.DP is an average measure, the actual DP can vary greatly where vulnerable areas of the transformer insulation strength below DP 300 is likely. T1 and T2 are the same design and age in service. The large delta in E.DP between the two can only be attributed to T1 having had a large quantity of oil renewed or has it has been streamlined resulting in a higher health score that is realistically possible.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
The Drive 33/11 kV TX Replace T1		0.69	3.99								4.68
The Drive 33/11 kV TX Replace T2			0.69	3.99							4.68

12a.3.9 TE PAPAPA REPLACE TRANSFORMER T1 AND T2

Te Papapa ZSS is currently supplied from the Penrose GXP via two 3-core Aluminium PICAS PVC oil-filled cables that terminate directly onto two Bonar Long 15/20 (ONAN/OFAN) MVA 33/11 kV transformers manufactured in 1972. The subtransmission cables and 11kV switchboard are planned for replacement in FY29.

Both transformers are undergoing a Fullers treatment to help maintain their integrity and reliability until their planned replacement in FY29 and FY30

The replacement transformers will be rated at 24/34 MVA to account for expected network growth and will have off-tank radiators to enable them to fit in the existing transformer and radiator rooms.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Te Papapa 33/11 kV TX Replace T1						0.69	3.99				4.68
Te Papapa 33/11 kV TX Replace T2					3.99						3.99

12a.3.10 PAKURANGA REPLACE TRANSFORMER T1 AND T2

Both Pakuranga transformers are supplied from TP Pakuranga by 33kV oil filled cables that terminate directly onto T1 and T2 being 16.5/20 MVA ONAN/OFAN units manufactured in 1968 by Brush. E.DP numbers of 463 and 490 respectively indicates that both transformers are nearing their end of life. The units also have downwards CBR trends which triggers their replacement.

The existing enclosures are suitable for current design 20/28 MVA ONAN/ONAF off tank units, however this station may be able to accommodate future 24/34 MVA units if their dimensions are suitable.

The 11 kV switchboard has been recently replaced and will be able to accommodate the larger transformers. T1 is due for replacement in FY32 with T2 following in FY33.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Pakuranga 33/11 kV TX Replace T1					0.69	3.99					4.68
Pakuranga 33/11 kV TX Replace T2						0.69	3.99				4.68

12a.3.11 KINGSLAND REPLACE TRANSFORMER T1 AND T2

Kingsland is a 110kV ZSS with two 110/22 kV transformers supplied directly from Transpower Mt Roskill. The transformers are supplied by 110kV cables that terminate onto a cable stand and supply the transformers overhead bushings. T1 and T2 were manufactured by Brush in 1968 and have E.DP values of 599 and 541 respectively. Each transformer has three single phase tap changers and parts are no longer available for these units, increasing the risk of an extended outage should one of these units develop a fault. These transformers are to be replaced by two new 110/22 kV 52.5/75 MVA units in FY32 and FY33 respectively. A project is currently underway to relocate Hobson T4 to Kingsland to provide an on-site replacement should T1 or T2 fail. The transformer replacements will be preceded by a new suite of 110kV GIS switchgear to supply three transformers at this station.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Kingsland 110/22 kV TX Replace T1						6.1					6.1
Kingsland 110/22 kV TX Replace T2							6.1				6.1

12a.3.12 HIGHBURY REPLACE TRANSFORMER T1

The installation of a new transformer, T2, is currently underway at Highbury. The site is constrained and after T2 has been installed, the existing T1 bay will be knocked down and rebuilt to accommodate an additional 20/28MVA 17% Z transformer of identical design to T2 in FY34. The 11 kV switchgear has a spare incomer to accommodate a second transformer however this switchgear has limited capacity and will have to be replaced to realise the full capacity of both transformers. A new 33kV switchboard is being established at Highbury with a tie between Wairau and Birkdale in order to supply both transformers.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Highbury 33/11 kV TX Replace T1							0.69	3.99			4.68

12a.3.13 MANUREWA REPLACE TRANSFORMER T1 AND T2

The transformer bays at Manurewa are currently being rebuilt with T53 bay under construction. T51, replacing T1 is scheduled for replacement in FY34 followed by T52, replacing T2 in FY35. Both transformers have low E.DP numbers of 480 and 557 respectively and are steadily declining. This puts them under increased risk of in-service failure. Both transformers will be 20/28 MVA 25% Z units to match the new T53 currently on order.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Manurewa 33/11 kV TX Replace T1					0.69	3.99					4.68
Manurewa 33/11 kV TX Replace T2						0.69	3.99				4.68

12a.3.14 SWANSON REPLACE TRANSFORMER T1

A reinforcement (RNF) programme is currently in progress to upgrade Swanson Substation, which is presently configured as a single-transformer site. The scope of works includes the installation of a new T2 transformer and provision for a future T51 bay.

The existing 11 kV switchgear represents a significant constraint at this location. To mitigate this, the Schneider GMA-type switchboard currently installed at Riverhead will be relocated to Swanson following completion of the Riverhead upgrade.

The proposed T2 transformer will be rated at 15/20 MVA with 12.5% impedance (Z) and will incorporate an attached radiator unit. Installation is scheduled for FY34, after the completion of the 11 kV switchgear works.

The planned T51 bay will be designed to complement the new T2 installation, ensuring adequate capacity and operational flexibility for future network requirements.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Swanson 33/11 kV TX Replace T1							0.69	3.99			4.68

12a.3.15 TRANSFORMER REPLACEMENTS IN THE LATTER PART OF THE AMP PERIOD

The forecast table below provides a summary of power transformers that have been identified for replacement in the latter part of this AMP period based on criticality and asset health. Maintenance and monitoring of these transformers will continue and any deterioration in the quality of paper insulation might require a bringing forward of replacement. Mid-life refurbishment more specifically Fuller's earth treatment and oil streamlining (see description further below) will not extend the life of a transformer but will decelerate oil related insulation depleting processes such as high acid, low breakdown voltage and moisture to ensure that a transformer at least achieves its standard asset life.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Balmain Rd 33/11kV TX Replace T1								0.47	2.84	1.42	4.74
Rockfield 33/11kV TX Replace T1								0.47	2.84	1.42	4.74
Mangere Central T1 33/11kV TX Replace T1								0.47	2.84	1.42	4.74
Papakura 33/11kV TX Replace T1 & T2								1.24	7.42	3.71	12.36
White Swan 22/11kV TX Replace T1 & T2 & T3								1.85	11.12	5.56	18.54
Howick 33/11kV TX Replace T1 & T2								1.24	7.42	3.71	12.36
Total								5.75	34.48	17.24	57.47

12a.3.16 TRANSFORMER REPAIRS, REFURBISHMENTS AND OIL STREAMING

The lifeblood of a transformer is the insulating oil and during its service life, the oil will degrade. This exposure degrades the quality of the oil which if left unchecked will accelerate the ageing of paper insulation, form sludge which then affects cooling and it also reduces the dielectric withstand capability of the oil. These factors can lead to the premature failure of transformers. The forecasts below are bucket allowances to refurbish and repair older transformers and treat the oil to reduce the risk of

accelerated degradation of paper insulation. This work will allow Vector to utilise the treated transformers up to their full expected asset lives or as far as possible. The works will be prioritised after scheduled maintenance testing of the older transformers in the fleet. This programme will include some of the transformers described above, ear-marked for replacement to help to maintain their integrity up to the time of replacement.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY31 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland ZSS TX Refurb and Repair	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	3.05
Northern ZSS TX Refurb and Repair	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	3.05
Auckland Transformer Oil Streaming	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	2.19
Northern Transformer Oil Streaming	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	2.44
Total	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.07	10.73

12a.3.17 NEUTRAL EARTHING RESISTORS

Neutral earthing resistors (NERs) are used to limit earth fault currents in power systems: their primary purpose is to decrease fault current when an earth fault occurs on the system. For certain customers, to provide uninterrupted supply from two 11 kV bus sections, the fault current has to be limited to maintain it within cable earth screen ratings. Installing NERs however has other consequences such as a rise in the phase to neutral voltages of the unfaulted phases during an earth fault on the third phase: this could cause failures on existing 11 kV surge arrestors. The financial provision in the table below will be used as and where required and will not be applied until or unless a study of the network in question has been undertaken to ascertain the benefits and risks to the chosen installation site.

DESCRIPTION	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	TOTAL $M
Auckland neutral earthing resistors	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	3.7
Northern neutral earthing resistors	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	3.7
Total	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	7.4

12a.4 Subtransmission cables

12a.4.1 WESTFIELD SUBTRANSMISSION CABLE REPLACEMENT

Westfield ZSS is supplied from the Penrose GXP 22 kV bus via three 22 kV rated subtransmission cables (circuits 1, 2 and 3). Circuits 2 and 3 are 3-core copper 240 mm^2 (0.37 $inch^2$) PICAS oil-filled cables both installed in 1967. Circuit 1 consists of two x 3-core copper PILC SWA cables: one is a 95 mm^2 (0.15 $inch^2$) cable installed in 1928 and the other is a 150 mm^2 (0.25 $inch^2$) cable installed in 1941. These two cables existed as separate cable circuits to Westfield in the past before the installation of the oil-filled cables in 1967 but were then, at the time, connected in parallel to become a single (third) subtransmission circuit.

Several faults have occurred on the paralleled cable circuit (#1) but there has not been an increase in the rate of failures over the last number of years. The peak demand at Westfield was 22.2 MVA in summer 2022 and is forecasted to reach 34.6 MVA in 2033. The two oil filled cables (circuits 2 and 3) each have long term cyclic ratings of 17.7 MVA.

Westfield ZSS also has about 10 MVA of 11 kV backstop capacity to adjacent ZSSs: so, with a contingency on circuit 1, the load at Westfield is not at risk and the existing subtransmission and backstop circuits will be able to supply the demand. Based on present asset health and performance, the capacity of the two oil-filled cables and backstop, this replacement project will take place in FY26.

As part of the civil works to replace circuit 1 the second set of trefoil ducts will be installed as future proofing for the replacement of one of the oil-filled cables in the long term. The replacement cable will be 33 kV rated to future proof the circuit for future conversion to the 33 kV bus at Penrose GXP.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Westfield SUBT cable replacement	.22		2.99	1.00							4.21

12a.4.2 110KV PIRELLI TERMINATIONS REPLACEMENT

This project covers the replacement of the ageing Pirelli 110 kV terminations. While no recent defects have been reported, the terminations have not had a comprehensive inspection in over 10 years, so potential issues may remain undetected. This termination type is known to present reliability risks, and Transpower has already replaced it across its fleet with modern plug-in terminations.

There are nine units in service. Past industry experience has identified assembly-related issues, including insulating compound leakage, gasket failures, and O-ring degradation leading to moisture ingress. Although Vector implemented modifications in 2007, further deterioration has since been observed.

Given the age, known failure modes, and the comparable labour effort between refurbishment and full replacement, it is recommended that these terminations be included in the replacement programme, with a project planned for FY27 to select and install suitable modern alternatives.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
110kV Pirelli terminations replacement	0.64	0.32									1.39

12a.4.3 ONEHUNGA SUBTRANSMISSION CABLE REPLACEMENT

The subtransmission supply to Onehunga ZSS is from Penrose GXP via two underground 3-core copper PILC SWA cables installed in 1963. Small and medium enterprises form a large part of this ZSS's customer base. Vector's asset strategy for PILC circuits over 1000m is to replace the entire circuit rather than undertake piecemeal replacements.

The medium-term plans for the subtransmission network in the area will see the expansion of the existing Transpower Southdown site (Hugo Johnston drive, Penrose) to include a new GXP connection to Vector. This new GXP connection will supply three zone substations (Westfield, Onehunga, and Carbine) currently taking supply from the Penrose GXP. Direct replacement of the aging subtransmission circuits from the Penrose GXP as a result is no longer a cost-effective long-term plan.

This project will include the installation of trefoil ducts and cable for two 33 kV circuits between Onehunga ZSS and the proposed Southdown GXP. A set of trefoil ducts will also be installed between Southdown GXP and the Te Papapa ZSS for a future 33 kV circuit along with smaller ducts for future DTS cables.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Onehunga SUBT cable replacement	18.58	3.89									22.47

12a.4.4 FLUID FILLED CABLE REPLACEMENT PROGRAMME

This programme covers the long-term replacement of Vector's fluid-filled cable fleet. Although these cables are only at mid-life and can operate for close to 100 years, the industry faces a shrinking pool of specialists, limited parts availability, and higher maintenance demands. Vector has experienced an average of four fluid-filled cable outages per year over the past decade, mostly from joint oil leaks which require prompt response to protect insulation and manage environmental risk.

Given these emerging constraints, Vector is maintaining close engagement with its FSPs while preparing to transition to a proactive replacement programme from FY30, prioritised by condition, risk, and CBARM modelling. Replacement will also be advanced where civil-sharing opportunities or capacity upgrades arise, with particular focus on substations supplied by multiple fluid-filled circuits due to the long repair durations.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Penrose GXP fluid SUBT TPEN - SJOH (1&2)					16.30	10.30					26.60
Roskill GXP fluid SUBT TROS- Kingsland (1&2)						10.43	10.43	10.43			31.29
St Johns fluid SUBT SJOH -ORAK (1&2)								7.85	7.85		15.71
Manurewa (1&2) fluid filled replacement										15.32	15.32

12a.4.5 NORTHERN SUBTRANSMISSION CABLES REPLACEMENT

The first-generation XLPE cables had taped semiconductor screens which were an ineffective barrier to stop water trees from developing and non-tree retardant XLPE which led to the "water tree growth" in the extruded insulation. Substantial portions of subtransmission cables in the Northern network are of this type and if left unchecked the water trees will lead to failure of the insulation and outages. For the interim, smaller cable-portions are replaced as required but, in the longer term a programme of partial discharge and tan-delta tests will be undertaken and those portions with poor test results will be replaced as whole circuit portions.

The output from the CBARM model typically categorises these cables either as R3 or R4 which are the highest risk categories. The cables currently categorised as R3 often regress into the R4 risk category by the end of the AMP period as their condition deteriorates.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Balmain (73) circuit replacement	0.4										
Hepburn (38,43,44A,50) SUBT Cable replace	5.95	.					,				5.95

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Hepburn (39,49) SUBT Cable replace	1.46	3.54	6.00								11.00
Rosedale (104) circuit replacement			2.22								3.25
Sunset road (20) SUBT Cable replace		0.74									0.40
Triangle road (25&26) SUBT Cable replace	1.41										1.41
Wairau (52A) SUBT Cable replace			2.23								2.23
Silverdale (55A) SUBT Cable replace				1.06							1.06

12a.5 Distribution equipment

12a.5.1 LV NETWORK REPLACEMENT

Vector's approach to replacement of assets in the LV distribution network is condition rather than age based. Vector has previously had programmes to replace specific population type assets in the LV network but has not had a proactive replacement programme for the LV distribution system in general. The LV network replacement programme will target assets identified during network inspections as being in a deteriorated and/or unsafe condition. LV asset replacements are normally done like for like but considerations will be made to enhance safety and demand growth from EV charging and distributed generation. Enhancements will also take consideration of the impact of climate change.

DESCRIPTION	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	TOTAL $M
Auckland LV network replacement		1.81	1.86	1.92	1.98	2.03	2.03	2.03	2.03	2.03	17.72
Northern LV network replacement		1.81	1.86	1.92	1.98	2.03	2.03	2.03	2.03	2.03	17.72
Total		3.62	3.72	3.84	3.96	4.06	4.06	4.06	4.06	4.06	35.44

12a.6 Auxiliary systems

12a.6.1 DC SYSTEMS

DC systems must be available 24/7 to ensure safe and secure zone substation asset operation for continuous power supply to customers. The failure of a DC charger and a subsequent loss of its DC system, therefore, has a zone substation outage SAIDI risk. Vector currently has a total of 335 110 V DC systems in service within zone substations, communications sites, and several distribution substations. Both Auckland and Northern networks have an on-stream system to provide an immediate 24/7 replacement response.

The 9 Northern and 19 Auckland network Benning 110 V charger end-of-life, non-vendor supported system replacements by Cordex systems will be completed in FY24. This has also standardised the DC systems fleet.

The fleet condition-based asset life replacement programme is shown by the annualised investment budget below. This ensures continued successful operation of zone substation control, protection, automation, interlocking and other essential equipment that is reliant on a correctly functioning DC system.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland DC replacement	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.73
Northern DC replacement	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.73
Total	0.15	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.14	1.46

12a.6.2 SECURITY, ACCESS, AND FIRE PROTECTION

Since 2016 NZS 7901 Public Safety annual audits by Telarc provide an independent safety assessment of randomly selected distribution asset and zone substation perimeter earthing, signage, safety, and security of access. A decreased trend of severity and occurrence for security risk was gained in 2019 following workshops held with the FSPs on how to improve planned maintenance inspections, such as looking outward as well as inward from the perimeter and Vector responding quicker to approve projects to address security concerns raised by the FSPs.

All buildings are monitored with intruder detection, with no unauthorised entry incidents. Although property entry incidents in previous years have been rare, in 2024 unauthorised access driven by copper theft has required increased hardening of property fencing and transformer bay security panelling. Although we monitor the benefit of grounds surveillance cameras, however preventing access, good lighting, and trespass investigations are more cost-effective solutions. Smart locks are being investigated for improved security management and can be implemented where they provide a cost-effective control.

Using this approach for site security to minimise the risk of unauthorised entry, copper theft or asset damage with potential harm to the intruder, our program of perimeter and transformer fencing, gate and padlock security upgrades continues from its inception in FY20 for critical customer sites and those typically in rural and industrial areas with their heightened potential risk of unobserved perimeter entry. Additionally, the Gallagher Cardax security system undergoes regular software security upgrades.

While fires in zone substations are rare the consequences can be very serious. The objectives of fire protection are clearly defined in Vector guideline "ENG-0028 Fire protection in zone substations" and asset strategy EAA600. All detection systems connected to the zone substation Fire Panel must comply with NZS4512 and maintenance standard ESM603 activities to ensure performance compliance is met during their installed life. Our program of replacing legacy fire panels to current standards was completed in FY22, while detection systems will continue their ongoing planned replacement into FY25.

Radio huts, which the northern network SCADA and EOC are dependent on, require new passive fire detection. Although the Swanson St minor tunnel cable joints are intumescent coated, the addition of fire protection is prudent.

The budget allows for progressing legacy site-by-site targeted improvements to meet new standards for zone substation security including perimeter fencing, and fire protection upgrades, for which Design Standard ESE703 applies.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Northern ZSS buildings security	0.38	0.39	0.39	0.39	0.39	0.39	0.40	0.32	0.32	0.32	3.69
Auckland ZSS buildings security	0.37	0.37	0.38	0.38	0.38	0.39	0.39	0.31	0.31	0.31	3.59
Northern ZSS perimeter/compound security upgrades	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	3.90
Auckland ZSS perimeter/compound security upgrades	0.53	0.54	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	4.04
Total	1.68	1.69	1.52	1.53	1.54	1.54	1.54	1.39	1.39	1.39	15.22

12a.6.3 HEATING, VENTILATION AND AIR CONDITIONING

Increasing ambient temperatures and the duration of these over summer has in recent years increased the need to provide cool dry air via heat pumps as part of our climate hardening response. New systems are required at up to six zone substation sites p.a. in addition to the usual new installs for ARP and RNF switchgear or building replacement projects. Sites are prioritised by their temperature/humidity excursions outside the specified measurement requirements of Vector standard ESM603 Auxiliary Systems.

Heat pumps are the industry standard to cost effectively control the zone substation and other facility building internal atmosphere temperature and humidity to ensure IEDs and metal clad switchgear operate within manufacturer, and their IEC standards recommended parameters. The positive air pressure systems draw filtered external air into the building to pressurise and provide continuous air changes as controls to minimise dust entry, stale air and to inhibit corrosion, rust, and deterioration.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland ZSS HVAC installations	0.29	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	2.09
Northern ZSS HVAC installations	0.25	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	2.05
Total	0.44	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	4.14

12a.7 Infrastructure and facilities

To safeguard personnel, the public, and supply performance for customers, Vector's zone substation and tunnels primary and secondary electrical equipment needs to be protected from natural hazards that can cause its maloperation, failure or loss.

Vector's infrastructure and facilities are part of providing that safety by design performance. Environmental natural hazard impact is evaluated during zone substation property acquisition for new sites, throughout the life of the substation, and for site rebuilds.

Site rebuilds are usually associated with the replacement of major primary and secondary equipment and those asset sections within the AMP will also include the expenditure required for environmental hazard response.

Acquiring new property for zone substations includes a planned hazard assessment of changing weather impact on flood plains and overland flow path hydrology, as well as other neighbouring and site-specific natural hazards of seismic, wind, fire, geotechnical, landfill, slope stability, archaeological remains, and hazardous materials and activities (HAIL). This is in addition to assessing our own impact on the local environment and neighbouring communities.

Similarly, rebuilds of existing zone substation (and other) infrastructure provides for these same natural environmental hazards, to cost-effectively provide infrastructure and facilities that safely endure environmental change for the life of their performance.

12a.7.1 PENROSE-HOBSON TUNNEL

The Penrose to Hobson Tunnel contains Vector's 110 kV subtransmission cables from Transpower Penrose GXP to Liverpool and 33 kV cables to Newmarket ZSSs as well as the TP 220 kV NAaN cable from Penrose GXP to Hobson GXP. The tunnel also contains 22 kV express feeder interconnectors between Liverpool ZSS and Hobson ZSS. Transpower has shared access rights for the tunnel. The tunnel was commissioned in 2001 and the auxiliary systems necessary for personnel safety and performance of the power cables now progressively require upgrade or replacement as they reach their end of life. To also ensure 24/7 access for maintenance and emergencies these systems cannot be run to failure. This includes the service train within the tunnel, which is subject to New Zealand Transport Authority regulations for rail safety. Furthermore, the tunnel is classed as a confined space that requires strict entry requirements and the auxiliary systems providing that safety for personnel must also be operational 24/7.

For an auxiliary system failure, there is a health and safety risk which could result in an incident. To ensure the integrity and safe operation of personnel and plant within this strategic asset there is a need to replace and refurbish auxiliary systems inclusive of the rail and its anchor systems.

A major on-off planned expenditure is replacement in FY26/27 of the tunnel vertical lift that provides personnel and equipment access/egress at the tunnel mid-point. The lift has performed well since its installation for construction of the tunnel services prior to the tunnel becoming operational, with the timing of its replacement determined by prior annual condition-based certification surveys of its remaining safe life. The rail system is now also undergoing a major refurbishment along with the replacement of the tunnel control and active fire suppression systems.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Tunnel - Portal's deluge systems replace	0.96	-	-	-	-	-	-	-	-	-	0.96
Tunnel - Rail Track and Anchor Major Refit	0.30	0.20	0.04	0.04	0.04	0.04	0.04	0.60	0.04	0.04	1.38
Tunnel - UPS Replace	-	-	0.10	-	-	0.10	-	-	0.10	-	0.30
Tunnel - Airlock Security replace	0.05	-	-	-	-	0.12	-	-	-	-	0.17
Tunnel - Train, Generator, Rolling Stock Replace	0.03	-	-	-	0.20	-	-	-	0.25	-	0.48
Tunnel - Ventilation Motor Replace	-	-	-	0.40	-	-	-	-	-	0.40	0.80
Tunnel - Rail Track and Anchor Routine Replace	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.5
Tunnel - Atmospheric Sensors Replace	0.30	-	-	-	-	0.31	-	-	-	-	0.60
Tunnel - Sump pump replace	-	0.13	-	-	0.12	-	-	-	-	-	0.25
Tunnel - PLC Firmware Upgrade	-	-	-	-	-	-	-	-	-	0.50	0.50
Tunnel - Ventilation VSD Replace	-	-	-	-	-	0.25	-	-	-	0.40	0.5
Tunnel - Newmarket Plant Room Exterior Replacement	-	-	-	-	-	-	0.51	-	-	-	0.51
Tunnel - Newmarket Egress Ladder Compliance replace	-	-	-	-	-	-	-	-	0.51	-	0.51
Tunnel - Sump pump control system	-	-	-	-	0.15	-	-	-	-	0.15	0.30
Tunnel - Newmarket Lift replacement	1.00	-	-	-	-	-	-	-	-	-	1.00
Total	**2.69**	**0.39**	**0.20**	**0.50**	**0.57**	**0.88**	**0.61**	**0.66**	**0.96**	**1.55**	**8.99**

12a.7.2 LIGHTING AND EMERGENCY LIGHTING UPGRADES

Vector's design standard ESE703 Zone substation building services follow the guidelines set out by the Department of Labour and NZS 1680.2, interior lighting – recommended illuminances. The investment forecast under this item is a prioritised risk-based programme for the upgrade of normal and emergency lighting in legacy zone substations that do not comply with Vector's design standard and there is thus a risk of workplace harm due to insufficient lighting or lack of emergency lighting.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland ZSSs Lighting Upgrades	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.00
Northern ZSSs Lighting Upgrades	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	1.00
Total	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**	**2.00**

12a.7.3 ZONE SUBSTATIONS CIVIL AND STRUCTURAL UPGRADES

Several ageing zone substation buildings exist in our network and although these are maintained following a rigorous and structured maintenance regime there are instances where normal maintenance is not enough to remedy larger civil and

structural defects. In such cases, a capital project must be undertaken to remedy issues. Examples of larger defects are seismic non-compliance and deterioration of a building due to soil movement where structural strengthening is then required. There are also instances where deficient construction methodologies, e.g. improperly installed monolithic construction, was used in the 2000's to construct some of our substations and these now require extensive repair work beyond normal maintenance.

Furthermore, switchroom and transformer bay roofing inspections and sporadic leakages are now driving the need for a full roof replacement programme to avoid the risk of metal clad primary plant failure in switch rooms and the need to add SEPA systems to transformer bunds. This is primarily for light timber frame galvanized steel roofing. Fire walls are also programmed for FY27/87 at existing Auckland network sites to meet AS2067 industry practice.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland ZSS building structural upgrades	1.65	2.35	-	-	-	-	-	-	-	-	4.00
Northern ZSS building structural upgrades	1.25	0.82	-	-	-	-	-	-	-	-	2.07
Total	**2.90**	**3.17**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**6.07**

12a.7.4 ZONE SUBSTATIONS EARTHING UPGRADES

Vector's zone substation earthing systems must limit the touch and step potential rise that occurs in the event of a fault on their network. This is to protect visitors and workers within the zone substation as well as the nearby public outside the property. Corroded joints above and below the ground will be repaired, transferred potentials corrected, and any bonds that arise between neighbouring metal fencing and the substation fence are corrected. Considerations will also be made for any fault level change that has occurred since the earthing system was initially designed and installed during the construction of the zone substation.

DESCRIPTION	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	TOTAL $M
Auckland ZSS Earthing upgrades	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.50
Northern ZSS Earthing upgrades	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.50
Total	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**1.00**

12a.8 Protection and operational technology

12a.8.1 AUCKLAND AND NORTHERN PROTECTION RELAY REPLACEMENT

In the Auckland region numerical relays are to be replaced based on relay supportability and age. The expected asset life of numerical protection relays is 15 to 20 years. The Siprotec 3 and 4 numerical relays are a discontinued line, replacement parts are very expensive, and some parts are simply not available for this generation of numerical relays. Replacement is more economical than repair and the devices are replaced with modern numerical relays. The program below applies to zone substations where a switchgear replacement is not planned within eight years. Where a switchgear replacement is scheduled within eight years, a protection relay replacement will be delayed to then be undertaken in concert with the switchgear replacement project.

In the Northern region static (1st generation numerical) relays form about 2% of Vector's relay population. These relays were the first-generation electronic relays installed in place of electro-mechanical relays in protection schemes in Vector's network (and the world over), about 25 to 30 years ago. The relays are replaced with modern numerical relays. Once static relays are replaced the program replaces Siprotec 3 and 4 numerical protection relays as per the program in the Auckland region.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland Protection Relay Replacement	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	12.6
Northern Protection Relay Replacement	0.7	1.3	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	12.2

12a.8.2 AUCKLAND AND NORTHERN ELECTRO-MECHANICAL RELAYS REPLACEMENT

Vector's population of electro-mechanical relays is around 60 years old and there remains 29 zone substations with this type of protection relay. The electro-mechanical relay population is about 13% of the total relay population in Vector's network. Electro-mechanical relays, although reliable, provide only basic overcurrent and earth fault protection and has no data storage or recording ability which makes analysis of faults onerous. Furthermore, these relays are not supervised which means that if they fail none will be aware of such failure of the relay until a network fault occurs and an upstream trip is required to clear the fault: such a scenario is not tenable as it could lead to a much larger outage and commensurate high SAIDI. This population of relays also do not have the ability for definite time protection settings to be implemented which is required for increased safety of our large rural overhead networks and cannot be remotely accessed for data interrogation or to load revised settings. The electro-mechanical protection relays will be replaced with modern numerical relays.

The program below applies to zone substations where a switchgear replacement is not planned within eight years. Where a switchgear replacement is scheduled within eight years, a protection relay replacement will be delayed to then be undertaken in concert with the switchgear replacement project.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland electro-mechanical relays replace	1.2	1.2	1.2	0.6	-	-	-	-	-	-	4.3
Northern electro-mechanical relays replace	0.6	-	-	-	-	-	-	-	-	-	0.6

12a.8.3 AUCKLAND AND NORTHERN POWER QUALITY METER REPLACEMENTS

Power Quality Meters (PQM) monitor in real time the condition of the power system and analyse the power quality by an enterprise software application. PQMs locally stores reports generated by the system and makes the information available when required and monitor frequency events affecting the Vector network. PQM meters are also used to initiate interruptible load via the ripple systems to reduce peak demand.

The expected asset life for a PQM meter is ~15 years, 13 have exceeded that period and the latest operating software upgrades are not compatible with these previous generations PQM meters in the network. The forecast below makes provision for the afore-mentioned sites at which replacement will take place in the 10- year forecast period.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland PQM replacements	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.9
Northern PQM replacements	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.9

12a.8.4 POLE TOP DEVICES CONTROLLER REPLACEMENT

The early installation of the SEL351R pole top device controller is reaching the twenty years end of life. It will be replaced with SEL651RA controller. The pole top G&W switch has twice the lifetime of the controller, therefore it doesn't need to be replaced. The program will replace approximately ten controllers per year at multiple locations starting from the oldest.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Pole Top Device Controller Replacement	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10.0

12a.8.5 SUB-TRANSMISSION NETWORK PROTECTION REPLACEMENT

The sub-transmission network is essential to the continuity of supply. The early numerical relay installations are reaching the 20 years end of design lifetime and needs to be replaced. leaving the relay in service after reaching the design lifetime increase the risk of large-scale failure. This program of work allows for the replacement of one zone substation per year starting from the oldest.

The program below applies to zone substations and GXP where a switchgear replacement is not planned within eight years. Where a switchgear replacement is scheduled within eight years, a sub-transmission protection replacement will be delayed to then be undertaken in concert with the switchgear replacement project.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Sub-transmission network relay replacement	0.6	1.1	0.6	0.6	1.1	1.1	0.6	0.6	1.1	1.1	8.4

12a.8.6 AUCKLAND AND NORTHERN SUBSTATION LOCAL AREA NETWORK REPLACEMENT

Vector adopted the IEC standard and internationally recognised open communications architecture that would allow different devices located within a zone substation to integrate seamlessly and communicate with the ADMS control system. The substation local area network (LAN) is based on a redundant optical ethernet architecture compliant with IEC 61850 Standards. The LAN enables the co-ordination of protection, automation, monitoring, metering and control functions using network switches and routers to the wide area network and then to the ADMS master station.

The existing Vector standard Ruggedcom RSG2100 models are restricted to a maximum number of 20 ports. These Ethernet switches do not support the latest redundancy protocols and Ethernet switches with a higher port density, could reduce the total number of switches required at a substation. The existing Cisco CGR2010 router are end of life and require replacement to maintain support. Router replacement program commenced in FY26 and an investigation into alternatives to the Ruggedcom RSG2100 switches is underway with rollout commencing FY27.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland Substation LAN replacement	0.6	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	4.3
Northern Substation LAN replacement	0.6	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	4.3

12a.8.7 AUCKLAND AND NORTHERN RTU REPLACEMENT

The RTUs located at our zone substations and distribution assets provide an essential part of the ADMS system to collect status information from the site and allow remote control of the auxiliary and facilities plant at the site. The maximum anticipated life of an RTU is 20 years. As an RTU approaches the end of life, reliability suffers, requiring more frequent maintenance. Also, older RTUs are no longer supported by suppliers and spares are difficult to get hold of. When an RTU fails, situational awareness of what is happening at the site is lost: the EOC is then unable to receive updates of events from the site or remotely control equipment. Hence, the EOC controller is unable to effectively respond to an incident.

This programme of work is for the replacement of substation RTUs and distribution controllers. The substation and distribution control RTU fleets consist of a mixture of ABB and Siemens RTUs for 11k V distribution switches and, GPT Plessey, Foxboro, SEL 2440 and SEL 2411 RTUs in zone substations. The first-generation Foxboro and GPT Plessey range of RTUs are no longer technically supported and production has halted a few years ago. These RTUs will be replaced.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland RTUs replace	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.60
Northern RTUs replace	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.60

12a.8.8 AUCKLAND AND NORTHERN COMMUNICATIONS UPGRADES

Under this program the network field communications to zone substations and GXP are assessed to identify sites with inadequate redundancy or connection points that could cause communications bottlenecks in the future. As more preferential communication paths become available the communications are upgraded. Chorus copper ADSL/HSNS connections are replaced with a fibre optic equivalent. Digital microwave radio network assets are replaced as they become end of life and no longer able to be supported.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland Communications Upgrade	0.10	0.10	0.10	0.10	0.20	0.20	0.20	0.20	0.20	0.20	1.70
Northern Communications Upgrade	0.30	0.20	0.20	0.30	0.30	0.30	0.30	0.30	0.30	0.30	3.20

12a.8.9 AUCKLAND AND NORTHERN COMMUNICATIONS UPGRADE IN DISTRIBUTION ASSETS

Vector has ~900 distribution switches in the Auckland and Northern networks that use cellular communications infrastructure for SCADA and engineering communications to enable remote control of the distribution switches. The distribution switches are a combination of pole top devices (e.g. reclosers, sectionalisers, disconnectors etc.) and ground mounted switches, mostly ring main units. Many of the routers have reached the end of life and low reliability and low availability are causing undue SAIDI.

Under this programme of works Digi WR31 routers will be replaced and optimized antennae combinations will be installed. This programme of works commenced in FY22 and will continue over the 10-year planning period. This programme includes provision for trials and proof of concept testing of 5G based router options.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland Comms Upgrade Distribution Assets	0.11	0.11	0.13	0.14	0.15	0.16	0.17	0.18	0.18	0.18	1.5
Northern Comms Upgrade Distribution Assets	0.3	0.12	0.13	0.14	0.15	0.16	0.17	0.18	0.18	0.18	1.7

12a.8.10 ARC FLASH DETECTION RETROFIT IN EXISTING SWITCHGEAR

The installation of arc-flash sensors on the inside of a switchgear panel together with an arc-flash relay can substantially reduce the amount of incident energy should an arc-flash occur, making switch rooms safer for personal to work in and visit. Early detection of arc flash also reduces the scale of collateral damage of plant. At selected sites, arc detection sensors will be installed in the cable boxes with VAMP 125 arc detection relays. Switchboards identified in Vector's ZSS switchboard replacement programme will be excluded from this programme as arc flash protection will be included in the replacement switchgear delivery scope.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland Arc Detection Retrofit	0.4	0.4	0.4	-	-	-	-	-	-	0.4	1.7
Northern Arc Detection Retrofit	0.3	0.3	0.3	-	-	-	-	-	-	0.3	1.3

12a.8.11 AUCKLAND AND NORTHERN DIGITAL SUBSTATION UPGRADE

The digital substation upgrade program will replace and modernise key components across zone substations and GXPs to migrate from legacy IEC 61850 implementations to fully compliant IEC 61850 Edition 2 architectures, including updated data-management, collection, and engineering toolchains. End-of-life SICAM PAS systems will be retired and replaced with modern substation gateway controllers. The project will also introduce IEC 61850 process-bus technologies, standardised protection-testing platforms, and role-based access-controlled station access systems to strengthen cybersecurity, improve interoperability, and enhance operational reliability.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Auckland Digital Substation Upgrade	-	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.6	4.5
Northern Digital Substation Upgrade	-	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.6	4.5

12a.8.12 SMALLER UPGRADE PROJECTS TO IMPROVE PROTECTION AND OPERATIONAL TECHNOLOGY

The following is a summary forecast table of smaller scale projects that will be undertaken during the AMP period to improve protection and operational technology assets

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Northern Fault Passage Indicator Replacement	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.38	2.9
Auckland Fault Passage Indicator Replacement	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.5
Self-powered relay replacement	-	-	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.4
Auckland TMS Replacement	-	-	-	-	0.15	0.15	0.15	0.15	0.15	0.15	0.9
Northern TMS Replacement	-	-	-	-	0.15	0.15	0.15	0.15	0.15	0.15	0.9
Auckland Clock Synchronisation improvements	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.5
Northern Clock Synchronisation improvements	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.5
Auckland BESS Controller Standardisation and Improvement	0.12	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.6
Northern BESS Controller Standardisation and Improvement	0.13	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.6



SECTION 13

Asset relocations

13 – Asset relocations

13.1 Overview

The growth and improvement of other asset types such as water infrastructure, roads infrastructure, rail, sewerage, stormwater as examples result in the relocation of Vector's assets. This section explains our approach to relocating assets on behalf of customers, other utilities or requiring authorities and describes typical relocation works, our process for managing these works, and how they are funded.

13.2 Asset relocation requests

One of Vector's objectives when planning projects and compiling the capital budget is to identify the need to relocate Vector assets when reasonably required by third parties. Vector is obliged to relocate its assets by Sections 32, 33 and 35 of the Electricity Act 1992, Section 54 of the Government Roading Powers Act 1989 and Sections 147A and 147B of the Telecommunications Act 2001 and by the specific terms of licences or easements under Sections 34 and 35 of the New Zealand Railways Corporation Act 1981.

Relocations generally occur when infrastructure projects are initiated by road or rail corridor managers, e.g. Auckland Council or Auckland Transport (AT), New Zealand Transport Agency (NZTA) and to a lesser extent, KiwiRail. Other utility providers such as Transpower, Chorus and Watercare can also initiate asset relocation projects. The process and funding of such relocation works is governed by the relevant Acts as listed above.

The timing and scope of relocation projects are driven by third parties and as a result of this Vector often has less advance notice of relocation projects and / or detailed scope compared to projects initiated from within Vector. The forecasting and timing of capital spend for relocation works are thus at a high level and preliminary in many cases. Asset relocations can vary from large extensive multimillion-dollar projects to small and minor relocations such as a pole replacement.

13.3 Asset relocation growth

Long term and consistent growth in the Auckland region has resulted in an increased demand for transport corridor owner requests for asset relocations. Extensive road corridor upgrades and new motorway projects by NZTA are continuing; the construction of bus lanes, cycle lanes and upgrades by Auckland Transport continue to be requested at a consistent growing pace alongside streetscape rejuvenation by Auckland Council. These types of works generally require the relocation of Vector assets within the project footprint.

Vector continues to liaise closely with transport corridor owners and private subdivision developers to understand the scope and timing of their future works and to look to integrate Vector initiated works where appropriate to make allowance for future grid exit points, new zone substations and transmission corridors, in alignment with our Asset Management Objectives. It is vital for Vector to understand how the corridor works and/or new subdivisions will impact on the network to ensure that we can maintain an integrated network to the satisfaction of our customers and stakeholders, while delivering on our Asset Management Objectives.

Planning rule changes in Auckland have seen multi-level buildings permitted to be constructed on land sections that previously contained single-level dwellings set back from the road front. The permitted multiple dwellings combined with shallow yard setbacks and their increased heights have become a contributor to increasing breaches of minimum distances to existing overhead lines. This in turn triggers relocations of portions of overhead power lines at the cost of developers. Vector is continuing to engage with many parties to raise awareness about close approach risks, particularly working and building near the network, and to find a solution to the problem of increasing numbers of permitted development occurring in breach of safe clearances detailed in ECP 34 - New Zealand Electrical Code of Practice for Electrical Safe Distances (NZECP 34:2001).

13.4 Managing relocation works

Vector's asset relocation works are generally smaller in scale, both in terms of scope and cost, when compared to transport corridor infrastructure works (usually less than 5% of the total project cost). Relocation projects are driven by the civil works programme of third parties, and this can impact the timing and duration of power outages our customers experience during the relocation works due to the requirements of traffic management, road closures etc. These parameters are outside of Vector's control and, if not managed carefully and in detail, can introduce inefficiencies and cost to the projects.

Vector's electricity network assets are generally installed in local authority owned and managed transport corridors in accordance with the Electricity Act 1992 and the Telecommunications Act 2001. Access to NZTA's motorways and state highways are subject to the provisions of the above legislation and the Government Roading Powers Act 1989. On Kiwirail corridors, Vector is required to sign a licence agreement (Kiwirail Deed of Grant) and contribute the full cost of the relocation works plus payment of an annual fee.

13.4.1 RELOCATIONS OF VECTOR ASSETS

When Vector's assets are requested to be relocated, the cost allocation of such relocations are governed by the applicable legislation (Electricity Act 1992, Government Roading Powers Act 1989 and the Utilities Access Act 2010). In all cases, Vector pays for any betterment works if and when Vector elects to improve its assets using the opportunity presented by the relocation works.

13.4.2 INFRASTRUCTURE AGREEMENTS AND SUCCESSFUL RELOCATION PROJECT OUTCOMES

The details of the Vector assets that will be relocated are recorded in Vector's standard Infrastructure Agreement. The financial contribution by the third party and any betterment costs that Vector will carry are also defined in the Infrastructure Agreement. It furthermore includes:

- an initial estimate for the cost and cost allocation of the relocation works (final cost allocation is based on the actual total cost of the works)
- a methodology of how the works will be delivered; and
- the payment of the actual costs incurred (the contribution) is undertaken at agreed milestones

Vector does not enter into agreements with third parties or corridor owners' contractors but will liaise with the contractors during the delivery of a relocation project to coordinate the works to ensure effective delivery. To ensure successful outcomes, an experienced Vector project manager is involved from the early scope development of relocation projects and throughout the project delivery phase. This leads to the project manager taking a proactive role in ensuring the construction contractors pay due consideration to the key outcomes relating to the Vector activities. This is achieved through clear communication of Vector's expectations and reinforcing them throughout the project. Creating and managing the right level of communication between the corridor owner and the civil contractor/construction contractor helps to deliver the works to the agreed standard. Variations are usually initiated by the entity requesting asset relocation and are governed by a scope change process that involves documentation, costing and agreement between Vector and the third party.

13.5 Current project summary

Table 13-1 presents a summary of projects where relocations will be required with a value of >$1M, which are either in progress or anticipated to be undertaken in the near term over the AMP period.

PRINCIPAL / CUSTOMER	DESCRIPTION
Auckland Transport (AT)	• Eastern Busway (Pakuranga to Botany) • Cycleway and Busway improvements – for example, Carrington Road, Mangere and Manukau Cycleway Improvements, Wellesley St Bus Improvements, Downtown Bus Improvements • Relocation works for the Level Crossing Removal Programme - Takanini • Glenvar & East Coast Road – Road Improvements
Watercare	• Herne Bay Interceptor • Queen Street WW Upgrade • Warkworth WW Upgrade
Auckland Council Healthy Waters	• Stormwater separation projects
NZTA Projects	• O Mahurangi - Penlink Motorway construction including the new Weiti Bridge • State Highway 16 Stage 1 and 2 road improvements • Roads of National Significant Programme (RONs) • Northwest Rapid Transit

TABLE 13-1: CURRENT RELOCATION PROJECT SUMMARY (>$1M)

13.6 Forecast expenditure – relocations

The timing and scope of relocation projects are driven by third parties and their project timing and schedule. The initial financial forecasts are always at a high level and as the project and its design and scheduling become more detailed, our capex forecasts will become more accurate. The expenditure profile below is based on our knowledge of FY27 asset relocations projects and incorporates our current indicator of capex spend for the 10-year AMP period. The initial years will have the highest level of pricing confidence but for the latter years the pricing confidence will be at a lower level of accuracy.



FIGURE 13-1: FORECAST EXPENDITURE - ASSET RELOCATION



SECTION 14

Non-network assets

14 – Non-network assets

14.1 Overview

At Vector our non-network capex assets include our digital systems and building leases.

As part of Vector's Symphony strategy, digital platforms and tools are critical enablers for our future, as well as supporting ongoing operations. Vector continues to invest in digital capabilities to establish, operate and support these platforms given their importance to core network operations.

In this section, we define the context for our material investments in digital, our major programmes and maintenance and renewal projects. As uncertainty increases over the forecast period, we use roadmaps to define the initial 24-36 months to some level of detail with following years indicating a level of forecasted investment. As roadmaps are updated, they provide increasing visibility to the latter years of the investment forecast.

14.1.1 UPDATE FROM AMP24 (I.E. VECTOR'S LAST FULL AMP)

There are two transformational programmes of work, which have commenced in FY26. We have entered the delivery phase of ADMS Phase 2, with work for this phase expected to complete in FY27. We also have sufficient clarity as to the timing and effort estimates associated with future phases of ADMS and our future operating environment.

Our ERP transformation programme has also commenced focusing on our future strategy and options. This will inform our technical solution(s) and implementation requirements across FY27 and FY28. This will be a complex programme of work with robust planning and deployment strategies required to minimise disruption to our day-to-day operations.

Our customer strategy and customer transformation programme to continue to build on our focus on customer. The centralised customer function brings together customer insights, channels, communications, experience and improvement has significant focus on improvements in customer experience and community engagement.

We have focussed digital investment as part of this strategy into two primary areas:

- Operational Scalability and Support Systems
- Customer Experience and Engagement

Operational Scalability and Support Systems investment encompasses increasing functionality and improvements of our core customer and self-service channels, including the capability of our Outage Centre – a key customer facing system that provides outage related information as well as improvements to existing and the introduction of new processes around connections and distributed generation registration. We continue to assess whether the current platforms provide an optimised customer experience.

Vector continues to focus on enhancing the maturity of our enterprise data and analytics practice level. The function is now centralised into the digital function under a single executive, the 'Chief Digital & Data Officer'. Key focus areas include improving data models for asset management to enable both prescriptive and predictive-based analytics to be conducted for the electricity business. Advanced capabilities have also been introduced that focus on operationalising solutions that safely incorporate artificial intelligence into core operations and practice.

Beyond the focus areas noted above our core investment roadmaps remain unchanged from previous years.

14.2 Non-network assets

14.2.1 INFORMATION SYSTEMS, PROCESSES AND DATA

Within Vector's suite of Information Systems (outlined in Section 6.6.), and the associated processes and data sources, there are a number of areas and opportunities we have identified where the use of digital technology can improve the way we plan for, monitor, control and manage our information assets.

The proposed investment in the upcoming years in enabling non-network digital systems, processes and information management will help Vector with the capability and tools required to deliver to our Asset Management Objectives (refer sections 5.2 and 5.3 for details).

We have identified several areas which require significant non-network investment to achieve the desired outcomes. Further details are outlined below.

14.2.1.1 NETWORK MODERNISATION

Traditional network growth, changing customer behaviours and requirements and technology advances all mean Vector expects to see a significant increase in both traditional and non-traditional/new asset types forming part of the network. To manage this increasingly variable future state, dynamic planning tools must be developed and utilised, to help better optimise capacity, cost, resilience and reliability. As new asset types (or other devices that may connect to the network) are introduced, we need to be able to understand their impact quickly and efficiently, in addition to providing potential customers with toolsets to help guide their planning. We must leverage both existing and new datasets to gain new and better insights to optimise asset lifecycles and direct our capital investment in the most effective way.

Progress continues in this area through Vector's partnership with X (formerly Google X), with whom we are collaboratively developing a platform that facilitates virtualisation and simulation across Vector's network, with a focus on expedient options analysis and ease of updating asset types and properties.

14.2.1.2 MANAGING COMPLEX OPERATIONS

As distribution technology advances, traditional Operational Technology (OT) devices are becoming more and more digital in nature. This drives increased connectivity of assets and devices, increased data collection, increased cyber security threats, and device management at scale. These factors continue to increase convergence between OT and digital devices and assets.

Further non-network asset investment is therefore required to allow new processes and technologies to be effectively and efficiently introduced and onboarded into Vector's operating systems. Non-network asset investment is required to:

- Secure and manage a greater volume and type of network devices
- Efficiently operate the network with greater fidelity
- Incorporate increasing data into processes and tools from an increasing number of 3rd party sources
- Safely allow both Vector and 3rd party support entities to secure and seamless access to relevant systems and data
- Provide greater visibility of the LV network

14.2.1.3 NETWORK VISIBILITY

A key element of the asset strategy is providing a complete and accurate view of the network from an as-built and as-operated perspective, in near real-time. This will require access to the right data and insights. Additionally, the growth in both network size and scope will potentially require the analysis of new data sources from both the field and/or external partners, in particular to provide greater visibility of the LV network.

14.2.1.4 DER INTEGRATION

The increasing prevalence of DERs on the network mean specific focus is required in this area, notwithstanding the management and utilisation of DERs being integral to the non-network solution aspect of Vector's Symphony Strategy. The proliferation of DERs will drive changes in customer and network demands, integration of new partners, and the potential for new pricing and planning strategies. Vector systems will need to accommodate these changes to appropriately enable smooth and effective DER integration into the Vector environment.

14.2.1.5 DIGITALISATION

Investment is required to future proof many of Vector's corporate systems, many of which have been part of the digital ecosystem for decades. Changing demands and existing system limitations necessitate the review and potential replacement/upgrade of systems that are no longer fit for purpose and that do not support our future aspirations.

14.2.1.6 ANALYTICS & INTELLIGENCE LAYER

Work is underway to establish an analytics and intelligence platform to enable data-driven decision-making across Vector's asset portfolio and network operations. The platform brings together asset, network, operational, and external data into a secure, governed cloud environment to create a trusted, scalable foundation for advanced analytics, forecasting, and AI. By standardising data engineering, modelling, and governance practices, the platform will provide consistent, high-quality insights that support asset planning, maintenance optimisation, risk management, and investment prioritisation. Over time, it will evolve into the intelligence layer of the asset business—unlocking predictive and prescriptive capabilities that improve network reliability, safety, and cost efficiency while supporting the transition to a more distributed, decarbonised energy system.

14.2.1.7 APPROACH TO INVESTMENT HORIZONS

Based on the factors outlined above, it is to be expected that our investment plan has a higher degree of certainty for the first two to three years, and less specificity thereafter. In the latter years, we have less fidelity over the exact projects, and we have proportionally projected investment levels in each of the key areas that define and manage the digital execution of components that make up our electricity distribution business. Given the rate of change in technology, we continuously look for the most optimal solution, whether through new and emerging digital technologies or optimising existing solutions. This section is structured to reflect this, and comprises two parts:

1. Strategic projects and programme investments
2. Need Statements outlining desired investment outcomes

For all the projects described below we assessed what would be the optimal solution before deciding on the investment choice (and will continue to do so). Whether through new and emerging digital technologies or existing solutions, in all cases we identify the solution that will deliver better outcomes for our customers.

Note: To comply with New Zealand climate standards, Vector is to disclose capital expenditure associated with enabling the orchestration of distributed energy resources. These include investments into core infrastructure that enables DER such as ADMS, LV Data, and the build out of our modern data platform. The combination of these investments comes to approximately $68m over the AMP period.

14.3 Significant projects / programmes of work – Networks Digital

14.3.1 ADMS (ADVANCED DISTRIBUTION MANAGEMENT SYSTEM)

ADMS Phase 1 was completed in FY24. Phase 1 established the foundational infrastructure and implemented our CIM integration (Common Information Model, provides a standardised framework for exchanging data between systems). Phase 2 of this programme focuses on a core operational uplift, predominantly by implementing Switch Order Management (SOM) and the Outage Management System (OMS) modules. Future phases which are yet to be fully designed and planned will focus on optimising our field operations, implementing field automation and if feasible moving towards self-healing capability via advanced automation and simulation.

14.3.1.1 ADMS PHASE 2

Key capabilities that are intended to be delivered as part of phase 2 include:

- Switch Order Management (SOM) - creates, validates, and executes the switching procedures necessary to safely, correctly, and efficiently isolate equipment for maintenance or reconfigure the network during an outage.
- Outage Management System (OMS) – detects, tracks, manages, and restores power outages. It is the core tool for unplanned events and emergency response and enables real-time tracking of restoration progress.

The programme aims to boost business efficiency, enhance customer experience, advance the data strategy and lay the groundwork for future strategic data, customer and operational initiatives. ADMS2's benefits include:

- Improved customer notifications for planned work
- Less operational effort and fewer cancellations or postponements of planned work, leading to better customer outcomes
- Automated data capture that helps eliminate manual auditing and validation
- Operational capacity increases by removing the existing limits of planned jobs per day
- Faster event response through automated safe switching plan validation
- Replacement of legacy systems
- Eliminating potential switch writing errors due to fully network-aware switching plans
- Enhanced engagement with FSPs: The SOM and OMS modules position Vector to potentially implement additional ADMS product features, further increasing the speed, quality, and efficiency of field operations

ADMS FUTURE PHASES

Future phases of ADMS focus on introducing and increases field mobility, field automation and ultimately advanced automation and simulation allowing us to move towards a self-healing network. Additionally, this work, creates an ecosystem where DERMS combined with outage management and real time LV Visibility, will allow us to be able to provide better outage planning utilising DERs as well as managing peaks with DER support, thus ensuring optimal investment from traditional assets.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY42 $M	FY35 $M	FY36 $M	TOTAL $M
ADMS Phase 2 & Future Phases	12.5	0	4.0	10.0	10.0	2.0	2.0	2.0	3.0	6.0	51.5

TABLE 14-1: ADMS PHASE 2 & FUTURE PHASES FORECAST

14.3.2 CUSTOMER STRATEGY

14.3.2.1 OPERATIONAL SCALABILITY AND SUPPORT SYSTEMS

To enable the customer experience transformation described in section 4.7, Vector continues to invest in the capabilities of its customer management platforms.

Customer insights have highlighted several key moments that shape customer experience and perceptions of Vector. In response, the business is focusing on continuously improving the customer experience related to:

- **Connections**, including responding to changes in regulatory requirements and undertaking end-to-end reviews to identify opportunities for continuous improvement.
- **Outages**, particularly through clearer, timelier, and more transparent communications using channels aligned to customer preferences.
- **Major events**, where expectations, uncertainty, and complexity are heightened, and where empathy and clarity are especially important.

These focus areas recognise that while not all outcomes are within Vector's direct control, how we communicate and engage with customers has a significant influence on trust and confidence. Continued investment in the systems and processes that support these experiences is critical to achieving our desired customer experience outcomes. A review of Vector's current Customer Relationship Management (CRM) system is planned with further investment being considered in FY28 and FY29.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Operational Scalability & Support Systems	1.55	5.4	5.7	0.4	0.5	0.5	0.5	0.5	0.5	0.5	16.05

TABLE 14-2: OPERATIONAL SCALABILITY & SUPPORT SYSTEMS INVESTMENT FORECAST CUSTOMER EXPERIENCE AND ENGAGEMENT

Our customer facing channels and touchpoints are critical interaction and engagement areas, which are pivotal to delivering to our customer strategy. Investment in our Outage Centre and Self-Service portal is captured here, among other channel improvements.

Investment is driven by (currently known) regulatory direction on process and system changes to support the Electricity Authority requirements for data transparency on connection and distributed generation applications are included in the investment outlook for FY27 and FY28.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Customer Experience & Engagement	3.4	1.2	1.0	1.25	1.0	1.0	1.0	1.0	1.0	1.0	12.85

TABLE 14-3: CUSTOMER EXPERIENCE & ENGAGEMENT FORECAST

14.4 Data & Analytics

14.4.1 MODERN DATA PLATFORM

Our underlying data and analytics platform requires further investment to support the ingestion, storage and processing of increased amounts of data, and ability to conduct more advanced analytics. Our data governance practices will require assessment to ensure we meet all regulatory obligations for sensitive data that we become custodians of and which we must safeguard.

To better understand our end-to-end asset portfolio and asset type relationships, we will need to develop enterprise-wide data models that cover all aspects of asset management including commercial, customer, performance. The Data and Analytics function will continue to integrate source systems, build asset-wide data models, and expose the data for the immediate different analytical use cases. Our data platform is a key enabler in reaching our needs of Symphony. Our investment focuses initially on build out of these capabilities within the platform, before moving into an operational management and maintenance phase.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Modern Data Platform	1.0	1.0	1.0	0.25	0.25	0.25	0.25	0.25	0.25	0.25	4.75.

TABLE 14-4: MODERN DATA PLATFORM INVESTMENT FORECAST

14.4.2 LV DATA STRATEGY & MODELLING

Vector's focus on servicing the customer with the best possible experience continues to remain front of mind, and central to Vector's Symphony strategy. This requires the organisation to understand clearly our end-to-end asset and network topography. Historically, Vector's efforts have been focused more so on the HV network, but Vector's aim is to get closer to service and experience more targeted and relevant to specific connections on the network, therefore, requiring the ability to strategically service the LV network. Thus meaning, the Data & Analytics function are strategically designing LV data models, data products, and data sharing and transformation. The investment will enable Vector to build this model in alignment with the standards set for the current HV models and ensuring the resulting analytics have complete asset visibility and insight.

A sample of key focus areas and deliverables include:

- Increased network monitoring to enable real-time modelling. Successful implementation may lead to the use of dynamic ratings to increase network utilisation without breaching equipment ratings, alongside new simulation capability. This is ultimately both a planning and operations tool.
- Improvements and simplification of the method to calculate the spare capacity on the distribution network to enable more efficient use of the network distribution assets and ultimately capex investment.
- Implementing a platform for managing those field devices that need to be managed, for both energy injection (e.g. solar/PV, batteries) and energy offset devices (e.g. HWLC, smart charging and implementation of Dynamic Operating Envelopes for specific customers).
- Increased demand and voltage monitoring capability of the LV network. Current practices of installing short-term dataloggers is inadequate as it still requires an estimate of peak demand. 24/7 monitoring is required together with efficient data management.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
LV Data Strategy & Modelling	1.0	1.0	1.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	5.0

TABLE 14-5: LV DATA STRATEGY & MODELLING INVESTMENT FORECAST

14.4.3 SMART METER DATA PROGRAMME

Vector will be leveraging smart meter data (SMD) to support visibility of the LV network to enable improved despatching of crews especially during major storms and improve customer communications around restoration timeframes.

Our intention is to deliver this capability in three phases. In summary the three phases (some of which are already complete) are:

- Phase I (FY21-23) – Establish foundation, gain access to data, discovery & trial (Complete)
- Phase II (FY23-25)- Scale data for whole of network view. Make the data outputs (consumption, device data, power quality) available to be operationalised in other Vector Electricity systems to drive more timely and effective decision making (Complete)
- Phase III (FY26-34) – Establish near-real-time data availability across Vector system landscape as we move towards increased automation

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Smart Meter and Data Use Cases	0.35	0.35	0.35	0.35	0.35	0.35	0.35	035	0.35	0.35	3.5

TABLE 14-6: SMART METER & DATA USE CASES INVESTMENT FORECAST

14.5 Significant projects / programmes of work – Vector Group and Core Digital

The following areas have been identified as requiring capital investment over the course of the planning period, with relevant commentary around their development, maintenance and/or renewal detailed below. All investment is in line with Vector's asset replacement lifecycle processes. Other minor systems are expected to require replacement or upgrade during the planning period however their cost is not material in terms of the non-network investment forecast.

14.5.1 IT NETWORK MODERNISATION

The Vector group, like most modern organisations, relies heavily on reliable, consistent, and secure access to the internet to conduct its day-to-day operations. This is required across all devices and all office locations, with both wired and wireless connectivity a baseline expectation of employees, team members and stakeholders across the organisation. As more services continue to move to the cloud, there is an increasing need to modernise the IT network to reduce functional issues and manage security risks. This is a critical and ongoing work as the IT network is foundational to all system technologies.

The Vector Group IT Network Modernisation project includes both corporate IT and elements of the Electricity OT (Operational Technology) computer networks. The functional role of these networks is to provide secure and reliable access to the internet and limit access to some areas of the network to provide redundancy and disaster recovery capability, enable the transfer of data from machine to machine both internally, and where appropriate, outside of the Vector network e.g. for Field Service Providers. Connectivity is a critical component of effectively managing and maintaining our core Network and Business operations, as losing connectivity, or having insecure access to the internet would directly impact our visibility of core network alarms and prevent us from effectively providing any services to our customers, stakeholders or businesses who rely on that connectivity.

Over the last two years significant improvements have been made with the replacement of all the OT Firewalls and modernisation of current network services. This area of investment continues, with the next phases focusing on Network segmentation and scaling.

DESCRIPTION	FY27 $M	FY86 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
IT Network Modernisation	0.4	0.2	0.2	2.0	0.7	0.2	02	0.2	0.2	0.7	5.0

TABLE 14-7: IT NETWORK MODERNISATION INVESTMENT FORECAST

14.5.2 ERP TRANSFORMATION

Vector currently uses SAP for several critical business functions. It is our financial system of record, provides core asset management and maintenance, material management and project systems.

Vector's version of SAP - whilst still currently supported - is approaching end of life. We are therefore reviewing our future ERP strategy, with any subsequent investment likely to be incurred in FY27 and beyond. We are currently assessing our options, with the investment profile required still uncertain. As such, the forecasts from previous AMP's will likely be updated once a clear direction and strategy is known.

It is anticipated the transformation will be integral in supporting timely, data-driven maintenance and asset insights, as well as strengthening asset lifecycle visibility with a single authoritative register and consistent risk and condition data. Considerations

for the transformation include allowing Vector to pursue a conditional based model for Asset Management across a significantly expanding number of assets. The demand in scale is driven not just by an expansion of network capacity but also by the number of new assets that will need to be tracked to meet the needs of network visibility.

DESCRIPTION	FY27 $M	FY28 $M	FY97 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
ERP Transformation	15.0	15.0									30.0

TABLE 14-8: ERP TRANSFORMATION INVESTMENT FORECAST

14.5.3 IT INFRASTRUCTURE LIFECYCLE MANAGEMENT

We have successfully migrated 90% of our tier 0, 1 and 2 applications from on-premises onto cloud, resulting in significant benefits in resilience, scalability and performance.

In line with our cloud-first strategy, we continue to work with the wider business to optimise native cloud across other applications.

As a result of this migration, we are now realising reduced physical data centre and hardware investment, previously captured within this investment area. As the cost of IT infrastructure in a cloud environment is consumption based, this is accounted for within our non-network opex (as described in Section 15.6.2).

Remaining investment reflects the nature of Vector's core Operational Technology (OT) systems, which, due to their critical role in supporting electricity operations, continue to operate on-premise. This lifecycle management programme is focused on continuous improvement and the proactive reduction or elimination of technical debt, ensuring ongoing stability, security, and supportability.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
IT Infrastructure Lifecycle Mgmt.	1.0	0.2	0.75	0.2	1.0	0.2	0.2	1.5	1.0	0.2	6.25

TABLE 14-9: IT INFRASTRUCURE LIFECYCLE MANAGEMENT INVESTMENT FORECAST

14.6 Needs statements – Digital Networks

Please note the investment breakdowns below include the 'significant' projects detailed above.

14.6.1 CUSTOMER

We are focused on customers having a consistent and positive experience whenever they engage with Vector. Investment is aligned to Vector's overall customer strategy, with an emphasis on developing new capabilities to meet customers' increasing and evolving needs, alongside continuous improvement informed by customer feedback. Projects incorporate customer research and testing to achieve fit for purpose solutions and a high-quality customer experience.

As outlined in Section 14.3.2, Vector has centralised customer functions with an overarching customer strategy. While the digital and technology initiatives that support this strategy continue to mature, provision has been made for ongoing improvements to customer facing systems/channels.

Vector continues to invest in designing experiences that enable simpler, richer, and more informative customer interactions during outages. The development of Vector's Outage Centre has made it easier for customers to report outages and receive timely updates on restoration progress. Customers are also able to access information on planned outages, allowing them to plan ahead and minimise disruption.

Investment continues to enhance the Outage Centre experience, alongside a transition toward increased customer self-service. This shift reflects customers' desire for greater choice and control in how they manage Vector products and services. Self-service platforms also provide the scalability required to support the anticipated growth in the volume and complexity of customer interactions over time.

The quality and timeliness of information provided during major events is particularly important to the overall customer experience. Post event reviews following recent major storm events continue to shape investment decisions, particularly in relation to the systems outlined above.

Investment driven by regulatory requirements is also captured within this value stream. In particular, process and system changes resulting from Electricity Authority direction on connection and distributed generation applications are included in the investment outlook for FY27 and FY28.

Finally, a review of Vector's Customer Relationship Management (CRM) system is included, with upgrade or replacement provisioned for FY28 and FY29. This investment is aimed at responding to changing customer behaviour, supporting the future customer experience, and enabling the evolution of Vector's service offerings.

DESCRIPTION	FY27 $M	FY86 $M	FY29 $M	FY30 $M	FY231 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Customer	5.0	7.0	7.3	2.0	2.0	2.1	2.1	2.1	2.1	2.1	33.6

TABLE 14-10: CUSTOMER INVESTMENT FORECAST

14.6.2 NETWORK OPERATIONS

Network operations investment support the digital capabilities required for a consistent, reliable, and resilient network. The network operations domain includes multiple categories and functions which are required to support the execution and management of a distribution network.

Scalability across all Network Operations functions remains critical to achieving our Asset Management objectives. As the number of network assets and customer connections continues to grow, alongside the proliferation of distributed energy resources (DERs) and increased opportunities for more active low-voltage (LV) network management, operational complexity is increasing. Meeting rising customer expectations in this environment makes the ability to manage complex operations at scale a core pillar of our investment roadmap.

As discussed in Section 14.3.1, the ADMS programme of work is central to Network Operations investment, with ADMS Phase 2 dominating investment throughout FY27, whilst we look towards future phases commencing from FY29.

In addition to investment in ADMS, the management of operational systems and processes that sit outside the scope of ADMS is included in this investment. As operational complexity increases, strong in-house capability to support the delivery of effective and efficient field services is critical to meeting customer needs.

Accordingly, investment is directed toward enhancing device control and increasing process automation. This includes initiatives such as permit management, scheduling and notification of planned works, field crew capacity and loading analysis, and improved work order scheduling, all of which form part of the Network Operations investment roadmap.

Together with ADMS, these investments are instrumental in enabling the effective operation of a growing network, improving the efficiency of field services, and strengthening our overall capability to meet customer expectations.

The Network Operations digital investment category targets both specific projects and expected investment in required capabilities to enable enhanced network performance, with the aim of delivering effective, resilient and reliable services.

DESCRIPTION	FY27$M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Network Operations	15.7	2.9	7.5	12.0	12.2	6.2	5.3	5.5	6.0	9.5	82.6

TABLE 14-11: NETWORK OPERATIONS INVESTMENT FORECAST

14.6.3 NETWORK PROCURE & CONSTRUCT

Investment in Network Procure & Construct aims to build the capacity necessary for scaling up delivery to accommodate future network demands. The digital enhancements are intended to transform current practices into a more integrated approach for both capital delivery and procurement. Ongoing investment in supply chain capability will help strengthen standard inventory management and planning, supporting the evolution of business practices. Capital delivery and programme management investments have undergone lean reviews to streamline processes, enabling optimal use of systems for efficient end-to-end delivery execution.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Procure and construct	1.2	2.3	1.8	1.0	0.3	0.3	1.0	0.3	0.3	0.3	8.7

TABLE 14-12: NETWORK PROCURE AND CONSTRUCT INVESTMENT FORECAST

14.6.4 NETWORK PLANNING & PERFORMANCE

Network Planning and Performance spans network planning, maintenance, and asset management. Investment in this area is focused on growing digital capabilities that support the optimisation of network health and the effective management of risk across the asset lifecycle. This allows a balanced outcome across functionality, resilience, reliability, and cost efficiency.

Asset Maintenance is undergoing modernisation through the use of advanced technologies and AI to provide more reliable, data-driven insights. This enables a transition from time-based to condition-based maintenance and supports the adoption of risk-based models to drive targeted maintenance activities. The key drivers are improved visibility of maintenance activities and outcomes alongside stronger asset management capabilities focused on total cost of ownership (TCO) and asset risk management.

SAP-PM is the current system of record for asset maintenance, capturing maintenance records from field service providers and providing visibility into asset health. This has supported a shift toward more proactive asset management. The ERP strategy addressed in Section 14.5.2 encompasses this functionality within its scope. Investment is included within the NPP value stream to enable continuous improvement of this functionality post ERP implementation.

Ongoing investment in Network Security and Protection ensures the cyber security posture of the network continues to be commensurate with the level of risk and ongoing threats. This includes enhancements to device management and operational technology (OT) data management.

Asset data and records also remain a key focus, with continued improvements in data quality and reliable records that can generate early insights and better inform investment decisions through the use of AI. Investment in low-voltage (LV) network visibility continues through a data-centric approach and is addressed within the Data & Analytics domain, discussed in Section 14.7.1.

Overall, the Network Planning & Performance digital investment targets both specific projects and expected investment in required capabilities to enable enhanced network performance effective and resilient services.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Network Planning & Performance	3.7	4.3	3.1	2.9	2.1	1.8	1.8	1.8	1.8	1.8	26.3

TABLE 14-13: NETWORK PLANNING & PERFORMANCE INVESTMENT FORECAST

14.7 Core Digital needs statements

14.7.1 DATA & ANALYTICS

Data and Analytics (previously titled Network Visibility) enables decision makers across the business have easy access to well-structured, integrated, and high-quality data to optimize operational processes, support regulatory compliance, and provide more advanced analytical capabilities.

The core capabilities of data and analytics within the business includes data product delivery, data and information governance, data platform and engineering, data analytics, data science, as well as business intelligence. Incorporating all these capabilities, are relevant projects and product development to grow the maturity of data-led decision making over time in our corporate, customer, and EGF Business Units.

The delivery of all development in both on-prem and cloud-based data environments is included within the scope. This includes the integration of all internal, and external data systems and sources, that flow data through these platforms to conduct the relevant transformations, data modelling, and analysis. The analysis is either presented via services and products or by self-service applications. The transfer of new data services and applications include the transition from project into a 'business as usual' operating state.

Throughout FY26, the focus has been on maturing the data landscape across end-to-end asset management and maintenance. This incorporates customer, financial, asset locations, and performance and management standards. This in turn is giving Vector a full 360-degree view of the assets that are currently under management within the network. Vector's aim is to continue investing in this platform for intelligence purposes and will expand coverage to include asset planning, capital works, and customer experience. Enabling Vector to have a more granular and controlled visualisation of the impact that changes in the system have to both the LV and HV networks, and subsequently customers.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Data & Analytics	5.2	5.2	5.8	3.2	2.5	2.1	2.1	2.1	2.1	2.1	32.6

TABLE 14-14: DATA AND ANALYTICS INVESTMENT FORECAST

14.7.2 CORPORATE

Appropriate systems and tools must be in place for the corporate functions of Vector to function effectively. Investments are focused to establish and support tools for functions such as Finance, Regulatory, Marketing and Communications, Legal and Risk.

Investment in our employee experience is also within scope. This equips and mobilises Vector employees to fully engage and perform their roles effectively and the lifecycle of an employee at Vector from Onboarding, to learning, leadership, performance management, employee engagement and offboarding is fit for purpose.

The most significant area of Investment in the upcoming years is the modernisation of Vector ERP system, as documented above. Other areas of focus continue to be employee management (HRIS) platform(s) and financial billing systems.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Corporate	16.1	17.3	2.4	0.3	1.4	1.6	1.4	1.4	1.5	1.4	44.7

TABLE 14-15: CORPORATE INVESTMENT FORECAST

14.7.3 DIGITAL WORKPLACE SERVICES (DWS)

DWS focuses on ensuring employees, have the appropriate devices, connectivity, IT support that allows for independent and collaborative work, along with the supporting mechanisms that encourage an engaged workforce.

With the prevalence of increased flexible working scenarios there continues to be investment in digital tools to support collaboration and dispersed workforces with a focus on security and user experience.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
DWS	1.6	1.5	1.6	1.6	1.6	1.7	1.6	1.7	1.7	1.7	16.1

TABLE 14-16: DWS INVESTMENT FORECAST

14.7.4 DIGITAL SERVICES & CYBER

The focus for this portfolio is to drive better efficiency and effectiveness by establishing consistent digital toolsets and core platform components that all digital solutions can leverage. The outputs are consumed Vector-wide, avoiding duplication and implementing standardisation leads to more efficiency in the operation and support of our digital ecosystem.

There are three focus areas within this portfolio:

- Shared Tools and Services: Lifecycle management and operationalisation of standardised digital tools and services, such as our CRM and IT Service Management platform
- Site Reliability: Provide Value Streams with the ability to build and operate scalable and highly reliable digital solutions, based on sound IT infrastructure
- Cyber: Maintain and provide a secure and scalable IT network to detect and protect against cyber security threats.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Digital Services & Cyber	2.5	0.8	2.8	3.8	2.5	1.7	1.0	2.3	1.8	1.5	20.8

TABLE 14-17: DIGITAL SERVICES & CYBER INVESTMENT FORECAST

14.8 Non-network capex

Total non-network capex is projected to be $351 million over the 10-year AMP planning period as shown in table 14-21.

- As detailed in the sections above, the focus in the near term (FY27-28) is ADMS Phase 2 and Vector's ERP transformation, alongside digital investment supporting our customer strategy, The investment in ERP transformation and electricity growth enablement technologies will leverage modern automation and toolsets to support a scaled operation beyond 2030. Throughout the AMP period we continue to invest in a modernised network and lifecycle management that will both replace aged platforms and leverage new technology delivered by modernised systems.
- Spend in the property and leases category relates to the timing of renewal of leases for the stock holding warehouse (FY33) and 110 Carlton Gore Road premises (FY35). An IRU is reflected in FY27, FY29 and FY31.
- Key changes in non-network capex over the 9 years for which the 2025 AMP and 2026 AMP overlap are discussed in section 15.3.2.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
Digital capex	47.0	36.7	31.2	25.7	16.7	15.5	16.1	16.2	44.2	19.4	**248.7**
Property and Leases	18.0	1.5	6.7	1.8	6.9	5.1	12.0	1.6	46.5	2.0	**102.2**

TABLE 14-18: NON-NETWORK CAPEX (FINANCIAL YEAR, CONSTANT FY26)

14.9 Non-network opex

Total non-network capex is projected to be $1,304 million over the 10-year AMP planning period as shown in table 14-22.

- Expenditure on system operations and network support is forecasted to be $430 million for the period FY27-FY36. This expenditure line item captures direct system and network support costs that are required to deliver on the capex and maintenance plans.
- The above expenditure also includes a share of expenditure related to the resource shared between Vector's Electricity and Gas Distribution businesses.
- Business support expenditure is forecasted to be $874 million over the AMP planning period. Business Support expenditure includes a share of health and safety, public policy & regulatory, legal & risk management, finance, human resources, digital and marketing costs incurred at Vector Group level.
- Key changes in non-network capex over the 9 years for which the 2025 AMP and 2026 AMP overlap are discussed in section 15.5.2.

DESCRIPTION	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	FY34 $M	FY35 $M	FY36 $M	TOTAL $M
System operations and network support	40.9	41.7	41.9	42.9	42.7	43.2	43.7	44.1	44.2	44.8	**430.2**
Business Support	86.8	86.1	87.3	87.2	87.2	87.2	87.2	87.2	89.4	88.6	**874.1**

TABLE 14-19: NON-NETWORK OPEX (FINANCIAL YEAR, CONSTANT FY26)



SECTION 15

Expenditure forecast

15 – Expenditure forecast –

15.1 Overview

This section describes the capex and opex forecasts for the electricity distribution network assets for the next 10-year planning period based on the investment proposals outlined in Sections 8 to 14. It includes context for key assumptions and provides a high-level comparison with the forecast included in the 2025 AMP (disclosed in March 2025).

The capex and opex forecasts presented in this section align with Vector's planning process and financial year (FY) reporting period 1 July to 30 June. All figures presented are in 2026 dollars. The regulatory disclosure forecast, shown in Appendix 7 and Appendix 8, are presented in regulatory year (RY) 1 April to 31 March, in both constant and nominal dollars, as per the Information Disclosure requirements.

15.2 CAPEX forecast

The forecast capex during the next 10-year planning period is presented below, based on our key asset management strategies, demand modelling and customer information available. These are grouped in the following categories:

- **Growth capex** – detail discussed in sections 9, 10 and 13, and includes customer connection, system growth and relocations.
- **Integrity capex** – detail discussed in sections 11 and 12 and includes asset replacement and renewal, and reliability, safety and environment.
- **Non-network capex** – detail discussed in section 14.

Note all capex figures shown here are gross.

15.2.1 TOTAL CAPEX

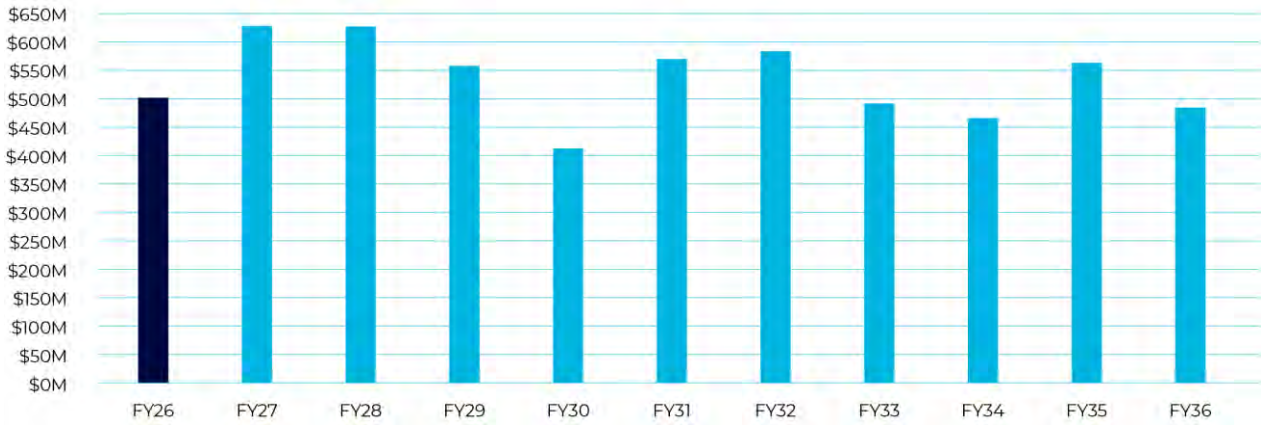


FIGURE 15-1: TOTAL CAPEX

Total capex averages $537m p.a. with the expenditure profile reflecting the growth and integrity forecasts (detailed in the following sections), which are punctuated by large significant projects for which there is more certainty in the short term. The higher gross expenditure in FY27 to FY28 is driven by increased customer connections expenditure and associated system reinforcement requirements, as well as a large number of primary asset replacement projects planned during this period. The expenditure profile also aligns with network technology initiatives including ADMS phase 2 delivery implementation of future phases, Enterprise Resource Planning (ERP) transformation and a programme of customer related initiatives (including a Customer Relationship Management (CRM) review and/or upgrade).

15.2.2 GROWTH CAPEX

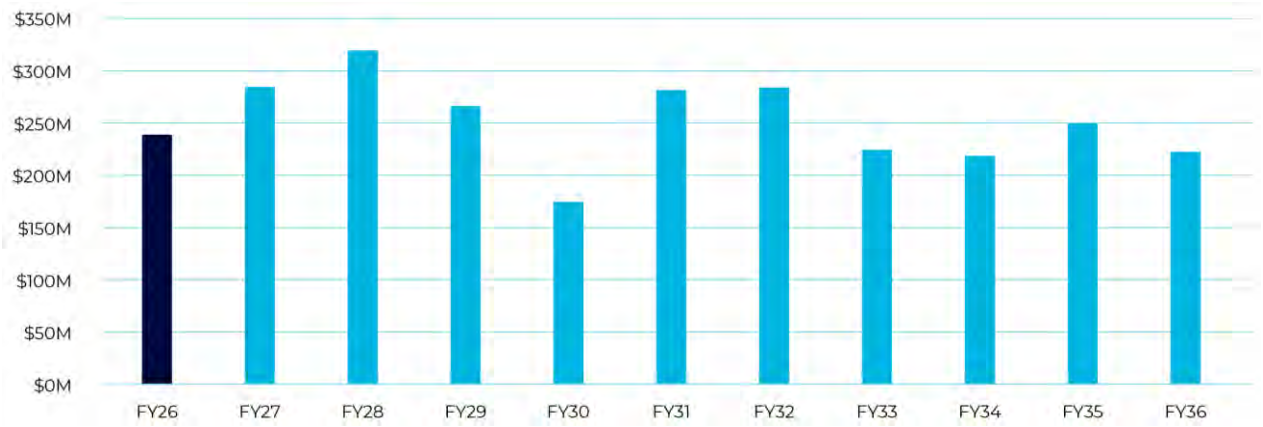


FIGURE 15-2: GROWTH CAPEX

The expenditure profile for growth capex is influenced by the timing of significant projects with large capital outlay. The higher spend in FY27and FY28 is driven by a provision for several large customer connections and network capacity investments including eight data centres, three large commercial connection projects and work relating to Auckland Airport. The key reinforcement projects include 4 new zone substations, 14 zone substation upgrades, 3 significant cable projects as well as provision for 6 land purchases.

The expenditure from FY29 onwards averages circa $240m p.a., increasing from $198m from the previous AMP. This is largely driven by a higher long term large customer connection forecast, a corresponding increase in network capacity investment, and recategorization of transformer capacity upgrades projects to better align with the nature of the expenditure. The expenditure profile is largely shaped by the timing of significant system growth investments in new zone substations, zone substations and subtransmission upgrades during this period.

15.2.3 INTEGRITY CAPEX

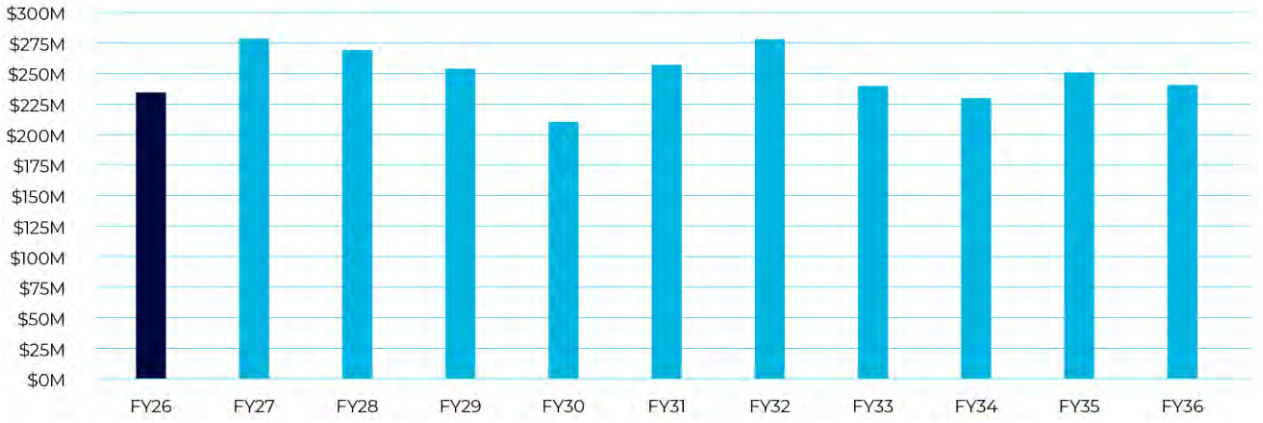


FIGURE 15-3: INTEGRITY CAPEX

The asset integrity expenditure averages $250m p.a. It is higher in FY27 and FY28 due to timing of many large multi-year projects that have started in FY26 carrying over to subsequent years, as well as many significant primary asset replacements including 8 transformer replacements, 11 switchboard replacements and 9 sub-transmission cable replacement projects forecast in this period. The timing of the large primary asset replacement continues to influence the expenditure profile from FY29 onwards.

15.2.4 NON-NETWORK DIGITAL CAPEX

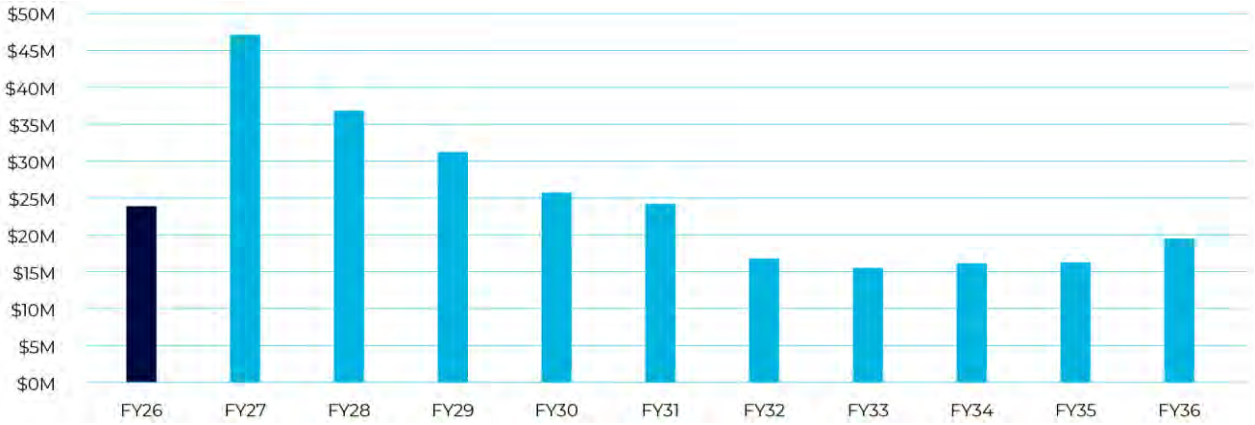


FIGURE 15-4: NON-NETWORK DIGITAL CAPEX

Digital investments support the technology required to execute our Symphony strategy. The proposed investment in the upcoming years in non-network digital systems, processes and information management will ensure Vector has the capability and tools required to deliver on our Asset Management Objectives. The focus in the near term (FY27-28) is ADMS Phase 2 and Vector's ERP transformation, alongside digital investment supporting our customer strategy, The investment in ERP transformation and electricity growth enablement technologies will leverage modern automation and toolsets to support a scaled operation beyond 2030. Throughout the AMP period we continue to invest in a modernised network and lifecycle management that will both replace aged platforms and leverage new technology delivered by modernised systems.

15.2.5 NON-NETWORK PROPERTY AND LEASES

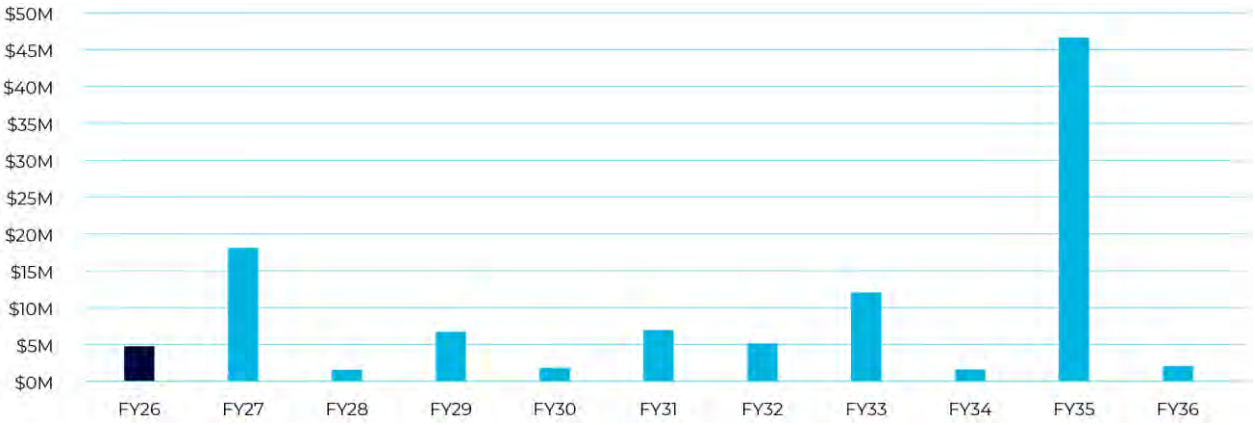


FIGURE 15-5: NON-NETWORK PROPERTY AND LEASES

Spend in the property and leases category relates to the timing of renewal of leases for the stock holding warehouse (FY33) and 110 Carlton Gore Road premises (FY35). IRU contracts supporting long term exclusive usage of fibre are also reflected in FY27, FY29 and FY31.

15.3 CAPEX forecast variance to previous AMP

The capex forecast during the next 10-year planning period is broken down into the key asset categories defined in the Commerce Commission's Electricity Distribution Information Disclosure Amendments Determination 2012 (shown in Table 15-1).

Figure 15-6 shows the difference between the 2025 and 2026 AMP expenditure forecasts year on year, with Table 15-2 breaks down the variance by expenditure categories.

KEY CAPEX CATEGORIES	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	TOTAL (FY27-36)
Consumer Connection	119,144	133,929	120,099	78,371	92,380	92,594	92,594	92,594	92,689	88,951	**1,003,347**
System growth	134,313	149,076	107,603	64,267	158,187	160,290	100,905	94,964	125,886	102,566	**1,198,056**
Asset relocations	30,315	35,678	37,781	31,435	30,315	30,315	30,315	30,315	30,315	30,315	**317,098**
Asset replacement and renewal	220,798	202,943	180,556	146,311	194,467	216,806	180,249	169,959	188,054	177,067	**1,877,209**
Reliability, safety and environment	57,147	65,701	72,666	63,572	62,104	60,645	58,992	59,224	62,270	62,969	**625,289**
Non-network assets	65,080	38,275	37,848	27,462	31,076	21,843	27,472	17,669	62,757	21,460	**350,940**
Total CAPEX	626,796	625,603	556,552	411,417	568,529	582,493	490,527	464,725	561,970	483,328	5,371,939

TABLE 15-1: AMP 2026 CAPEX FORECAST (FINANCIAL YEAR, $'000 CONSTANT FY26)



FIGURE 15-6: AMP 2026 VARIANCE TO AMP 2025 CAPEX FORECAST (FINANCIAL YEAR, $M CONSTANT FY26)

KEY CAPEX CATEGORIES	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	TOTAL (FY27-35)
Consumer Connection	736	32,614	32,832	2,276	18,700	18,614	18,614	18,614	22,086	165,084
System growth	37,088	80,415	40,936	23,247	79,913	55,466	(5,207)	(3,276)	3,890	312,473
Asset relocations	(5,645)	165	2,912	(2,788)	(3,262)	(3,262)	(3,262)	(3,262)	(3,262)	(21,667)
Asset replacement and renewal	(4,522)	12,087	26,767	11,282	8,332	28,097	1,164	(21,780)	6,977	68,403
Reliability, safety and environment	(26,145)	6,849	17,314	9,381	2,117	683	2,364	(2,546)	5,234	15,251
Non-network assets	28,930	8,762	10,342	3,386	11,829	(1,190)	(4,995)	(1,540)	11,220	66,743
Total CAPEX	**30,440**	**140,891**	**131,104**	**46,784**	**117,628**	**98,407**	**8,678**	**(13,791)**	**46,145**	**606,287**

TABLE 15-2: AMP 2026 VARIANCE TO AMP2025 CAPEX FORECAST TABLE (FINANCIAL YEAR, $'000 CONSTANT FY26)

15.3.1 EXPLANATION OF MAJOR NETWORK CAPEX VARIANCES

Key changes in network capex over the 9 years for which the 2026 AMP and 2025 AMP overlap are as follows:

- The $165m increase in customer connection gross expenditure is driven by higher large customer dedicated network investments ($177m) primarily relating to data centres ($80m), infrastructure projects ($29m), large commercial entities ($10m) and an uplift of longer terms forecast ($75m) from updated historical average expenditure. This is offset by a lower residential and commercial connection and reticulation forecast ($12m)
- System growth forecast has increased by $186m largely due to key drivers below:
  - Alignment with 3rd party infrastructure project, primarily roadworks, has brought forward $47m of spend to capture civil works synergies.
  - Alignment with internal Vector projects has brought forward $32m of spend. This reduces the amount of disruption experienced by customers whilst also reducing civil works costs.
  - $35m has been rolled over into the period due to changes in delivery timeframes on existing projects.
  - Large customers and new load growth (e.g. electricity to gas conversion and new large residential/commercial developments), has added $76m of additional investment requirements.
- Asset integrity expenditure (include asset replacement and reliability, safety and environment) has increased by $84m compared to last year's AMP as a result of the following:
  - Increased primary asset replacement including zone substation transformers ($52m, including project recategorized from system growth), switchgear ($2m) and sub-transmission cables ($21m) due to updated asset condition and criticality assessment. This is offset by a recategorization of power transformer capacity upgrade projects ($154m) that better aligns with the nature of the expenditure in system growth to provide more capacity in the network.
  - Additional provision for distribution asset replacement including overhead transformer and switchgear ($32m), ring main unit replacement ($39m) and LV frame and overhead capacitor replacement ($13m) to accelerate risk-based, proactive replacements in DPP4. This investment will ensure aged distribution assets are replaced at a rate that keeps them within their intended service life.
  - An increase investment in distribution overheard conductor circuits ($26m) driven by a new proactive Chorus pole replacement programme, an increase expenditure in low lines to improve health and safety and a higher overhead remediation expenditure based on asset conditions.
- The timing of asset relocation projects is dictated by third party projects. The expenditure forecast largely aligns with the previous AMP, with updated long-term forecast based on historical expenditure resulting in a reduction of $22m over the 9-year period (-$22m).

15.3.2 EXPLANATION OF MAJOR NON-NETWORK CAPEX VARIANCES

Key changes in non-network capex over the 9 years for which the 2025 AMP and 2026 AMP overlap are as follows:

- An increase in non-network digital expenditure of $31.5m, is largely attributed to:
  - ADMS Phase 2 investment has commenced as of FY26. Total ADMS investment increases $30.6m, including a $15m uplift allocated to Phase 2 in FY27, and increased provision for future phases. This number includes ongoing ADMS lifecycle management, which has largely remained constant between AMPs
  - Investment in Customer related initiatives increases $13.5m, driven by a $7.2m uplift to support our customer strategy, alongside $3.4m in DG Load connections processes as per EA requirements.
  - With some investment related to ERP transformation falling in FY26, additional ERP transformation investment has been concentrated over FY27 and 28, with total investment increasing $4m.
  - Offsetting this, we have seen decreases across most other value streams as a period of sustained network modernisation tails off.
  - Property and leasing costs differ due to the inclusion of the IRU in FY27, FY29 & FY31. The office lease renewal CPI assumption has also increased slightly in FY36

15.4 OPEX forecast

The forecast opex during the next 10-year planning period are presented below, based on our key asset maintenance standard and operational structure. These are grouped in the following categories:

- **Network opex** – discussed in Section 8
- **Non-network opex** – discussed in Section 14

15.4.1 TOTAL OPEX

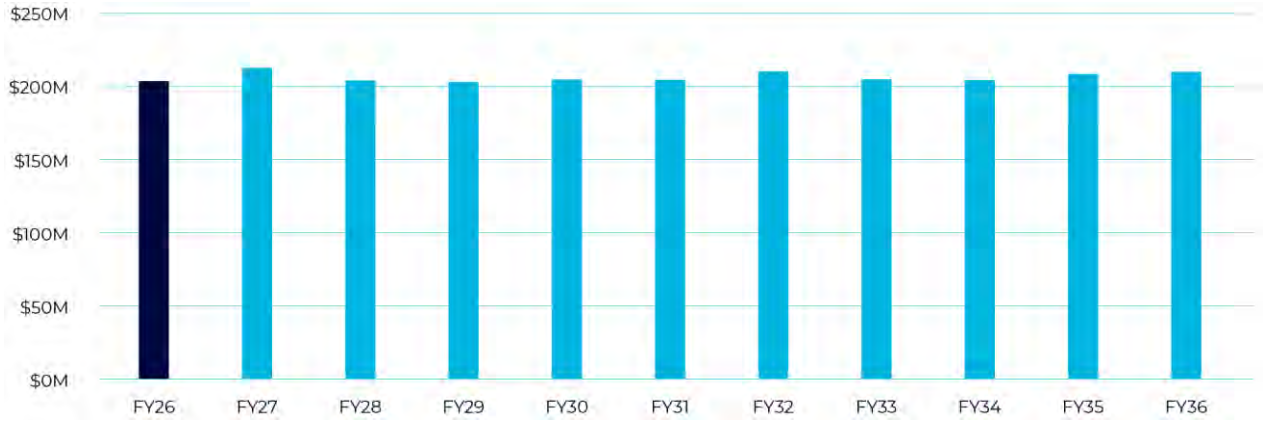


FIGURE 15-7: TOTAL OPEX (FINANCIAL YEAR, $'000 CONSTANT FY26)

The total opex expenditure profile is relatively consistent over the AMP horizon with an initial increase in FY27 due to increased expenditure in response to the increased number of weather events and higher computer expenses. FY27 and FY32 includes $7.5m each year for a major storm event as experienced twice over the past 10 years.

15.4.2 NETWORK OPEX

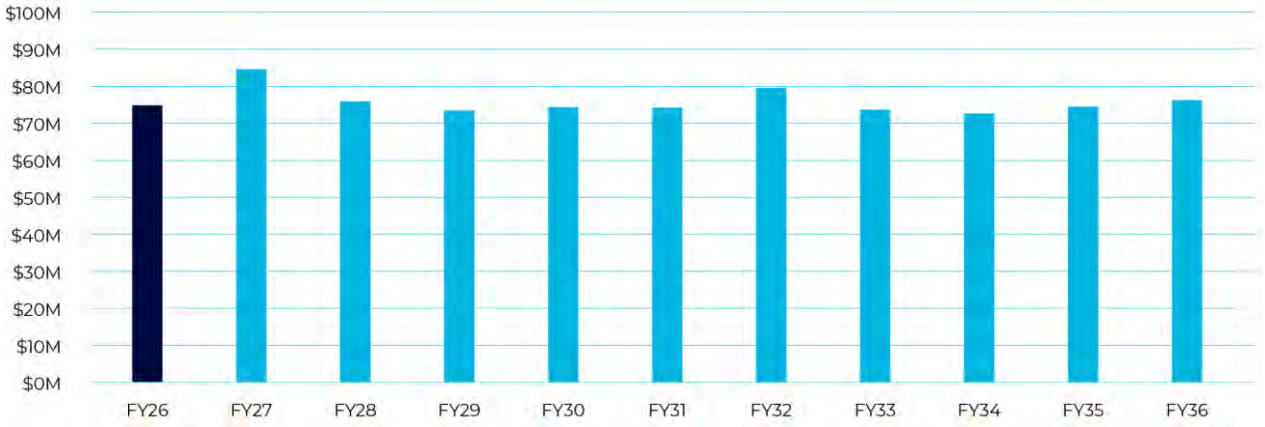


FIGURE 15-8: NETWORK OPEX (FINANCIAL YEAR, $'000 CONSTANT FY26)

The network opex forecast expenditure is underpinned by the latest asset maintenance standards. Over the 10-year planning period the expenditure profile varies based on the network requirements in particular timing of additional line clearance work, vegetation spend and asset cycles for planned maintenance and corrective maintenance inspection work introduced as part of the SAP PM system. FY27 includes uplifts for reactive maintenance for the impact of increased number of weather events and an increase in corrective maintenance activities. These increases are partially offset by reduced planned maintenance resulting from changes to maintenance standards. FY27 and FY32 includes $7.5m each year for a major storm event.

15.4.3 NON-NETWORK OPEX



FIGURE 15-9: NON-NETWORK OPEX (FINANCIAL YEAR, $'000 CONSTANT FY26)

Non-network opex forecast expenditure is trending slightly higher over the AMP period driven by increasing computer-related expenditure.

15.5 OPEX forecast variance to previous AMP

The forecast opex during the next 10-year planning period is broken down into the key asset categories defined in the Commerce Commission's Electricity Distribution Information Disclosure Amendments Determination 2012 and shown in Table 15-3.

Figure 15-9 shows the difference between the 2026 and 2025 AMP expenditure forecasts year on year, with Table 15-4 breaking down the variance by expenditure categories.

KEY OPEX CATEGORIES	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	TOTAL (FY27-36)
Service Interruptions and emergencies	27,570	20,034	20,053	20,213	20,355	27,996	20,667	20,821	20,998	21,168	**219,876**
Vegetation management	9,000	9,000	8,000	8,000	7,000	6,000	6,000	5,000	5,000	5,000	**68,000**
Routine and corrective maintenance and inspection	26,416	27,083	26,473	26,962	27,761	26,199	27,372	26,989	28,389	29,664	**273,306**
Asset Replacement and renewal	21,408	19,595	18,732	18,972	18,948	19,192	19,439	19,689	19,944	20,203	**196,122**
System operations and network support	40,928	41,731	41,940	42,855	42,748	43,185	43,668	44,131	44,185	44,817	**430,187**
Business Support	86,836	86,105	87,254	87,226	87,199	87,177	87,161	87,151	89,430	88,563	**874,103**
Total OPEX	**212,158**	**203,549**	**202,452**	**204,227**	**204,011**	**209,749**	**204,307**	**203,781**	**207,946**	**209,415**	**2,061,594**

TABLE 15-3: OPEX FORECAST (FINANCIAL YEAR, $'000 CONSTANT FY26)

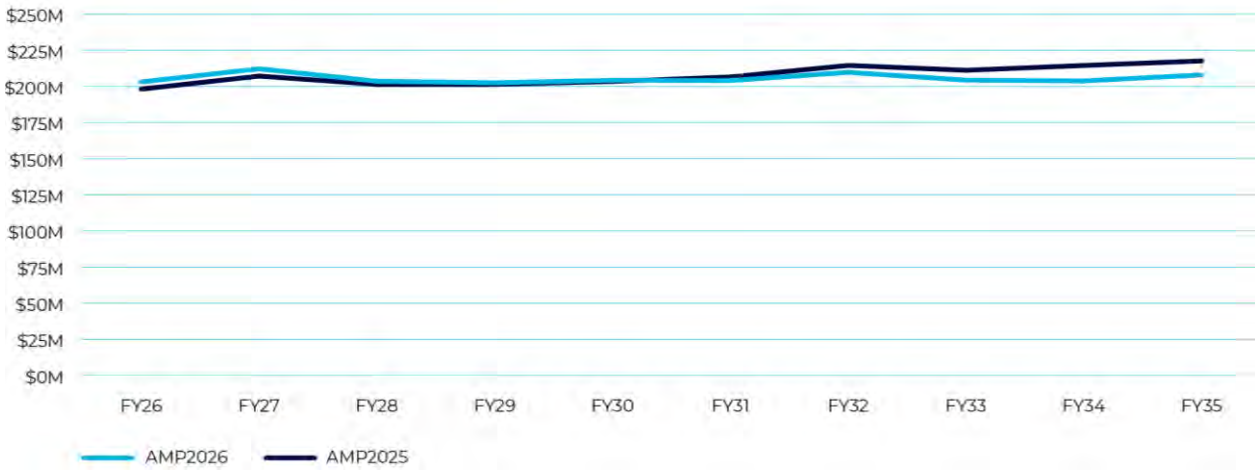


FIGURE 15-10: AMP 2026 VARIANCE TO AMP 2025 OPEX FORECAST CHART (FINANCIAL YEAR, $M CONSTANT FY26)

AMP26 V AMP25	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	TOTAL
Service Interruptions and emergencies	(425)	(427)	(303)	(318)	(314)	(127)	(330)	(334)	(359)	(2,937)
Vegetation management	217	217	(320)	(1,344)	(856)	(880)	(880)	120	120	(3,604)
Routine and corrective maintenance and inspection	1,301	1,927	1,843	590	1,023	825	1,166	1,156	(190)	9,642
Asset Replacement and renewal	(1,930)	(2,125)	(1,176)	(1,328)	(1,218)	(1,373)	(1,532)	(1,694)	(1,859)	(14,233)
System operations and network support	9,036	9,425	9,946	11,240	12,124	13,099	13,719	15,210	16,442	110,240
Business Support	(13,219)	(11,210)	(11,045)	(9,665)	(8,248)	(6,797)	(5,308)	(3,779)	(4,493)	(73,763)
Total OPEX	**(5,020)**	**(2,193)**	**(1,054)**	**(825)**	**2,511**	**4,748**	**6,836**	**10,679**	**9,662**	**25,343**

TABLE 15-4: AMP 2026 VARIANCE TO AMP 2025 OPEX FORECAST (FINANCIAL YEAR, $'000 CONSTANT FY26)

15.5.1 EXPLANATION OF MAJOR NETWORK OPEX VARIANCES

Key changes in network opex over the 9 years for which the 2025 AMP and 2026 AMP overlap are as follows:

- $3m increase in service interruptions and emergencies expenditure is largely due to the additional reactive maintenance costs included from FY27 onward each year, reflecting the impacts of climate change and the increased frequency of severe weather events.
- $4m increase in vegetation management reflects the continued rise in vegetation-related SAIDI impacts. This trend requires additional vegetation risk removal to maintain network reliability and restore SAIDI performance to acceptable levels.
- A decrease of $10m in routine and corrective maintenance and Inspection is primarily driven by unit rate optimisation and changes to maintenance standards and the asset population.
- An increase of $14m in asset replacement and renewal is due to higher costs for line clearance, power transformers, overhead lines, distribution and infrastructure & facilities, as well as additional costs for tunnel rail maintenance and accelerated ZSS P1 & P2 defect work

15.5.2 EXPLANATION OF MAJOR NON-NETWORK OPEX VARIANCES

Variances in non-network opex over the 9 years for which the current and prior year AMP overlap, reflect the following key changes:

- Systems operations and network support expenditure is forecasted to be $110m lower as a result of decreased DERMs platform charges, network data costs, personal costs and insurance.
- A forecast increase in Business Support expenditure of $74m driven by increased investment in ERP and ADMS programmes, ongoing data-strategy and AI initiatives, the shift from perpetual to subscription and consumption-based licensing, expected CRM/work-order system investment, and capitalisable data-improvement work.

15.6 Inputs and assumptions for information disclosed

15.6.1 OVERVIEW

This section outlines key inputs and assumptions used for the forecast expenditure in the AMP planning period. Estimates for projects and programmes for the first few years in the AMP period receive a higher level of scrutiny during the compilation of estimates and thus have a higher level of accuracy than projects in the latter years.

15.6.2 NETWORK CAPITAL EXPENDITURES

15.6.2.1 SPECIFIC PROJECTS

The requirement to invest capital for specific individual projects is either borne out of large customer connection requests, asset relocations triggered by third party infrastructure projects, asset condition and failure risks and network system reinforcement requirement to ensure security of supply.

Vector has extended the use of Condition Based Asset Risk Management (CBARM) modelling to primary assets including indoor primary switchgear and subtransmission cables. It is also used to support and prioritise programmes of work for distribution assets (section below) over the 10-year forecast horizon.

The CBARM models are based on the principles and calculation methodologies outlined in the OFGEM DNO Common Methodology and tailored to reflect Vector's operational environment. The models incorporate Vector's input data such as historical failure rates and asset health data to predict the volume of assets that will need to be replaced and thus the level of investment needed to manage each of the asset fleets. Historical actual costs are used as the basis for the unit cost applied in the forecast expenditure. Vector utilises other modelling techniques to forecast replacement capital expenditure for asset types where CBARM models is not suitable – refer to section 12.2.

The assumptions and processes that build up the reinforcement expenditure are detailed in section 10.4. It is initiated by an annual assessment of the customer peak loading on all distribution feeders and zone substations. Any capacity shortfalls and breaches of our security of supply standard are identified through network constraint modelling and solutions are assessed and proposed through investment option analysis.

Cost estimation for significant capital projects (greater than $1m) involves site inspections to determine site and other constraints and risks to deliver a solution. From this, a scope and constraints summary is compiled with a relatively detailed project estimate. The cost estimate is built with a bottom-up approach using a standardised cost estimating model, which draws the inputs from the moving cost from SAP inventory data for materials and plant, standard rates for internal staff time writing and standard agreed rates for external commissioning support and contracted project management.

15.6.2.2 PROGRAMMES OF WORK

Forecasting for volumetric programmes of work applies to most of Vector's customer connection expenditure and investment relating to Vector's distribution assets.

The forecast for customer connections volumes is supported by data from the Auckland Forecasting Group (AFG). The assumption for consents converting to gross connections has dropped in the medium term from the prior year but expected to rise back up in the long term. The cost estimates for customer connections are based on an average cost using historical data, but a cost estimate is built bottom-up for each connection application.

For distribution assets, Vector has continued with the use of CBARM models for asset classes including distribution ring main units, distribution transformers, overhead conductors, and overhead 11 kV switchgear to inform the forecasted volume of assets to be replaced and/or remedied during the AMP cycle.

15.6.3 NETWORK DIGITAL ASSUMPTIONS

Given the fast-changing landscape, the uncertainty of some investments increases with time. There is reasonable certainty for the investments over the initial 18-24 months period, with less certainty beyond that. The investment forecasts provided are based on projects currently being undertaken and current market conditions. Vector has a standard quarterly planning process that reviews investments, reprioritises as required and follows a business case process to proceed with investments.

Our forecasts include provision for appropriate lifecycle management and support of all existing platforms, thus avoiding unexpected replacement. Specifically, the current SAP version is reaching end of life, with an ERP modernisation programme to further determine support requirements for the future. The nature of a future ERP modernisation programme is currently assumed to be asset creation (capitalisable cost) however this will be dependent on the solution(s) implemented. In addition, cybersecurity threats are assumed to remain at a level where current investment forecasts are sufficient to protect Vector systems and respond to incidents within the IT domain. Investment forecasts do assume increased investment in OT Cybersecurity controls, as the number of sensors and devices connecting to the OT network increases. The Electricity business will need to leverage modern automation technology and tools to scale its operations efficiently to meet growing consumption demand. Vector operations also require investment to achieve the scale necessary to service increased connections and increased consumption over the next 10 years.

15.6.4 PROPERTY AND LEASES

There are no significant changes in the forecasts from the prior year.

15.6.5 OPERATING EXPENDITURES

To a large extent, the network operating expenditure relates to a programme of planned maintenance work driven by a suite of maintenance standards and corrective asset maintenance. To this end, our planned maintenance network operating expenditure

forecast has been constructed bottom-up, taking into consideration the various activity unit rates, frequencies and the quantum of activities.

We have constructed the non-network operating expenditure forecast primarily based on the existing operating structure with modifications for known changes and excludes one-off transitional type cost items. Further, in certain instances, we have relied on historical averages to form a baseline view, where we believe forecasting the expenditure items with a reasonable degree of accuracy is challenging.



SECTION 16

Programme delivery

16 – Programme delivery

16.1 Overview

This section provides an overview of the processes used to manage the delivery of our capital and maintenance works programmes. The aims of our Programme Delivery process are to consistently deliver our work safely, cost effectively, on schedule and to a high-quality standard. We also provide an overview of our approach to prioritising works and optimising resources for delivering our works programme.

Vector operates an outsourced model with all design and construction activities being undertaken by external service providers that are managed by Vector through a number of delivery and commercial models.

16.2 Major capital works delivery

Major capital projects are identified based on an assessment of network risk, a high-level solution, ranked in the order of priority and timing, and incorporated into the AMP. Major capital projects including large, complex customer-initiated projects are delivered by the Capital Programme Delivery team.

The Capital Programme Delivery team manages project engineering, project management, procurement, construction and contract management functions as well as providing overall governance and portfolio management. Design and construction is outsourced to external service providers.

16.2.1 CAPITAL DELIVERY MODEL

We use a pool of external providers to deliver our capital works programme:

1. **Electrical Installation Contractors:** Four electrical installation contractors are retained under an umbrella agreement that defines the overall commercial terms with each individual project engagement undertaken using the NZS3910 form of contract with no guarantee of work volumes. These contractors in turn may subcontract elements of the work but are required to use subcontractors that are part of a pre-qualified specialist pool. This ensures that works are carried out by contractors who are familiar with our processes and critical risks.
2. **Civil contractors:** We use a pool of civil contractors; specialising in either vertical build or horizontal excavation. Like the electrical panel, this a restricted pool of contractors ensures that we maintain our quality and safety standards and provides the contractors with the confidence to invest in processes, equipment and people to deliver high-quality work, safely. Again, there is no minimum work volume commitment and the contractors are engaged using NZS3910 form of contract.
3. **Design and Specialist consultants:** Our concept and detailed design is undertaken by external engineering consultants Additionally, specialist activities such as consenting, geotechnical investigations, acoustic assessments and the like are undertaken by specialist consultants. These consultants are engaged under Vector's standard framework agreement terms.
4. **Equipment Suppliers:** We procure and free issue high value equipment such as power transformers and switchgear through our pre-approved equipment vendors. These are long term relationships that covered by our standard framework agreements.

To help our contractors plan their resourcing we provide quarterly updates of upcoming projects. Our major projects are published on the National Forward Works Viewer to help identify synergies across electricity, gas, and other utility projects.

16.2.2 GOVERNANCE

Vector has established processes for identifying network upgrade needs and capital justification to achieve its business objectives and reduce network risk. Our network investment planning and project delivery follows a stage-gate governance approval process. The process, shown in Figure 16.1, covers all expenditure and comprises five approval 'gates' that are governed by the Delegated Authority Framework. Our SAP workflow mirrors this approval stage gate process for budget applications. The first three gates relate to the identification of the risk and need for a project or program, analysis of the options for the works and development of the preferred solution. A Capital Expenditure Justification (CEJ), essentially a business case to gain approval to undertake capital investment, together with a detailed cost estimate, are prepared to demonstrate prudence and efficiency of expenditure and that the governance process has been followed.



FIGURE 16-1: PROJECT LIFECYCLE

Individual project progress is recorded and monitored using a Project Management System, it is also used to manage document approvals and change requests, as well as being the repository for standard reports, construction standards, training guides and document templates.

Portfolio Managers conduct monthly reviews with the project managers of each project to ensure that projects are going to plan and identify any issues, constraints and challenges for resolution. Portfolio Managers also meet regularly with our designers and construction contractors to review their performance on projects.

The Programme Management Office provides overall oversight of the entire portfolio of projects. The Programme Manager chairs monthly and quarterly portfolio governance meetings that focus the overall portfolio performance against financial year, regulatory year and 5-year DPP delivery and financial targets.

16.2.3 PROGRAMME MANAGEMENT

The Project Management Office (PMO) plays a critical role in enabling stronger governance, strategic work allocation, smarter reporting, and insight-led decision-making - aligned with Vector's Symphony and data strategies. The structure of our Programme Management Office was reshaped in 2025 to reflect our changing delivery needs.

Using our Project Management System, the PMO maintains a full rolling 10-year portfolio of active and future AMP projects to establish the delivery priorities as set out in the AMP. Working with the portfolio managers and the project managers, the PMO aims to optimise the overall programme based on a number of inputs, including customer and external stakeholder requirements, opportunities for related project synergies, operational constraints and resource availability.

Overall scheduling of major projects is overseen by the PMO team within the capital project delivery team. The delivery schedule priorities and timelines are based on the AMP.

16.2.4 SCOPE OF WORKS AND DESIGN

Project scopes of work are developed by Vector's asset and project engineers. These are developed up to completion of the concept design and identification of long lead items for early procurement. This process was refreshed in 2025 with the aim of improving efficiency and effective delivery of both design and construction activities.

A formal handover for delivery transfers accountability for the delivery to the capital programme delivery team and an assigned project manager.

Detailed electrical and civil designs are prepared by external design consultants who provide a full suite of design services for the duration of the project lifecycle.

16.2.5 PROCUREMENT OF WORKS DELIVERY

Capital Works are either tendered or sole sourced/allocated to our pool of electrical and civil contractors. Tendering is performed using industry recognised processes to ensure fairness and transparency in selecting most appropriate contractor. Tenders are evaluated using pre-determined weighted scoring against both non-financial and financial criteria.

The choice of procurement methodology is largely based on the following criteria:

1. Contract works complexity
2. Contract value
3. Contractor workload
4. Need to ensure best value for money

Final approval of recommendations follows our Delegated Authority Framework.

The form of tender and contract issued is the based on NZS:3910.

16.2.6 DELIVERY

Projects are delivered using PMI delivery framework and are tailored to fit Vector's needs. The project manager is supported in the delivery of the project by other delivery specialists including HSE, procurement, resource management, quality specialists and project and asset engineers.

Project delivery is managed using our Project Management System and includes tracking of project health, risks, budgets, scope, quality and schedule. Any change that places the success of the project at risk is flagged and reported so that it can be mitigated.

16.2.7 COMMISSIONING AND OPERATIONAL HANDOVER

Vector operates a robust commissioning process aiming to ensure all new assets are fit for purpose and safe to operate, prior to final livening onto the network. This process includes the development and approval of a commissioning plan, site inspections throughout the project stages, testing of all components and a final overall inspection and official sign off.

The commissioning team comprises asset specialists, operations and maintenance representatives and dedicated commissioning engineers.

Once any defects are rectified, the final handover from project to operations is undertaken through the issuance of a handover certificate signed by all parties, confirming that the assets are fully commissioned, defect free, fit for purpose and can be operated safely.

16.3 Customer initiated capital projects

The customer contracts and programme team delivers customer-initiated capital projects like subdivisions and commercial connections as well as small connections. Our FSPs, Omexom and Northpower, deliver the works under the Multi-Utility Services Agreement (MUSA). Our FSPs design and deliver works by geographic region. With around 800 customer-initiated projects per year, the FSPs knowledge of the local network is critical in delivering these smaller, short-duration capital projects effectively.

Vector has an internal team of customer advisors that work with the customers, administering the project delivery and liaise with the planning and network performance teams on the customer's behalf.

The work is contracted using MUSA capital works job sheet providing a simple and easy to understand contract engagement that reduces the administrative costs associated with tendering works while ensuring we demonstrate value for money through comparison with similar recent works and standard negotiated rates.

16.3.1 RESOURCE SCHEDULING

The priority of customer-initiated projects is generally governed by when the client contracts Vector to deliver the works. FSP resource levelling and outage scheduling are then used to fine-tune delivery scheduling.

16.3.2 FEASIBILITY AND DETAILED DESIGN

The electrical design of projects delivered by the customer contracts and programme delivery team comprise a mix of designs including 11 kV network, distribution substations and low-voltage distribution network infrastructure. These designs do not require a multi-disciplinary approach and are ideally suited for delivery by our FSPs. The design and quotation is provided to the customer as our offer to undertake the works.

The more complex customer-initiated projects that require multi engineering disciplines involvement, e.g. large datacentres, are delivered by the Capital Programme Delivery team.

16.3.3 DELIVERY

With the exception of complex customer-initiated projects, all customer works are delivered by our two FSPs under the MUSA framework.

Vector's customer advisors use our customer relationship management platform, Siebel, to monitor project progress and manage variations.

Our FSPs build and commission new equipment being connected onto the network to ensure it complies with our standards and can be operated and maintained safely. Once the work is complete, they update Vector's information systems and hand the installation over to Vector's Electricity Operations and Maintenance team.

16.4 Maintenance works delivery

16.4.1 FIELD SERVICE MODEL

Vector uses four main field service providers to perform maintenance activities:

- Omexom Ltd is the electrical maintenance contractor for the Northern network area;
- Northpower Ltd is the electrical maintenance contractor for the Auckland network area; and
- Treescape Ltd is the vegetation management contractor for the Northern network.
- Asplundh Ltd is the vegetation management contractor in the Auckland network.

Omexom and Northpower undertake maintenance activities under the MUSA framework. The scope of the electricity maintenance works covers reactive, preventative, and corrective maintenance works programmes. The preventative and corrective maintenance programmes are driven by our maintenance standards and overarching maintenance strategy set by the asset management and network planning team.

Our operations and maintenance team is responsible for managing the relationship coordination and performance of our field service providers. The MUSA contract defines the responsibilities, obligations and Key Performance Indicators (KPIs) needed to complete scheduled works.

Treescape and Asplundh operate under separate services agreements managed by our operations and maintenance team. The prioritization of tree maintenance is guided by an external service provider, Arborlab Limited, who use a combination of tree fall risk, potential SAIDI impact, safety, etc. to establish the forward programme of vegetation maintenance activities.

The delivery of all these maintenance activities is closely monitored and adjusted monthly and quarterly by our operations and maintenance team, in alignment with agreed annual targets. Data and insights are reviewed monthly covering actual versus planned progress, KPI performance, causality and issues impacting progress or performance, new risks, action plans and focal points for the coming months.

The overall effectiveness of the programme is evaluated by KPI performance measures and the roll-up to Vector's corporate performance metrics, of which environmental compliance, public, employee and contractor safety and network SAIDI (via a CAIDI KPI) are the core measures.

Standard MUSA rates for prescribed activities are reviewed annually. Out of cycle rate increases or new rates arising from changes to standards, legislative requirements or other special circumstances are negotiated and managed using the MUSA change management process.

16.4.2 GOVERNANCE

Performance against annual budgets is closely monitored, with formalised change management and escalation procedures in place. Regular reporting monitors:

- Health, safety and environmental performance;
- Monthly expenditure against budget;
- Network reliability performance -SAIDI, SAIFI, CAIDI;
- Progress with risk register actions (the board has a risk committee with a specific focus on key business risks); and
- Progress of actions identified in the Strategic Reliability Management Plan.

A MUSA Governance group comprising senior executive and managers from both Vector and the FSP meets quarterly to review performance against KPIs as well as the progress of improvement initiatives.

16.5 Supply chain management

Global demand for limited production capacity will maintain upward pressure on prices and lead times for primary equipment. Manufacturers of secondary equipment and cable are aggregating production in regional facilities, with significant investments in plant and automation. Vector does not have the scale to compete on equal terms in this market. Our sourcing strategy is therefore to improve value and efficiency, and reduce risk, by strengthening relationships with these regional manufacturers and diversifying supply. That is:

- to continue to purchase from local manufacturers who consistently meet Vector's quality standards at a fair price;
- to source equipment manufactured by prequalified factories in China and South East Asia, rather than Europe; and
- to develop at least two competing sources of supply of functionally equivalent items in each category.

Vector responded to the fulfilment challenges of the Covid-19 pandemic by building relationships with trusted suppliers, forecasting demand for long lead-time items, rationalising the range of "standard" items purchased and introducing new suppliers to mitigate the impact of bottlenecks. We have also strengthened relationships with other electricity distributors to identify opportunities for alignment on equipment specifications, reducing portfolio complexity and risk. In 2026 we plan to work with other EDBs to build scale, reducing barriers to entry for new suppliers and improving access to global incumbents.

Inventory of frequently used items such as distribution transformers and switchgear now enables forecast project and network maintenance requirements to be met from stock. Our partnership with logistics expert Rohlig has improved the quality and consistency of our fulfilment function and enabled more dynamic inventory management. We are continuing to invest in software platforms and capability to transition from a just-in-time ordering model to an integrated business planning process that aggregates demand projections from planning, delivery and operations functions.

Primary equipment and most secondary equipment required for Vector's capital, customer and maintenance delivery programmes is purchased by Vector and free issued to contractors for installation. Less complex, high-volume equipment such as poles and cross arms are purchased by contractors, to Vector's specifications, with the cost passed through to Vector when the item is installed. To ensure that our sourcing strategy is effective we are focused on improving the quality of data shared by field service providers and better leveraging scale to improve access, price and lead times.



SECTION 17

Appendices

17 – Appendices

17.1 Appendix 1 – Glossary and terms

AAAC	All Aluminium Alloy Conductor
AAC	Aluminium Alloy Conductor
ABC	Aerial Bundled Cable
ABI	Air break isolator
ABS	Air break switch
AC	Alternating current
ACSR	Aluminium Conductor Steel Reinforced
ADMS	Advanced Distribution Management System
ADSL	Asymmetric Digital Subscriber Line
AFG	Auckland Forecasting Group
AIS	Air-insulated switchgear
AKL	Auckland
ALR	Auckland Light Rail
AMETI	Auckland Manukau Eastern Transport Initiative
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
AMS	Asset Management Standard
ARP	Asset replacement project
AS/NZ	Australian/New Zealand Standard
AT	Auckland Transport
BESS	Battery Energy Storage Solutions
BI	Business Intelligence
BRAC	Board Risk and Assurance Committee
BSP	Bulk supply point
Bulk supply substation	A substation owned by Vector that directly connects the Vector network to the national grid. A bulk supply substation may contain more than one supply bus (of same or different voltages).
CAB	Citizens Advisory Board
CAD	Computer Aided Design
CAIDI	Customer average interruption duration index
CAPEX	Capital expenditure
CB	Circuit breaker
CBARM	Condition based asset risk management
CBD	Central business district
CCT	Covered conductor type
CDEM	Civil Defence and Emergency Management
CEJ	Capital Expenditure Justification
CEMS	Customer Effort Mean Score
CEO	Chief Executive Officer
CGPI	Capital Goods Price Index
CM	Corrective Maintenance
CO2e	Carbon Dioxide Equivalent

COO	Chief Operating Officer Electricity, Gas, Fibre
CRL	City Rail Link
CRLL	City Rail Link Limited
CRM	Customer relationship management
DA	Delegated Authority
DAF	Delegated Authority Framework
DC	Direct current
DER	Distributed energy resource
DERMs	Distributed energy resource management system
DGA	Dissolved Gas Analysis
Distribution substation	A substation for transforming electricity from distribution voltage (22 kV or 11 kV) to 400V distribution voltage and provides switching, protection, and control to safely manage power flows and isolate faults.
DMR	Digital Microwave Radio
DNO	Distribution network operator
DP	Degree of polymerization
DPP	Default price-quality path
DPP2	The price-quality path set under Part 4 of the Commerce Act for the period 1 April 2015 to 31 March 2020
DPP3	The price-quality path set under Part 4 of the Commerce Act for the period 1 April 2020 to 31 March 2025
DPP4	The price-quality path set under Part 4 of the Commerce Act for the period 1 April 2025 to 31 March 2030
DSM	Demand Side Management
EDB	Electricity distribution business
EECA	Energy Efficiency and Conservation Authority
EGF	Electricity, gas, and fibre
EDIM	Enterprise Data and Information Management
EIPC	Electricity Industry Participation Code
ENA	Electricity Networks Association
ENS	Electricity Network specification
EOC	Electricity Operations Centre
ERM	Enterprise Risk Management
ERP	Enterprise resource planning
ESE	Electricity Standard Engineering
ESM	Electricity Standard Maintenance
ESS	Electricity Standard Specification
EV	Electric vehicle
FCAS	Frequency control ancillary services
FENZ	Fire and Emergency New Zealand
FMEA	Failure Mode Effect Analysis
FNR	Future Network Roadmap
FPI	Fault Passage Indicator
FSP	Field Service Provider
FY	Vector financial year (year ending 30th June)
GHG	Greenhouse Gas
GIS	Geographic information system
GOS	Grade of Service
GXP	Grid Exit Point
HILP	High impact low probability

HR	Human resources
HSE	Health, safety and environment
HSNS	High Speed Network Services
HSWA	Health and Safety at Work Act
HV	High voltage: a nominal AC voltage of 1000 volts and more
HVAC	Heating, Ventilation and Air Conditioning
HV-GIS	High voltage gas insulated switchgear
HWLC	Hot water load control
ICCC	Interim Climate Change Committee
ICP	Installation control point
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IED	intelligent electronic device
IEECP	Institute for European Energy and Climate Policy
IND	Industrial
IP	Internet Protocol
IPCC	Intergovernmental Panel for Climate Change
ISO	International Organization for Standardization
IT	Information Technology
KPI	Key Performance Indicator
kV	Kilovolt
kW	Kilowatt
LAN	Local area network
LBS	Load break switch
LCI	Labour Cost Index
LiDAR	Light Detection and Ranging
LRT	Light Rail Transit
LV	Low voltage – a nominal AC voltage of less than 1000 volts
MO	Minimum Oil
MSM	Macro Strategic Model.
MUSA	Multi-Utility Services Agreement
MV	Medium voltage
MVA	Megavolt amperes
MW	Mega Watt
MWh	Megawatt Hour
National grid (or grid)	The 110 kV and/or 220 kV AC network and the DC link between the North Island and the South Island owned by Transpower for connecting electricity generation stations to grid exit points.
NBS	New building standard
NIWA	National Institute of Water and Atmospheric Research
NPV	Net present value
NTHN	Northern
NWA	Non-Wires Alternative
N-x security	Subtransmission security class rating.
NZS	Standards New Zealand
NZSEE	New Zealand Society of Earthquake Engineering
NZTA	New Zealand Transport Agency
OD	Outdoor
ODID	Outdoor to Indoor

ODV	Optimised deprival value
OEM	Original equipment manufacturer
OH	Overhead
ON	Oil Natural
ONAF	oil natural air forced
ONAN	oil natural air natural
OPEX	Operational Expenditure
OT	Operational Technology
PD	Partial Discharge
PE	Polyethylene
PI	Plant Information
PICAS	Paper Insulated Corrugated Aluminium Sheath
PII	Personally Identifiable Information
PILC	Paper insulated lead sheath
PM	Planned Maintenance
PMI	Project Management Institute
PMO	Programme Management office
PPI	Producer Price Index
PQM	Power Quality Meter
PV	Photovoltaic
PVC	Polyvinyl acetate
QTRA	Quantitative Tree Risk Assessment
RAB	Regulatory Asset Base
RBA	Risk Based Approach
Reliability	The ability of the network to deliver electricity consistently when demanded.
RES	Residential
Resilience	The ability of the network to recover quickly and effectively from an event.
RM	Reactive Maintenance
RMU	Ring-main Units
RNF	Reinforcement project
ROU	Right of use
RTU	Remote terminal unit
RY	Regulatory year (year ending 31st March)
SAA/SNZ HB	Standards Association Australia / Standards New Zealand Handbook
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAMP	Strategic asset management plan
SAP	Enterprise Resource Planning (ERP) System (SAP)
SAP PM	Plant maintenance module of SAP
SCADA	Supervisory control and data acquisition
SF6	Sulphur Hexaflouride
SFRA	Sweep Frequency Response Analysis
SH	State Highway
SID	Safety in Design
SIP	Sandwich insulated panel
SME	Small and medium-sized enterprises
SMF	Special moment frame
SO	System Operator

SOC	Security Operations Centre
SoSS	Security of Supply Standard
SQL	Structured Query Language
SRMP	Strategic Reliability Management Plan
Substation	A network facility containing a transformer for the purpose of transforming electricity from one voltage to another. A substation may contain switchboards for dispatch or marshalling purpose. A substation may also contain more than one building or structure on the same facility.
SUBT	Subtransmission
SWA	Steel wire armoured
SWBD	Switchboard
Switching station	A facility containing one or more switchboards (or switches) for the purpose of rearranging network configuration or marshalling the network through switching operation.
TASA	Tap Changer Activity Signature Analysis
TCA	Transformer Condition Assessment
TCO	Total cost of ownership
TERP	Transport Emissions Reduction Pathway
TMS	Transformer Management Systems
TOTEX	Total cost of expenditure
TOU	Time of use
TRIFR	Total recordable injury frequency rate
TX	Transformer
UHF	Ultra-high frequency
UPS	Uninterruptible power supply
VAMS	Vegetation asset management strategy
VHF	Very high frequency
VOX	Outdoor deadtank circuit breaker
VSP	Vegetation Service Provider
VT	Voltage transformer
WAN	Wide Area Network
WIP	Work in progress
XLPE	Cross-linked Polyethylene
Zone substation	A substation for transforming electricity from subtransmission voltage (110 kV, 33 kV or 22 kV) to distribution voltage (22 kV or 11 kV).
ZSS	Zone Sub Station

17.2 Appendix 2 – Key asset strategies and standards

Vector has a set of asset strategies and standards that together define Vector's approach to Asset Management. An overview of the key policies and standards are set out below.

ASSET CLASS	GENERAL
Strategies	EPA001 Electricity Asset Management Policy EAA010 Reliability and Resilience Strategy EAA018 Asset health Modelling Strategy EAM001 Electricity Maintenance Strategy
Technical Specifications	ENS-0099 General technical requirements ESP005 Technical Requirements for the connection of generation ESP009 Technical Requirements for small scale Inverter connected DG ESP010 Security of Supply EGP503 Smart Metering Guideline
Maintenance Standards	ESM001 General Maintenance Requirements
Engineering Standards	ESE001 Computer Aided Design (CAD) Drawing Standard ESE003 Electricity Network Drawing Management ESE004 Engineering Management Standard

ASSET CLASS	100 SUBTRANSMISSION SWITCHGEAR
Strategies	EAA100 Sub transmission Switchgear
Technical Specifications	ENS-0005 Specification for 11 kV to 33 kV indoor switchboards ENS-0022 Specification for 110 kV GIS indoor switchboards ENS-0106 Specification for 33 kV outdoor circuit breakers
Maintenance Standards	ESM101 Maintenance of Primary Switchgear – MV fixed pattern ESM102 Maintenance of Primary Switchgear – 110 kV GIS ESM103 Maintenance of Indoor and Outdoor Conventional Switchgear ESM104 Primary Switchgear -Outdoor
Engineering Standards	ESE101 Primary Indoor Switchgear ESE102 Instrument Transformers Indoor ESE103 33 kV Switchyard Renewal and Extension Design Criteria

ASSET CLASS	200 POWER TRANSFORMERS
Strategies	EAA200 Power Transformers
Technical Specifications	ENS-0201 Specification for 110 kV-22 kV two-winding power transformers ENS-0149 Specification for neutral earthing resistors ESS-0200 Specification for 33 kV-11 kV two-Winding Transformer
Maintenance Standards	ESM201 Maintenance of Transformers 22-110 kV Power Transformers in Zone Substation
Engineering Standards	ESE201 Power Transformers Zone Substations

ASSET CLASS	300 HV CABLES
Strategies	EAA300 11 – 110 kV cable systems
Technical Specifications	ENS-0032 Specification for SC-triplex 22-33 kV cable ENS-0078 Specification for 400V underground cable ENS-0110 Thermal backfill for underground cables ENS-0191 Specification for single core 110 kV cable ENS -0028 Testing of High Voltage Cables and Switchgear ENS -0102 Specification FOR Polymetric cable protection covers ENS-127 Specification for 11& 22kV underground distribution cable ENS-0169 11 kV cable current ratings for planning purposes SCOTT ESS301 Ducting for Electrical Installations
Maintenance Standards	ESM-301 Maintenance of cables
Engineering Standards	ESE301 Cable Support Systems-in enclosed basements ESE302 Design requirements for sub transmission and distribution cables ESE303 Installation requirements for cables and ducts

ASSET CLASS	400 OVERHEAD LINES
Strategies	EAA400 Overhead lines
Technical Specifications	ENS-0091 Specification for treated timber utility services poles ENS- 101 Specification for Surge Arrestors ENS-0153 Specification for overhead conductors ENS-0160 Specification for LV ABC fittings ENS-0163 Specification for overhead line connectors ENS-0084 Specification for pole mounted fuse carriers and links ENS-0134 Overhead conductor current ratings for planning purposes ESS401 Specification for hardwood and composite crossarms ESS402 Specification for prestressed concrete and composite poles ESS404 Specification for Overhead Line Insulators ESS405 Specification for Overhead Line Fittings and Accessories
Maintenance Standards	ESM401 Maintenance of Overhead Lines
Engineering Standards	ESE401 Overhead Line Design Requirements ESE402 Overhead Standard Design Applications ESE403 CCT installation on 11kV network ESE406 Overhead Standard Applications Structures with Streetlights ESE413 Aerial Fibre Cables Installation

ASSET CLASS	500 DISTRIBUTION NETWORK
Strategies	EAA500 Distribution Equipment
Technical Specifications	ENS-0093 Specification for fluid filled distribution transformers ENS-0097 Specification for pole mounted SF_6 switches ENS-0098 Specification for sectionalisers and remote switches ENS-0101 Specification for Surge Arrestors ENS-0103 Specification for 11 kV and 22 kV distribution switchgear ENS-0121 Specification for auto-reclosers ENS-0154 Specification for LV distribution service pits ENS-0155 Specification for IPPCs for LV distribution Pit ENS-0162 Specification for fault passage indicators ENS-0170 Refurbishment of distribution Transformers and oil filled switchgear ENS-0224 Standard for Design of Customer Supply ESP001 Residential Subdivision Design Standard ESP002 Non-residential subdivision design and planning standard ESP004 LV Voltage Drop Calculation
Maintenance Standards	ESM501 Maintenance of Overhead Switchgear ESM502 Maintenance of Pole Mounted Distribution Transformers ESM503 Maintenance of Ground Mounted Distribution Equipment ESM504 Maintenance of Voltage Regulators ESM505 Maintenance of LV Distribution Systems ESM607 Maintenance of Earthing System
Engineering Standards	ESE501 Distribution Substations in Buildings ESE502 Outdoor Ground Mounted Distribution Equipment ESE503 Distribution Switchgear ESE504 Low Voltage Underground Distribution ESE505 Ground Mounted Distribution Transformer ESE506 Distribution Earthing

ASSET CLASS	600 AUXILIARY SYSTEMS
Strategies	EAA600 Auxiliary Systems
Technical Specifications	ENS-0080 Specification for earthing rods and accessories
Maintenance Standards	ESM601 Maintenance of DC and AC Supply Systems ESM602 Maintenance of Capacitor and Reactor Banks ESM603 Maintenance of Building Security, Air and Fire Management Systems ESM604 Maintenance of Ripple Plant ESM607 Maintenance of Earthing System

ASSET CLASS	600 AUXILIARY SYSTEMS
Engineering Standards	ESE601 DC Systems ESE602 AC Systems

ASSET CLASS	700 INFRASTRUCTURE AND FACILITIES
Strategies	EAA700 Infrastructure and Facilities
Technical Specifications	ENS-0206 Specification for crushed rock for switchyards
Maintenance Standards	ESM701 Maintenance of Building, Structures and Facilities ESM708 Maintenance of Minor Tunnels ESM709 Maintenance of Penrose-Hobson Tunnel
Engineering Standards	EDE7031 Standard Zone Substation Lighting Design EDE7032 Standard Zone Substation Small Power Design EDE7033 Standard Zone Substation HVAC Design EDE7035 Zone Substation Sump Standard Design EDE7011 Zone Substation Standard Building Penetrations EDE0021 Zone Substation Signage ESE002 Zone Substation Signage EDE7505 33kV Cable Termination Copper Earth Bars EDE7506 33kV Cable Termination Copper Jug Handle Earthing Bar EDE7034 Zone Substation Fire and Security Design ESE703 Zone Substation Building Services ESE701 Zone Substation Buildings ESE702 Zone Substation Grounds ESE704 Zone Substation Earthing EDE7012 Zone Substation Template Building EDE7041 Zone Substation Earthing EDE5001 Substation Room General EDE5002 Substation Room Equipment layouts

ASSET CLASS	800 PROTECTION AND OPERATIONAL TECHNOLOGY
Strategies	EAA800 Protection and Operational Technology
Technical Specifications	ENS-4002 Protection and Control – Protection Settings Management System ENS-4003 Protection and control – Technical documentation
Maintenance Standards	ESM801 Maintenance of Protection and Control Systems ESM804 Maintenance of Pilot Cables ESM805 Maintenance of Radio Equipment
Engineering Standards	ESE801 Protection System ESE802 Automation and Control in Zone Substations ESE803 Protection and Control for Overhead Distribution Feeders ESE805 Secondary Cabling ESE806 Protection distribution Substation ESE807 Protection Philosophy Subtransmission Zone Substations and Distribution ESE810 Testing and Commissioning of Protection Relays

ASSET CLASS	900 NEW ENERGY SOLUTIONS
Strategies	EAA900 Distributed (Decentralized) Energy Systems
Technical Specifications	Being developed – work in progress
Maintenance Standards	ESM901 Generation and Energy storage ESM903 Maintenance of Residential PV and Battery Energy Systems
Engineering Standards	Being developed – work in progress

HEALTH, SAFETY AND ENVIRONMENT MANAGEMENT STANDARDS
HSEMS01 Management systems framework and HSE policies
HSEMS02 Leadership and Accountability
HSEMS03 Competence and Behaviour
HSEMS04 Engagement, Participation and Consultation
HSEMS05 Contractor HSE Management
HSEMS06 Emergency Management
HSEMS07 Wellness and Fitness to Work
HSEMS08 Risk Management
HSEMS09 Incident Management
HSEMS10 Audits, Reviews and Performance Reporting
HSEMS11 Operational Control
HSEMS12 HSE in Project Management
HSEMS13 Legal Compliance
HSEMS14 Document, Data and Record management
HSEMS15 Action Management

ELECTRICITY OPERATING STANDARDS
ESH001 Electricity Network Safety and Operating Plan
EOS001 Operational Control of the Network
EOS002 Release of Network Equipment
EOS003 Procedures for Operations on the Vector Network
EOS004 Switching Schedules and Permits Preparation Use and Operating Terms
EOS006 Live Line Operating Standard
EOS007 Zone Substation Access and Security
EOS009 Commissioning of Network Equipment
EOS010 Operational Numbering of Vector Equipment
EOS011 Protocol for Communications with the Electricity Operations Centre
EOS012 Operation of Ground Mounted Switchgear up to and including 33 kV
EOS013 Standard Operational Terms and Abbreviations
EOS014 Operation of Circuit Breakers and associated Equipment
EOS015 Procedures for Operation of OH Equipment up to and including 110 kV
EOS018d Tunnel Procedures Rail Maintenance Planning
EOS019 Contingency Plans (36 documents)
EOS020 Procedures for Management and Operations on the Vector Low Voltage Network
EOS026 Managing Asset Rating Changes

NETWORK INFORMATION STANDARDS
ECD005 HV Event Quality Assurance Process
ECD010 HVSpec Planned Work Data Capture (DRAFT – work in progress)
EGD003 Calculation Guidelines for Electricity Reliability Metrics
ENSD001 Asset Data Standards SAP and GIS (Electricity)
EOC-009 HV Event Quality Control Procedure
ESD001 Functional Location Structure Electricity
ESD002 Reactive Maintenance Data Standard
ESD003 HV Event Data Standard
ESD005 Asset Data and GIS Data Standard
ESD006 Planned and Corrective Maintenance Data Standard
ESD007 Vegetation Cut or Trim Data Standard (DRAFT – work in progress)
USD003 Data Update Request Data Standard

17.3 Appendix 3 – Typical load profiles

Figures 17.1, 17.2 and 17.3 show typical demand profiles for residential, commercial and CBD customer segments.

The profiles are normalised so that the shape characteristics can be compared. The true peak demand of each profile can differ significantly between winter and summer and is discussed in the sections below.

17.3.1 RESIDENTIAL DEMAND PROFILE

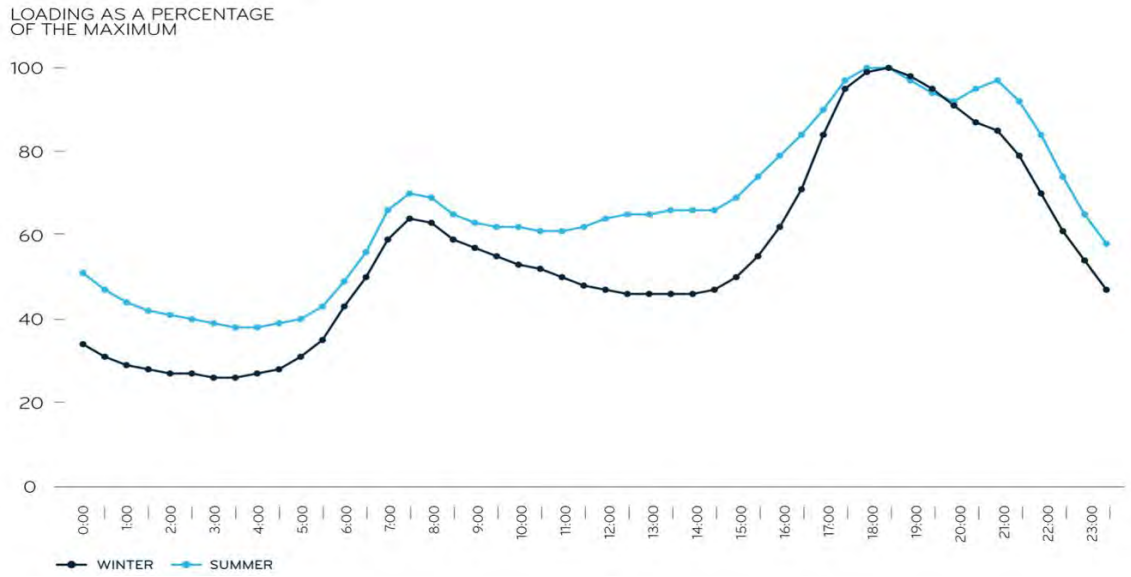


FIGURE 17-1: TYPICAL RESIDENTIAL DEMAND PROFILE (NORMALISED – LOADING AS A PERCENTAGE OF MAXIMUM)

The key characteristics of the residential demand profile are the distinct morning and evening peaks. There is a significant difference in demand between summer and winter profiles, where in absolute usage terms, winter is almost double that of summer. The profile characteristics are viewed at an 11 kV distribution feeder level rather than an individual customer profile

Capturing the profiles at this level in the network hierarchy shows a diversified demand profile illustrating the length of the evening winter peak which can extend upwards of three hours. There is no evidence of significant solar/PV in the summer profile which would show up as significantly reduced demand from late morning until late afternoon.

17.3.2 COMMERCIAL DEMAND PROFILE

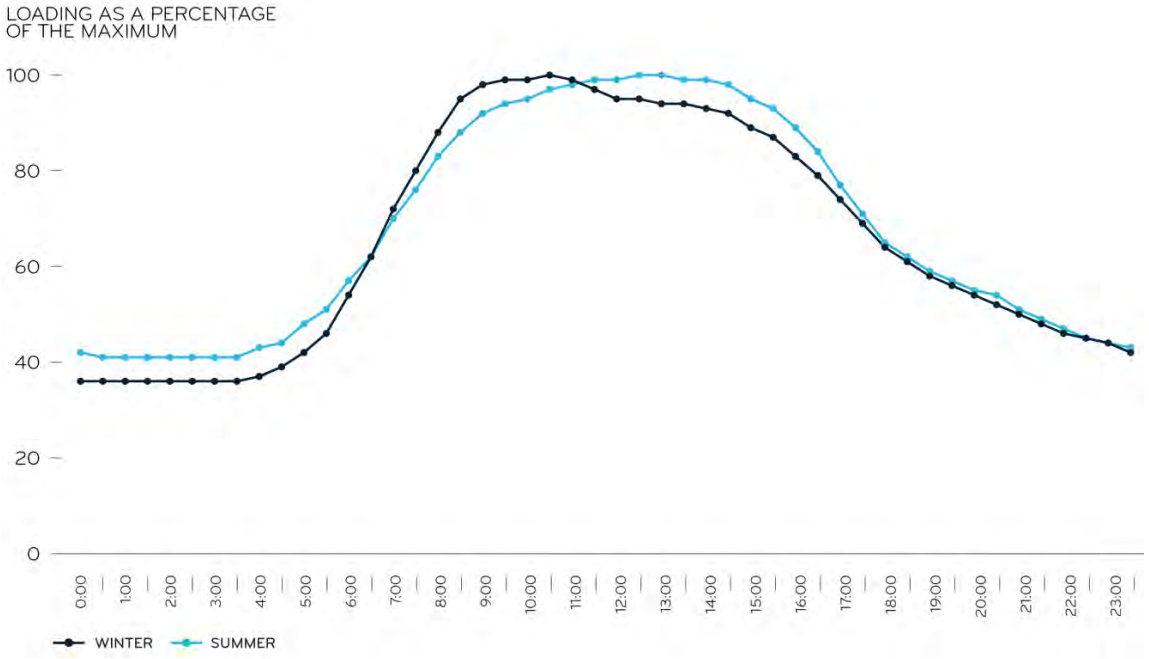


FIGURE 17-2: TYPICAL COMMERCIAL DEMAND PROFILE

Commercial demand follows a similar profile and loading as residential for both winter and summer.

17.3.3 CBD DEMAND PROFILE

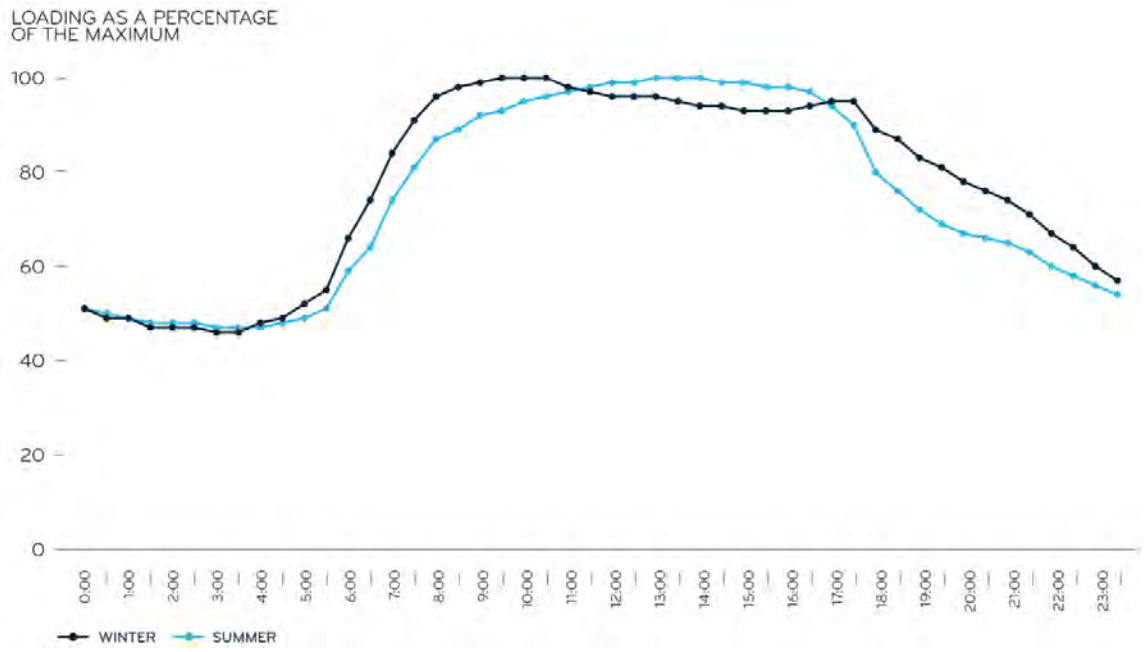


FIGURE 17-3: TYPICAL CBD DEMAND PROFILE

The Auckland CBD load is characterised by the summer profile where load rises quickly in the morning and drops off equally as rapidly in the evening. The winter load profile demonstrates a similar characteristic to the summer although more aggressive uptake before 7.00am and a slower ramp-down in the evenings. The peak load is summer driven mainly by air-conditioning, adding an extra 10% load above the winter demand profile.

17.3.4 LARGE CUSTOMERS THAT HAVE A SIGNIFICANT IMPACT ON THE NETWORK

Vector has several large customer sites at various locations in its network. The following are those customer sites with individual demand above 5 MVA, which are considered to have a significant impact on network operations and asset management:

- Fonterra at Lichfield;
- Auckland International Airport;
- Mangere Wastewater Treatment Plant;
- Bluescope Steel at Mangere;
- Pacific Steel at Mangere;
- Auckland Hospital at Newmarket;
- Carter Holt Harvey at Penrose
- Owens Illinois at Penrose

There has also been an increase in large customer queries supplied from Henderson and Silverdale GXPs.

17.4 Appendix 4 – AMP information disclosure compliance

INFORMATION DISCLOSURE DETERMINATION REQUIREMENT (EXISTING)

CLAUSE	DESCRIPTION	AMP SECTION
	Overview	
3.1.	A summary that provides a brief overview of the AMP contents and highlights information that the EDB considers significant;	1.3, 1.4.1
3.2.	Details of the background and objectives of the EDB's asset management and planning processes;	5.3, 5.4
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;	1.4.1
3.3.2.	states the corporate mission or vision as it relates to asset management;	1.4.5
3.3.3.	identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	5.5
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	5.5
3.3.5.	includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	1.4.5, 5.2
3.4.	Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed;	1.4.2
3.5.	The date that it was approved by the directors;	1.4.3
3.6.	A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates -	4.5
3.6.1.	how the interests of stakeholders are identified	4.5
3.6.2.	what these interests are;	4.5.3
3.6.3.	how these interests are accommodated in asset management practices; and	5.3
3.6.4.	how conflicting interests are managed;	4.10
3.7.	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including -	6.2
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;	6.2
3.7.2.	executive—an indication of how the in-house asset management and planning organisation is structured; and	6.2
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;	16.2-16.4
3.8.	All significant assumptions -	
3.8.1.	quantified where possible;	Appendix 6
3.8.2.	clearly identified in a manner that makes their significance understandable to interested persons, including-	Appendix 6
3.8.3.	a description of changes proposed where the information is not based on the EDB's existing business;	Appendix 6
3.8.4.	the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	1.2, 15.6
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;	Schedule 14a
3.9.	A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;	1.2, 1.4, 15.6.1
3.10.	An overview of asset management strategy and delivery; • how the asset management strategy is consistent with the EDB's other strategy and policies;	5, 5.1, 5.2

CLAUSE	DESCRIPTION	AMP SECTION
3.10.	• how the asset strategy takes into account the life cycle of the assets;	5.3
	• the link between the asset management strategy and the AMP; and	5.1, 5.2, 5.3
	• processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.	5.6.2, 16.2
3.11.	An overview of systems and information management data; 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; 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; c) the systems and controls to ensure the quality and accuracy of asset management information; d) the extent to which these systems, processes and controls are integrated; e) how asset management data informs the models that an EDB develops and uses to assess asset health; and f) how the outputs of these models are used in developing capital expenditure projections.	5, 6.3, 6.6, 6.7 5.6.3 5.6.3
3.12.	A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data;	6.7.2
3.13.	A description of the processes used within the EDB for -	
3.13.1.	managing routine asset inspections and network maintenance;	8.2
3.13.2.	planning and implementing network development projects; and	10.4
3.13.3.	measuring network performance;	7.5, 7.6
3.14.	An overview of asset management documentation, controls and review processes: (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.	5.5, 5.6
3.15.	An overview of communication and participation processes; (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	5.6.6
	ii) demonstrate staff engagement in the efficient and cost-effective delivery of the asset management requirements.	5.6.6, 16.1, 16.2.3
3.16.	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	Compliant
3.17.	The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination	Compliant
	Assets Covered	
4	The AMP must provide details of the assets covered, and non-network solutions including-	10.3.5, 10.5, 10a, 12.9, 12.10
4.1.	a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	3.1
4.1.1.	the region(s) covered;	3.1
4.1.2.	identification of large consumers that have a significant impact on network operations or asset management priorities;	3.1, Appendix 3
4.1.3.	description of the load characteristics for different parts of the network;	3, 10.6
4.1.4.	peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	3, 10.6
4.2.	A description of the network configuration, including-	3, 10.6

CLAUSE	DESCRIPTION	AMP SECTION
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;	10.6
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;	7.6, 10.6, Schedule 12b
4.2.3.	a description of the distribution system, including the extent to which it is underground;	3.3, 3.6
4.2.4.	a brief description of the network's distribution substation arrangements;	12.7.3, 12.7.4
4.2.5.	a description of the low voltage network including the extent to which it is underground; and	3.3, 3.6
4.2.6.	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	12.8
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. 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.	12.10.21 3.1
4.3.	If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	3, 10.6
	Network assets by category	
4.4	The AMP must describe the network assets by providing the following information for each asset category-	
4.4.1.	voltage levels;	8, 12.3-12.11
4.4.2.	description and quantity of assets;	8, 12.3-12.11
4.4.3.	age profiles; and	8, 12.3-12.11
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.	8,12.2.3, 12.3-12.11
4.5.	The asset categories discussed in clause 4.4 should include at least the following-	12.3-12.11
4.5.1.	the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	8, 12.2.4
4.5.2.	assets owned by the EDB but installed at bulk electricity supply points owned by others;	12.3-12.11
4.5.3.	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	12.10.5
4.5.4.	other generation plant owned by the EDB.	12.10
	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.	7
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.	7.5
7.	Performance indicators for which targets have been defined in clause 5 should also include-	
7.1.	Consumer oriented indicators that preferably differentiate between different consumer types; and	7.2
7.2.	Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	7, 12.2-12.11
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.	7
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	7

CLAUSE	DESCRIPTION	AMP SECTION
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.	7
	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;	10.3, 10.4, Appendix 6
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;	10.4
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;	5.5.3
11.4.	The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	5.5.3
11.4.1.	the categories of assets and designs that are standardised; and	5.5.3
11.4.2.	the approach used to identify standard designs;	5.5.3
11.5.	A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	2.3, 2.4
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;	10.4
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;	10.4
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;	10.4.1, 10.6
11.8.1.	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	10.4.1
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;	10.6
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	10.6
11.8.4.	discuss the impact on the load forecasts of any anticipated levels of non-network solutions in a network.	10.4, 10.5
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-	10.6, 10a
11.9.1.	the reasons for choosing a selected option for projects where decisions have been made;	10.6, 10a
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	10.6, 10a
11.9.3.	consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	2.3
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-	10.6
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;	10.6, 10a
11.10.2.	a summary description of the programmes and projects planned for the following four years (where known); and	10.6, 10a
11.10.3.	an overview of the material projects being considered for the remainder of the AMP planning period;	10.6, 10a
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	9.3.4, 10.4.1.2
11.12.	A description of the EDB's policies on non-network solutions, including-	10.5.1
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;	10
11.12.2.	the potential for non-network solutions to address network problems or constraints; and	10
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.	10.3.2, 10.5.1, 10.6

CLAUSE	DESCRIPTION	AMP SECTION
	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;	8, 12
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-	12
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;	12
12.2.2.	any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	12
12.2.3.	budgets for maintenance activities broken down by asset category for the AMP planning period;	8.4-8.6
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-	11, 12
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;	12.2
12.3.2.	a description of innovations that have deferred asset replacements;	12.1.2.6
12.3.3.	a description of the projects currently underway or planned for the next 12 months;	12a
12.3.4.	a summary of the projects planned for the following four years (where known); and	12a
12.3.5.	an overview of other work being considered for the remainder of the AMP planning period; and	12a
12.4.	The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	8, 12
12.5	Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of -	12.2
12.5.1	the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	12.2
12.5.2	the rationale for using the approach for each asset category.	12.2
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.	8.8, 8.8.5, 11.4.1
12.7	The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB used to inform these expenditure projections;	10.3.5, 10.5.2
	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;	14.2, 14.8
13.2.	development, maintenance and renewal policies that cover them;	14.2-14.7
13.3.	a description of material capital expenditure projects (where known) planned for the next five years; and	14.5
13.4.	a description of material maintenance and renewal projects (where known) planned for the next five years.	14.1, 14.2-14.7
	Risk Management	
14.	AMPs must provide details of risk policies, assessment, and mitigation, including—	
14.1.	Methods, details and conclusions of risk analysis;	6.3, 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;	6.3, 11
14.3.	A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	6.3, 11
14.4.	Details of emergency response and contingency plans.	6.4
	Evaluation of Performance	
15.	AMPs must provide details of performance measurement, evaluation, and improvement, including—	

CLAUSE	DESCRIPTION	AMP SECTION
15.1.	A review of progress against plan, both physical and financial;	5.6, 7, 8.4.3, 15, 16.2.3, Appendix 5
15.2.	An evaluation and comparison of actual service level performance against targeted performance;	7
15.3.	An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	5.6
15.4.	An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	5.6, 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	5.3
16.2.	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	6.1, 6.2
	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:	
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;	7.5.1
	Voltage quality and constraints	
17.2	A description of the EDB's practices for;	
17.2.1	monitoring voltage quality including; a) the EDB's practices for monitoring voltage quality on its low voltage network 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; 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 d) how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and e) any plans for improvements to any of the practices outlined at clauses (a)-(d) above;	7.3
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 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).	7.3
	Customer Service Practices	
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;	4.5, 7.2, 10.3.2
17.3.2	the EDB's approach to planning and managing customer complaint resolution;	7.8
	Practices for connecting new customers and altering existing connections	
17.4	A description of the EDB's practices for connecting consumers, including -	9
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 (b) alterations to existing connections (offtake and injection connections);	9.3
17.4.2	how the EDB is seeking to minimise the cost to consumers of new or altered connections;	9.1, 9.3
17.4.3	the EDB's approach to planning and managing communication with consumers about new or altered connections; and	9.3
17.4.4	commonly encountered delays and potential timeframes for different connections.	9.3
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.	7.3.1, 10.3.2, 10.5.1
17.5	A description of the following:	

CLAUSE	DESCRIPTION	AMP SECTION
17.5.1	how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity; (b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account; (c) how the EDB takes other factors into account, e.g., the network location of new demand, generation, or storage capacity; and	10.3, 10.4
17.5.2	how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	10.3, 10.4
	Innovation Practices	
17.6	Must include a description of the following -	2
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;	2
17.6.2	the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	2
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;	2
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	2
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.	2

17.5 Appendix 5 – Significant changes from AMP2025

2026 AMP SCHEDULE DATE	SUBSTATION	PROJECT AND PROGRAMME DESCRITPION	2025 AMP SCHEDULE DATE	REASON FOR CHANGE
TBA	Highbury	Highbury k11 and k03 reinforcement for E-Ferry	FY26	Change in customer requirement
TBA	Hillsborough	Hillsborough new 11kV feeder to supply Carr Rd E-bus	FY26	Change in customer requirement
TBA	Howick	Half Moon Bay E-Ferry Phase 2	FY26	Change in customer requirement
TBA	Takanini	Takanini Heb Place 11kV feeder new E-Bus	FY26	Change in customer requirement
TBA	Ngataringa Bay	NGAT K01 & BMON K01 reinforcement for E-Ferry	FY26	Change in customer requirement
FY28	Redhills	Redhills land purchase for ZSS	FY26	Change in customer requirement
FY31	Redhills	Redhills ZSS 11kV ducts install	FY26	Change in customer requirement
FY32	McNab	McNab new 11kV feeder to Holloway Place for security in WEST K09	FY26	Revised load forecast
FY29	Whenuapai	Whenuapai Zone Substation New	FY27	Change in delivery schedule
FY29	Manly	Penlink Whangaparaoa reinforcement	FY27	Change in 3rd party infrastructure timing
FY30	Westfield	Westfield SUBT cable replace	FY27	Change in 3rd party timeline
FY30	Westfield	Westfield to Southdown cables and FP ducts	FY27	Change in 3rd party timeline
On Hold	Hobson	CBD 22kV extension High St	FY27	Change in 3rd party infrastructure timing
FY32	Takanini	Waiheke 33kV 3rd SUBT cable new	FY28	Change in 3rd party timeline
FY27	Quay/Hobson	AT -EV Ferry 14 MVA - RNF Portion	FY29	Change in customer requirement
FY27	Various	AMETI EB2, 3 and 4	FY29	Change in 3rd party infrastructure timing
FY31	Te Papapa	Te Papapa 11kV SWBD Replace	FY29	Align with internal project timing
FY31	Albany GXP	Rosedale GXP subtransmission cables	FY29	Detail network optimisation
FY31	Rosedale	Albany GXP Rosedale Subtrans Cable Reinforcement	FY29	Change in 3rd party infrastructure timing
FY31	Hobson	Nicholas New 110-22kV ZSS	FY29	Change in project schedule
FY28	Mangere Central	Mangere Central K11 Feeder Reinforcement	FY31	Change in customer requirement
FY35	Woodford	Woodford 11kV SWBD replace	FY31	Align with internal project timing
FY28	Clendon	Clendon Weymouth Rd 11kV feeder new	FY32	Detail network optimisation
FY28	Flat Bush	Flat Bush Murphys Rd 11kV feeder new	FY32	Change in customer requirement
FY30	Various	North West Rapid Transit	FY32	Change in 3rd party infrastructure timing
FY36	Orewa	Orewa ZS West Hoe Heights 11kV cable upgrade	FY32	Revised load forecast
FY29	Mangere	Mangere South 11kV Switchgear and 33/11kV Transformer	FY33	Change in customer requirement
FY36	Forrest Hill	Forrest Hill 33/11kV TX upgrade T1+T2	FY33	Revised load forecast
FY32	Torbay	Torbay 11kV SWBD replace	FY34	Align with internal project timing

2026 AMP SCHEDULE DATE	SUBSTATION	PROJECT AND PROGRAMME DESCRITPION	2025 AMP SCHEDULE DATE	REASON FOR CHANGE
FY32	Manurewa	Manurewa 33/11kV TX Replace T1	FY34	Change in asset risk assessment
FY32	Mt Albert	Mt Albert ZSS 2nd Tx and new subtran cables	FY34	Revised load forecast
FY32	Papakura	Papakura Settlement Rd 11kV feeder new	FY34	Change in customer driven demand
FY36	Rockfield	Rockfield ZSS 3rd TX and subtran	FY34	Revised load forecast
FY36	Newmarket	Newmarket substation upgrade	FY34	Revised load forecast
FY36	Sunset Rd	Sunset Road 33/11kV TX upgrade T1+T2	FY34	Revised load forecast
FY31	Waimauku	Waimauku 33kV 2nd SUBT cable and 33kV SWBD	FY35	Change in 3rd party timeline
FY32	Hobsonville Point	Henderson to Hobsonville point Subtrans future-proofing ducts + Cable via Hobsonville ZSS & Trig road	FY35	Change in 3rd party timeline
FY32	Riverhead	Huapai to Riverhead 2 x Subtrans future-proofing ducts + cable	FY35	Change in 3rd party timeline
FY32	Riverhead	Huapai to Kumeu future proofing ducts	FY35	Detail network optimisation
FY33	McLeod Rd	McLeod Road 33kV SWBD ODID replace	FY35	Align with internal project timing
FY33	Torbay	Torbay 33kV SWBD ODID replace	FY35	Align with internal project timing
FY33	Manurewa	Manurewa 33/11kV TX Replace T2	FY35	Change in asset risk assessment
FY33	Ponsonby	Ponsonby substation upgrade	FY35	Revised load forecast
FY33	Kingsland	Kingsland new 11kV feeders capacity and security in KING K20	FY35	Revised load forecast
FY33	McLeod	McLeod Rd 33/11kV TX upgrade T1	FY35	Revised load forecast
FY28	Mangere East	West Wiri Puhinui Rd 11kV feeder new	Beyond AMP Horizon	Change in customer requirement
FY29	CBD	CBD Bankside St 22kV extension and conversion	Beyond AMP Horizon	Align with internal project timing
FY30	CBD	CBD Eden Cre and Anzac Av 22kV extension and conversion	Beyond AMP Horizon	Combined with another project
FY30	Manurewa	Manurewa Alfriston Rd 11kV feeder new	Beyond AMP Horizon	Revised load forecast
FY31	CBD	CBD 11kV to 22kV conversion for security in LIVE K01	Beyond AMP Horizon	Revised load forecast
FY32	CBD	CBD Liverpool St 22kV extension and conversion	Beyond AMP Horizon	Align with internal project
FY32	CBD	CBD Vincent St 22kV extension and conversion	Beyond AMP Horizon	Align with internal project
FY32	CBD	CBD Liverpool 11kV to 22kV conversion for security	Beyond AMP Horizon	Revised load forecast
FY34	CBD	CBD Victoria 11kV to 22kV conversion for security	Beyond AMP Horizon	Revised load forecast
FY35	Hobsonville	Hobsonville 33/11kV T1+T2 TX Upgrade	Beyond AMP Horizon	Change in customer requirement

2026 AMP SCHEDULE DATE	SUBSTATION	PROJECT AND PROGRAMME DESCRITPION	2025 AMP SCHEDULE DATE	REASON FOR CHANGE
FY35	Mangere Central	Mangere Central Massey Rd 11kV feeder new	Beyond AMP Horizon	Revised load forecast
FY36	Hobson	Hobson ZSS 3rd 75MVA 110-22kV TX	Beyond AMP Horizon	Revised load forecast
FY36	Sandringham	Sandringham Stoddard Rd 11kV feeders new (KO driven)	Beyond AMP Horizon	Revised load forecast
FY36	Mangere Central	Mangere Central Idlewild Ave 11kV feeder new	Beyond AMP Horizon	Revised load forecast
FY29	Quay/ Liverpool	Auckland University Upgrades	TBA	Change in customer requirement
FY30	Glenvar	East Coast Rd and Glenvar Rd	On Hold	Change in 3rd party infrastructure timing
FY27	Hobson	Swanson tunnel 11kV derisk		New Project
FY27	Maraetai	TAKA Airfield Rd Maraetai 33kV SUBT Reinforcement		New Project
FY27	Takanini	Takanini K17 Alfriston-Ardmore Rd Overhead Upgrade		New Project
FY28	Takapuna	Amaia 33kV Undergrounding		New Project
FY28	Birkdale	Birkdale (66) circuit replacement		New Project
FY28	Maraetai	Maraetai 11kV New Feeder - Beachlands Rd		New Project
FY28	White Swan	White Swan Rd future proofing ducts		New Project
FY28	Newmarket	Newmarket new feeders to off load NEWM K19 and NEWM K30		New Project
FY28	Orewa	Milldale Land Purchase		New Project
FY28	Howick	Howick 11kV New Feeder - Half Moon Bay		New Project
FY28	Various	Auckland Digital Substation Upgrade		New Project
FY28	Various	Northern Digital Substation Upgrade		New Project
FY29	Auckland Airport	Mangere South 33kV Node - AIAL contribution		New Project
FY29	CBD	Customs St – Bus Priority REL		New Project
FY29	Rosedale	Rosedale (104) circuit replacement		New Project
FY29	Various	MEGA-AT-WSBI STAGE 2		New Project
FY29	CBD	Customs& Sturdee Street		New Project
FY29	Hobson	Nicholas ZSS new 22kV feeders		New Project
FY29	CBD	Customs St Bus Priority 22kV Conversion		New Project
FY29	Liverpool	Liverpool ZSS 22kV SWBD Extension		New Project
FY29	Wairau	Rosedale GXP Enabling Works		New Project
FY30	Various	NZTA SH1 Warkworth to Te Hana		New Project
FY30	Onehunga	Onehunga to Southdown SUBT Cable Installation		New Project

2026 AMP SCHEDULE DATE	SUBSTATION	PROJECT AND PROGRAMME DESCRITPION	2025 AMP SCHEDULE DATE	REASON FOR CHANGE
FY31	Quay/Hobson	AT -EV Ferry 14 MVA		New Project
FY31	Various	East West Link - REL		New Project
FY31	Waimauku	Waimauku 11kV SWBD replace		New Project
FY31	Hobson	Nicholas ZSS 110kV cables from Hobson ZSS		New Project
FY31	Orewa	Milldale ZSS		New Project
FY32	Takanini	Mill Road Future Proofing Ducts		New Project
FY32	Clevedon	Clevedon 11kV New Feeder		New Project
FY32	Ranui	Ranui K04 Glen Road 11kV reinforcement		New Project
FY33	Manly	Manly 33kV SWBD ODID		New Project
FY33	Maraetai	Maraetai T1 & T2 Upgrade		New Project
FY33	West Wiri	West Wiri Subtransmission Cable		New Project
FY34	Warkworth	Warkworth 33kV SWBD ODOD replace		New Project
FY35	Keeling Rd	KEEL K06 Hickory Avenue 11kV reinforcement		New Project
FY36	Simpson Rd	Simpson Road 33kV SWBD ODID replace		New Project
FY36	Remuera	Remuera 11kV SWBD replace		New Project
FY36	Woodford	Woodford 33kV SWBD ODID replace		New Project
FY36	Balmain	Balmain Rd 33/11kV TX Replace T1		New Project
FY36	Rockfield	Rockfield 33/11kV TX Replace T1		New Project
FY36	Mangere Central	Mangere Central T1 33/11kV TX Replace T1		New Project
FY36	Papakura	Papakura 33/11kV TX Replace T1 & T2		New Project
FY36	White Swan	White Swan 22/11kV TX Replace T1 & T2 & T3		New Project
FY36	Howick	Howick 33/11kV TX Replace T1 & T2		New Project
FY36	Manurewa	Manurewa (1&2) fluid filled replacement		New Project
FY36	Papakura	Papakura 3rd Tx, Subt Cable and Swbd Extension		New Project

17.6 Appendix 6 – Assumptions table

AREA	ASSUMPTION MADE OVER 10-YEAR PLANNING PERIOD
Commerce Commission regulatory environment	DPP5 will be consistent with DPP4 with no significant changes to Commerce Commission regulatory settings, input methodologies or innovation and non-traditional solutions allowance (INTSA).
EA pricing and connections regime	Any EA changes to capital contributions and connection processes will not significantly alter Vector's ability to recover costs and deliver value to customers.
Government policy	No new major government energy reforms or policy change (including decarbonisation and subsidies) are assumed beyond those currently known.
Long-term climate development	The climate is expected to develop according to the IPCC's Shared Socio-economic Pathways (SSP) 5-8.5 climate scenario which is a high greenhouse gas emission scenario (>4°C warmer world).
Economic inflators	Economic inflators used to convert between nominal and constant price are summarised in Appendix 14.
Market settings and regulation for flexibility	Market settings and regulation are expected to prevent EDBs from directly managing most behind-the-meter controllable devices. Instead, EDBs will work through third parties, such as retailers, with regulators continuing to promote flexibility mechanisms including cost-reflective pricing and EDB-contracted flexibility (including flexible connections). Third parties will be required to make flexibility available to the EDB to manage system emergencies and to ensure their actions stay within the limits of the network.
Load shifting from pricing	Demand forecasts implicitly assume that consumer uptake of, and response to, time-of-use pricing and other load-shifting measures remain at current levels, with no assumed material decrease or increase in demand due to load management by third parties.
Objective for CER management	Government and regulators will promote flexible load management that minimises whole-energy-system costs (i.e. generation, transmission, distribution and retail), meaning distribution network cost optimisation will not necessarily be prioritised over other system cost reductions.
EV uptake	EV uptake assumptions are based on a modified interpretation of the former New Zealand Government Emissions Reduction Plan targets and the Climate Change Commission's "Further Behaviour Change" scenario. As the original targets applied exclusively to battery electric vehicles (BEVs), the inclusion of plug-in electric vehicles (PHEVs) reduces the overall target by approximately 30 percent. EV uptake in the Auckland region is expected to reach roughly 500k electric vehicles (including PHEVs) at the end of the 10-year AMP window and about 40% of customers will be using dedicated EV charger as preferred charging technology at home.
Solar uptake	Solar PV adoption of mass market customers will reach 40k installations at the end of the 10-year AMP period with over half also installing battery systems. Annual distributed generation forecasts are shown in Section 10 on Forecast Network Demand.
Gas to electricity conversion	The potential network impact of future conversions from natural gas and LPG to electricity is assessed using actual gas consumption data from individual customers on the Auckland gas network. Gas usage is translated into equivalent electrical demand through the application of assumed appliance and process specific conversion factors across different customer types. Assumptions for commercial conversions are informed by historical surveys and initiatives, including internal DETA Consulting work, the EECA Regional Energy Transition Accelerator report, and the former EECA Government Investment in Decarbonising Industry Fund. Residential conversions are assumed to remain low in the near to medium term, before increasing significantly toward the end of the 30-year forecast horizon. The assumed switching rates are consistent with the gas reduction assumptions used in the Gas Asset Management Plan.
Energy efficiency	Energy efficiency and technology improvements will continue to reduce energy use in buildings and improve the performance of new energy technologies (i.e. EV, solar PV, home batteries).
Population, housing and connection point growth	Short term customer growth (less than five years) is informed by historical trends in the conversion of existing building consents. Long term growth assumptions are based on the Auckland Council Growth Scenario AGS23v1, developed by the Auckland Plan, Strategy and Research Department . This modelling provides suburb level forecasts of household and employment growth over a 30-year horizon and reflects adopted strategies, plans, policies, and investment decisions. In addition to growth captured within the Auckland Council scenario, Vector incorporates identified point loads. These represent large individual customer connections derived from direct engagement, connection requests, and discussions associated with major commercial developments, such as data centres and electric bus charging facilities.

AREA	ASSUMPTION MADE OVER 10-YEAR PLANNING PERIOD
Demand per customer	The demand forecast adopts a bottom-up approach, using forward-looking estimates of individual customer loads informed by historical consumption and assumptions about evolving energy-use behaviour. Key drivers (other than the ones described above) include housing intensification leading to smaller dwellings, increased daytime residential demand from working-from-home trends, tighter energy-efficiency standards, greater uptake of efficient appliances, economic and environmental pressures on commercial customers to reduce energy costs or change processes, and a structural shift away from energy-intensive manufacturing toward service-based industries.
Cyber security	Cybersecurity threat environment remains broadly consistent with current expectations, and that forecast investment levels are sufficient to manage IT risks.
Global supply chain and trade	Global geopolitical conditions and associated impacts on supply chains and foreign exchange markets do not materially disrupt the cost or delivery of the investments forecast in this AMP beyond current expectations.
Digital platform	Existing enterprise and operational digital platforms will continue to be supported for their planned vendor support life.

											Company Name	Vector Limited
											AMP Planning Period	1 April 2026 to 31 March 2036

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8			RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35	RY36
9	**11a(i): Expenditure on Assets Forecast**		$000 (in nominal dollars)										
10		Consumer connection	108,229	129,202	135,703	132,105	97,482	100,206	107,192	110,219	113,323	116,604	116,291
11		System growth	69,857	141,683	147,232	122,588	80,123	147,606	179,853	133,910	114,721	144,497	136,295
12		Asset replacement and renewal	161,593	226,309	215,146	198,138	169,246	204,755	243,560	224,423	210,206	229,903	231,590
13		Asset relocations	30,376	28,256	35,578	39,608	36,044	34,299	34,916	35,881	36,891	37,930	38,998
14		Reliability, safety and environment:											
15		Quality of supply	-	-	-	-	-	-	-	-	-	-	-
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	36,753	48,449	64,430	73,768	70,313	68,516	68,745	68,789	70,440	75,291	79,030
18		**Total reliability, safety and environment**	36,753	48,449	64,430	73,768	70,313	68,516	68,745	68,789	70,440	75,291	79,030
19		**Expenditure on network assets**	406,808	573,899	598,089	566,207	453,208	555,382	634,266	573,222	545,581	604,225	602,204
20		**Expenditure on non-network assets**	29,147	56,241	45,932	39,773	32,339	33,340	27,418	30,408	24,134	63,495	40,302
21		**Expenditure on assets**	435,955	630,140	644,021	605,980	485,547	588,722	661,684	603,630	569,715	667,720	642,506
22													
23	*plus*	Cost of financing	6,585	11,364	11,833	10,985	8,672	11,337	12,750	11,068	10,179	12,632	11,897
24	*less*	Value of capital contributions	175,996	222,986	254,314	268,231	231,921	222,557	228,622	235,045	241,664	248,559	253,508
25	*plus*	Value of vested assets											
26													
27		**Capital expenditure forecast**	266,544	418,518	401,540	348,734	262,298	377,502	445,812	379,653	338,230	431,793	400,895
28													
29		Assets commissioned	237,039	418,519	401,540	348,734	262,300	377,503	445,812	379,653	338,230	431,794	400,896
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31			RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35	RY36
32			$000 (in constant prices)										
33		Consumer connection	108,229	126,372	129,505	122,866	88,306	88,381	92,024	92,077	92,077	92,148	89,384
34		System growth	69,857	138,579	140,508	114,014	72,581	130,188	154,404	111,868	93,213	114,191	104,759
35		Asset replacement and renewal	161,593	221,351	205,320	184,280	153,315	180,593	209,096	187,483	170,796	181,684	178,005
36		Asset relocations	30,376	27,637	33,953	36,838	32,651	30,252	29,975	29,975	29,975	29,975	29,975
37		Reliability, safety and environment:											
38		Quality of supply	-	-	-	-	-	-	-	-	-	-	-
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	36,753	47,388	61,487	68,609	63,695	60,431	59,018	57,466	57,234	59,500	60,744
41		**Total reliability, safety and environment**	36,753	47,388	61,487	68,609	63,695	60,431	59,018	57,466	57,234	59,500	60,744
42		**Expenditure on network assets**	406,808	561,327	570,773	526,607	410,548	489,845	544,517	478,869	443,295	477,498	462,867
43		Expenditure on non-network assets	29,147	55,009	43,834	36,991	29,295	29,406	23,538	25,403	19,609	50,178	30,977
44		**Expenditure on assets**	435,955	616,336	614,607	563,598	439,843	519,251	568,055	504,272	462,904	527,676	493,844
45													
46		**Subcomponents of expenditure on assets (where known)**											
48		Energy efficiency and demand side management, reduction of energy losses											
49		Overhead to underground conversion	17,699	12,308	13,052	13,052	13,052	13,052	13,052	13,052	13,052	13,052	13,052
50		Research and development	-	-	-	-	-	-	-	-	-	-	-
52													

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35	RY36
Difference between nominal and constant price forecasts	$000											
Consumer connection		-	2,830	6,198	9,239	9,176	11,825	15,168	18,142	21,246	24,456	26,907
System growth		-	3,104	6,724	8,574	7,542	17,418	25,449	22,042	21,508	30,306	31,536
Asset replacement and renewal		-	4,958	9,826	13,858	15,931	24,162	34,464	36,940	39,410	48,219	53,585
Asset relocations		-	619	1,625	2,770	3,393	4,047	4,941	5,906	6,916	7,955	9,023
Reliability, safety and environment:												
Quality of supply		-	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment		-	1,061	2,943	5,159	6,618	8,085	9,727	11,323	13,206	15,791	18,286
Total reliability, safety and environment		-	1,061	2,943	5,159	6,618	8,085	9,727	11,323	13,206	15,791	18,286
Expenditure on network assets		-	12,572	27,316	39,600	42,660	65,537	89,749	94,353	102,286	126,727	139,337
Expenditure on non-network assets		-	1,232	2,098	2,782	3,044	3,934	3,880	5,005	4,525	13,317	9,325
Expenditure on assets		-	13,804	29,414	42,382	45,704	69,471	93,629	99,358	106,811	140,044	148,662

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 expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

11a(ii): Consumer Connection

$000 (in constant prices)

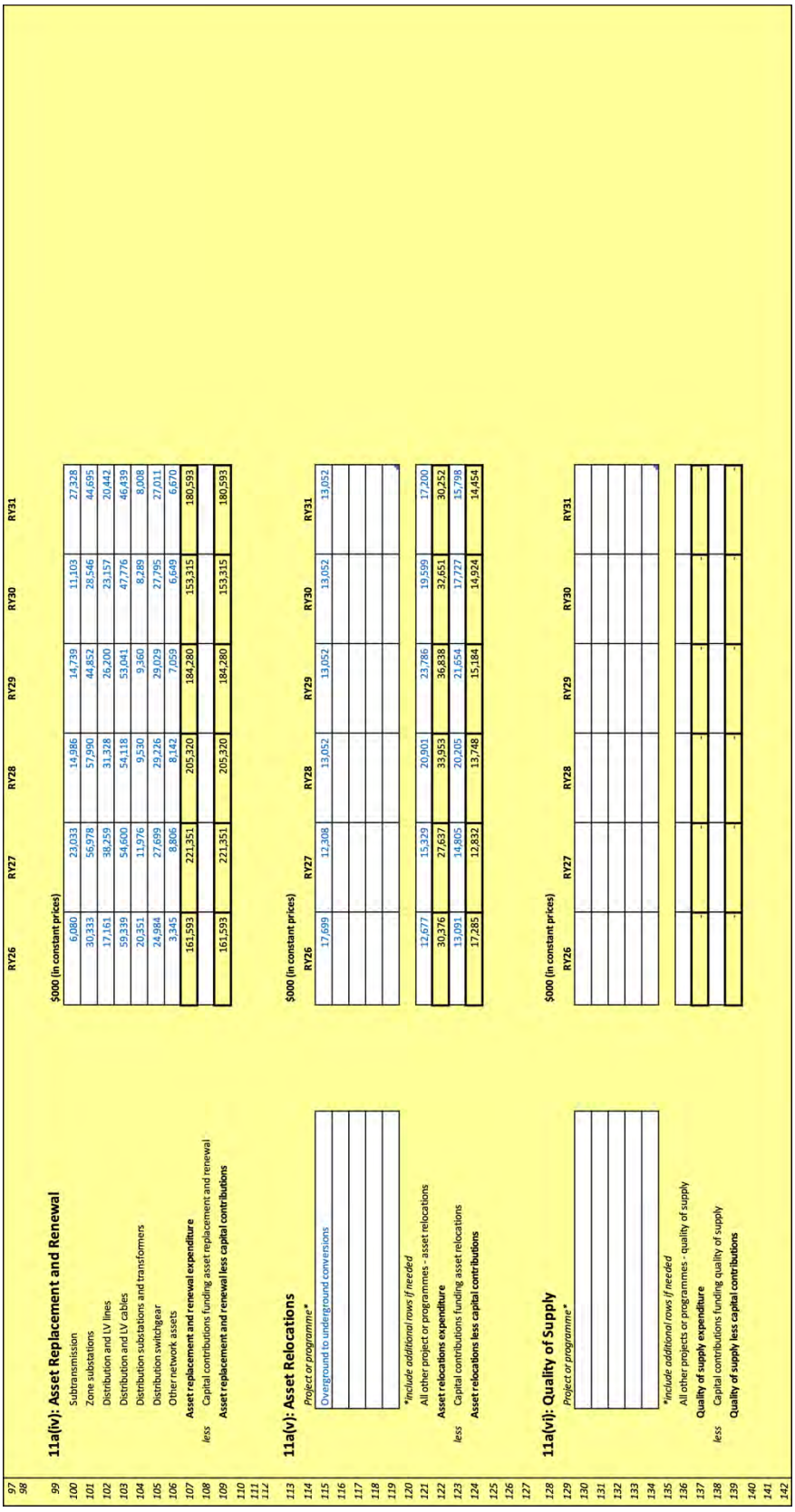
*Consumer types defined by EDB**	RY26	RY27	RY28	RY29	RY30	RY31
Service Connection	27,624	26,811	27,406	28,896	26,899	23,689
Customer Substations	33,586	61,876	66,477	56,203	26,339	33,962
Business subdivisions	3,494	964	933	932	932	932
Residential Subdivisions	35,013	29,945	30,565	32,709	30,010	25,672
Capacity Changes	5,522	5,837	3,097	3,099	3,099	3,099
Street Lighting	2,982	939	1,027	1,027	1,027	1,027
Easements	8	-	-	-	-	-
**include additional rows if needed*						
Consumer connection expenditure	108,229	126,372	129,505	122,866	88,306	88,381
less Capital contributions funding consumer connection	110,291	125,913	130,233	123,557	88,803	88,878
Consumer connection less capital contributions	(2,062)	459	(728)	(691)	(497)	(497)

11a(iii): System Growth

	RY26	RY27	RY28	RY29	RY30	RY31
Subtransmission	7,872	20,556	13,694	11,979	12,680	37,134
Zone substations	32,155	73,707	78,209	64,696	28,868	52,949
Distribution and LV lines	23	476	-	-	-	-
Distribution and LV cables	23,824	43,623	48,315	37,049	30,743	39,815
Distribution substations and transformers	5,892	-	-	-	-	-
Distribution switchgear	1	-	-	-	-	-
Other network assets	90	217	290	290	290	290
System growth expenditure	69,857	138,579	140,508	114,014	72,581	130,188
less Capital contributions funding system growth	52,614	77,384	92,262	104,261	103,560	91,618
System growth less capital contributions	17,243	61,195	48,246	9,753	(30,979)	38,570

For capital contributions, we've assumed recovery of system growth capex for all customer groups by applying our current system growth charge approach from 1 April 2026 to 31 March 2027. For periods after 31 March 2027, AMP26 uses, as a default, the capacity rates recently determined by Vector under the Electricity Authority's regulated approach. This is on the basis that such rates reflect the best information available at the time of preparing AMP26. Readers of the AMP should however be aware that Vector (1) intends to test the data used and the approach for its recently published capacity rates during 1 April 2026 to 31 March 2027, (2) to better understand customer impacts and (3) continue to engage with the EA on its proposed further customer connection reforms that intend to oblige EDBs to target a balance point when determining individual customer

contribution levels. It is anticipated that all these factors will shape our future capacity charging practices and ultimately our contribution recovery levels. Therefore, the capital contributions disclosed in AMP26 may materially change when disclosed again in AMP27.



11a(iv): Asset Replacement and Renewal

$000 (in constant prices)	RY26	RY27	RY28	RY29	RY30	RY31
Subtransmission	6,080	23,033	14,986	14,739	11,103	27,328
Zone substations	30,333	56,978	57,990	44,852	28,546	44,695
Distribution and LV lines	17,161	38,259	31,328	26,200	23,157	20,442
Distribution and LV cables	59,339	54,600	54,118	53,041	47,776	46,439
Distribution substations and transformers	20,351	11,976	9,530	9,360	8,289	8,008
Distribution switchgear	24,984	27,699	29,226	29,029	27,795	27,011
Other network assets	3,345	8,806	8,142	7,059	6,649	6,670
Asset replacement and renewal expenditure	161,593	221,351	205,320	184,280	153,315	180,593
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	161,593	221,351	205,320	184,280	153,315	180,593

11a(v): Asset Relocations

$000 (in constant prices) *Project or programme**	RY26	RY27	RY28	RY29	RY30	RY31
Overground to underground conversions	17,699	12,308	13,052	13,052	13,052	13,052
**Include additional rows if needed*						
All other project or programmes - asset relocations	12,677	15,329	20,901	23,786	19,599	17,200
Asset relocations expenditure	30,376	27,637	33,953	36,838	32,651	30,252
less Capital contributions funding asset relocations	13,091	14,805	20,205	21,654	17,727	15,798
Asset relocations less capital contributions	17,285	12,832	13,748	15,184	14,924	14,454

11a(vi): Quality of Supply

$000 (in constant prices) *Project or programme**	RY26	RY27	RY28	RY29	RY30	RY31
**Include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	-	-	-	-	-	-
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	-	-	-	-	-	-

11a(vii): Legislative and Regulatory

$000 (in constant prices)

Project or programme*	RY26	RY27	RY28	RY29	RY30	RY31
*include additional rows if needed						
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	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

$000 (in constant prices)

Project or programme*	RY26	RY27	RY28	RY29	RY30	RY31
*include additional rows if needed						
All other projects or programmes - other reliability, safety and environment	36,753	47,388	61,487	68,609	63,695	60,431
Other reliability, safety and environment expenditure	36,753	47,388	61,487	68,609	63,695	60,431
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	36,753	47,388	61,487	68,609	63,695	60,431

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*

11a(ix): Non-Network Assets

Routine expenditure

$000 (in constant prices)

Project or programme*	RY26	RY27	RY28	RY29	RY30	RY31
*include additional rows if needed						
All other projects or programmes - routine expenditure	8,177	24,619	18,909	20,341	14,335	16,129
Routine expenditure	8,177	24,619	18,909	20,341	14,335	16,129

Atypical expenditure

Project or programme*	RY26	RY27	RY28	RY29	RY30	RY31
*include additional rows if needed						
All other projects or programmes - atypical expenditure	20,970	30,390	24,925	16,650	14,960	13,277
Atypical expenditure	20,970	30,390	24,925	16,650	14,960	13,277
Expenditure on non-network assets	29,147	55,009	43,834	36,991	29,295	29,406

											Company Name	Vector Limited
											AMP Planning Period	1 April 2026 to 31 March 2036

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35	RY36
	Operational Expenditure Forecast	$000 (in nominal dollars)										
	Service interruptions and emergencies	19,565	25,925	22,691	21,243	21,896	22,608	29,790	26,263	24,906	25,741	26,602
	Vegetation management	9,103	9,087	9,330	8,737	8,683	8,061	7,123	7,014	6,286	6,142	6,296
	Routine and corrective maintenance and inspection	25,914	27,001	27,905	28,209	29,134	30,668	30,316	31,663	32,455	34,451	36,958
	Asset replacement and renewal	18,269	21,259	20,776	20,073	20,528	21,088	21,819	22,654	23,521	24,423	25,359
	Network Opex	72,851	83,272	80,702	78,263	80,242	82,425	89,049	87,594	87,168	90,756	95,216
	System operations and network support	46,171	42,405	43,056	44,385	46,271	47,589	49,129	50,912	52,749	54,260	56,238
	Business support	77,932	87,501	89,447	92,154	94,683	97,023	99,429	101,901	104,441	109,169	111,786
	Non-network solutions provided by a related party or third party											
	Non-network opex	124,103	129,906	132,503	136,539	140,954	144,613	148,558	152,813	157,190	163,429	168,023
	Operational expenditure	196,954	213,178	213,206	214,802	221,196	227,038	237,606	240,407	244,358	254,185	263,239
		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		$000 (in constant prices)										
	Service interruptions and emergencies	19,565	25,498	21,918	20,048	20,173	20,320	26,086	22,499	20,783	20,954	21,126
	Vegetation management	9,103	8,947	9,000	8,250	8,000	7,250	6,250	6,000	5,250	5,000	5,000
	Routine and corrective maintenance and inspection	25,914	26,591	26,916	26,626	26,839	27,561	26,589	27,079	27,085	28,039	29,345
	Asset replacement and renewal	18,269	20,927	20,048	18,948	18,912	18,954	19,131	19,377	19,627	19,880	20,138
	Network Opex	72,851	81,964	77,883	73,872	73,924	74,085	78,056	74,955	72,744	73,873	75,609
	System operations and network support	46,171	41,771	41,530	41,888	42,626	42,774	43,075	43,547	44,015	44,171	44,659
	Business support	77,932	86,154	86,288	86,967	87,233	87,206	87,183	87,165	87,153	88,861	88,780
	Non-network solutions provided by a related party or third party											
	Non-network opex	124,103	127,925	127,818	128,854	129,859	129,980	130,258	130,713	131,169	133,032	133,439
	Operational expenditure	196,954	209,888	205,701	202,726	203,783	204,065	208,314	205,667	203,913	206,905	209,048
	Subcomponents of operational expenditure (where known)											
	losses											
	Direct billing*											
	Research and Development											
	Insurance	5,885	6,181	6,609	7,071	7,571	8,108	8,687	9,309	9,979	10,700	11,475
	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		RY26	RY27	RY28	RY29	RY30	RY31	RY32	RY33	RY34	RY35	RY36
	Difference between nominal and real forecasts	$000										
	Service interruptions and emergencies	-	428	773	1,195	1,724	2,288	3,704	3,764	4,123	4,787	5,477
	Vegetation management	-	140	330	487	683	811	873	1,014	1,036	1,142	1,296
	Routine and corrective maintenance and inspection	-	410	989	1,584	2,295	3,107	3,727	4,584	5,370	6,412	7,613
	Asset replacement and renewal	-	332	728	1,125	1,616	2,134	2,689	3,277	3,895	4,542	5,221
	Network Opex	-	1,309	2,820	4,391	6,318	8,340	10,993	12,640	14,424	16,883	19,607
	System operations and network support	-	635	1,525	2,497	3,645	4,815	6,053	7,365	8,733	10,089	11,579
	Business support	-	1,347	3,160	5,187	7,450	9,818	12,246	14,736	17,288	20,309	23,006
	Non-network solutions provided by a related party or third party	-	-	-	-	-	-	-	-	-	-	-
	Non-network opex	-	1,981	4,685	7,684	11,095	14,633	18,300	22,100	26,021	30,397	34,585
	Operational expenditure	-	3,290	7,504	12,076	17,413	22,973	29,292	34,740	40,445	47,280	54,191

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.

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2026 to 31 March 2036**

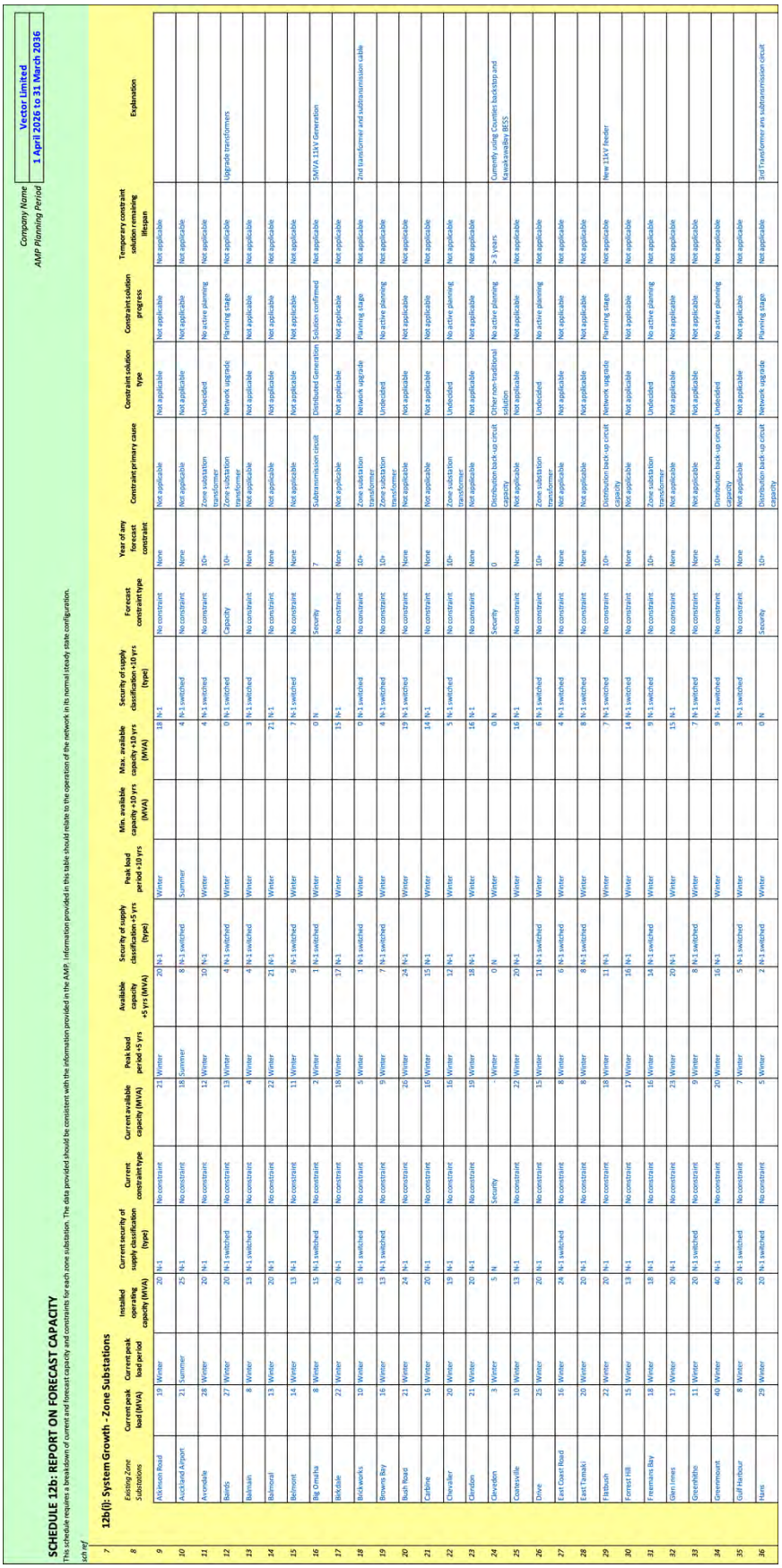
SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref					Asset condition at start of planning period (percentage of units by grade)							
	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	0.00%	0.02%	23.45%	29.35%	47.18%		4	6.81%
11	All	Overhead Line	Wood poles	No.	0.06%	6.64%	77.00%	10.32%	5.98%		4	76.74%
12	All	Overhead Line	Other pole types	No.	-	-	2.53%	8.24%	89.23%		4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	89.56%	9.33%	1.12%		3	0.27%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	72.35%	27.33%	0.32%		3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	3.92%	0.97%	40.84%	54.27%		2	3.70%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	5.06%	92.47%	2.47%		2	2.76%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	65.54%	14.39%	17.08%	3.00%		2	65.70%
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	88.43%	11.57%		2	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	65.93%	26.90%	7.17%		2	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	97.38%	2.62%	-		2	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	7.41%	67.59%	25.00%		4	12.96%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	42.86%	57.14%		4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	5.22%	4.67%	26.65%	63.46%		3	5.22%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	35.37%	37.80%	18.29%	8.54%		3	43.90%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	6.00%	22.00%	6.00%	57.00%	9.00%		3	43.36%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	66.67%	-	33.33%		3	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	40.91%	59.09%		3	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	100.00%	-	-	-		3	100.00%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	8.22%	23.17%	21.49%	47.12%		3	13.34%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	

					Asset condition at start of planning period (percentage of units by grade)							
	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	13.62%	37.02%	19.15%	30.21%		4	12.34%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	85.98%	10.80%	3.22%		3	1.23%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km							N/A	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.42%	0.69%	1.42%	31.71%	65.78%		2	1.10%
44	HV	Distribution Cable	Distribution UG PILC	km	0.24%	1.14%	7.19%	78.74%	12.68%		2	1.39%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	86.10%	13.86%	0.04%		2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.87%	0.29%	5.22%	38.84%	54.78%		4	11.36%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	1.56%	6.67%	13.56%	78.22%		4	2.84%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.93%	0.21%	43.76%	23.44%	31.66%		4	9.13%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	5.37%	15.17%	60.66%	12.16%	6.64%		3	26.73%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	3.02%	5.71%	32.71%	17.73%	40.83%		3	9.54%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.60%	5.79%	41.88%	24.84%	25.89%		3	7.39%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	5.67%	3.28%	32.46%	25.42%	33.17%		3	8.95%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	14.29%	42.86%	42.86%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2.23%	2.54%	73.88%	7.32%	14.03%		4	4.77%
55	LV	LV Line	LV OH Conductor	km	-	-	84.21%	8.75%	7.04%		3	2.33%
56	LV	LV Cable	LV UG Cable	km	0.50%	7.98%	21.09%	38.54%	31.89%		2	8.48%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km						100.00%	1	
58	LV	Connections	OH/UG consumer service connections	No.						100.00%	1	
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	0.16%	51.75%	23.64%	24.45%		3	0.16%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	1.77%	42.26%	35.84%	20.13%		4	1.77%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	92.98%	7.02%	-		3	-
62	All	Load Control	Centralised plant	Lot	-	-	100.00%	-	-		4	-
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km	-	-	8.62%	89.44%	1.94%		4	-

17.10 Appendix 10 – Report on forecast capacity (Schedule 12b)



Company Name: Vector Limited
AMP Planning Period: 1 April 2026 to 31 March 2036

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

12b(i): System Growth - Zone Substations

sch ref	Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed firm capacity capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
9	Atkinson Road	19	Winter	20	N-1	No constraint	21	Winter	20	N-1	Winter		18	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
10	Auckland Airport	21	Summer	25	N-1	No constraint	18	Summer	8	N-1 switched	Summer		4	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
11	Avondale	28	Winter	20	N-1	No constraint	12	Winter	10	N-1	Winter		4	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
12	Bairds	27	Winter	20	N-1 switched	No constraint	13	Winter	4	N-1 switched	Winter		0	N-1 switched	Capacity	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Upgrade transformers
13	Balmain	8	Winter	13	N-1 switched	No constraint	4	Winter	4	N-1 switched	Winter		3	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
14	Belmont	13	Winter	20	N-1	No constraint	22	Winter	21	N-1	Winter		21	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
15	Belmont	14	Winter	13	N-1	No constraint	11	Winter	9	N-1 switched	Winter		7	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
16	Big Omaha	8	Winter	15	N-1 switched	No constraint	2	Winter	1	N-1 switched	Winter		0	N	Security	7	Subtransmission circuit	Distributed Generation	Solution confirmed	Not applicable	5MVA 11kV Generation
17	Birkdale	22	Winter	20	N-1	No constraint	18	Winter	17	N-1	Winter		15	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
18	Brickworks	10	Winter	13	N-1 switched	No constraint	5	Winter	1	N-1 switched	Winter		0	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	2nd transformer and subtransmission cable
19	Browns Bay	16	Winter	13	N-1 switched	No constraint	9	Winter	7	N-1 switched	Winter		4	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
20	Bush Road	21	Winter	24	N-1	No constraint	26	Winter	24	N-1	Winter		19	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
21	Carbine	16	Winter	20	N-1	No constraint	16	Winter	15	N-1	Winter		14	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
22	Chevalier	20	Winter	19	N-1	No constraint	16	Winter	12	N-1	Winter		5	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
23	Clendon	21	Winter	20	N-1	No constraint	19	Winter	18	N-1	Winter		16	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
24	Cleveden	3	Winter	5	N	Security	0	Winter	0	N	Winter		0	N	Security	0	Distribution back-up circuit capacity	Other non-traditional solution	No active planning	> 3 years	Currently using Counties backstop and Kawakawaibay BESS
25	Coatesville	10	Winter	13	N-1	No constraint	22	Winter	20	N-1	Winter		18	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
26	Drive	25	Winter	20	N-1	No constraint	15	Winter	11	N-1 switched	Winter		6	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
27	East Coast Road	16	Winter	24	N-1 switched	No constraint	8	Winter	6	N-1 switched	Winter		4	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
28	East Tamaki	20	Winter	20	N-1	No constraint	8	Winter	8	N-1 switched	Winter		8	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
29	Fairbrook	22	Winter	20	N-1	No constraint	18	Winter	11	N-1	Winter		7	N-1 switched	No constraint	10+	Distribution back-up circuit capacity	Network upgrade	Planning stage	Not applicable	New 11kV feeder
30	Forrest Hill	15	Winter	13	N-1	No constraint	17	Winter	16	N-1	Winter		14	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
31	Freemans Bay	18	Winter	18	N-1	No constraint	16	Winter	14	N-1 switched	Winter		9	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
32	Glen Innes	17	Winter	20	N-1	No constraint	23	Winter	20	N-1	Winter		15	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
33	Greenhithe	11	Winter	20	N-1 switched	No constraint	9	Winter	8	N-1 switched	Winter		7	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
34	Greenmount	40	Winter	40	N-1	No constraint	20	Winter	16	N-1	Winter		9	N-1 switched	No constraint	10+	Distribution back-up circuit capacity	Undecided	No active planning	Not applicable	
35	Gulf Harbour	8	Winter	20	N-1 switched	No constraint	7	Winter	5	N-1 switched	Winter		3	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
36	Hans	29	Winter	20	N-1 switched	No constraint	5	Winter	2	N-1 switched	Winter		0	N	Security	10+	Distribution back-up circuit capacity	Network upgrade	Planning stage	Not applicable	3rd Transformer ans subtransmission circuit

	Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
37	Hauraki	8	Winter	20	N-1 switched	No constraint	12	Winter	10	N-1 switched	Winter		8	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
38	Helensville	10	Winter	15	N-1	No constraint	20	Winter	19	N-1	Winter		17	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
39	Henderson Valley	17	Winter	13	N-1 switched	No constraint	8	Winter	6	N-1 switched	Winter		2	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Upgrade Transformers
40	Highbrook	10	Winter	23	N-1	No constraint	14	Winter	13	N-1	Winter		12	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
41	Highbury	12	Winter	13	N-1 switched	No constraint	0	Winter	0	N-1 switched	Winter		0	N-1 switched	Capacity	3	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	2nd Transformer and subtransmission circuit
42	Hillcrest	20	Winter	24	N-1	No constraint	27	Winter	24	N-1	Winter		19	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
43	Hillsborough	20	Winter	20	N-1	No constraint	20	Winter	20	N-1	Winter		16	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
44	Hobson 110/11kV	12	Summer	25	N-1	No constraint	26	Summer	29	N-1	Winter		25	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
45	Hobson 22/11kV	8	Winter	12	N-1	No constraint	19	Winter	17	N-1	Winter		14	N-1 switched	No constraint	10+	Distribution back-up circuit capacity	Network upgrade	Implementation stage	Not applicable	Marginal case will be offset though 11kV to 22kV conversion programme to off load at 11kV bus
46	Hobson 22kV	61	Winter	80	N-1	No constraint	19	Winter	0	N	Winter		0	N	Security	5	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	Upgrade transformer
47	Hobsonville	17	Winter	13	N-1	No constraint	8	Winter	5	N-1 switched	Winter		2	N-1 switched	No constraint	10+	Zone substation transformer	Divert load to alternative substation	Implementation stage	Not applicable	New Whenuapai substation
48	Hobsonville Point	19	Winter	20	N-1	No constraint	20	Winter	13	N-1	Winter		10	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
49	Howick	39	Winter	40	N-1	No constraint	21	Winter	18	N-1	Winter		13	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
50	James Street	20	Winter	13	N-1 switched	No constraint	5	Winter	3	N-1 switched	Winter		0	N-1 switched	Capacity	10+	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	Upgrade Transformers
51	Kaukapakapa	6	Winter	15	N-1 switched	No constraint	9	Winter	8	N-1 switched	Winter		7	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
52	Keeling Road	17	Winter	37	N-1 switched	No constraint	19	Winter	17	N-1 switched	Winter		14	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
53	Kingsland	25	Winter	20	N-1	No constraint	15	Winter	8	N-1 switched	Winter		0	N-1 switched	Capacity	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Relocating Transformer to Kingsland
54	Laingholm	9	Winter	8	N-1	No constraint	6	Winter	5	N-1	Winter		5	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
55	Lichfield	16	Winter	20	N-1	No constraint	4	Winter	4	N-1	Winter		4	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
56	Liverpool	33	Winter	40	N-1	No constraint	27	Winter	21	N-1	Winter		12	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Marginal case will be offset though 11kV to 22kV conversion programme to off load at 11kV bus
57	Liverpool 22kV	94	Winter	150	N-1	No constraint	56	Winter	0	N	Winter		0	N	Security	4	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	New Nicholas Zone Substation
58	Mangere Central	51	Winter	40	N-1 switched	No constraint	9	Winter	4	N-1 switched	Winter		0	N-1 switched	Capacity	8	Zone substation transformer	Undecided	Solution confirmed	Not applicable	New Mangere South Zone Substation
59	Mangere East	34	Winter	20	N-1 switched	No constraint	6	Winter	3	N-1 switched	Winter		0	N-1 switched	Capacity	9	Zone substation transformer	Undecided	Planning stage	Not applicable	3rd transformer
60	Mangere West	25	Winter	30	N-1	No constraint	15	Winter	13	N-1	Winter		10	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
61	Manly	18	Winter	13	N-1 switched	No constraint	7	Winter	6	N-1 switched	Winter		3	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
62	Manukau	31	Winter	40	N-1	No constraint	29	Winter	24	N-1	Winter		17	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
63	Manurewa	55	Winter	40	N-1 switched	No constraint	5	Winter	0	N-1 switched	Winter		0	N-1 switched	Capacity	6	Distribution back-up circuit capacity	Network upgrade	Implementation stage	Not applicable	11kV reinforcement to offload zone substation. Transformer replacements to increase zone sub
64	Maraetai	14	Winter	15	N-1	No constraint	9	Winter	1	N-1 switched	Winter		0	N	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Upgrade transformers
65	McKinnon	23	Winter	20	N-1	No constraint	21	Winter	18	N-1 switched	Winter		14	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	

	Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
66	Mcleod Road	11	Winter	16	N-1 switched	No constraint	5	Winter	5	N-1 switched	Winter		3	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
67	McNab	38	Winter	40	N-1	No constraint	22	Winter	6	N-1 switched	Winter		0	N-1 switched	No constraint	10+	Distribution back-up circuit capacity	Network upgrade	Planning stage	Not applicable	Rockfield third transformer
68	Milford	7	Winter	13	N-1 switched	No constraint	5	Winter	4	N-1 switched	Winter		3	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Upgrade Transformer
69	Mt Albert	8	Winter	14	N-1 switched	No constraint	7	Winter	4	N-1 switched	Winter		0	N-1 switched	Capacity	10+	Subtransmission circuit	Network upgrade	Planning stage	Not applicable	New subtran circuits and 2nd transformer
70	Mt Wellington	16	Winter	20	N-1	No constraint	21	Winter	20	N-1	Winter		13	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
71	New Lynn	14	Winter	13	N-1	No constraint	11	Winter	9	N-1	Winter		6	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Upgrade Transformers
72	Newmarket	35	Winter	40	N-1	No constraint	25	Winter	17	N-1	Winter		3	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	New zone substation build
73	Newton	18	Winter	16	N-1	No constraint	14	Winter	5	N-1 switched	Winter		0	N-1 switched	No constraint	10+	Subtransmission circuit	Divert load to alternative substation	Planning stage	Not applicable	New planned Mt Eden zone substation to offload Newton
74	Ngataringa Bay	7	Winter	13	N-1 switched	No constraint	2	Winter	0	N	Winter		0	N	Security	3	Other	Network upgrade	Implementation stage	Not applicable	Substation will be decomissioned and Belmont will supply the area
75	Northcote	6	Winter	15	N-1 switched	No constraint	10	Winter	7	N-1 switched	Winter		6	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
76	Onehunga	18	Winter	15	N-1 switched	No constraint	10	Winter	6	N-1 switched	Winter		1	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
77	Orakei	23	Winter	18	N-1	No constraint	13	Winter	10	N-1	Winter		7	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
78	Oratia	7	Winter	10	N-1 switched	No constraint	3	Winter	3	N-1 switched	Winter		3	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
79	Orewa	24	Winter	20	N-1	No constraint	16	Winter	8	N-1 switched	Winter		3	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
80	Otara	32	Winter	30	N-1	No constraint	18	Winter	13	N-1 switched	Winter		7	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
81	Pacific Steel	32	Summer	40	N-1	No constraint	8	Summer	8	N-1	Summer		8	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
82	Pakuranga	22	Winter	20	N-1	No constraint	16	Winter	16	N-1	Winter		13	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
83	Papakura	34	Winter	20	N-1 switched	No constraint	5	Winter	2	N-1 switched	Winter		0	N	Capacity	7	Zone substation transformer	Network upgrade	Planning stage	Not applicable	3rd transformer
84	Parnell	17	Winter	15	N-1	No constraint	17	Winter	14	N-1 switched	Winter		7	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
85	Ponsonby	15	Winter	12	N-1	No constraint	9	Winter	7	N-1 switched	Winter		2	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Substation Upgrade
86	Quay	13	Summer	20	N-1	No constraint	17	Summer	16	N-1	Summer		16	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
87	Quay 22kV	48	Summer	60	N-1	No constraint	12	Summer	1	N-1	Summer		0	N	Security	5	Distribution back-up circuit capacity	Network upgrade	Implementation stage	Not applicable	Upgrade transformers
88	Ranui	17	Winter	20	N-1 switched	No constraint	3	Winter	0	N-1 switched	Winter		0	N-1 switched	Capacity	3	Zone substation transformer	Network upgrade	Planning stage	Not applicable	2nd transformer
89	Red Beach	23	Winter	20	N-1	No constraint	17	Winter	12	N-1	Winter		7	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
90	Remuera	28	Winter	20	N-1 switched	No constraint	12	Winter	8	N-1 switched	Winter		4	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
91	Riverhead	14	Winter	8	N-1 switched	No constraint	1	Winter	0	N-1 switched	Winter		0	N	Capacity	5	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	Replace transformers
92	Rockfield	22	Winter	20	N-1	No constraint	18	Winter	15	N-1	Winter		11	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
93	Rosebank	22	Winter	22	N-1	No constraint	19	Winter	17	N-1	Winter		12	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	

	Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
94	Rosedale	15	Winter	20	N-1	No constraint	25	Winter	22	N-1	Winter		18	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
95	Sabulite Road	22	Winter	13	N-1 switched	No constraint	3	Winter	1	N-1 switched	Winter		0	N-1 switched	Capacity	7	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	Replace transformers
96	Sandringham	26	Winter	20	N-1	No constraint	14	Winter	10	N-1 switched	Winter		5	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
97	Sandspit	1	Winter	15	N-1 switched	No constraint	14	Winter	14	N-1 switched	Winter		12	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
98	Simpson Road	5	Winter	8	N-1 switched	No constraint	3	Winter	2	N-1 switched	Winter		2	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
99	Snells Beach	6	Winter	8	N-1 switched	No constraint	2	Winter	1	N-1 switched	Winter		0	N-1 switched	No constraint	10+	Zone substation transformer	Divert load to alternative substation	Planning stage	Not applicable	Move load to new Sandspit substation
100	South Howick	29	Winter	20	N-1 switched	No constraint	11	Winter	9	N-1 switched	Winter		5	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
101	Spur Road	14	Winter	20	N-1	No constraint	26	Winter	23	N-1	Winter		19	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
102	St Heliers	21	Winter	18	N-1	No constraint	14	Winter	12	N-1	Winter		9	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
103	St Johns	19	Winter	20	N-1	No constraint	21	Winter	18	N-1	Winter		14	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
104	Sunset Road	13	Winter	13	N-1	No constraint	12	Winter	10	N-1	Winter		6	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Upgrade Transformers
105	Swanson	13	Winter	13	N-1 switched	Capacity	-	Winter	0	N-1 switched	Winter		0	N-1 switched	Capacity	0	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	2nd Transformer
106	Sylvia Park	15	Winter	20	N-1	No constraint	15	Winter	15	N-1	Winter		15	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
107	Takanini	32	Winter	15	N-1 switched	Capacity	-	Winter	0	N-1 switched	Winter		0	N-1 switched	Capacity	0	Zone substation transformer	Network upgrade	Implementation stage	Not applicable	Add 3rd transformer and subtransmission cable
108	Takapuna	6	Winter	20	N-1	No constraint	28	Winter	23	N-1	Winter		18	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
109	Te Atatu	23	Winter	13	N-1 switched	No constraint	2	Winter	0	N-1 switched	Winter		0	N-1 switched	Capacity	5	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Replace transformers
110	Te Papapa	16	Summer	20	N-1	No constraint	21	Summer	18	N-1	Summer		16	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
111	Torbay	10	Winter	13	N-1 switched	No constraint	3	Winter	2	N-1 switched	Winter		1	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Upgrade Transformer
112	Triangle Road	15	Winter	20	N-1	No constraint	25	Winter	23	N-1	Winter		21	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
113	Victoria	15	Summer	20	N-1	No constraint	16	Summer	16	N-1	Summer		16	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
114	Waiake	8	Winter	13	N-1 switched	No constraint	5	Winter	4	N-1 switched	Winter		3	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Upgrade Transformer
115	Waiheke	12	Winter	13	N-1	No constraint	3	Winter	1	N-1	Winter		0	N	Security	8	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Replace transformers
116	Waikaukau	7	Winter	8	N-1 switched	No constraint	0	Winter	0	N-1 switched	Winter		0	N-1 switched	Capacity	6	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Transformer upgrade
117	Waimauku	13	Winter	30	N-1 switched	No constraint	4	Winter	3	N-1 switched	Winter		1	N-1 switched	No constraint	10+	Distribution back-up circuit capacity	Undecided	No active planning	Not applicable	
118	Wairau Road	22	Winter	16	N-1 switched	No constraint	10	Winter	4	N-1 switched	Winter		0	N-1 switched	No constraint	10+	Zone substation transformer	Network upgrade	Solution confirmed	Not applicable	Upgrade Transformers
119	Warkworth	18	Winter	15	N-1 switched	No constraint	4	Winter	1	N-1 switched	Winter		0	N-1 switched	Capacity	6	Zone substation transformer	Network upgrade	Planning stage	Not applicable	Replace transformers + planned Warkworth South Zone substation

	Existing Zone Substations	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
120	Wellsford	10	Winter	8	N-1 switched	No constraint	5	Winter	3	N-1 switched	Winter		0	N-1 switched	Capacity	10+	Zone substation transformer	Network upgrade	Solution confirmed	Not applicable	Upgrade Transformers
121	Westfield	27	Winter	20	N-1 switched	No constraint	13	Winter	10	N-1 switched	Winter		6	N-1 switched	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
122	Westgate	15	Summer	20	N-1	No constraint	25	Winter	16	N-1	Winter		12	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
123	West Wiri	22	Summer	28	N-1	No constraint	23	Summer	13	N-1 switched	Summer		12	N-1 switched	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
124	White Swan	24	Winter	29	N-1	No constraint	18	Winter	12	N-1	Winter		8	N-1	No constraint	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
125	Wiri	29	Winter	40	N-1	No constraint	31	Winter	26	N-1	Winter		22	N-1	No constraint	None	Not applicable	Not applicable	Not applicable	Not applicable	
126	Woodford	10	Winter	13	N-1 switched	No constraint	2	Winter	1	N-1 switched	Winter		0	N-1 switched	Capacity	10+	Zone substation transformer	Undecided	No active planning	Not applicable	
127												* Vector does not calculate a range of demands and therefore only has a single value for available capacity										

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2026 to 31 March 2036**

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

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

sch ref

12c(i): Consumer Connections

Number of ICPs connected during year by consumer type

		Number of connections					
	*Consumer types defined by EDB**	RY26	RY27	RY28	RY29	RY30	RY31
	Residential & Small Medium Enterprise (SME)	12,386	12,524	13,023	13,815	12,267	10,492
	Industrial & Commercial	139	163	163	163	163	136
	Connections total	12,525	12,687	13,186	13,978	12,430	10,628

**include additional rows if needed*

Distributed generation

	RY26	RY27	RY28	RY29	RY30	RY31
Number of connections made in year	1,342	2,491	2,491	2,491	2,491	2,491
Capacity of distributed generation installed in year (MVA)	20	29	29	29	29	29

12c(ii): System Demand

		RY26	RY27	RY28	RY29	RY30	RY31
	Maximum coincident system demand (MW)						
	GXP demand	1,797	1,994	2,126	2,210	2,309	2,411
plus	Distributed generation output at HV and above	15	15	15	15	15	15
	Maximum coincident system demand	1,812	2,009	2,141	2,225	2,324	2,426
less	Net transfers to (from) other EDBs at HV and above						
	Demand on system for supply to consumers' connection points	1,812	2,009	2,141	2,225	2,324	2,426
	Electricity volumes carried (GWh)						
	Electricity supplied from GXPs	8,909	9,030	9,369	9,568	9,802	10,041
less	Electricity exports to GXPs						
plus	Electricity supplied from distributed generation	188	188	188	188	188	188
less	Net electricity supplied to (from) other EDBs						
	Electricity entering system for supply to ICPs	9,097	9,218	9,557	9,756	9,990	10,229
less	Total energy delivered to ICPs	8,725	8,841	9,167	9,357	9,582	9,811
	Losses	372	377	391	399	409	418
	Load factor	57%	52%	51%	50%	49%	48%
	Loss ratio	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2026 - 31 March 2036**
Network / Sub-network Name	**Vector Limited**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY* RY26	*CY+1* RY27	*CY+2* RY28	*CY+3* RY29	*CY+4* RY30	*CY+5* RY31
10	**SAIDI**						
11	Class B (planned interruptions on the network)	128.8	128.8	128.8	128.8	128.8	128.8
12	Class C (unplanned interruptions on the network)	110.1	110.1	110.1	110.1	110.1	110.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.63	0.63	0.63	0.63	0.63	0.63
15	Class C (unplanned interruptions on the network)	1.40	1.40	1.40	1.40	1.40	1.40

Note: The SAIDI and SAIFI forecast in Schedule 12d are calculated based on their normalisation.

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2026 - 31 March 2036**
Network / Sub-network Name	**Southern**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY* RY26	*CY+1* RY27	*CY+2* RY28	*CY+3* RY29	*CY+4* RY30	*CY+5* RY31
10	**SAIDI**						
11	Class B (planned interruptions on the network)	53.9	53.9	53.9	53.9	53.9	53.9
12	Class C (unplanned interruptions on the network)	46.1	46.1	46.1	46.1	46.1	46.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.28	0.28	0.28	0.28	0.28	0.28
15	Class C (unplanned interruptions on the network)	0.62	0.62	0.62	0.62	0.62	0.62

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2026 - 31 March 2036**
Network / Sub-network Name	**Nothern**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY* **RY26**	*CY+1* **RY27**	*CY+2* **RY28**	*CY+3* **RY29**	*CY+4* **RY30**	*CY+5* **RY31**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	74.9	74.9	74.9	74.9	74.9	74.9
12	Class C (unplanned interruptions on the network)	64.0	64.0	64.0	64.0	64.0	64.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.35	0.35	0.35	0.35	0.35	0.35
15	Class C (unplanned interruptions on the network)	0.79	0.79	0.79	0.79	0.79	0.79

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2026 to 31 March 2036**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	Vector's Electricity Asset Management Policy has been reviewed and published in March 2025, authorised by our Chief Operating Officer - Electricity, Gas, Fibre and Chief Engineer. The document is part of the controlled document management system is reviewed periodically and has been communicated to all relevant stakeholders.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (e.g., as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	The electricity asset management system demonstrates linkage to the Vector symphony strategy. This has been documented through the objectives in the asset management policy and the Asset management plan (AMP) section 5. The electricity asset management system is consistent and integrated with other organisational policies, H&S, Risk management, data management and procurement.		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 (e.g., 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	Asset header class (asset fleet) strategies have been prepared and reviewed for all asset classes within the electricity network. Lifecycle cost risk and network functionality are considered and balanced in maintenance and replacement decisions. Asset strategies are reviewed on an annual basis. This is an ongoing program of work with the opportunity to improve and integrate the results with Vector's Condition Based Asset Risk Management (CBARM) and other relevant models.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	The Asset management plan (AMP) is documented, implemented and maintained with alignment to asset management strategies and cover all asset life cycle activities (documented in the form of header class strategies, standards covering planning, design, equipment selection, procurement, operation, maintenance, inspection, testing and decommissioning.)		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	**Vector Limited**
AMP Planning Period	
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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.

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2026 to 31 March 2036**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3.5	The AMP is communicated to all stakeholders including employees and Field Service Providers (FSPs) and is publicly disclosed. Asset management data and management documents are collaboratively used and updated both internally at Vector, and with contractors. Vector has integrated FSP and contracted personnel into its IT systems to allow full communication and collaboration to deliver asset management activities. Vector maintains a range of asset management information systems, such as SAP that contain plans for asset management activities which are accessible to Vector personnel and FSPs as required.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	The AMP outlines the key roles responsible for its delivery. Vector's delegated authorities framework and policy, and position descriptions for each role further define the roles and authorities. Governance frameworks ensure that key tasks and responsibilities are allocated to team members who report on progress against the plan on an agreed basis.		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)	3.5	The AMP is physically delivered by our Field Service Providers for both Capex projects and Opex works. Capex delivery of works is governed by a staged gate process that is defined in detail. A project can only move to the next stage gate once the actions for a specific stage-gate is completed. Works are competitively tendered in accordance with standard contract arrangements including NZS3910. For large programs of works the workload are split between a larger panel of service providers to ensure a workload balance		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3.5	Our response to emergency situations, e.g., extreme weather events, natural disasters and similar is governed by our operational document, the Networks Event Management and Investigation. This guide sets the scene for responses, reactions and actions. During an emergency event a specific response group will be assigned with tasks to and for each member. The group will meet daily until the contingency plan is in place and during the contingency. Reviews of pending risks or pending events are conducted fortnightly during which action plans are reviewed, renewed and/or closed		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.

Company Name	**Vector Limited**
AMP Planning Period	
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3.5	Overall responsibility to deliver the AMP rests with the Chief Operating Officer, Electricity, Gas and Fibre. The Chief Engineer together with the General Managers of the Asset Management and Planning, Capital Programme Delivery Team, Customer Excellence Team and Commercial Strategy, report to the COO. Each GM is assigned the appropriate authority to deliver a certain part(s) of the asset management plan in accordance with the asset management policy. The AMP is delivered by our panel of external field service providers in terms of contractual agreements and arrangements and they understand their roles in the delivery of the asset management strategy, its objectives and plans		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 e.g., 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?	3.5	Asset Management and Planning teams assess network risk, compile scopes of work and/or programmes of work to address the risk and then after the works have been delivered, review the residual risks. Two dedicated teams schedule and program the delivery of capex works and maintenance works respectively. A dedicated Supply Team has been setup for the planning of long lead items, establishment of umbrella agreements and other procurement arrangements. A Governance Group has been setup that meets weekly to discuss the delivery of the asset management plan, risks, delays and action plans. Agreements are in place for external consultancies to provide advice and specialist services.		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.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Service Levels and KPI's are set and monitored across the organisation through readily accessible dashboards. In addition, monthly reporting, quarterly team updates and strong engagement with programme delivery and service providers ensure that there is a strong focus on the delivery of asset management requirements. Weekly update sessions are held to convey network events, network reliability targets and specific project updates and challenges. "All Hands" sessions have been introduced quarterly to convey the asset management objectives to the wider EGF team. Asset performance metrics including SAIFI, CAIDI and SAIDI are continually monitored, reviewed in governance meetings and interventions determined.		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 (e.g., 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?	3.5	Outsourced asset management activities are governed by published standards, and active relationship management between Vector and their service providers. Maintenance standards, design standards and planning standards are in place for Vector and its service providers to guide the delivery of the asset management plan. Standards are controlled, changed and improved via a well-defined change control process that involves our field service providers in the formal review and approval process. A strict as-building regime is in place to ensure works are delivered, checked and recorded in accordance with our standards. The recording of faults is done via clear guidance in our maintenance standards and network fault information collected and recorded in our software application for this purpose. Its corrective actions and outcomes are checked and controlled via this software app. A team of dedicated field assessors provide assurance by means of inspections in the field against the standards. A full time standards engineer is in place to record proposed improvements to standards and then arrange for their change controlled reviews, updates, revisioning and publishing. This person also reviews requests for deviations, their approval or rejection.		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 (e.g., PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	Core competencies required to undertake asset management activities are identified by our HR department in the job design process. Such requirements are determined and defined in conjunction with asset managers and included in Vector's job profiles-position descriptions. Our HR in-house training provides the opportunity for general professional development. We also have a formal engineering progression scheme in place that encourages employees to develop their skills. Vector engineers attend industry conferences and professional organisation membership is subsidised by Vector. Regular inspections of worksites is a requirement to hone asset management skills and ensure contact with the real world asset environment		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3.5	Our competency requirements are clearly defined for different roles and responsibilities to achieve our asset management plan. For our FSPs, we conduct random audits of their competency compliance and check that competencies are maintained in their internal database. Vector also maintains an internal database of the competencies of our internal staff as well as our FSP qualified personnel. Under our letters of authorisation to access our network, all FSPs and contractors have a legal obligation to maintain competency currencies.		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. (e.g., 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 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?	3	For our FSPs, we conduct random audits of their competency compliance and check that competencies are maintained in their internal database. Vector also maintains an internal database of the competencies of our internal staff as well as our FSP qualified personnel. Under our letters of authorisation to access our network, all FSPs and contractors have a legal obligation to maintain competency currencies.		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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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.
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 organization 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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3.5	A group meeting is held every Wednesday in which the SAIDI and SAIFI performance of the network is presented and discussed. Network risks, incidents and asset management challenges are also presented and discussed. Asset management information and asset performance information are presented in detailed and comprehensive dashboards and daily fault reports internally and with service providers as required. Monthly operational meetings are held with our FSPs where progress, risks and challenges against targets, are discussed and actions agreed. Short update meetings are held every second day for more granular updates on specific programmes and projects. Under contingency or emergency scenarios specific teams are setup and daily meetings are scheduled for the duration of such events. Specific network instructions are issued to FSPs via a numbered and controlled formal instruction in which FSPs are required to acknowledge receipt.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2.5	Vector's Controlled Document Management standard, USD001, defines asset management documents and sets out the hierarchy of documentation for our asset management plan. This standard also sets out in detail how changes to documents are to be managed, as well as the change control, approval and acceptance process. Similarly there are numerous standards for asset management systems and activity plans such as SAP and data governance standards. Our Asset Management Plan (AMP) is communicated to our Board and internal stakeholders and is available to external parties via our web portal. Our AMP is shared widely with our FSPs. Supporting the asset management plan and its objectives is a comprehensive set of design, maintenance and operating standards. The latest copies are held in our Information portal. We have made good progress with our asset management framework that describes the overarching requirements for asset management system.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (i.e., the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (e.g., 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?	3.5	Vector's primary information systems of record supporting Asset Management are SAP-PM, GE Small World GIS, and the Data Analytics platform. Collectively these systems capture, manage and allow the use of data for asset management decision making. In order to ensure that these systems contain the data necessary to support asset management, Vector has the following processes in place. A set of data standards have been developed governing the asset master data required to be captured in GIS and SAP-PM. These standards define the asset data model, which are based upon (and aligned to) Vector's asset and maintenance standards. A set of data standards have been developed for planned, corrective and reactive maintenance data capture. The data standards are based upon Vector's maintenance standards and define in detail the data to be captured in the field when performing the respective forms of maintenance. The systems of record have been designed and built based upon these two sets of data standards. Change management processes exist to ensure changes to maintenance standards or asset standards (including the introduction of new asset types) flow into the data standards and respective system of record. The data analytics platform has been developed to facilitate improved reporting and analysis of data, and also to develop complex analytical models, providing deeper insights into asset management not available or apparent from the raw data.		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	Vector has implemented a number of steps to ensure the data contained in SAP-PM and GE Small World GIS are consistent, accurate and of requisite quality. Data standards are in place for the capture of data. This includes asset master data, spatial data, connectivity, and maintenance data. Systems of record (SAP-PM and GIS) have been developed to align to these data standards. Data validation routines exist in all systems, based up data standards, to ensure all data captured conforms to the defined data standards. Service levels are in place for data updaters to ensure data is captured according to the defined standards and in a timely fashion. System automation and integration has been developed to reduce manual data capture wherever possible. Vector has established an Information Management Team responsible for ensuring the data and systems are curated and continually improved, and ensure that the data standards are adhered to. Independent data quality assurance testing is conducted on key data sets.		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 (e.g., s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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.
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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3.5	Asset information systems are a core aspect of the wider Asset Management System. A key element of this is the alignment of asset standards and maintenance standards with data standards and system or record. An established an Information Team, that is responsible for ensuring the data and systems are curated and continually improved. Data quality improvement programmes are funded to address legacy data issues and make improvements to data. A change management process is in place to ensure all changes to asset standards and maintenance standards are flowed through into the system of record and associate data capture and maintenance standards. A data analytics team and platform has been implemented to improve access to data in a consistent and integrated fashion. Condition based risk models and CBARM models have been developed using the analytical platform, to inform and improve asset decision making with regard to asset management replacement and refurbishment programs and projects.		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?	3.5	A dedicated Risk Assessment team is in place in Vector. They investigate, assess, evaluate and document incidents and make recommendations for the risk treatments and mitigations. Each incident investigation report is numbered, registered, stored and issued for action, information and learning. Risks are recorded in our risk recording application Donesafe, and are escalated to executive or Board level as required for governance and approval of treatments. Vector also records the failure modes and effects analysis (FMEA), action plans and target dates to address risks across the asset lifecycle. Regular meetings are held to address, assess and record progress with regard to risks. The networks risk management process is defined in standard UCD001, which states how risks are managed		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 (e.g., 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?	3	The outcomes of risk and incidents are recorded and a formal and numbered network instruction issued to our FSPs where training and/or a change in asset management process is required. We also work with our equipment suppliers, training facility and FSPs to setup up training sessions on the use of specific equipment to reduce the risk of failure. In some instances, risks and incidents will require a change in procurement standards, planning standards and/or operational standards. Such recommendations will be made as part of a risk assessment, evaluation or incident reports and will be		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	The Legal and Assurance function is responsible for the management of the management of legal, regulatory, statutory requirements. These requirements are governed by the Legal Compliance Policy and managed within the Comply With system. Independent assurance of regulatory compliance is achieved through external audits, an example being the annual NZS 7901 public safety audits during which the network is physically inspected and issues and actions recorded.		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 (e.g., 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

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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.
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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User	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	Our asset management plan for the acquisition, creation and enhancement of assets is done in accordance with a circular lifecycle asset management process underpinned by suites of engineering & design standards and operational instructions. The life cycle process is initiated by a recorded network risk that is assessed and scored, a needs statement is established that is converted into a monetized asset management item, included into the asset management plan, a scope is compiled and the works are physically delivered. Where a new type of asset is to be introduced it will be via a formal asset introduction process that goes through a formal change control that involves our field service providers. As and where necessary this will include field trials. The consideration of climate change and carbon footprint form an important part of this process. Enhanced assets are recorded in our regulated asset base and formal drawing repository application and handed over for maintenance and acceptance via a formal process		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (e.g., 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	Our suite of maintenance standards is very specific and clear in their requirements for the recording of asset condition data for all our asset classes. The maintenance standards underwent a comprehensive review and update in 2024/2025 to provide more comprehensive guidance for defect assessment and the incorporation of aerial inspection methods for the overhead network. The recording of asset condition data is done via field handheld tables by our field service providers via our SAP software. This uses the SAP-PM application in which defects, their severity and corrective actions are recorded and immediately updated. SAP-PM also records the corrective actions and costs for corrective actions and provides a quick and efficient overview of costs, remaining risks, remaining activities and performance. Identified defects are reviewed by the Vector asset engineering teams as part of monthly QA to ensure that defects are identified and prioritised correctly.		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 (e.g., 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?	3.5	Asset performance is determined by both network performance against KPIs including SAIDI, and SAIFI. Asset types or areas of the network that do not meet required performance levels are evaluated and interventions carried out to rectify performance. Our detailed maintenance standards form the basis for the condition of our assets. Asset are inspected in accordance with the requirements of our maintenance standards under a planned maintenance regime. Overhead assets (poles, lines and overhead equipment) are inspected by drones and helicopter mounted cameras generating high quality imagery to train AI models to enable automated defect detection in future. The conditions and performance of our assets are recorded by our field service providers in our SAP-PM application and further corrective actions undertaken as required. For our asset replacement and enhancement programmes and projects we have adopted condition based asset risk models to inform our works.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and 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	Asset related failures, incidents and emergency situations are recorded in incident reports complete with recommendations and actions. A dedicated investigations team provides a focussed and internally independent investigation function. Incident reports are registered, numbered and stored in a SharePoint repository. Risks, corrective actions and responsibility assignments are managed in Donesafe and followed up with regular meetings. For high potential incidents, senior management is involved to provide review of any corrective actions. Where specific actions and responses are required by our field service providers, numbered and registered network instructions are used to our FSPs. They have to acknowledge receipt. Progress is checked during the monthly operational meetings with our FSPs and/or the second daily update meetings		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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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.
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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The asset management plan is reviewed annually, and full updates are undertaken every second year. Design and maintenance standards has a document has a current date and proposed review date which is governed automatically by the change control SharePoint site settings. For our capital works asset management process we have in place a stage-gate process that clearly demarcates the actions and gates that need to be achieved before works can progress. Risks and actions are recorded in minutes of meeting and risk registers for each capital works project that can be audited post works completion under the lessons learnt stage		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (e.g., 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	When poor performance and non-conformance of an asset or asset management activity is identified it is either managed as it arises or investigated under a formal process. Anything more severe than a minor non-conformance will be investigated by either Vector or the relevant service provider or supplier and corrective and preventative actions managed within Donesafe to track progress, completion and effectiveness. If the non-performance is delivery related a meeting will be held with the field service provider in which corrective actions will be conveyed and formally recorded. Training is provided if deemed necessary.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	All asset management decisions are undertaken on the basis of an optimised balance of cost and risk, within Vectors risk appetite. Continuous evaluation of asset management system and asset performance is undertaken as part of governance meetings for programme delivery, cost control or asset reliability. Actions are recorded and tracked as a result of these governance meetings, and may be defined to provide ad-hoc performance improvement for a particular project or initiative or may be permanent changes for improved performance and documented in the relevant policy, procedures or standards. A defined programme of continual improvement for the asset management system, AM2030 has been implemented with initiatives to increase capability across all key elements of the asset management practise has been initiated in 2025.		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?	3.5	The performance of the network is a driver to explore new technologies to improve the performance of the network. For this purpose, the Vector Asset specialists will liaise with equipment suppliers and other electricity lines businesses to explore the use of other technologies and products. Tests will be undertaken to check the viability of such technologies. Where necessary trials will be instigated and formally recorded as part of the asset introduction process and if the trial proves successful the asset will be formally introduced for use in the network. This introduction of the asset will involve our field service providers via a change control process. Vector also participates in a number of international and Australia-NZ working groups to identify new asset management technologies and practices. Vector has also been proactive in implementing advanced asset management practises and supporting systems, an example is the implementation of aerial imagery inspections that provide a detailed imagery and LiDAR dataset into the GridAware platform for geospatial asset data and AI driven defect identification.		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 (e.g., 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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	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.

17.14 Appendix 14 – Mandatory explanatory notes on forecast information (Schedule 14a)

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

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

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

BOX 1: COMMENTARY ON DIFFERENCE BETWEEN NOMINAL AND CONSTANT PRICE CAPITAL EXPENDITURE FORECASTS

Vector has used the capital expenditure inflator based on the model used by the Commerce Commission in its DPP price reset on 1 April 2025. We have used a forecast of the Capital Goods Price Index (CGPI) as the inflator with a compounded uplift of 0.80% specified by the Commerce Commission.

Vector has used the NZIER (New Zealand Institute of Economic Research) September 2025 CGPI forecast up to December 2032. Thereafter, we have assumed a long-term CGPI inflation rate of 2.0% with a compounded uplift of 0.80%.

The capex inflator forecast increases from 1.68% in RY26 to 2.82% in RY34 and is stable thereafter.

The constant price capital expenditure forecast is inflated by the above-mentioned index to convert to a nominal price capital expenditure forecast.

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

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

BOX 2: COMMENTARY ON DIFFERENCE BETWEEN NOMINAL AND CONSTANT PRICE OPERATIONAL EXPENDITURE FORECASTS

Vector has used the operational expenditure inflator based on the model used by the Commerce Commission in its DPP price reset on 1 April 2025. We have used an inflator which is a mix of the Producer Price Index (PPI) and the Labour Cost Index (LCI) with a compounded uplift of 0.30% specified by the Commerce Commission. The weighting between PPI (40%) and LCI (60%) is as per the Commission's model.

Vector has used the NZIER (New Zealand Institute of Economic Research) September 2025 PPI (Producer Price Index-inputs) and LCI (Labour Cost Index) forecasts up to December and June 2029 respectively. Thereafter, we have assumed a long-term inflation rate of 2.0% for LCI and 2.5% for PPI, with the 0.30% compounded uplift.

The constant price operational expenditure forecast is inflated by the above-mentioned index to convert to a nominal price operational expenditure forecast

17.15 Appendix 15 – Schedule 17 Certification for year-beginning disclosures

Schedule 17 Certification for Year-beginning Disclosures

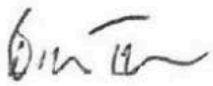
Clause 2.9.1

We, Bruce Turner, and Paul Hutchison, being directors of Vector Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Vector Limited prepared for the purposes of clauses 2.6.1, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

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

c) The forecasts in Schedules 11a, 11b, 11c, 12a, 12b, 12c, 12d and 13 are based on objective and reasonable assumptions which both align with Vector Limited's corporate vision and strategy and are documented in retained records.



Director



Director

24 March 2026

Date

