ELECTRICITY ASSET MANAGEMENT PLAN

2019-29


ELECTRICITY OPERATIONS CENTRE
SMART POLE
SUPERMARKET
SUPERMARKET
PUBLIC EV CAR CHARGE STATION
MOBILE GENERATOR
MOBILE GENERATOR
MOBILE-GENERATORS


COMMERCIAL SOLAR AND STORAGE
REMOTE COMMUNITY
MICROGRID
SUBSTATION
HYDRO GENERATION
PUBLIC TRANSPORT
URBAN FOREST
MOBILE GENERATOR
Vector
NEW SUBDIVISION
PEER-TO-PEER

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INTRODUCTION

SECTION 01.

EXECUTIVE SUMMARY

Vector's 2019 – 2029 Asset Management Plan (AMP) sets out what we believe constitutes a leading asset management plan for the long-term interests of Auckland's energy consumers. For the avoidance of doubt, Vector's view is that the long-term interests of Auckland's energy consumers cannot be served by a traditional view of what a network is and needs to deliver.

To expand this view, we look through the lens of our customers and consider multiple inputs, these include:

- customer engagement; multiple channels including direct engagement and community groups
- customer insights; garnered from analytics applied across various data sources, including socio-economic trends
- extensive engagement with leading international energy technology providers; to inform how we can leverage new technologies to deliver for our customers and overcome the myriad challenges in our operating environment
- electricity network quality guidelines from other jurisdictions; to better understand how other providers are defining and measuring quality standards according to their customers' needs
- observations from Customised Price Plan (CPP) verifier reports from New Zealand

Above all, this engagement and research confirmed there is a rising expectation from our customers that energy should perform like any other modern-day service. It needs to be readily available, provide choice and seamlessly adapt to an individual's personal needs and preferences. Importantly, for affordability, we must bring down the overall cost of energy solutions and avoid burdening future generations with costs for infrastructure that may no longer be required.

While planning to meet the growing and changing expectations of our customers, we have a responsibility to enable Auckland growth and manage any associated constraints. To put this growth into context, in the past five years we have seen the number of subdivisions built in Auckland increase from 84 to 205. Last year, it was reported that 40,000 vehicles were added to Auckland roads over a 12 month period[1]. Further to this, we have a responsibility to align with central and local Government objectives regarding housing and transport. Other considerations include uptake of new technology and the electrification of transport.

We also have a responsibility to prepare the network for the impacts of our changing climate. There are various reports, including one we ourselves commissioned from Ernst & Young, that signal greater volatility of weather is coming. We must consider this long-term impact – as an example, we have included a project in this AMP to relocate a low-lying sub-station to higher ground.

In summary, preparing the network for the long-term interest of customers is an art not a science. The plan must balance all our responsibilities and challenges. We can choose to bury our head in the sand and ignore the opportunities that lie in front of us, or we can embrace them, take steps to innovate sensibly and with purpose, and invest efficiently so our customers can have confidence for the future and know we are meeting their expectations of today. Vector does not favour building a network that leverages high capital intensity based on historic paradigms. Instead we favour innovation that balances the long-term best interests of consumers whilst earning our shareholders a commercially appropriate return.

1. https://www.newshub.co.nz/home/new-zealand/2018/02/why-auckland-s-traffic-just-keeps-getting-worse.html

PURPOSE OF THE AMP

The 2019-2029 Asset Management Plan updates our 2018 plan for the period 1 April 2019 to 31 March 2029. We note that at time of publishing our 2018-28 AMP, we clearly identified that it would not be the appropriate plan to inform the default price-quality path (DPP) reset in 2020.

As noted in the 2018 AMP, we have expanded the scenario modelling that underpins our asset management and investment plans, and the load and expenditure forecast in this AMP is more robust because of that modelling. For that reason, we confirm that this 2019 AMP is better suited to providing the load and expenditure forecasts required by the Commerce Commission to use for the setting of Vector's price path from 1 April 2020.

This AMP document has the following structure beyond this Executive Summary:

- Section 2 Customers, Stakeholders and Service Levels
- Section 3 Asset Management System
- Section 4 Our Assets
- Section 5 Managing our Assets Lifecycle
- Section 6 Delivering our Plan

As a requirement of the Deed Recording Essential Operating Requirements (DREOR) held with Entrust, we are required to provide a report from an independent expert to advise on the state of the network.[2] In addition, there have also been other external reviews of the network and its asset management practices relating to specific events, such as the April 2018 storm and the Commerce Commission investigation into quality breaches.

All findings and recommendations from such reviews are carefully considered and adopted into the asset management policies and practices where it is deemed appropriate. The expenditure associated with these programmes and projects has been included in this AMP.

Vector engaged the services of WSP to review the robustness and compliance of this document.

This AMP was certified by Directors on 21 March 2019.

"THE PACE OF CHANGE HAS NEVER BEEN THIS FAST, YET IT WILL NEVER BE THIS SLOW AGAIN."

JUSTIN TRUDEAU

2. https://www.entrustnz.co.nz/resource-library/network-security-reports/

MEGA TRENDS:

OUR OPERATING ENVIRONMENT IS CHANGING

There are powerful forces shaping the energy sector, both here in New Zealand and around the globe. Enveloped in continuous change, planning long-term network investments is more challenging than ever before.

Auckland is changing under the forces of urbanisation. More than a third of New Zealanders now call Auckland home. It produces 38% of the country's gross domestic product[3] and also happens to be one of the fastest growing cities globally. We're seeing an increase in customer density in the older parts of the network and new demand for electricity at the fringes. Once sparsely populated rural areas are becoming increasingly popular areas to live in as a lifestyle choice. There is an insatiable appetite for new housing, which will almost certainly continue over the next decade, as will associated growth in infrastructure building, such as the City Rail Link. Auckland's growth is unprecedented and it is putting pressure on our network at almost every turn, so managing the dynamic demands of this will continue to be a key responsibility for Vector.

In the coming decade, the energy system as we know it will be impacted further as the energy and transport sectors converge, advances in network and digital technologies continue at pace, and as we seek to decarbonise our economy. Already our customers expect more personalisation, choice and participation when it comes to their energy needs, and they expect us to innovate and adapt quickly to meet their expectations. New technologies are having a monumental impact on customer preferences and our network, and it will continue to play a key role in delivering for our customers. There are also the undeniable impacts of climate change making network resilience and sustainability more of an imperative in everything we do. As we plan, we must mitigate and adapt to the physical impacts of climate change as well as the economic impacts associated with decarbonising the economy.

These and other macro trends will continue to influence and disrupt our operating environment over the time-frame of this AMP. In this section, we consider the key trends in detail. We assess their implications for our network and outline our intention to respond with the best possible mix of strategies and plans.

Last year Vector added 11,135 new properties to its power-line network, a 22 per cent increase compared with the previous year, and the biggest leap in growth in Vector's history.

THE GLOBAL RISK OUTLOOK FOR 2019

Types of Risks: Environmental, Geopolitical, Societal, Technological, Economic

TOP 5 GLOBAL RISKS IN TERMS OF IMPACT

1	Weapons of mass destruction
2	Failure of climate-change mitigation and adaption
3	Extreme weather events
4	Water crises
5	Natural disasters

TOP 5 GLOBAL RISKS IN TERMS OF LIKELIHOOD

1	Extreme weather events
2	Failure of climate-change mitigation and adaption
3	Natural disasters
4	Data fraud or theft
5	Cyber-attacks

Figure 1-1 Global Risk Outlook for 2019 from the World Economic Forum. Interestingly, this risk outlook aligns with the key trends creating the most impact for us, our network and our customers

3. https://www.aucklandnz.com/business-and-investment/economy-and-sectors

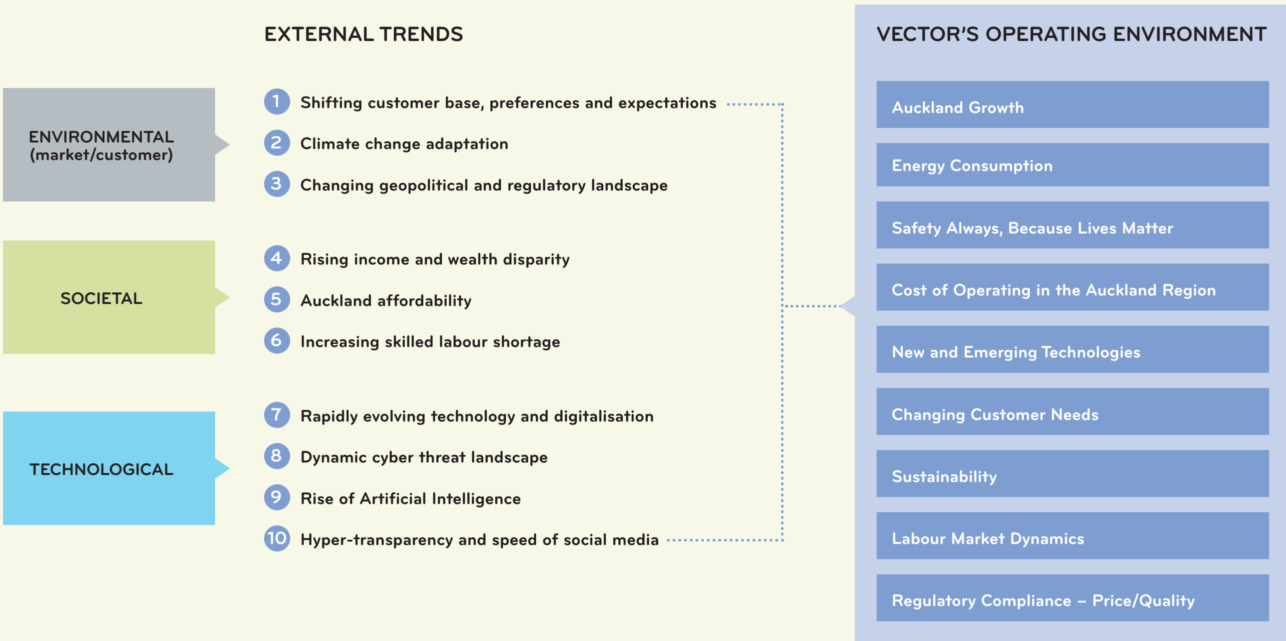

Figure 1-2 Key macro-economic external trends shaping Vector's operating environment

AUCKLAND GROWTH

Auckland's population is expected to grow by the size of Tauranga city every three years[4]. Auckland Council estimates the city will have two million residents by 2028, which is a five-year average annual growth rate of more than 20 per cent. Because the city is set to swell, investments in civil infrastructure projects will need to grow too, by more than 30 per cent just over the next five years. Vector's core focus is to balance our complex regulatory, operating and customer expectations in a time of unprecedented growth and other challenges such as affordability. As Auckland continues to grow, it is essential that we continue to evolve our network infrastructure, operations and investment strategies to reduce the impact of network outages for customers.

INFRASTRUCTURE DEVELOPMENTS

Whether a development project is as significant as the Light Rail Project, or as small as a suburban sub-division, Vector must understand its impact on the network and ensure customers remain connected to a reliable, affordable and resilient supply of electricity. Right now, new ICP (installation control point) connections, as well as projects to relocate existing network assets to accommodate growth, are at an all-time high. This presents a mix of challenges and opportunities for New Zealand's fastest growing city. Vector is embracing a broader range of network extension and augmentation technologies that will enable us to grow the network to meet the needs of customers. Beyond traditional solutions, like poles, wires and substations, new network options like microgrids and battery systems can, in some cases, deliver a more resilient electricity service for customers without the need to invest in traditional assets, that typically have longer lives and could burden future generations if they are no longer needed. While traditional physical assets will form the backbone of our network for decades to come, we will continue to look at how alternative options can – and should – be used to build a network that is in the long-term interests of Aucklanders.

CONSUMPTION TRENDS

Energy consumption rates across Auckland's 1.4 million residents is trending down on average, while overall network peak is increasing, as the number of connections continues to grow. Since 2005, the average level of energy used per residential connection has declined by about one per cent every year however since 2012 network peak has grown by seven per cent. Vector must invest in its network to ensure a reliable supply during the peaks in demand. We are incentivised to manage or 'cap' them as best we can.

It is unclear where Auckland's consumption trends will head next but it is expected that this trend will flatten or reverse as EVs become more commonplace. Whatever happens, in today's world there is no excuse for not making data driven decisions in response to such trends. Therefore, Vector is boosting its ability to better

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4. http://archive.stats.govt.nz/browse_for_stats/population/census_counts/2013CensusUsuallyResidentPopulationCounts_HOTP2013Census.aspx And, Auckland Plan 2050, updated June 2018.

understand customer behaviour and track demand trends with greater precision. Our investment in data collection and analytics technology is central to developing this understanding. Real evidence about our customers will help inform our decision making – reducing the risk of over-investing or under-investing in different areas of Auckland.

CAUSE OF ENERGY USE DECLINE IN AUCKLAND

- **Socio-economic factors, such as affordability and environmental concerns**
- **A region-wide shift towards medium and high-density living**
- **Technology – improved building practices and standards, greater building energy efficiencies, a higher penetration of dwelling insulation and better equipment efficiencies**
- **The increasing prevalence of 'energy efficient' appliances in homes (such as heat pumps and LED (Light-Emitting Diode) lights**
- **New and emerging technologies such as solar panels and storage batteries**

VEGETATION MANAGEMENT

Vegetation encroaching and falling on power lines is one of the main causes of power outages in Auckland. A recent survey of Electricity Network Association (ENA) members found that 60 to 70 percent of outages during storms were caused by trees. The challenge for network companies is that under the Electricity (Hazards from Trees) Regulations 2003, vegetation can only be trimmed in a limited zone, essentially where it is almost directly against power lines – the 'growth limit zone'. This hinders network companies' ability to adequately protect the electricity network during adverse weather events, where trees damage power lines from outside of the growth limit zone. Even after a tree is trimmed, the problem persists. While a newly-pruned tree might be physically separated by up to 1.5m from a line, the tree might tower many metres directly above a line, meaning branches can fall across lines, shorting them out or bringing them down.

CASE STUDY
URBAN FOREST INITIATIVE

The Vector Urban Forest is an initiative from Vector to plant two native trees for every one tree we remove to protect Auckland's power lines. The new planting takes place in areas where local ecological restoration schemes are already underway.

Aucklanders love their trees but unfortunately there is a real lack of awareness of the issues they can cause to network resiliency if they are not maintained or planted with consideration to power line proximity.

Managing tree risk is especially important given the extensive network damage that occurs during storms and other high wind events. Our climate modelling projects a significant increase in the number of hours with sustained wind speed in excess of 70km/h – the point where damage to the power network is historically high.

A further complicating factor for Vector and the other EDBs is the existing tree management regulations which limit our ability to trim or remove problem trees.

As we continue to work with government to revise tree management regulations, the Urban Forest Initiative is an example of the action we are taking now to raise awareness of the issue.

Each year the Urban Forest Initiative aims to plant at least 20,000 new seedlings to make up for the approximately 10,000 trees we remove from near the electricity network. The trees we remove are first identified as a risk by an expert and removed with permission from the landowner.

The Urban Forest also plays a key role in educating the public about the importance of proper tree management and what their responsibilities are as a tree owner. We've also published a planting guide on our website that shows what trees and plants are safe to plant near power lines.

Some trees are also very fast growing and may require two trims in a season, which is both costly and inefficient. Fast-growing trees also tend to be less resilient to high winds and therefore pose a greater risk.

Unfortunately, risk is not considered under the tree regulations, only distance. The first 'trim' of vegetation inside the growth limit zone is funded by Electricity Distribution Businesses (EDBs), and then all further tree trimming should be paid for by the tree owner. Often, tree owners do not complete the tree trimming they are legally required to do due to cost.

Under current regulations we are limited in our ability to reduce the negative impact vegetation can have on our network. We rely on tree-owners, including private landowners and Council, to ensure that they are aware of their obligations under the tree regulations, and are aware of at-risk vegetation near power lines. Vector is investing in education and awareness efforts to encourage tree-owners to remove at-risk vegetation (such as fast-growing trees) and replacing them with more suitable vegetation. The advantage to the tree owner is that they will avoid the risk of having to pay for subsequent trims in future years, or any damage to the network caused by the tree. As effective tree management is a nationwide issue affecting every electricity lines company, we will continue to work with the ENA to call for a review of the regulations governing vegetation management. To date, the ENA has raised these concerns directly with the Ministry of Business Innovation and Employment (MBIE), and is awaiting guidance on how appropriate amendments to the current regulations can be made to improve outcomes for consumers.

AUCKLAND TRAFFIC

Auckland's growth is impacting how long it takes for Vector's field crews to reach power outages across the city, which adds to the length of time that customers can be without power. Commonly-used arterial roads and routes in Auckland are now increasingly affected by traffic congestion, and this is affecting outage response times. Vector is investigating alternative measures to overcome traffic congestion, including increasing the number of equipment depots across the city and basing crews at these locations during peak traffic periods. In the future, it may be possible for scoping work to be carried out using drones.

RIGHT-OF-WAY POLES

The ownership structure, maintenance responsibilities and regulation governing right-of-way pole management is a growing concern for Vector. Like service lines, the lines and poles that connect properties located down right-of-ways are technically the responsibility of customers. There is low awareness of this however, and as a result many of the cables, lines and poles have reached end of life or are not being properly maintained. This leads to a poor service experience for some and is also a health and safety risk if the assets are not maintained. It is also driving cost into Vector's business as customers rely on us to deploy field services crews to diagnose problems with their electricity supply. Vector is of the view that the regulations governing right-of-way assets need review to provide better planning certainty for our customers, field crews and Vector in the long term. As this is a nationwide issue affecting every electricity lines company, we will continue to work with the ENA to call for a review of the regulation governing right-of-way poles. To date, the ENA has raised these concerns directly with the MBIE, and is awaiting guidance on how appropriate amendments to the current regulations can be made.

THE WAY FORWARD FOR AUCKLAND

Auckland City is expansive. People's homes and businesses are spread far and wide. We have a high-density CBD, along with harbours, islands, mountain ranges, and isolated peninsulas, and we live and work in all these places. There are significant costs associated with continuing to build a traditional network to keep up with demand. Putting the interests of our customers first, we are turning to new, affordable and cost-deferring technology options to grow our network as efficiently as we can. If we do not innovate in how we design, plan and adjust for Auckland's growth, especially when we consider the rapid pace of disruption, then we run a real risk of increasing the stranded asset risk. This could also potentially result in a large traditional asset base paid for by future generations, that may not be required.

PUTTING CUSTOMERS AT THE CENTRE

The way customers use energy is changing. Our homes and businesses are becoming more energy efficient, but at the same time, our lives are becoming more electricity dependent. This, coupled with Auckland growth, is increasing demand for electricity and the criticality of electricity will further increase with the electrification of transport.

We can no longer assume the preferences of our customers fall along traditional demographic lines, such as urban and rural, residential and business, or a household of one versus a family of ten. Instead, it is becoming increasingly important to define specific customer archetypes and back this up with evidence. This level of detail is essential for planning and preparing our total customer experience.

In recent years, digital service providers have launched services like streaming and ride-sharing that have taken the world by storm. Unshackled from the constraints of physical infrastructure, these companies have raised the service-level bar by providing intuitive, relevant and mostly friction-free experiences to their customers. Their services almost always come at a competitive price too. This shift has conditioned customers to expect a similar exemplary level of service at every turn, and will happen in electricity as well[5]. With the technology that is now available, Vector wants to go as far as it can in meeting its customer expectations.

LISTENING TO OUR CUSTOMERS

Vector has responded to these demand imperatives by developing a deeper understanding of customers' changing needs, preferences and expectations. We have carried out market research, and employed smart analytics methods, across a wide range of data sources (for example, the census, council and transport data). This gives us greater customer insights.

GREATER ACCESS TO SMART METER DATA

We are also seeking greater access to our customers' smart-meter data, so we can better integrate the low-voltage network into our overall view of the service our customers are experiencing. Right now, a significant challenge is that many distribution companies do not have ready access to smart meter data. This impedes the ability of networks to adequately respond to outages as they cannot 'see' faults at the household level. As a collective industry, it is clear there needs to be better sharing of secure information to deliver improved customer service and enable efficient investment.

THE CASE FOR SHARED RESILIENCE

Over the past year Vector has promoted more informed discussion on the different ways to deliver network resilience. Shared resilience solutions offer more control, security and choice for consumers – but are not necessarily grounded in traditional or centralised network investments. Vector will continue to do its part to ensure a reliable supply of energy for our customers by maintaining and reinforcing our assets where this is needed. But we also need to play a role in enabling customers to take more control by using the energy options becoming available to them. These options include solar and battery systems, and other forms of grid-edge distributed energy resources (DERs). These consumer-centric solutions give households and businesses greater control. They take less time to realise a financial return too, which can avoid burdening future generations with the costs of investing in traditional network assets that could become stranded. They also guarantee that consumers benefit directly from their 'resilience' investments, and provide extra benefits such as off-setting energy costs.

Customers are increasingly willing to take control of their energy and this will change the way the energy market operates. We will continue to grow our understanding of how we prepare our network to actively facilitate this control.

Read more about our approach to customer service in 'Delivering for our customers with urgency', page 24.

5. Shell's intent to become the world's largest power company also serves to highlight the disruption in service provision and customer satisfaction coming to the electricity industry.
'Shell aims to become world's largest electricity company'; ft.com

HARNESSING THE POWER OF EMERGING TECHNOLOGIES

Vector's core focus is on ensuring our distribution network provides an affordable and high-quality service for Aucklanders, and is an enabler not a hindrance to the new energy future. While traditional network assets will form the backbone of the network for many decades to come, new network technologies are fast becoming an essential part of the mix.

DISTRIBUTED RENEWABLE ENERGY GENERATION

Foremost in this energy revolution is the emergence of technologies that can renew or generate their own electricity, such as solar panels. These technologies are trickling down from an industrial level (solar energy farms) to become directly available to people and businesses (solar panels installed in the home, for example). As technology innovation continues and prices drop, solar is becoming more available and affordable.

Solar panels will have an increasing influence on our electrical system. Until now, the energy generation/retail model has been based on customers getting their power from a central location and then paying for this in a standardised way. Solar panels are changing this. They will let households and businesses become energy 'prosumers' (producer / consumers), and, through channels such as peer-to-peer trading, allow solar energy to be shared within 'energy communities' on their own terms. These solar households will be able to generate their own clean electricity on-site and convert any surplus into revenue by trading locally.

These changing power flows undermine the unidirectional flow that our current networks were designed for. As a result, we anticipate investment in electricity distribution networks will shift away from where it has traditionally been spent and towards an increasing number of lower voltage networks that will support customer technology adoption and enablement through integration with the network. We are also monitoring the use of hydrogen and fuel cells as potential new technology options our customers may adopt. There is a broad range of possible applications as it could be utilised for commercial vehicles or even for peak load management using our gas network.

ENERGY STORAGE

Advances in energy storage, in particular how much energy batteries can store, will mean that mass energy storage could soon become cheaper to purchase, build and manage. Like solar panels, lithium-ion storage batteries are becoming more common in homes and businesses. As the cost of solar and lithium-ion battery technology trends down, there will be a tipping point for mass market adoption. However, we don't know when this will occur. This creates uncertainty when planning for investment in the network.

At the industrial level, electrification linked with thermal storage, metal-air and battery alternatives like supercapacitors are emerging. This proliferation of energy storage options could also change the way power flows through electricity networks.

If managed and integrated with the network, these storage options could lead to less demand for electricity from homes and businesses, which would result in less strain on the network, along with other economic and operational benefits. Such storage options would provide people with the capability to store excess energy generated from solar panels.

ENERGY UTILISATION AND MANAGEMENT

Energy utilisation and management technologies are also advancing. There is a growing array of electrical devices and equipment that are much more energy-efficient. LED lighting, heat pumps, refrigeration and energy efficient air-handling systems are reducing the energy needs of our factories, offices and homes.

Internet and cloud-based software, which control and manage how energy is used and co-ordinated across different sites, is also helping create 'smart' buildings and infrastructure. As these smart technologies evolve, even smarter developments like machine learning and artificial intelligence, which are now at the early leading-edge stage, will allow these energy technologies to dynamically adapt and optimise.

For Vector's network, the potential of these technologies is huge. We are continuing to invest in them to understand how they can help us manage, control and utilise our network to meet Auckland's growing demand for energy.

THE ELECTRIFICATION OF TRANSPORT

Electric vehicles (EVs) are growing in popularity, not just globally but also in Auckland. They will continue to do so as the purchase cost of an electric car declines over the next decade. Vector has trialled a number of 50 kilowatt (kW) rapid EV chargers across the city to cater to the region's growing fleet of EVs and to build understanding of how charging technology interacts and impacts on the electricity network. This has highlighted a wider, future challenge - as EV use increases, it will only be a matter of time before charging these cars puts pressure on Auckland's electricity network to supply the demand.

A greater penetration of EVs charging at peak times using residential feeders could lead to a need for more infrastructure to meet this peak demand. A standard dwelling tends to operate at an after diversity maximum demand of 2.5kW. If a 50kW rapid charger was installed into an average home, it is comparable to adding another 20 dwellings to the feeder circuit. A proliferation of chargers (even a typical home AC charger which is closer to 7 kW) could lead to challenges around peak demand if not managed.

Vector's investment in software management systems will help reduce the impact residential EV chargers have on peak demand. If we have access to data to enhance visibility and understanding of each customer's behaviour, it provides the opportunity to incentivise behaviour to better manage demand peaks. For example, we can offer a financial incentive to customers who opt to charge their EV in the middle of the night by choosing that option themselves or giving us permission to do it on their behalf.

Vector has also explored the potential of Vehicle to Grid (V2G) and Vehicle to Home (V2H) chargers. EVs take power from the grid to charge the car's battery. A V2G system can reverse the process by putting power back into the grid from the battery. This has the potential to transform EVs into mobile power sources for homes and businesses (for example, an EV with a 30kWh battery capacity could supply the average household load for 12 hours before fully discharging.)

This new rechargeable energy source could be used to supplement imported electricity to buildings, and be a cheaper power source during times of peak consumption. It could also be a way to supply homes during power outages – and to release energy back to the grid to support the network during times of high energy demand.

Vector is committed to understanding more about these emerging technologies, and facilitate their uptake to benefit our customers by putting more control into their hands.

PROGRESSING THE JOURNEY TOWARDS CUSTOMER CENTRICITY THROUGH DATA ANALYTICS

We are continuing our journey to meet our customers' needs in a safe, reliable and affordable way. A key aspect of this journey is enabling the network to facilitate and integrate the new energy management technologies our customers are adopting in such a way that the overall cost of managing the network is reduced. At the same time, this approach can improve overall resilience, the customer experience and the way we communicate and update our customers. We are transforming our systems to deal with new data from multiple sources, allow faster processing of data and minimise manual intervention, while improving our ability to collaborate with external parties such as Civil Defence. These systems consider activity across network operations, network integration, data and customer experience.

CASE STUDY

COMMUNICATING WITH CUSTOMERS DURING OUTAGES

Given the impact of severe weather events on the network and the community, we have asked our customers to tell us what is important to them when it comes to their service experience during outages. This feedback has enabled us to redesign our customer facing tools and systems to ensure they are fit for purpose. Our customers tell us that accurate and up to date communications during power outages is very important. They expect us to provide network information that is relevant to them – and they want the message delivered through their preferred communications channel.

Vector is delivering on this by investing in a totally new web based outage application, which provides customers information and updates of outages affecting them irrespective of where they live in Auckland. Through the new online portal, customers can set up their own notification preferences. This gives Vector the necessary permissions to provide customers with notifications to keep them up to date with planned and unplanned outages.

This new online outage app replaces Vector's previous outage app - which could not cope with the unprecedented surge in customers trying to contact us after the extreme storm of April 2018. The outage app has been built to a standard that enables Vector to seamlessly scale our customer communications in the event of a major storm.

CYBER SECURITY

Increased customer demand and expectation in relation to the capabilities of the network coupled with the need to adequately address the macro trends impacting the Auckland region, require a different approach to network design.

There will be increased use of non-traditional technologies and designs which will enable greater visibility, control, resiliency and access to the distribution network. The network of the future will no longer consist of proprietary components and legacy protocols and will become far more accessible, open and have a less definitive boundary. All of these factors increase the attack surface and significantly increase the risk of unauthorised access and disruptive cyber-attacks.

We expect the transition to this new type of network to continue at pace. To adequately manage the increasing cyber risk from targeted attacks on critical infrastructure, Vector needs to continually assess the threat landscape to ensure the network is appropriately protected and invest in appropriate preventative and detective technologies, tools and resources. Maintaining trust and confidence in the network and ensuring security of supply is critical to our future.

The investments we have made to date have improved our ability to detect and respond to cyber threats but are only the start of our journey. The controls we have in place today are likely to require upgrade, replacement or enhancement to remain relevant and effective. At times, we will need to be leading edge (such as our deployment of an Intrusion Detection System (IDS) specifically for our electricity control systems, which, as we understand, was the first in our sector in New Zealand) and at other times a more conservative approach may be required. The cyber threat can never be fully eliminated and therefore to manage any exposures will require a constant level of assessment and investment.

The evolving cyber threat cannot be ignored and will remain a key strategic risk for Vector and our industry moving forward.

CASE STUDY

MANAGED INTEGRATION

Technological disruption in the electricity sector is advancing every year. Customer-owned distributed energy resources (DERs) are changing the way energy is transferred across the network. In response to this, there is a pressing need to manage the impact of these changes to enable Vector to continue to provide a service that is affordable and fair to all customers.

Traditionally, energy has always moved in one direction: from large power stations through to the transmission network, then to the distribution network, before terminating at an end-point in appliances and devices. When you add solar panels and battery storage into the mix, energy can also flow back the other way.

It is important that Vector has visibility of the customer owned DERs on the network, and that we understand the impact they have on bi-directional power flows. Without this visibility, there is a risk DERs could lead to significant network investment, cause unplanned interruptions for customers as well as creating a safety risk for line mechanics due to the bi-directional power flows. The benefits of this visibility go far beyond network resilience and reliability. As well as enabling customer choice, managing dynamic power flows can reduce the load on physical assets during peak times. This enables Vector to defer capital investment.

Vector has invested in a system known as the 'Vector DERMS Platform'. The acronym DERMS stands for *distributed energy resource management system.*

Co-developed with software firm mPrest, the Vector DERMS Platform allows us to securely connect DERs and manage them in conjunction with our customers by ensuring alignment with network requirements while also providing direct benefits to customers.

This system that we are co-developing will challenge the traditional mindset that has seen EDBs grow their networks to accommodate greater peaks. It helps Vector defer network reinforcements costs and reduces the risk of stranded assets at a time when industry disruption is almost certain by utilising DERs to their full extent.

In the long term, this kind of system has the potential to actively facilitate customer choice. For example, if a customer has a full storage battery at their home or business and doesn't need to use its energy, the Vector DERMS Platform could allow the person to share this excess energy with a neighbour, or even sell it back to the grid. Customers could also choose to let Vector integrate their DER into the network. This has the potential to enhance network resiliency and reliability – meeting the needs of the customer's wider community – while also providing commercial benefits to the customer and Vector. It's the same principle as room-sharing models, but, instead of booking accommodation in someone's home, customers can put their home's generated energy into an open marketplace. Vector could choose to run the network as a closed system, but we have chosen a bold strategic path of evolving a traditionally closed system to one that is open, intelligent and connected, in a way that provides satisfactory commercial aspects to customers and all others.

PLANNING OUR NETWORK IN A SUSTAINABLE WAY

The next decade is a key time-frame for creating a shift in the way societies operate, and energy systems will be a key aspect of this.

To facilitate this, we aim to design the network to enable customers to get value from their investment in on-premise decarbonisation technologies, e.g. electric vehicles. We also have the obligation to ensure we mitigate the potential network investment impact of these technologies on the network to avoid unforeseen equity, fairness and deprivation consequences. Addressing the impact of climate change on our assets, e.g. weather events, sea level rises and drought are obvious issues, but there are a range of other challenges to consider in ensuring sustainability remains at the heart of creating a new energy future.

Sustainability is a principle that underpins the delivery and management of our network assets, and we recognise that every decision made in respect of the network must take into consideration the environmental, social and economic impacts, both positive and negative. To ensure our approach to sustainability has real meaning, we have committed to helping achieve the United Nations' 17 Sustainable Development Goals. From these 17, there are seven we have prioritised that we can directly contribute to with the most relevant to asset management being Goal 9, which focuses on developing infrastructure that is both sustainable and innovative, Goal 11 addressing sustainable urbanisation and Goal 13, the climate action goal, which is concerned with reducing carbon emissions and adapting to the impacts of climate change.

The sustainability framework we have developed takes account of both the sustainable development goals and the concept of doing no harm. Alongside key principles of kaitiakitanga (guardianship and protection) integrity, transparency and inclusion, these inform our approach to making decisions across our business, including our network.

Figure 1-3 Vector's alignment with UN Sustainable Development Goals

PHYSICAL IMPACTS OF CLIMATE CHANGE

Vector's approach to sustainability recognises that climate change poses a risk to our assets and operation, and the reliability of services we provide to our customers. The evidence of this could be seen in the April 2018 storm where the level of damage across our network was unprecedented and offered a stark insight into the type of event that may become more frequent with climate change, and that could threaten the reliability of electricity networks in the future.

In 2017 and 2018, Vector commissioned research from Ernst & Young (EY) to better understand how climate change could impact on our electricity network out to 2050. The climate model developed suggests that occurrences of high-wind speeds are likely to increase significantly, putting Auckland's energy distribution network increasingly at risk unless adaptive and remedial action is taken.

The network is also expected to continue to be at potential risk from flooding (including coastal flooding), landslides and soil erosion. In the longer term, sea level rise, particularly in combination with storm surges, will impact on assets in coastal areas both in terms of direct, physical risk, and in changing availability of finance and insurance that could lead to stranded assets.

These findings confirm that our approach to ensuring network resilience, both now and into the future, is appropriate. The EY research provided a firm base from which to further develop and articulate our understanding of the relationship between the electricity network and changing climatic parameters. Over the course of this AMP period, we will build on this base to develop this understanding further, including broader modelling and granularity of impact.

Beyond distribution related impacts Auckland runs on imported power from a variety of geothermal and hydro power stations that means it is exposed to supply and pricing risks. Climate change may create uncertainty for New Zealand's current centralised sources of generation, particularly hydro-electricity with its reliance on precipitation and snow-melt filling the lakes at certain times of the year. This is another reason the popularity of DERs discussed above are expected to increase over the coming years – diversification of generation and greater resilience for Auckland consumers.

WORKING TOWARD A NET-ZERO EMISSIONS ECONOMY

The policy changes that may be put in place to move the country towards becoming a low emissions economy will also affect the electricity system. The speed and level of uptake of electrified transport, particularly an increase in light vehicles switching over to EVs is likely to be the most relevant to our current asset management plan. A separate EY report says while EV numbers are currently low, exponential growth is expected, driven by both the price of carbon increasing and expected price parity with internal combustion engine (ICE) vehicles within the next five to 10 years. The expected growth in EV numbers forms a key part of demand-modelling in New Zealand and overseas.

This information feeds into the broader scenario modelling Vector does for potential future outcomes discussed further below.

We have set our own target of net zero emissions by 2030 to ensure we play our part in transitioning to a low carbon economy. This will provide visibility of carbon as part of our management of assets, shining a different light on where there may be inefficiencies or waste in the network that can be removed leading to a number of direct cost savings.

This approach supports the international aim of holding global warming to less than two degrees centigrade relative to pre-industrial levels. It is a goal Vector has committed to support.

In 2017, New Zealand ratified the Paris Climate Agreement. New Zealand's related Zero Carbon Bill is currently making its way through parliament – with new carbon targets expected to be set into law by 2020.

However, like most industrialised countries, New Zealand's emissions profile is still trending upwards. The curve needs to trend downwards, but the only effective way to do this is through an economic lever – such as carbon pricing. Soon, New Zealand under its Climate Commission will set five-year carbon budgets that will gradually cause the price of carbon to increase. Carbon pricing extends into the supply chain also, and embodied carbon in goods such as steel and concrete will flow into Vector's network construction and maintenance costs.

CIRCULAR ECONOMY

As part of our commitment to sustainability, we are taking steps to improve our understanding of what goes into any new energy technology and all other products in use across our business, so we can understand their social and environmental impacts.

An example of this effort can be seen in Vector's recent move to establish the Battery Leaders Group. Consisting of local and international businesses, the Group aims to find circular economy solutions for the batteries that are used in electric vehicles, and in networks for shaving demand peaks.

Eventually, these batteries will reach end of life and the question of repurposing or recycling them will become important for the industry to understand. The Battery Leaders Group has committed to researching the market with a view to developing formal recommendations on how a future product stewardship scheme could be implemented.

EMBRACING SCENARIO MODELLING TO 2050

There is a strong expectation that customer-side DERs could come to dominate over the next 10 years. Regardless of when, how or if this eventuates, it would have a profound impact on network design, performance and cost. Vector is embracing a scenario modelling to better understand the impact of potential future outcomes.

The two largest uncertainties around future demand growth are the speed of the uptake of new customer side technologies, and the network response to such technologies.

Scenarios enable us to derive robust business strategies to respond to disruption by understanding how changes in the input variables affect outcomes to the network, customers and investment requirements. Vector's scenario planning tool used in the AMP models electricity demand growth for a set of different possible futures.

Vector has named the potential scenarios after music genres. They are called Pop, Rock and Symphony. We also refer to two other scenarios - Disco and Indie - which are long-term alternative futures that could materialise after 2030.

- Pop is well-established today. The customers steadily adopt new energy technology (mainly EVs and energy efficiency) and the network responds by granularly becoming more intelligent;
- Rock is counterfactual to Pop. Customers aggressively adopt new technology, but the network relies primarily on physical assets to meet growing demand. This reliance on traditional technology does not align with the network requirements;
- Symphony is where the network proactively facilitates customer engagement and technology uptake, leading to Low Voltage (LV) network and customer integration. Symphony results in the alignment between network requirements which minimise investment and customer investment in non-traditional distributed energy resources

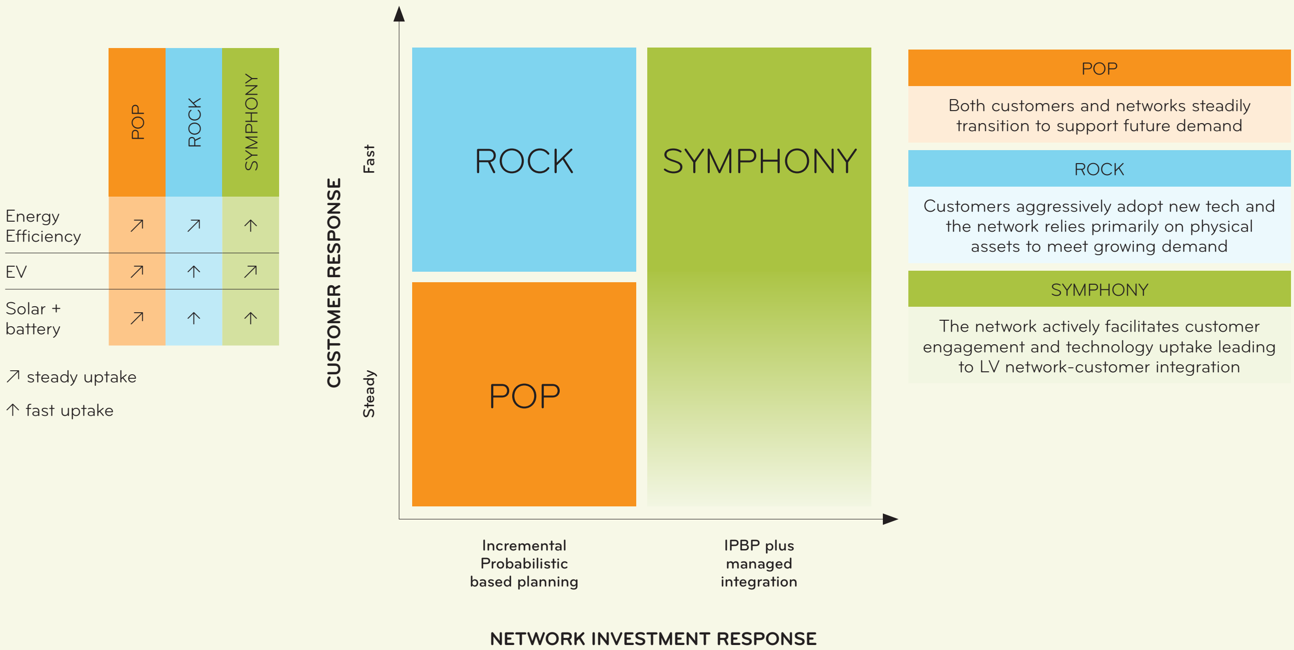


Figure 1-4 Scenarios defined

- Disco (long-term alternative) - customers become self-sufficient and therefore some disconnect from the network and some new customers do not connect to the network
- Indie (long terms alternative) - cars become independent from the network due to reduced fleet size in an age of mobility-as-a-service and/or due to the uptake of alternative fuels and charging solutions

In preparing this AMP, we have focused our attention on Symphony. In the Symphony scenario, our network can mould to the demand curves of the future. Our solution optionality increases, allowing us to buy time and have more options to solve energy challenges across communities. This in turn allows us to defer investments in physical assets that may not have a place in the future if they can't align with the evolving interests of consumers. In this year's AMP, we make the case for the Symphony, which at its core, is a technology and analytics-led approach to asset management and planning.

SCENARIO METHODOLOGY

Our scenario methodology stems from a mixture of bottom-up and top-down approaches.

Most importantly, the model is based on a rich list of Vector data sources and assumptions from different national statistics We have analysed every ICP on our network to gain an understanding of their attributes.

Other statistical data includes demographics, dwelling characteristics, household composition, appliance sales and motor vehicle sales, and international studies and reports on technology development and uptake.

Customer growth is the same in all scenarios and is based on Auckland City Council data. This data forecasts net changes in households and employees for each of the Auckland Transport zones that cover Vector's electricity network. The model converts this forecast into ICP numbers for Residential, Small Medium Enterprise and Industrial and Commercial, and scales the first 10 years to match Vector's 10-year ICP forecast. The cross-pollination of this data ensures the future demand outputs are realistic and robust.

The model results are highly granular across the Auckland region and provides customer-demand growth for small blocks (or small geographical areas) of approximately 1,000 dwellings. These small areas can be aggregated to an area of interest (e.g. new urban areas and areas of network constraint) or to existing zone substation assets.

The scenarios analyse different future energy growth patterns. New customer side technologies modelled include residential energy efficiency gains caused by things such as improved insulation, LED lighting, modern energy efficient appliances and the use of home energy management systems. In our scenario modelling attention was given to the impact of residential EV charging, public and business EV charging at places such as service stations, in carparks, and at fleet vehicle depots. We also considered the potential impact that solar and battery systems may have.

INVESTMENT AND BENEFIT FROM A SYMPHONY SCENARIO

The investments and customer outcomes in each scenario differ. Last year the POP scenario formed the basis for the AMP because it seamlessly fit with the legacy regulatory framework.

Symphony and Pop scenarios stand in stark contrast. The benefits of enabling our network to integrate and manage the impact of distributed energy resources, while getting more visibility of the low voltage network through access to smart meter data and additional measuring and sensing devices enables the same resilience but at a lower cost overall.

We believe that Symphony will enable a more customer-centric energy network. The Pop and Rock scenarios however, increase the stranded asset risk that could potentially result in physical assets that may not be required by future generations.

MAIN DRIVERS OF SCENARIOS

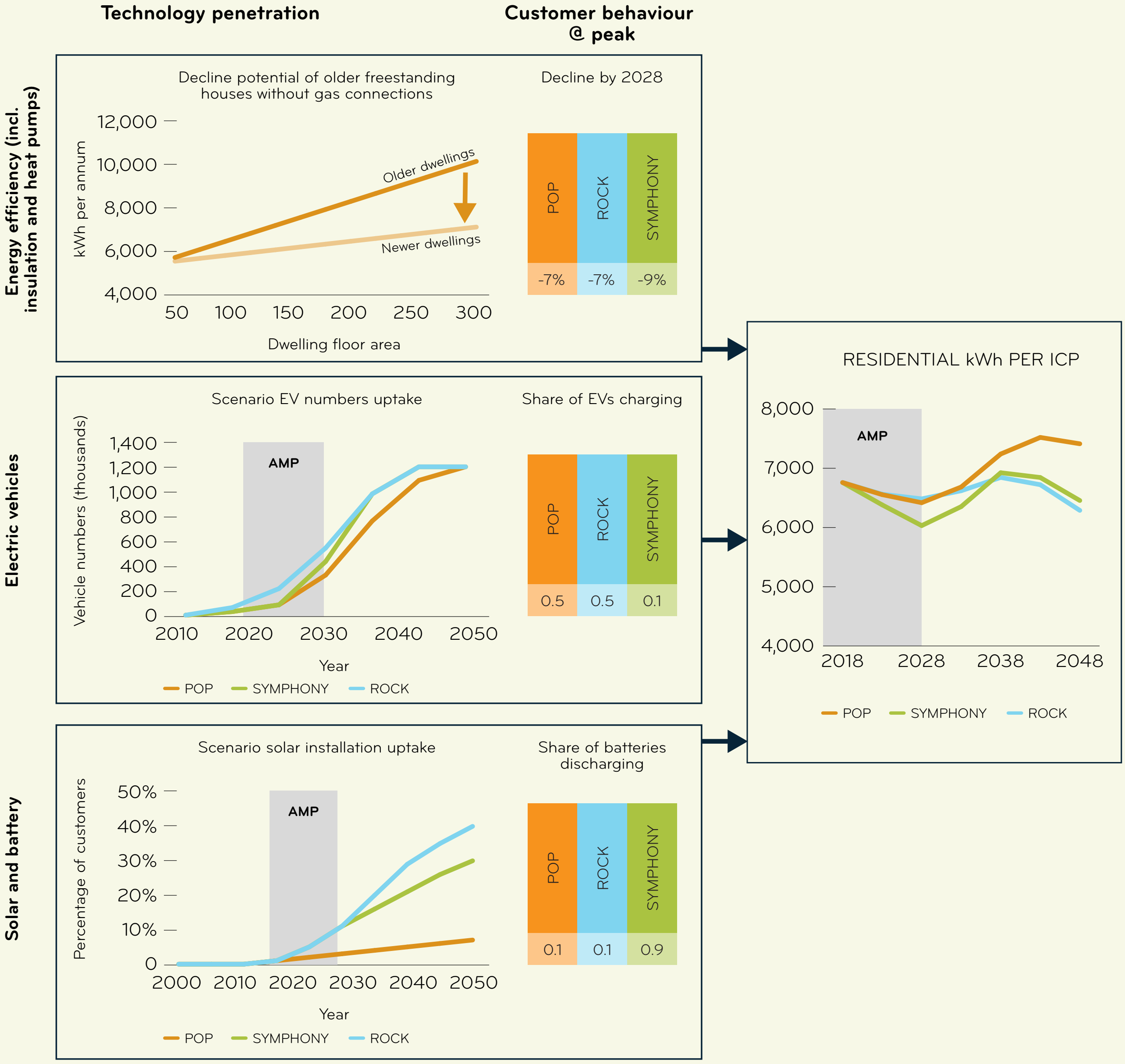


Figure 1-5 Main drivers of scenarios

DELIVERING FOR OUR CUSTOMERS WITH URGENCY

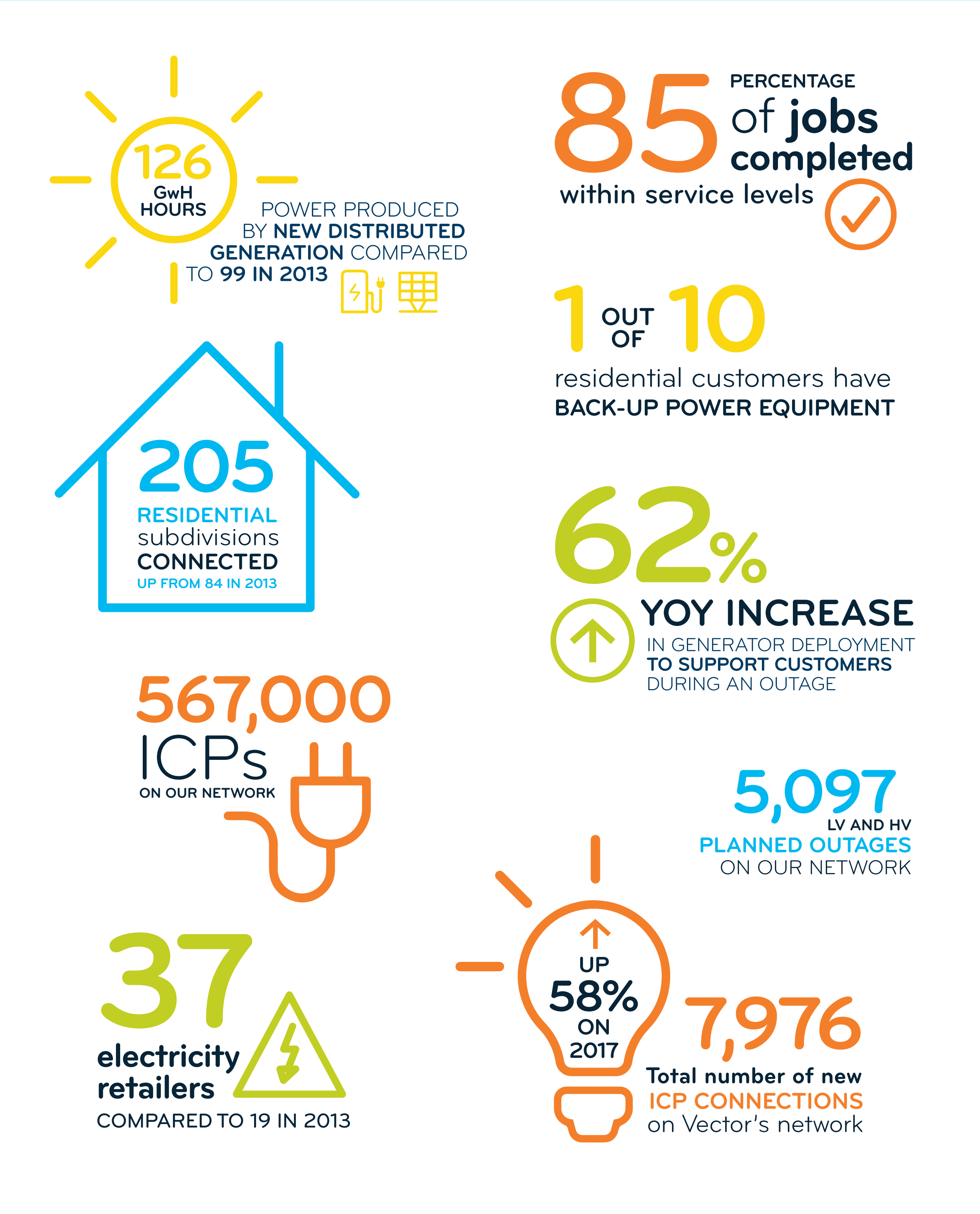


Figure 1-6 FY18 customer performance snapshot

DELIVERING FOR OUR CUSTOMERS WITH URGENCY

Our commitment to deliver for our customers with urgency means we have a responsibility to know them, understand when our relationship matters most to them, and deliver meaningful experiences that make a difference.

Vector's vision for the future puts customers' needs at the centre of our asset management strategy. Investing in customer research, working harder to understand our customers problems and challenges, and then looking for creative yet sensible solutions is going to improve our ability to strike the best outcome.

Right now, we know that energy technology is changing fast, which is making investment decisions more complex. In instances where investment in traditional infrastructure is not necessarily the best course of action – we have the option of introducing an alternative solution. We will continue to invest in traditional assets when we're certain they will deliver the best outcome for that community. In other instances, we will first look to provide alternate solution options that deliver the required service in a more flexible manner.

At the same time, electric cars, solar panels, batteries, home energy management systems, intelligent networks and other digital technologies are creating possibilities and choice for customers. The vision of a future where communities are more self-sufficient, resilient and decarbonised is one that is being embraced by customers from all corners. They may soon be feeding electricity from roof-top solar panels and their electric car battery into the network, becoming energy producers as well as consumers.

Our customers have told us, through our research, exactly what they want. And that is to understand them, inform them and empower them to take more control over their energy needs and preferences.

Our customers want more visibility of what is happening in the physical world of electricity – through relevant and timely information that is easily accessible and delivered as a great experience via their preferred communication channel. Just as when you can see the real-time location of a taxi on your mobile phone, or shop online and track the progress of your parcel delivery, that increased service expectation is applied to us.

Ahmad Faruqui, Principal of the Brattle Group, is an internationally recognised authority on the design, evaluation and benchmarking of tariffs and has also designed experiments to model the impact of these tariffs and organised focus groups to study customer acceptance.

Besides tariffs, his areas of expertise include demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He has worked for nearly 150 clients on five continents, including electric and gas utilities.

He has reviewed several of our data analytics studies dealing with customer behaviour and considers they exceed what he has seen in other utilities in North America.

"

They are yielding meaningful and rich insights about customer preferences organised by demographic and socio-economic characteristics. They are also quite revealing about how customers are using energy and interacting with the grid.

The insights derived from the studies are being used by Vector to enhance the customer engagement experience."

CASE STUDY
TAPORA MICROGRID – A NEW ENERGY SOLUTION

Increasing extreme weather events are exposing the northern Auckland rural community on the Tapora Peninsula to more weather-related outages, making the connection to the electricity grid more vulnerable. Tapora is also a growing region and land use is changing. New horticulture industries that have a strong dependency on reliable electricity supply, for irrigation and frost protection, are springing up. In consultation with the community, a micro-grid solution has been developed, to improve reliability, as an alternative to traditional network reinforcement or replacement solutions. It will provide continuity of supply for domestic loads during network outages.

CASE STUDY
BETHELLS BEACH UNDERGROUNDING – A TRADITIONAL ENERGY SOLUTION

Popular with locals, tourists and adventurers from all over, Bethells Beach is a much-loved seaside community on the West Coast of Auckland. Vector's network has served the area for many decades. Unfortunately, a recent copper conductor failure on a section of network intersecting with the Hilary Track made it very clear that certain parts of the network needed to be upgraded. Compounding matters were a cluster of unstable power poles that were at risk of failing because a river flowing through the land had eroded the riverbank, thus affecting the integrity of the assets. Vector's network team considered a range of potential network solutions before engaging with the community to understand their options. A new energy solution (such as a battery or microgrid) was considered, but soon ruled out because traditional assets like the poles and conductors would still need to be replaced to achieve the desired outcome. Instead, landowners backed Vector's more cost-effective recommendation – which was to underground a section of network and remove the problematic equipment completely. As part of the solution, landowners granted easements over their properties to protect Vector's assets and entry rights in future. Today, this part of the network has been successfully placed underground, improving reliability, public safety and visual impact in the area.

A DATA DRIVEN APPROACH TO SERVING OUR CUSTOMERS

A 'one size fits all' approach is not appropriate to meet the electricity needs of Auckland.

We have for a number of years adopted a more holistic and data driven approach to inform our investments. With the cost of investments distributed equally and consistently across all Aucklanders, decisions are not as simple as understanding what customers are prepared to pay for certain service levels. At a basic level, we recognise our customers want a reliable supply of electricity, the power of choice and a sense of control. However, we require a far more sophisticated and granular approach to understand the diverse makeup of Auckland and the evolving energy needs of communities to help inform investment decisions.

Ongoing customer research allows us to truly understand the diverse communities that exist in Auckland and how their corresponding expectations and needs differ. Customers are not always able to readily articulate their needs so we use a range of validated research methods to determine what is important to consumers and communities. These methods include world leading data analytics to inform and provide insights into changing customer behaviour and preferences, structured surveys, daily feedback from customers, in-person community engagement, and qualitative techniques such as interviews. We see our customer's preferences evolving such as the desire to engage and communicate through social media channels, so we explore and leverage additional tools that allow us to monitor and analyse those channels.

Utilising these research methods we can triangulate on key themes that provide strong guidance for our decision making that aligns with our customers' needs.

Our approach to inform our investment decisions with a variety of inputs is not a unique challenge. We actively look to world-class examples to leverage approaches to accelerate our evolution. Ofgem in the UK align with our view on how quality performance should be customer focussed and relevant to those impacted. The Australian Energy Regulator (AER) actively sets service levels for a variety of services including connection times and outage notifications.

We recognise Auckland's hugely diverse makeup and that its geographically spread communities often have different needs. A 'one size fits all' approach won't work for Auckland.

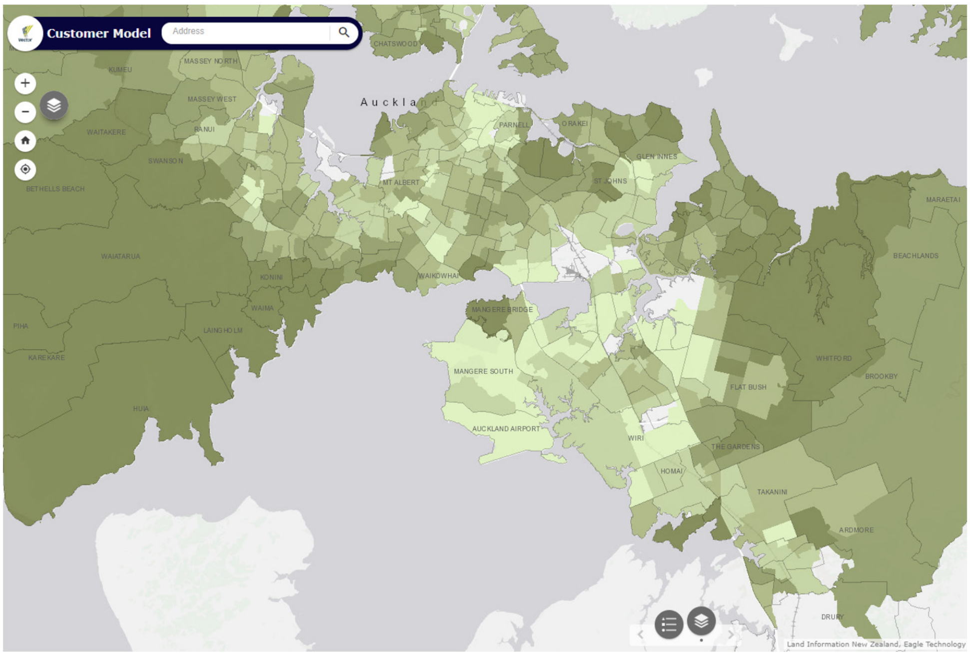
'The fantail looks over the community, while the tui looks ahead'

Māori urban artists Charles and Janine Williams created this Glen Innes substation mural in consultation with local people

CUSTOMER INSIGHTS

From the various data approaches noted above and collected from many sources (see Section 4.1.12), we are able to create meaningful insight information about what our customers are doing and how this can and does impact the network. Examples of this are included below (please note for the first diagram, the shades of green represent the level of home ownership with the darker shades depicting higher levels of ownership).

HOME OWNERSHIP



Vector maps all census and other customer related data

This map shows the ratio of home ownership by mesh-block as per Census 2013 – useful for analysing against efficiency changes etc

Other data includes:

- EV ownership
- DG installations
- Consumption
- Peak demand (requires smart meter data)

Figure 1-7 Customer Insights 1 – Home ownership

ELECTRIC VEHICLE OWNERSHIP

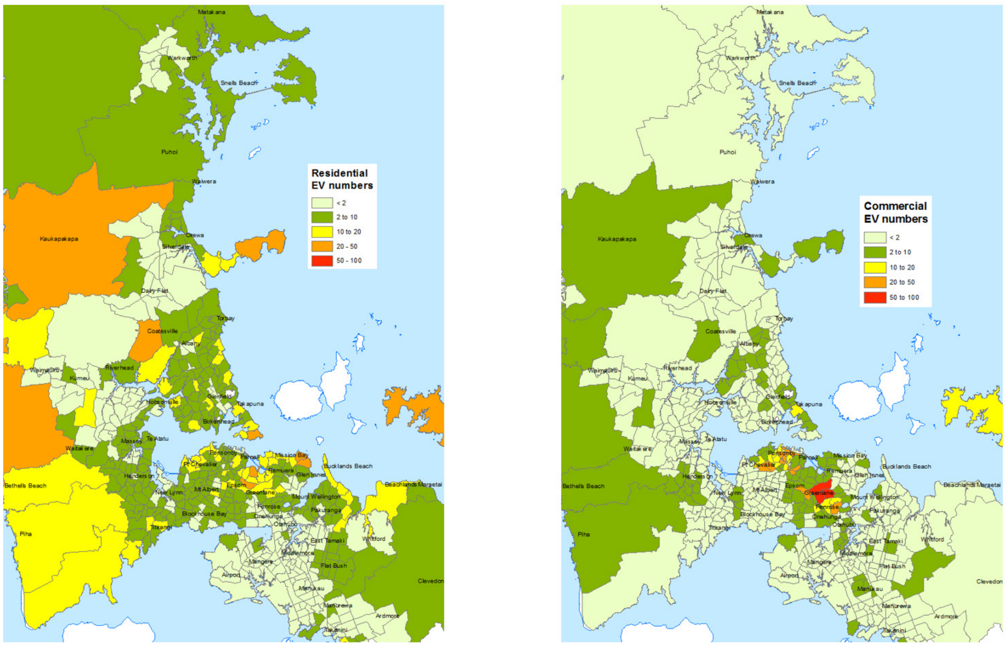


Figure 1-8 Customer Insights 2 – Electric vehicle ownership

TALKING TO OUR CUSTOMERS

We know how important it is to understand our customers, and that this effort must be continuous to add real value. We carry out multiple customer engagements as part of our standard business operations to understand our customers better.

DIRECT CUSTOMER ENGAGEMENT (KNOWING OUR CUSTOMER)

The table below highlights the key areas of customer interaction and engagement:

Interaction/Engagement	Purpose
Customer Connections	• ICP creation, e.g. *I am subdividing my section and satisfaction throughoutrequire an ICP for a new dwelling* • Distributed Generation – e.g. *I need to connect my new solar and battery installation* • Residential Subdivisions – developers building new subdivisions work with a dedicated team who arrange the electrical engineering design, commercial terms and pricing for large residential subdivisions and developments. • Commercial Projects – Auckland's skyline has a substantial number of cranes working across the city. Each of these sites will require a new commercial connection. We have a team providing these customers individual management of their engagement with Vector quote, design and contract. The projects require complex civil management and increasing levels of traffic management. Information is constantly sought by consultants and developers around the implications of new technology such as commercial batteries, distributed generation and rapid EV charging.
Outages	• Contact Centre manages phone calls, social media interactions and emails for outages and general enquiries.
Customer Resolutions	• Deal with customer queries, service guarantee payments and utility dispute case management.
Community Engagement	• Provides the human face of the network at a local community level. They listen and respond to local community queries. The issues they deal with include discussing concerns with the proposed design of substations and art work on transformers. • Facilitate the CAB (Customer Advisory Board). The CAB provides a forum to listen to individuals representing a variety of sectors with a wide array of perspectives and understand their concerns, issues and the opportunities they see associated with our electricity network.
Retailer Relationships	• A person is dedicated to ensure the services we provide via retailers can be maximised to deliver the best end customer experience.
Key Account Customers	• A 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. • Have direct account management of 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.
Community events	• Meet members of the community in their space, hearing their concerns and explaining what we do, demonstrate we care e.g. Pacifika, Lantern Festival, Devonport GLOW Festival.

Table 1-1 Customer interactions

Vector employees engage with members of the community at Pacifika Festival.

CUSTOMER ADVISORY BOARD (CAB)

Our Customer Advisory Board is comprised of representatives of our different customer groups who give freely of their time. They are brought together each quarter so we can share our thinking and test our approach on a variety of topics, from pricing to technology enhancements and more. Our customer 'advisers' are open and honest in their views, learn and then share this new knowledge with their peers, and become, in turn, our advocates. Participants take part on the Board for a time before new members take their place to provide fresh thinking. The CAB does not replace other survey forms, it just adds to the richness of the research we carry out.

CUSTOMER PERSONAS

We use a variety of data-driven customer personas to focus our understanding of our different customers and their unique needs – and to inform our investment and design decisions regarding the technology used to interact with them.

CUSTOMER JOURNEY MAPS

We take our understanding of different customer personas and map out what their experience is like – and what they would like it to be. For outages, we consider how we notify customers about planned outages and what communication channels they prefer for both planned and unplanned events. This allows us to determine where gaps exist between what we do and what customers want, from which we can establish programmes of work to address those gaps.

Our Customer Journey Maps are periodically reviewed and updated as we identify new challenges facing our customers and continually seek to improve our service.

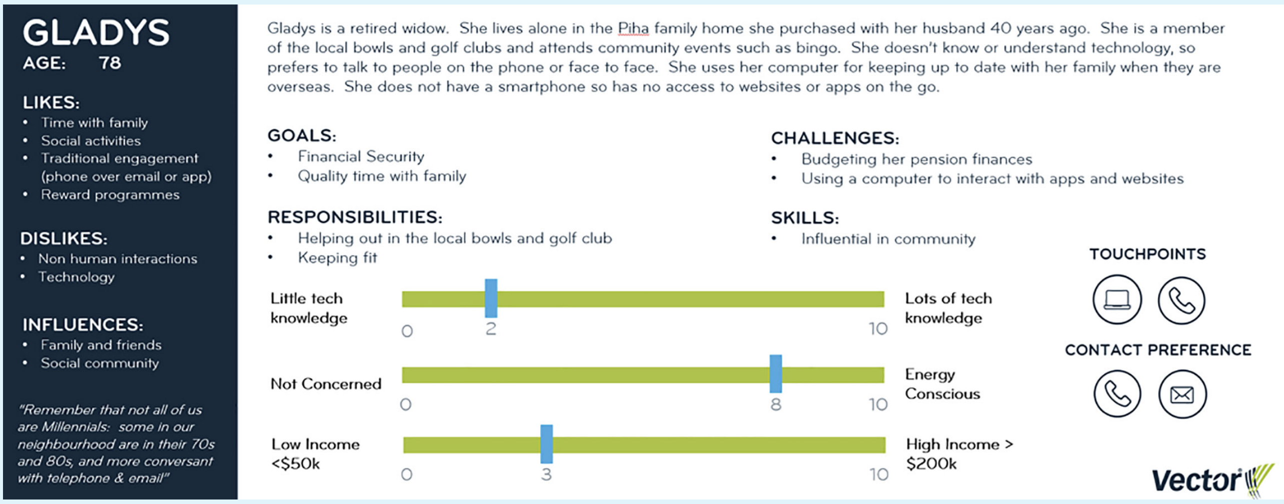


Figure 1-9 Example of customer persona 'Gladys'

GREATER UNDERSTANDING LEADS TO BETTER SOLUTIONS

The reason for understanding our customers, their lives and the role energy plays in them, all helps us deliver creative solutions of real benefit.

Our analysis flows directly through to our understanding of the challenges our customers face. We do this in practical ways that create a better customer experience. Below are some examples of how our customer research has helped inform our operational and investment strategy. We continue to evolve our approach here to better understand customers including the use of research, advisory boards and community engagement.

SIMPLIFYING NEW CONNECTIONS FOR OUR CUSTOMERS

Because Auckland is growing so fast, Vector gets a lot of requests to connect new homes; this year alone we received 7976 of these requests, a 58 per cent increase on last year. But customers don't always find the connection process easy. Concerns range from frustration at not being able to request multiple connections, inconsistent pricing and approvals taking too long.

From initial request to installation usually takes 8 to 12 weeks but can be quicker if it's a simple connection. Customers have said the process is too complex, so to simplify it we have created standard pricing for common types of connections and simplified the design process. We are looking to add extra service providers, so customers have a choice of which contractor they can use.

We have worked to set accurate expectations for customers too. This has been helped by streamlining both the pricing and unit costs across different types of jobs, and by providing more concise job and design descriptions. Customers who need a new connection can make the request through our on-line self-service web portal, or simply call us.

These changes are all about customers having more control and the ability to decide how and when they want to communicate – and who they want to interact with. Vector is further speeding up these processes by automating them where possible.

RELIABILITY MATTERS

Clearly, reliability matters to customers and this is a constant challenge. We recognise that changes to practices such as ceasing live line work has impacted customers and we are actively working to lower the impacts through such activities as mobile generation, new hot-sticking technology and also customer notifications.

THE ROLE OF SHARED RESILIENCE

Our analysis shows customers are not planning a long-term resilience strategy, they are instead taking a reactive approach and mitigating the resulting disruption and damage as best they feel they can.

Only one in 10 residential customers currently have back-up power equipment. The incidence is higher for businesses, who have more to lose because of power outages. A third of SMEs have some type of back-up power. A quarter of customers are aware of residential battery technology. However, the high capital cost is limiting interest. A third of customers would consider installing solar panels and a battery, with the most looking for at least some control over usage, however cost is a barrier to uptake for both residential and SME customers.

There is quite low ownership of electric cars among our customers, and while those who do own one are aware of V2H (vehicle-to-home) technology, the high cost of installing it is a major barrier. In talking to our customers, it became clear that resiliency isn't the driving force behind taking up consumer power solutions. Discussions were dominated by sustainability and environmental concerns, or reducing costs. Alternative eco-friendly power sources are desirable, but uptake is low.

The cost and return on investment are both deciding factors when it comes to taking up new technologies. The main barriers are seen as the large up-front cost; waiting for others to try the technology out first, and wondering whether a new, cheaper product will be available soon, so not wanting to invest now.

COMMERCIAL CUSTOMER PROJECTS

Our commercial customers who are working on sub-divisions and other larger projects are keen to build their own energy solutions – particularly now solar PV (photovoltaic), batteries and electric cars are becoming cheaper and more desirable. They also expect a choice of connection services to accommodate their changing requirements, given there is uncertainty around the speed of uptake of these new technologies.

As with smaller projects we provide customers with a range of design solutions and associated standard prices to help them make an informed decision around their connection needs. For instance, they can choose differing levels of resiliency, from basic (suitable for housing) to super-resilient – the level you would want for a food business needing reliable refrigeration 24 hours a day. However, some customers will always need a bespoke solution and we can provide this. These customers can choose which service provider they would like to undertake their installation.

REPORTING AND TRACKING OUTAGES

As we focus on particular areas of need for customers, we start creating potential solutions we believe will meet their expectations. These can be tested and refined as needed. The focus is to make it easier for customers to report outages to us and then receive key updates.

Customers want to know their power outage has been noted by Vector, when work starts and when power will be back on.

Multiple communication channels are also expected. And the longer the outage, the more likely that customers will use multiple touch-points, such as Vector's website, contact centre and mobile app. Ensuring that these communication channels are easy to access, provide the right kind of information and are updated frequently, is key to customers having a good overall customer experience.

For reporting outages to Vector most customers prefer to use text message or phone. Residential customers also have some preference for email with a third of SME preferring to use an app.

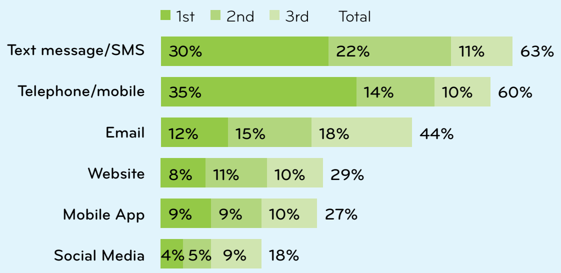
The true test of whether a design solution like those above can solve customers' problems is to test it with real customers. We test multiple times throughout the design process, and evolve and improve the design based on what we learn as we test. When we launch our solutions to market, we have a high level of confidence they will work for customers.

OUR COMMITMENT

Delivering on our commitment to meet customer expectations of us is a responsibility we take seriously. We are fully committed to evolving the way we work alongside them to ensure we deliver solutions and experiences that make a meaningful difference in their lives.

RESIDENTIAL

PREFERENCE FOR CONTACTING VECTOR TO REPORT OUTAGE[1]

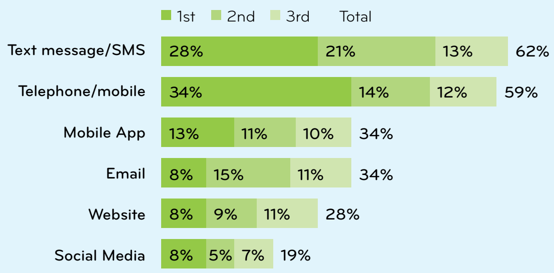


Q. When an unplanned power cut happens, what are your preferred methods of contacting Vector to report the outage or to get information (e.g. how long, cause, etc)?

1. Sample size n=1042

SME

PREFERENCE FOR CONTACTING VECTOR TO REPORT OUTAGE[2]



Q. How would you like us to communicate with you regarding planned/scheduled power cuts?

2. Sample size n=303

Figure 1-10 Residential and SME preferences for contacting Vector to report outages

CUSTOMERS, STAKEHOLDERS AND SERVICE LEVELS

SECTION 02.

SECTION 2. CUSTOMERS, STAKEHOLDERS AND SERVICE LEVELS

HOW WE SERVE OUR CUSTOMERS

WE MEASURE OUR SERVICE LEVELS, BUT WE ALSO GO WAY BEYOND THIS

We have a simple motto, to deliver to customers with urgency. The aim is to ensure we provide our customers with a high-quality experience that is fast, intuitive and seamless.

Vector uses a range of service-level targets to measure how we meet customer needs. While we have always had a strong customer focus, we will always refine and expand the measurement of how well we were doing in meeting their needs, especially considering the dynamic environment we operate in. To this end, we are introducing additional customer service level metrics that complement the use of standard industry reliability indicators to measure how well we deliver on customer expectations. These additional customer level measures are more targeted, equitable and fair, while, importantly, also enable effective cost quality trade-offs to be made in the long-term interest of our customers.

These service levels are informed by customer insights enabled by advanced data analytics. These insights are complemented by engaging with our customers using surveys, focus groups, journey maps, community visits and our customer advisory board.

Importantly, the AMP now includes service levels for cyber security and privacy.

In this section, we describe our service-level measures and performance targets, and report on how we are doing against these targets. Where we do find performance gaps, we look at the root causes and this information is used to guide our strategy and investment plans to improve performance against the service levels. In Section 5 we go into detail about our asset performance management and investment plans.

In addition, through our contracting model review, we are ensuring that our service providers have incentives that are aligned with our customer service levels.

CUSTOMER EXPERIENCE – A MORE COMPREHENSIVE WAY TO MEASURE HOW WE MEET OUR CUSTOMER NEEDS
We are introducing a new service level category – customer experience, to ensure we provide our customers with a high-quality experience when they deal with us. This should be an intuitive and seamless experience encompassing all our customers' interactions with us.

We measure multiple components of our interactions, however the key four aspects of how customers deal with us are: how easy we are to deal with; speed of new connections; early customer notification of planned outages, and how well our call centre is performing.

2.1 STAKEHOLDER REQUIREMENTS

The services we provide to the Auckland community to enable Auckland's growth and the city's economy, are essential. The role and importance of these services to customers are rapidly changing with new technology adoption, changes in how customers communicate with us and each other, higher expectations around resilience of electricity supply, the decarbonisation of the economy, electrification of transport and, in general, changing customer expectations around the speed of delivery. Their importance means they create great interest in our asset management practices from a wide range of stakeholders. Figure 2-1 highlights the primary stakeholders that have a keen interest in how we manage our assets.

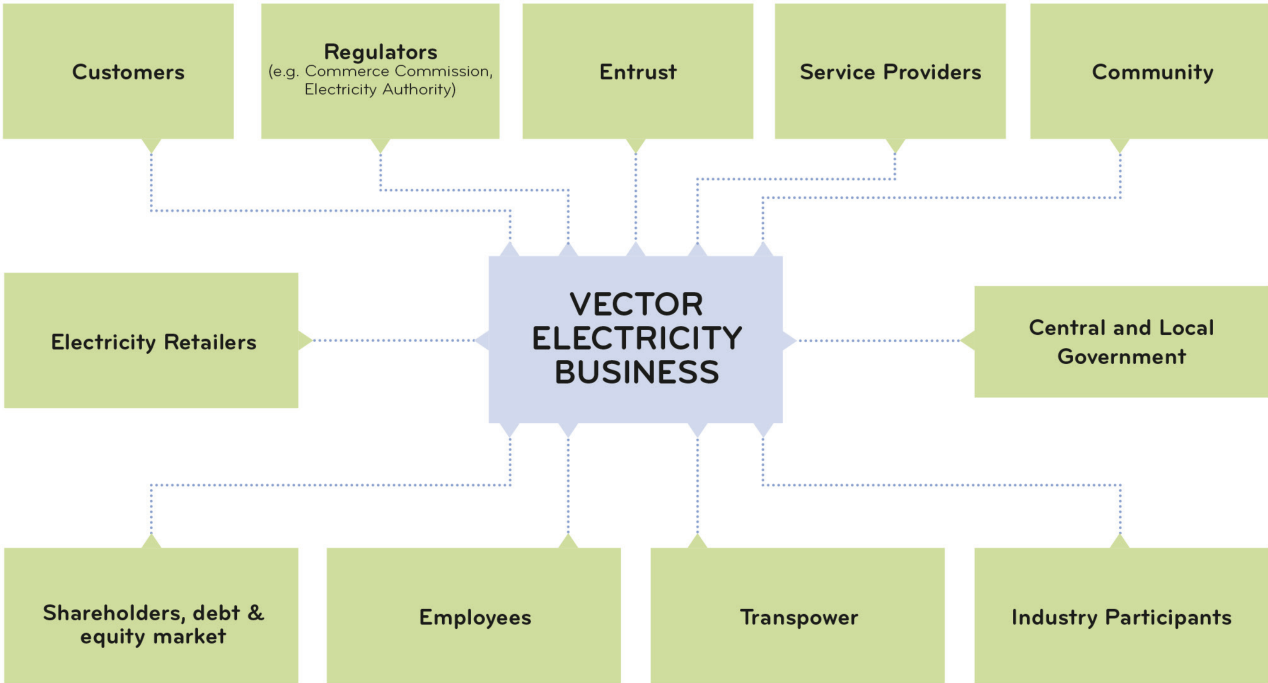


Figure 2-1 Primary Stakeholders

To identify stakeholder's expectations we engage with them via several channels, we use customer insights enabled by advanced data analytics. These insights are complemented by direct liaison with customers (e.g. customer advisory board), discussion forums, active engagement in legislative and regulatory consultations, membership on industry working groups, investor roadshows and annual general meetings. We also use surveys and working groups, and monitor multiple analyst reports and media publications.

Vector's stakeholders have a broad range of requirements summarised in Table 2-1.

Public and worker health and safety risk management	Confidence in board and management	Participating in policy proposals and addressing regulatory issues
Sound management of customer issues and information, including timely outage management	Good governance, reputation, and ethical behaviour	Ensure service providers have stable forward work volumes and construction standards
Quality, security and reliability of electricity supply	Maintain legal and regulatory compliance	Maintain effective relationships and ensure ease of doing business
Sustainability and the environment	Prudent risk management	Work with stakeholders to influence regulators and government
Timely network connections and asset relocations	Develop and maintain a clear strategic direction	Share our experience and what we've learnt with the industry
Engage with the community and stakeholders on relevant issues	Return on investment and sustainable growth	Ensure effective co-ordination of planning and operations with other utilities and stakeholders
Provide cost-effective and efficient operations	Accurate and timely information and reporting	Ensure transmission network interface is well maintained

Table 2-1 Examples of the broad range of stakeholder requirements

These requirements not only influence our asset management practices but they guide our values, shape our objectives and inform our service-level requirements.

Vector accommodates stakeholders' expectations in its asset management practices by, amongst other things:

- due consideration of the health, safety and environmental impact of Vector's operations;
- providing a reliable distribution network;
- due consideration for the affordability of our services;
- quality of supply performance meeting consumers' needs and expectations, subject to; trade-off of capital and operational expenditures (capex and opex);
- maintaining a sustainable business that caters for consumer growth requirements; comprehensive risk management strategies and contingency planning;
- compliance with regulatory and legal obligations; development of innovative solutions; and comprehensive asset replacement strategies.

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

- clearly identifying and analysing stakeholder conflicts (existing or potential);
- effective communication with affected stakeholders to assist them to understand Vector's position, as well as that of other stakeholders that may have different requirements;
- having a clear set of fundamental principles drawing on Vector's vision and goals, on which compromises will normally not be considered and where Vector fundamentals are not compromised, seeking an acceptable alternative or commercial solution.

Vector has developed an extensive set of asset management and investment policies, guidelines and standards which implicitly embrace practical solutions to the requirements of stakeholders. These policies and standards provide guidance to the safe operation and maintenance of the electricity network assets.

We have assessed our stakeholders' requirements in service terms and defined a set of service-level metrics and associated performance targets. Our metrics have been developed in such a way as to be meaningful to our stakeholders. They are also relevant in terms of the investments required to meet and maintain our service-level performance. We provide details of our key service-level metrics in the section below.

KEY OUTCOMES AND SERVICE LEVELS

In this AMP we have grouped the service levels around our key network outcomes. Each outcome has one or more associated service levels that measure our performance in that category.

2.2 CUSTOMER EXPERIENCE

We aim to deliver a high-quality, intuitive experience – one that meets our customers' needs and offers them choice. It also needs to be a seamless experience across all the interactions our customers have with us. We see this experience having four key parts: ease of dealing with us; speed of new connections; early notification of planned outages, and how well our contact centre is performing.

2.2.1 CUSTOMER EFFORT MEAN SCORE (CEMS) SERVICE LEVEL

DEFINITION

The Customer Effort Mean Score (CEMS) service level measures the ease of customers' experience with Vector. In other words, how easy we are to deal with.

MEASUREMENT

We will measure both single interactions and series of interactions with our customers – whatever makes up that direct experience with our customers . We will align this metric to customer journeys with the aim of continually improving our customers' experiences.

OUR HISTORICAL PERFORMANCE

Previously we have measured the level of customer satisfaction using the overall customer satisfaction score. This has served us well; however we need to ensure we measure in a way that aligns with the needs of customers and results in improved customer efficiencies. CEMS has been measured quarterly for the past two years. Table 2-2 summarises this service level performance out of a rating of 10.

DESCRIPTION	RY15	RY16	RY17	RY18
Customer Effort Means Score	-	-	6.9	6.7

Table 2-2 Customer Effort Means Score

OUR TARGET

The target is to improve the Customer Effort Mean Score for RY19 to 6.8 and maintain this in RY20. Our aim to achieve a CEMS level of 7.2 by RY25 This will be reassessed every two years over the AMP period.

2.2.2 SPEED OF QUOTES FOR NEW CONNECTIONS (SMALL CONNECTION CUSTOMERS) SERVICE LEVEL

DEFINITION

This service level applies to customers dealing with fewer than five 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 the information as quickly as possible.

MEASUREMENT

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

OUR HISTORICAL PERFORMANCE

At present, 84 per cent of standard quotes are sent out within two days, and 68 per cent of quotes for non-standard connections are sent out within seven days. These are relatively new measures implemented in RY18 when standard charges were introduced for residential, 60amp, single phase customer connections.

DESCRIPTION	RY15	RY16	RY17	RY18
Speed of quotes for new connections – Standard	-	-	-	84%
Speed of quotes for new connections – Non-standard	-	-	-	68%

Table 2-3 Speed of quotes for new connections

OUR TARGET
We aim to have 86 per cent of standard quotes sent out within two days by RY20, and 72 per cent of non-standard quotes sent out within seven days by RY22. These are reassessed every two years and we will continue this practice over the AMP period.

2.2.3 ADVANCE NOTIFICATION OF PLANNED OUTAGES SERVICE LEVEL

DEFINITION
To provide timely, accurate and reliable notification of planned outages. This is important to our customers as it allows them to plan ahead.

MEASUREMENT
All customers must be notified four working days in advance under the UoSA (Use of System Agreement) with electricity retailers. This was monitored to ensure compliance and tracked manually through customer complaints where there was lack of sufficient notification.

OUR HISTORICAL PERFORMANCE
Under the Use of Systems Agreement (UoSA) with our retailer customers we must provide four (4) working days' notice, however in practice we provide 10+ working days' notice.

We have improved our service recently by automating the reporting capability and being able to notify 90 per cent of our customers of a planned outage at least 10 working days in advance. With this automation we have introduced a new dashboard to better monitor target achievement.

OUR TARGET
Our customers tell us they want as much notice as possible and our target at 10+ days has been set to meet their expectations. This will be reassessed every two years over the AMP period.

2.2.4 CALL CENTRE GRADE OF SERVICE (GOS) SERVICE LEVEL

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

MEASUREMENT
We use the Grade of Service (GOS) call centre measure to judge how well we are doing. The GOS measures how quickly incoming calls are answered.

OUR HISTORICAL PERFORMANCE

DESCRIPTION	RY15	RY16	RY17	RY18
Average Grade of Service (GOS)	86%	87%	81%	75%

Table 2-4 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.

The no-live-line work policy was rolled out to the Field Service Providers during 2016. Feedback from the contact centre provider (Telnet) has been that this impacted their ability to regularly meet their GOS targets. This is because peaks in call volume are often caused by outages. If a feeder is turned off after an outage to allow for repairs to be made, this causes a secondary peak in customer demand, increasing the number of call volume that are beyond the contact centre's ability to answer promptly. Weather-related spikes in outages can also substantially impacted performance against GOS.

Vector is continuously working with our 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.

OUR TARGET
Our aim is a 75 percent success rate for RY20, RY21 and 80 percent for the remainder of the planning period from RY22 to RY28.

2.3 SAFETY

Our focus on Safety is to design assets and work practices that prioritise the elimination of hazards and harm for workers, customers and the public in the delivery of electricity services.

2.3.1 TOTAL RECORDABLE INJURY FREQUENCY RATE SERVICE LEVEL

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

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

HISTORICAL PERFORMANCE
Table 2-6 shows the Networks TRIFR performance in accordance with the definition of this service level metric. Over the last two years we have created a change in focus to enhance reporting and drive improved wellness which has caused an increase in this calculated rate. Increasingly, focus is being given to underlying issues and treatment with more targeted at critical risk events. This movement in the rate is a temporary situation with the RY19 showing the expected decrease.

DESCRIPTION	RY15	RY16	RY17	RY18
Total recordable injury frequency rate (TRIFR)	6.89	7.17	5.28	14.07

Table 2-5 TRIFR

TARGET
The Networks TFIFR target for RY19 is 9.58. Future years targets are yet to be confirmed but it is likely a 5% movement band will be introduced rather than a reduction only target.

2.3.2 ASSET SAFETY INCIDENT SERVICE LEVEL

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

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

HISTORICAL PERFORMANCE
Table 2-7 shows the asset safety incident performance in accordance with the definition of this service level metric.

DESCRIPTION	RY15	RY16	RY17	RY18
Asset safety incident	0	2	1	7

Table 2-6 Asset Safety Incidents

The increase in the number of asset safety incidents was unusually high in RY18. Out of the seven incidents, two involved animals coming in contact with lines down, three were related to loose neutral connections and minor electric shock and two causing minor mechanical abrasion. Contributing to the increase in RY18 is the improved reporting of incidents mentioned in Section 2.3.1.

TARGET
Zero. With safety always being Vector's highest priority, we strive to achieve no asset safety related incidents causing harm to employees, contractors, and the public.

2.4 RELIABILITY

This considers the ability of the network to deliver electricity consistently when demanded under normal design conditions. We are committed to meeting the Regulatory quality metrics.

2.4.1 SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI) SERVICE LEVEL

DEFINITION
SAIFI measures the average number of outages per customer per RY, the value expressed in 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 a period of 1 minute or longer.

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. The SAIFI dataset is normalised using a process defined by the Commerce Commission in the DPP. This process reduces planned interruptions by 50% as it is considered that customers are less impacted by interruptions that are planned. It also limits unplanned SAIFI on days where a major event has occurred (e.g. storms), to prevent these extreme events distorting the overall SAIFI data. The following formula is used:

$$〖SAIFI〗\_Normalised = (0.5\ x\ \ 〖SAIFI〗\_planned\ ) +\ \ 〖SAIFI〗\_unplanned$$

Where:

〖SAIFI〗_planned is the sum of daily planned SAIFI values in the assessment period; and

〖SAIDI〗_unplanned is the sum of daily unplanned SAIFI values in the assessment period, where if any daily value of unplanned SAIFI is greater than the SAIFI Unplanned Boundary Value then the daily value equals the SAIFI Unplanned Boundary Value.

The SAIFI Unplanned Boundary Value is calculated in accordance with the Commerce Commission process. This limit is set to 0.039 for the current regulatory period (1 April 2015 to 31 March 2020).

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 measured on a monthly and annual basis to inform asset management practises. 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.

DESCRIPTION	RY15	RY16	RY17	RY18
SAIFI	1.41	1.11	1.85	2.14

Table 2-7 SAIFI

Remote Safety Isolations

The most significant cause for the SAIFI performance in RY18 exceeding the current DPP target was from the application of Vector's new Remote Safety Isolation policy for public reporting of low or downed lines. Previously isolation would occur only after a field crew went to site and confirmed the need for de-energising a circuit for public safety risks. This change was undertaken to meet the heightened expectations of the community for health and safety. It is also a practice that was undertaken in response to the enactment of the Health and Safety at Work Act 2015 (the HSWA). There were 0.6 interruptions for the year caused by Remote Safety Isolations in RY18. The interruption frequency for Remote Safety Isolations has no allowance in the Reference Period.

Planned works

The other significant cause for the SAIFI performance in RY18 was the impact of Planned Works for the period and the application of the Vector's Live-Line Policy. The new Live-Line Policy limits the risk of working on or near assets in a livened electrified state to only occur in exceptional circumstances. Undertaking more of our Planned Works program in a de-energised state is a significant operational change to the conditions for Planned Works incurred during the Reference Period. Its impact is more than six times greater than the Reference Period.

Third-Party Damage

In RY18 the impact of Third-Party Damage was significant. For RY18, 0.22 of the SAIFI for Third-Party Damage SAIFI can be attributed to vehicle damage. The higher car vs pole incidents reflect the growing traffic fleet in Auckland. These types of incidents possess a stochastic nature to their impact on the network and therefore cannot be controlled within a reasonably defined price constraint for asset management.

Activities to improve SAIFI performance are included in the Section 5 programmes of work.

TARGET

For the Regulatory Period (1 April 2015 to 31 March 2020) Vector's SAIFI target has been set at 1.2914 (refer to DPP).

2.4.2 NUMBER OF CUSTOMER INTERRUPTIONS PERFORMANCE AGAINST AGREED SERVICE STANDARDS SERVICE LEVEL

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 that enables us to effectively engage customers affected by outages on issues such as cost quality trade-offs, etc.

The Use of System 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.

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	RY15	RY16	RY17	RY18
Customer interruptions performance	99.3%	97.8%	96.6%	92.6%

Table 2-8 Customer interruptions performance

The number of customer interruptions exceeding the agreed service standards has increased over the past year. In general, the cause of these interruptions is comparable to the reasons for increased SAIFI. An increase in the frequency of interruptions results in more customers exceeding Vector's minimum number of interruptions target. The impact of the application of the new Remote Safety Isolation policy for public reporting of low or downed lines was also a contributing factor to performance of the service level in RY18. This change was undertaken to meet the heightened expectations of the community for health and safety. It is also a practice that was undertaken in response to the enactment of the HSWA.

TARGET

Target under development following review of isolation for safety policy impact.

2.5 RESILIENCE

We are committed to ensuring that we prepare our network and our customers to not only adapt to changing conditions but also to withstand and recover rapidly from a disruptive event. We are deploying new network solutions such as microgrids, that will improve supply resilience in vulnerable areas. At the same time, as the uptake of customer-owned distributed energy resources (such as solar energy, battery solutions and electric vehicles) increase with time, these resources together with network solutions will play a critical role in improving the overall network and its resilience to customers. We call this concept Shared-Resilience.

2.5.1 PERFORMANCE AGAINST OUR SECURITY OF SUPPLY STANDARD (SOSS) SERVICE LEVEL

DEFINITION

Vector uses a probabilistic approach to security of supply standards (SoSS) which set out Vector's performance expectations in relation to restoration targets following planned and unplanned equipment outages. We prepare a demand forecast that is used to assess the performance of the network against the SoSS service level. The SoSS performance assessment is based on the demand forecast for the Symphony scenario described in Section 1. Appendix 10 sets out the forecast for RY19 onwards. Based on this demand forecast, we can anticipate the implication on the network Security of Supply, by essentially comparing asset capacity against demand and determining risks and shortfalls in the network.

MEASUREMENT

SoSSs are defined in terms of N-x where x is the number of coincident outages that can occur during times of high demand without extended loss of supply to customers. Security levels are also defined by the time allowed to restore supply after an asset failure. The security of supply strategy and standards aim to provide customers with an acceptable reliability of supply at an acceptable cost. This means balancing economic and service level risks appropriately.

SoSSs and restoration targets are categorised by the particular asset failure (e.g. zone substations, distribution feeders), the load at risk and by the asset location (e.g. CBD and urban).

This service level metric captures the number of breaches of the SoSS, (should no investment be made). It is another key metric used to establish the reliability and availability of the network and is used to justify expenditure on the network as part of our annual planning cycle. The number of SoSS breaches are forecast on an annual basis.

Table 2-10 shows the forecast number of security of supply breaches in accordance with the definitions of this service level metric should no investment be made. It should be noted that for SoSS distribution feeder breaches, the forecast number of breaches is only accurate to FY22 as 11 kV reinforcements projects are only identified one or two years in advance. Section 5 lists the projects needed to mitigate the security of supply breaches. These projects may address more than one breach.

CLAUSE	RY20	RY21	RY22	RY23	RY24	RY25	RY26	RY27	RY28	RY29
CBD substation and subtransmission	1		2							
Zone substation and subtransmission (non-CBD)	4	2	1	3	2	1	4	4	3	2
Distribution feeders (11 kV or 22 kV)		6	4		5	2	1	1		2
Total	**5**	**8**	**7**	**3**	**7**	**3**	**5**	**5**	**3**	**4**

Table 2-9 Security of supply breaches forecast, should no investment be made

TARGET
With the level of investment described in Section 5, our network will meet the Security of Supply Standards described in Table 2-11.

CLAUSE	DEMAND	CATEGORY	STANDARD
1	Any	Single events incurring greater than 4 SAIDI minutes	>4 SAIDI minutes: investment evaluated using a risk-based approach <4 SAIDI minutes: assessment as below
2	Any	CBD substation and subtransmission	N-1: 100% demand (no interruption) N-2: 100% demand restored in 2 hours
3	Any	Zone substations (non-CBD)	N-1: 100% demand restored in 2.5 hours (urban), 4.5 hours (rural). This requirement to be met for 95% of the year for primarily residential substations and 98% of the year for primarily commercial substations in line with our probabilistic based network planning philosophy
4	Any	CBD distribution feeders, 11 kilovolt (kV) or 22 kV	Demand restored to all but a single distribution substation in 2.0 hours. Remainder restored in repair time
5	Any	Distribution feeders (non-CBD), 11 kV or 22 kV	Primarily underground: demand restored to all but 800 kVA , 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
6	Any	Distribution substations (11 kV/400 kVA)	Restored within repair time
7	Any	Distribution feeders (400 V)	Restored within repair time
8	Any	All subtransmission	Maximum of one month on reduced security
9	Any	Subtransmission and zone substations	Spatial separation of primary network assets sufficient to avoid common mode failure

Table 2-10 SoSS

2.5.2 SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI) SERVICE LEVEL

DEFINITION
The SAIDI index measures the average duration of outages per customer per RY, the value 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 a period of 1 minute or longer.

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 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 distorting the overall SAIDI data. The following formula is used:

$$〚SAIDI〛\_Normalised = (0.5\ x\ \ 〚SAIDI〛\_planned\ ) + 〚SAIDI〛\_unplanned$$

Where:

〚SAIDI〛_planned is the sum of daily planned SAIDI values in the assessment period; and

〖SAIDI〗_unplanned is the sum of daily unplanned SAIDI values in the assessment period, where if any daily value of unplanned SAIDI is greater than the SAIDI Unplanned Boundary Value then the daily value equals the SAIDI Unplanned Boundary Value.

The SAIDI Unplanned Boundary Value is calculated in accordance with the Commerce Commission process. This limit is set to 3.374 minutes per day for the current regulatory period (1 April 2015 to 31 March 2020).

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 measured on a monthly and annual basis to inform asset management practises. 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	RY15	RY16	RY17	RY18
Customer interruptions performance	128.5	117.0	173.6	226.2

Table 2-11 SAIDI

Remote Safety Isolations

One of the most significant causes for the SAIDI performance in RY18 exceeding the current DPP target was from the application of Vector's new Remote Safety Isolation policy for public reporting of low or downed lines. Unfortunately, most public reported downed lines relate to non-Vector assets which results in spurious isolations relating to Chorus or Auckland Transport assets. However, this can only be confirmed post an on-site inspection. For RY18 remote safety isolations contributed approximately 30 SAIDI minutes. Of the different causes for SAIDI this cause is the most significant when compared to the Reference Period.

Planned works

The other significant cause for the SAIDI performance in RY18 was the impact of Planned Works for the period. For RY18 planned SAIDI contributed approximately 50 minutes of total SAIDI, more than eight times the impact to what was allowed for in the Reference Period (six minutes). This cause is the largest contributor to Vector's accumulated SAIDI for RY18.

Third-Party Damage

In RY18 the impact of Third-Party Damage was significant. The SAIDI impact of Third-Party Damage was 33 minutes, almost double the impact assumed in the Reference Period of 17 minutes. In RY18 Vector experienced 28 minutes of SAIDI because of vehicle damage to Vector's network assets, generally referred to as car v pole incidents. The SAIDI from car v pole incidents in RY2018 eclipse the tolerance provided for in the Reference Period for Third-Party Damage which captures other causes such as "dig-ins".

Overhead asset incidents

In RY18 overhead (OH) asset incidents was a major cause of SAIDI. Vector has a large and extensive OH network with long routes through remote and bush vegetated areas which means that OH asset incidents are a significant contributor of faults for the distribution network. The impact of OH asset SAIDI is approximately 16 minutes higher for RY18 when compared to the Reference Period. The largest contributing cause in RY18 to the OH asset related SAIDI was conductor incidents.

Underground asset incidents

In RY18 underground (UG) asset incidents also had a higher SAIDI than the Reference Period. The UG asset SAIDI for RY18 was approximately 11 minutes higher than the Reference Period allowance. A higher volume of cable faults was the reason for this increase. This cause contributed 26 minutes of SAIDI for RY18. Determining the location of cables faults and their repair are quite time consuming especially in highly built up areas.

Activities to improve SAIDI performance are included in the Section 5 programmes of work.

TARGET
For the Regulatory Period (1 April 2015 to 31 March 2020) Vector's SAIDI target has been set at 96.0364 minutes (refer to DPP).

2.6 CYBER SECURITY AND PRIVACY

We are committed to investing in technology solutions, processes and capabilities to ensure that we appropriately protect and detect potential disruptive security events that could impact our network services or customer privacy. The threat of a successful attack is ever present and we can therefore no longer solely rely on detective and preventative controls to mitigate the risk. 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. Effective 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. 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 the how we define security incidents for the purposes of our targets:

PRIORITY	DESCRIPTION	NARRATIVE
1	Critical Incident	Interruption making a critical function inaccessible or a complete network interruption causing a severe impact on service availability. There is no possible alternative function/service available.
2	Priority Incident	Critical functions or network services are interrupted, degraded or unusable, having a severe impact on availability. No acceptable alternative is possible.
3	Standard Incident	Non-critical functions or services, are unusable or have intermittent issues resulting in an operational impact, but with no significant or direct impact on availability.

Table 2-12 Incident levels for cyber security

2.6.1 INCIDENT DETECTION SERVICE LEVEL

DEFINITION
This service level measures the effectiveness of our security systems/Security Operations Centre (SOC) to analyse potential security threats and detect actual security events that require action and containment by the Cyber Security team. This service target has recently been introduced in RY19 and coincides with the launch of our improved SOC and detection capabilities.

MEASUREMENT
The service level is based on the time from the detection of an actual cyber event or threat by our SOC to the alerting/escalation for action to the Cyber security team.

2.6.2 INCIDENT RESPONSE SERVICE LEVEL

DEFINITION
This service level measures the effectiveness of our security systems/Security Operations Centre (SOC) to quickly analyse actual security events and provide an appropriate containment strategy that minimises the impact to the Vector network. This service target has recently been introduced in RY19 and coincides with the launch of our improved SOC and detection capabilities.

MEASUREMENT
This service level measures the time from the detection of an actual cyber event or threat by our SOC to the development of the containment strategy to be implemented and managed by the Cyber Security team.

2.6.3 INCIDENT CONTAINMENT SERVICE LEVEL

DEFINITION

This service level measures the time between the response notification/containment plan to effectively containing the immediate threat. The measure excludes full remediation activities. This service target has recently been introduced and coincides with the launch of our improved SOC and detection capabilities.

MEASUREMENT

We measure the time from the release of initial response notification/containment plan to the implementation of all containment strategies and actions such that any further loss or disruption is minimised.

2.6.4 PRIVACY

Privacy is both a legal requirement and a critical customer engagement topic. Vector has a Group Data and Information Policy which includes industry aligned privacy principles and policies that apply to all data and every person at Vector and is reviewed on a regular basis. This includes clear guidance on the collection, storage, use and sharing of personal information. Vector's Privacy Officer is responsible for ensuring policy compliance and can be contacted at privacy@vector.co.nz. Regular training and education is mandatory for all staff and staff with access to particularly sensitive information are required to adhere to additional training and education requirements.

All employees and partners are required to understand and comply with our privacy commitments, and these align with the public commitments published on the Vector web site. Where an activity requires a change in the collection or handling of personal information, including the use or sharing of personal information in a new way, a Privacy Impact Assessment must be completed and approved by the Privacy Officer.

We will not sell personal information to third parties nor will we share personal information externally unless this sharing has been made clear in our privacy statement, the individuals concerned have consented to it, or it is otherwise permitted by law.

ASSET MANAGEMENT SYSTEM

SECTION 03.

SECTION 3. ASSET MANAGEMENT SYSTEM

PROVIDING A SAFE, RELIABLE AND RESILIENT NETWORK

Vector's asset management system is used to guide all aspects of the investment decision-making process. The system sets the foundation to meet the Networks' business purpose to provide a safe, reliable and affordable network that provides a high-quality customer experience as we deliver with urgency on our promises to customers, in support of Vector's vision to *Create a New Energy Future*.

While this section provides insight into Vector's asset management practice across its range of assets, for the purposes of this AMP it is limited to the Auckland region's local electricity distribution networks that includes assets such as poles, cables, transformers and substations that take electricity to the consumer's point of supply. The asset management system is designed to manage this growing suite of assets and make the best use of them for the benefit of Vector's customers and stakeholders.

As the rate of new technology adoption by our customers increases and their behaviours and expectations change accordingly, new challenges are created from an asset management perspective. The way electricity flows around the network is changing as customers adopt new technologies to manage their energy costs and reduce their carbon footprint. This increases investment uncertainty, since the changing electricity generation, storage and consumption patterns could result in assets that are either underutilised or redundant in the long term. Our stated objective to provide a safe, reliable and resilient network, that is affordable and drives investment decisions that are in the long-term interest of consumers.

New technologies for asset management purposes have also become more economically viable and is key to manage the increasing uncertainty and new challenges we are facing. Piloting new technology options and deployment new technology alternatives where proven in the long-term interest of customers are baseline practices of a reasonable and prudent operator responding to changes in customer behaviours, needs and expectations. As such Vector's Asset Management practices will increasingly rely on a growing investment in smarter connected hardware and Information systems. Associated new investment in the data including the capture, transmission, storage, security and governance, is also needed to support these systems. For example, the need for Cyber security and information management disciplines is increasing as the threats increase as do community and regulatory requirements.

The continuous improvement of the Asset Management systems, practices and policies is important to Vector. Service Level performance reporting focuses our continuous improvement actions on what is required to target our service-levels and turn the dial on our Asset Management maturity.

3.1 ASSET MANAGEMENT VALUES AND OBJECTIVES

Vector's asset management policy is the overarching governance document that defines the principles and objectives that guide all aspects of our network asset management practice. These principles and objectives accord with our corporate values and align with our corporate vision and mission.

Vector is committed to ensuring a safe, reliable and resilient electricity network. Our aim is that is affordable for the long term benefit of all our customers. This commitment is demonstrated through the principles and objectives that we apply in managing our network assets.

- We are committed to Safety Always with safety being a key focus of how we design, develop, deliver and service our assets over their entire lifecycle. Safety Always extends not only to our employees but also to our contractors and the public
- As a regulated provider of distribution network services, we aim to comply with all applicable statutory and regulatory obligations and draw on good asset management practice to achieve and maintain this compliance
- We manage the impact of our asset management practices to ensure fairness, affordability and equity of prices and by ensuring our decisions don't burden future generations
- Enabling Auckland's growth and delivering returns set by the regulator to our shareholders and choice to our customers is at the core of our business and we maximise the value that our assets deliver across their entire lifecycle through the use of customer insights, technology, good practice asset management, risk management and sound asset investment decisions underpinned by good governance

- We strive to serve our customers by managing our assets to provide a safe, reliable, resilient, and efficient distribution network that meets our customer's present and future service expectations, without burdening future generations and in the long-term interest of consumers
- We recognise that our people are our most valuable resource and we foster a culture of innovation by ensuring we have the right mindsets, skillsets and structure in support of Vector's values
- Our asset management is fact based, underpinned by customer insights enabled by advanced data analytics to drive the right decision making that allows the management of our assets in the long-term interests of our customers
- We care for our natural environment, and so we manage our assets and work with our suppliers and communities to support energy efficiency and to manage the environmental impact of our asset, reduce greenhouse gases and minimise the environmental footprint of our distribution network assets through commercial and consumer-choice enabling strategies
- We create sustainable value through a long term strategic focus where we leverage technology, data and systems to drive an innovative approach to asset management that aligns with Vector's corporate vision
- We manage the impact of climate change on our assets and other resources we deploy in providing essential services to Auckland residents and businesses

In addition to these principles and objectives, Vector's asset management practice seeks to accord with the principles of ISO 55001 (*Asset management – Management systems – Requirements*) and reflects a whole of lifecycle approach.

3.2 ASSET MANAGEMENT SCOPE

As per Information Disclosure requirements this AMP covers the period from 1 April 2019 to 31 March 2029 with a greater level of planning detail provided for the first five years of this AMP period. This AMP covers the electricity distribution network in the context of increasing complexity and in a time when electricity consumption is changing rapidly as consumers electrify their lives and adopt non-traditional energy solutions. Our electricity network is an interconnected network that operates as a geographically distributed machine with many interdependent elements. The traditional model of remote generation connected to the transmission grid and then connected to lines companies for the distribution of electricity to 'end-customers' is being challenged and will not suffice for the network of the future in which low carbon emissions and sustainability will become key factors and where consumers will require a greater say and become active participants in the production and delivery of energy. Distributed energy resources (DERs) are increasing in our network and assets that form part of the decentralised energy network, distributed generation and our distributed energy resource management system (our information model that documents the grid assets and maintains their status at any point in time), are now included in the asset category table below. While Section 4 and Appendix 6 provide details that align with the Information Disclosure asset categories[1] as per Schedule 11A(iii), the broader AMP is developed in terms of the AMP asset categories shown in Table 3-1.

Detailed single line diagrams of our subtransmission network can be supplied to interested persons.

SCHEDULE 11A(III) ASSET CATEGORIES	AMP ASSET CATEGORIES
Subtransmission	Subtransmission 110 kV cables Subtransmission 33 kV and 22 kV cables Subtransmission 110 kV OH lines Subtransmission 33 kV and 22 kV OH lines
Zone substations	Zone substations Power transformers Primary switchgear Battery energy storage systems and microgrids Capacitor banks and static compensators Load control Fire and security systems
Distribution and LV lines	Distribution feeders HV overhead Distribution feeders HV overhead supports Distribution feeders HV underground

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1 Commerce Commission, Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018), Clause 4.5.1

Distribution and LV cables	Distribution feeders LV overhead Distribution feeders LV underground Distribution feeders solar and battery distributed generation
Distribution substations and transformers	Distribution ground mounted substations Distribution ground mounted transformers Distribution substations LV frames Distribution pole mounted transformers Distribution voltage regulators
Distribution switchgear	Distribution ground mounted switchgear
Other network assets	Protection systems Transformer management systems Power quality meters Network automation systems

Table 3-1 Asset category relationships

As costs reduce and DERs grow in popularity, capacity stranding and the related thinning of the network will mostly impact subtransmission feeders first and progressively zone substations, while DERs themselves will influence the function and operation of distribution feeders (HV & LV) as bidirectional power flows start to create impact. The functional capability of distribution substations will also alter as DER changes power flows and impacts on customers' service needs. As these implications become clearer, specific strategies will need to be established that reflects the impact of new technology on these major functional elements of our network. Similarly, our network vision has specific implications for each of our AMP asset categories listed in Table 3-1.

Details of Vector's electricity distribution network assets, how they are defined and key statistics, are provided in Section 4.

3.3 ASSET MANAGEMENT ORGANISATION AND GOVERNANCE

Vector's asset management organisation and our governance structure is shown in Figure 3-1. This structure provides oversight and controls all aspects of our asset management practice. An overview of the asset management responsibilities and governance roles within this structure are set out below.

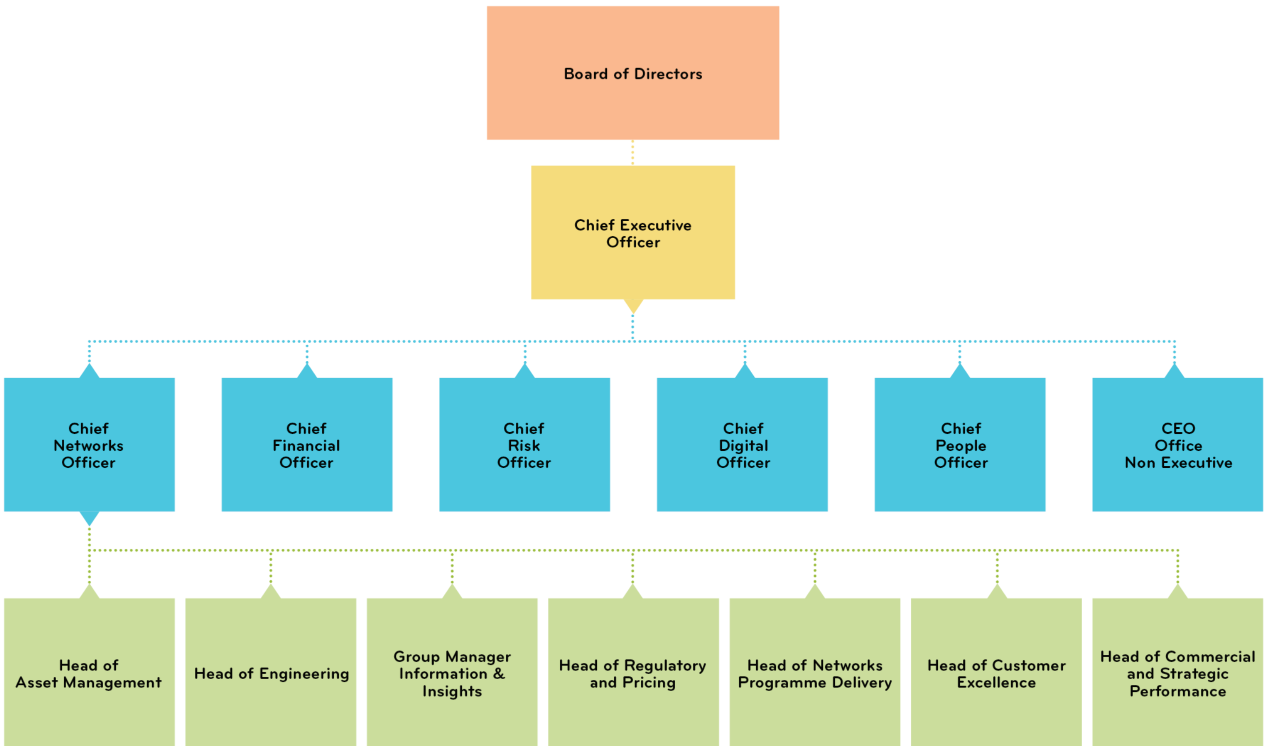

Figure 3-1 Asset management governance structure

BOARD OF DIRECTORS

At the highest level, the Board of Directors operates under the Board Charter, and provides governance over all aspects of Vector's asset management practices on behalf of Vector's owners and the broader stakeholder community. While taking advice from Vector's management, the board exercises oversight of the objectives of asset management, its strategic direction, 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 authorities framework, management reporting and periodic reviews including internal and external operational audits. The Board also receives performance reporting which among other things include reporting against key service levels and regulatory reliability targets.

The Board Risk and Assurance Committee (BRAC) assists the board in fulfilling its responsibilities to protect the interests of shareholders, customers, employees and communities in which Vector operates. It provides strategic guidance on the development of the maturity of Vector's Enterprise Risk Management framework, oversees the effective management of the company's material risks, and ensures rigorous processes for internal control.

Vector is committed to maintaining the highest standards of corporate governance, ensuring transparency and fairness, and recognising the interests of our shareholders and other stakeholders. Full details of Vector's board members, the executive leadership team and our corporate governance structure are available in our Annual Report.

GROUP CHIEF EXECUTIVE

Under the delegated authorities' framework, the approved strategic plan, approved annual budgets and the day to day operation of the business is the responsibility of the Group Chief Executive (GCE). The GCE 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 GCE receives performance reporting against key metrics and service levels which include reporting against regulatory reliability targets.

All Vector's activities are governed through the delegated authorities' framework which links approved budgets to the authority to authorise or commit expenditure. Under this structure, the GCE has delegated responsibility for asset management to the Chief Networks Officer (CNO).

CHIEF NETWORKS OFFICER

Under delegation from the Board and GCE, the CNO also 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 with the delegated authorities' framework.

Within the asset management context, the CNO is supported by the Chief Financial Officer, Chief Risk & Sustainability Officer, Chief People Officer and the Chief Digital Officer in ensuring that appropriate systems, policies and procedures are in place that support and enable asset management, as well as implementation of the management and governance practices required by the Board of Directors and GCE. The CNO role is responsible for compliance with the requirements of Vector's risk management framework, delegated financial authorities, and in conjunction with the Chief Digital Officer, for ensuring that Vector's Digital Strategy meets the needs of our asset management practice and enables our network vision.

HEAD OF ASSET MANAGEMENT

The Head of Asset Management reports to the CNO and has responsibility for Vector's asset management practice. This position is responsible for asset performance, for ensuring that Vector's Asset Management Policy is implemented, for monitoring the service level performance and quality of our assets, for the development of asset strategy, for the development of Vector's AMPs (including maintenance standards) and for developing asset management practice.

HEAD OF ENGINEERING

The Head of Engineering reports to the CNO and is responsible for Network Planning, Engineering and Design Standards, Protection, Monitoring & Control as well as development and integration of new technology options. The primary focus of this role is planning and development of the assets to meet the forecasted demand and specified service levels. In particular, the Head of Engineering is responsible for network configuration, segmentation and automation, security standards, resilience, quality of supply and for new connection demand associated with large connections, as well as demand for significant asset relocations.

HEAD OF NETWORKS PROGRAMME DELIVERY

The Head of Networks Programme Delivery reports to the CNO and manages the day to day networks operations and the Electricity Operations Centre (EOC) as well as delivery of the approved CAPEX (including design) and OPEX works programme under Vector's Multi Utility Service Agreement (MUSA) and other contracts with our FSPs and other service providers. This role is also accountable for reactive, scheduled and corrective maintenance including restoration times during network outage. The works programme is delivered through our Project Delivery Framework (PDF) that ensures compliance with Vector's requirements and in accordance with the AMP. It also ensures efficient and cost effective delivery of the AMP investment programme. Details of the asset management process are provided further below.

OTHER SENIOR POSITIONS THAT SUPPORT ASSET MANAGEMENT

There are several other senior roles that provide critical support to the CNO role, the Head of Asset Management and the Head of Engineering. Specifically:

- Head of Customer Excellence: this role is responsible for ensuring customer expectations are met through the Call Centre Management and Customer Initiated Projects processes. The Head of Customer Excellence also champions the voice of our customers within Vector's asset management practice.
- Group Manager Information & Insights: this role is responsible for Network Analytics, Business Intelligence, Information Management and Data Platforms. This function provides analytical support and information that is essential to understanding customer behaviour, asset performance, developing and evaluating asset strategy and managing asset risks.
- Head of Regulatory and Pricing: this role ensures that Vector's regulatory activities and pricing is managed appropriately. The Head of Regulatory and Pricing provides regulatory compliance oversight as well as expert regulatory advice and support to Vector's asset management practice.
- Head of Commercial and Strategic Performance: This role leads and enables the development of the strategic plan/framework for Networks, and the detailed current year operating plan. This function leads the transition from electricity distributor to customer energy enabler and provides management oversight for quality business cases and budget – matching projects, incentives and expenditure profiles over various timeframes.

The governance framework overarching each of these roles is defined by the Code of Conduct and Ethics – the Vector Way, Vector's Delegated Authorities Framework (DAF), and position descriptions for each role. Vector's Board has delegated specific authorities to the GCE 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 a 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 ERP system. 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. Further details of Vector's asset management practice and our project management practice are provided in Sections 6.3 and 6.4.

3.4 KEY DOCUMENTS

This AMP is a cornerstone document and is the tactical plan for managing the physical assets to deliver targeted outcomes of safety, reliability, resilience, operational efficiency, data and cyber security, improve the customer experience while also achieving optimal financial impact. The outputs from the AMP are: (i) the operational programme which drives OPEX on our electricity network and informs the development of asset maintenance plans and, (ii) the capital programme which drives CAPEX on Vector's electricity network and informs the business cases prepared for capital investments. To achieve this, Vector uses a range of documents to stipulate and control the requirements for its network and that inform our asset management practices. The pyramid below represents Vector's document hierarchy.[2]

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2 Our safety alerts are not controlled and are therefore not included in the hierarchy

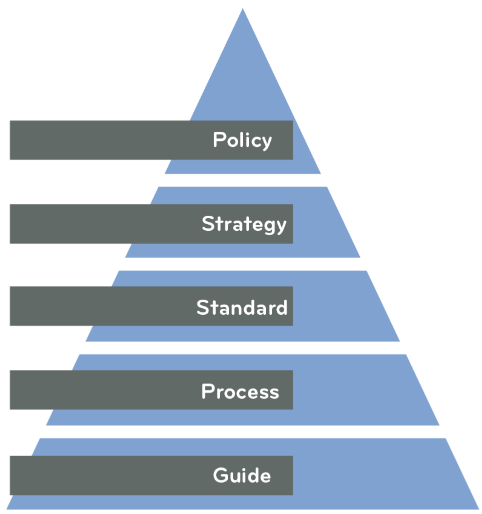

Figure 3-2 Document hierarchy

POLICIES

Policies are high level statements that outline Vector's compulsory state of performance. Policies provide statements of fact from which other documentation is developed and aligned. The table below summarises those policies that relate to asset management. Appendix 2 provides an overview of other important asset management policies and related documents that inform specific aspects of Vector's asset management practice.

SCHEDULE 11A(III) ASSET CATEGORIES	AMP ASSET CATEGORIES
Asset management policy	This policy is Vector's formative asset management document. It defines the principles and objectives that guide all aspects of our asset management practice.
Delegated authorities (DA) framework	The DA framework applies to all business activities that have financial or non-financial consequences including contracts and expenses. The DA framework set out specific approvals for particular transactions and governs the level of financial commitment that individuals can make on behalf of Vector. All decisions within asset management that require expenditure or involve significant risk will be made under this policy and in accordance with Vector's project approval process. Under this policy, projects in the early stages of development are given preliminary approval, while final approval must be provided before expenditure is committed.
Risk Management Policy	This policy provides the overarching risk management intent that Vector strives for. Its purpose is to (a) outline our key management objectives and the principles underpinning them, (b) provide a framework for optimising opportunities and minimising risks, (c) demonstrate Vector's understanding and commitment to promoting a culture of risk awareness throughout the organisation, and (d) define key risk management roles, responsibilities, accountabilities and reporting requirements.
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 of Vector Limited and its related companies ("Vector People"), the public and visitors in its work environment
Environmental policy	This policy sets out Vector's commitment for managing the environmental aspects of its businesses and sets out the

	standards expected of all workers of Vector Limited and its related companies ("Vector People")
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.
Electricity safety and operating plan	This 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 refers collectively to all records and documents (both physical and electronic) used to describe and document Vector's business

Table 3-2 Major asset management policies

STRATEGIES

Strategies provide a course of action that stipulates the direction and key processes required. They are strategic documents required to bridge the gap between the criteria detailed in the standards and specifications and the key decision points listed in the policies. Our strategies are listed in Section 7, Appendix 2.

STANDARDS

Engineering standards and specifications provide the basis for how our network is designed and operated and for the procurement of equipment and plant. Standards and specifications are an integral part of our asset management framework and Vector applies a large number of these standards to the management of our electricity distribution assets. Standards also allow us to ensure any concept design takes the initial hazards into consideration. We also have a process in place to introduce any new asset into the network in a controlled manner to ensure the equipment will comply with our technical objectives and H&S requirements. We draw extensively on AS/NZS and IEC standards for our design, procurement and installation of equipment and plant. Ongoing assessment of design effectiveness reviews are undertaken and used to improve future designs, guidelines and standards. Table 3-3 lists the major standards and specifications that support the design, procurement, supply, commissioning, operation and maintenance of existing, new or replacement assets. Our standards are listed in Section 7, Appendix 2.

SCHEDULE 11A(III) ASSET CATEGORIES	AMP ASSET CATEGORIES
Planning standards (ESP and ENS series)	Planning standards guide the planning and development of Vector's overall distribution network architecture. These standards 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 appropriate operation of the network in accordance with the Network Operating Standards. Technical specifications are listed in Appendix 2 in Section 7.
Maintenance standards (ENI, ENS and ESM series)	The objective of maintenance is to ensure the realisation of the required safety and reliability levels of the asset at optimum cost. Vector has developed a set of maintenance standards for each major class of asset that detail the required inspection, condition monitoring, maintenance and data capture requirements. Where a cyclic maintenance strategy is applied these standards also set out the maximum maintenance cycle frequency. Maintenance standards are listed in Appendix 2 in Section 7.

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 minimum requirements for network planning and design practices
Design and construction standards (ENG, END, EDE, ESE, CND and ESS series)	Design standards and their accompanying standard design drawings sets out the requirements for and the detailed design and installation of equipment. They also include the data capture requirements for our asset management systems. and plant in Vector's network. Our design standards and standard designs has modularity and simplicity at its core to enable deployment at any site or situation. Design standards are listed in Appendix 2 in Section 7.
Technical specifications (ENS)	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 shall comply. Technical specifications are listed in Appendix 2 in Section 7.
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. A full list of the standards that we reference is beyond the scope of this AMP.

Table 3-3 Major asset standards

PROCESSES

A process document is a detailed view of tasks to achieve a particular end. It includes business rules for the running of day to day operations and established protocols of a procedure or behaviour in any group or situation. In many cases these will include process flowcharts. We are reliant to a large extent on standards and specifications to guide use but we have a number of processes for which flowcharts are required: for example our engineering design manual contains the flow process from inception of a project to delivery and commissioning; our controlled document standard explains the flow process for a how a new standard or document is assigned a number; our process for the replacement of an 11 kV overhead automation devices describes the flow to determine protection and SCADA requirements, procurement, installation and protection settings updates. Not all of our standards and specifications include processes – they form part of the document as appropriate and where required.

GUIDES

A guide or guideline is a written instruction that shows or tells how something should be done, e.g. manuals, handbooks, guidelines, codes of practice. We make extensive use of manuals and guidelines for our network plant: manuals are delivered as part of the delivery and commissioning of the plant in both hard and soft copies. Hard copies are stored on site in dedicated shelves to be available for operating and maintenance personnel to refer to. Soft copies are stored in our structured software filing system. We also refer extensively to guides for our engineering designs and system modelling; examples are the AS/NZS overhead line design handbook that we refer to for the design of our overhead network and the extensive guide for our Digsilent subtransmission and distribution software analysis tool (for powerflows and fault levels).

The EEA has issued and continues to revise and update a number of guides and we refer and use these guides extensively in the management of our assets. Examples are: guide on arc flash protection, guide to power system earthing etc. We refer and extensively use a number of New Zealand codes of practices, e.g. NZECP34, NZ Electrical code of practice for electrical safe distances. There are many other that we refer to in our asset management practices.

3.5 ASSET MANAGEMENT SYSTEM

Our Asset Management System encompasses all practices associated with a co-ordinated approach to realise value across the full asset lifecycle, from planning to disposal; and consideration of the circular economy for new technology. This aims to create clear linkages from organisational strategic objectives that set clear Asset Management objectives, and enable effective Asset Management Plans to be created that, when delivered, achieve on the series of aligned objectives.

Continuous improvements in our Asset Management System, with supporting risk, cost and performance monitoring, and data driven reporting, will ensure a full "Line of Sight" throughout the Asset Management governance structure, from organisational objectives to individual asset level performance. We continuously measure and review the progress against the stated objectives to ensure we remain on track and respond quickly to changes in our operating environment.

Our Asset Management System is shown in Figure 3-3.

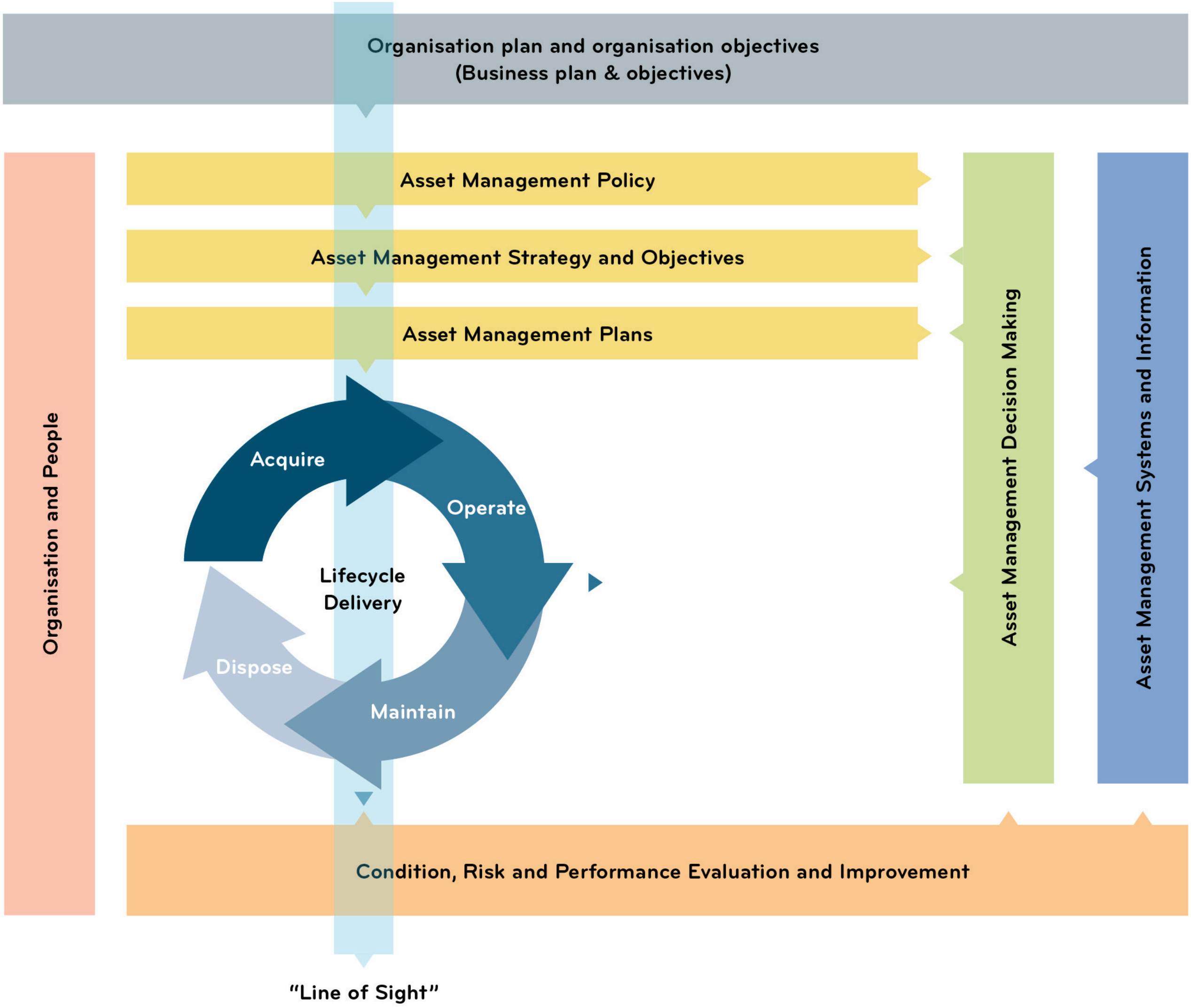

Figure 3-3 Asset management system

The Vector Asset Management System has been designed utilising knowledge available internationally as best practise to support the strategic objective of seeking accord with the principles of ISO 55000.

The Asset Management System comprises of a series of six documented process standards which cover the entire landscape of Asset Management. As they are finalised, they will supersede the existing practice and ensure any pre-existing gaps in process, structure or accountability are closed. These standards will be continually reviewed and updated as a process of continuous improvement. The Asset Management Standards being formalised are:

- AMS 01: Asset Management System, Strategy and Planning;
  Documents the Asset Management System as a series of six Vector standards, outlining the framework for setting the Asset Management Policy, Asset Management Strategy (including Asset Insight Strategy), Asset Management Objectives and finally Asset Management Plans. It is the latter that specify the detailed activities, resources, responsibilities and timescales required, in conjunction with the associated risks, in order to achieve the Asset Management Objectives, which in turn should then see Vector achieve the required organisational / corporate objectives as expected by our stakeholders and customers.

- AMS 02: Asset Investment Planning & Decision Making;
  Documents how asset investment decisions around prioritisation and optimisation are made to compile the final asset management plans. Includes capital investment for new growth requirements as well as replacement for end of life existing assets. This standard also establishes the maintenance requirements for the assets, documents these as standards, and seeks to make optimal decisions with the objective of achieving the lowest overall asset lifecycle cost. The last element of this standard is how resourcing, procurement and shutdown planning strategies are derived to enabled effective delivery of the plans, in terms of required service providers, materials and spares, and with the smallest noticeable impact on our stakeholders and environment.

- AMS 03: Life Cycle Delivery;
  Documents how Asset Management Plans are translated into more detailed work plans, namely project scopes, programme scopes or routine maintenance plans. It covers the acquisition phase of the asset lifecycle including programme management, project management, commissioning and handover, plus the detailed plans that drive the delivery of required ongoing operations and maintenance activities throughout the asset life. This includes shutdown/outage planning, fault and incident response, contingency plans for critical assets and business continuity. Configuration management is included, being the management processes in place to ensure desired asset functions are retained, examples such as required capacity rating or required protection setting. Assurance of compliance with relevant legislation, standards and industry best practise also falls into this standard. The final element is the policy, procedures and plans around asset decommissioning, including the re-assessment of the impact of asset disposal if the situation has changed since this was considered at acquisition stage.

- AMS 04: Asset Insights;
  Documents how Asset Data Standards and Systems are defined and implemented in line with the Asset Insight Strategy in order to collect, store and utilise meaningful data to drive effective decisions around asset management activities. Undertaken effectively, data becomes information, leading to knowledge and ultimately wisdom - a deep understanding (the definition of insight) of the assets. This standard also documents how the Asset Data Standards are compiled to specify the required structure, format, location and desired quality for storing data, as well the associated management processes in place around data collection, management, governance, assurance and audit.

- AMS 05: Organisation and People;
  Documents how outsourced activities such as equipment suppliers, service providers and other contracted services are aligned to the objectives of the organisation and the ongoing monitoring that is required to be in place to provide assurance this is the case. Asset Management leadership is also covered, how the leadership team of the organisation is aligned to promote a whole life asset management approach that delivers on the clearly stated objectives of the organisation, with corresponding documented accountabilities. Other enablers to this are also documented such as how the organisation structure, roles and responsibilities are set, plus how it is ensured that a supply of competent and motivated people is available now and into the future to meet and continue to fulfil the set objectives.

- AMS 06: Evaluation (of Cost, Risk and Performance), Review and Improvement.
  The final document in the set, and arguably the most important in completing the line of sight through to the stakeholders, documents how continuous evaluation of asset performance takes place to identify any discrepancies with the desired objectives. This is undertaken utilising data and analytical abilities in terms of cost, risk and performance against key indicators and metrics aligned to the objectives, these in turn being set as an output of reliability and resilience planning where the expected performance of an asset is set within a defined normal operating environment. For scenarios where the environment deviates from the normal stated operating environment, such as a major weather event, this standard documents how the need for resilience/contingency plans is identified and how they are derived. Aside from just the assets, this standard also documents how the performance of the Asset Management System itself is measured, and how this feeds into a continuous improvement process. The processes in place to manage risk within the Asset Management System are documented and align to the organisational risk management system. The final element is how management / stakeholder review and audit is undertaken.

3.6 ASSET INVESTMENT PROCESS

Our present asset investment process consists of four stages as highlighted in Figure 3-4 and described in the following subsections.

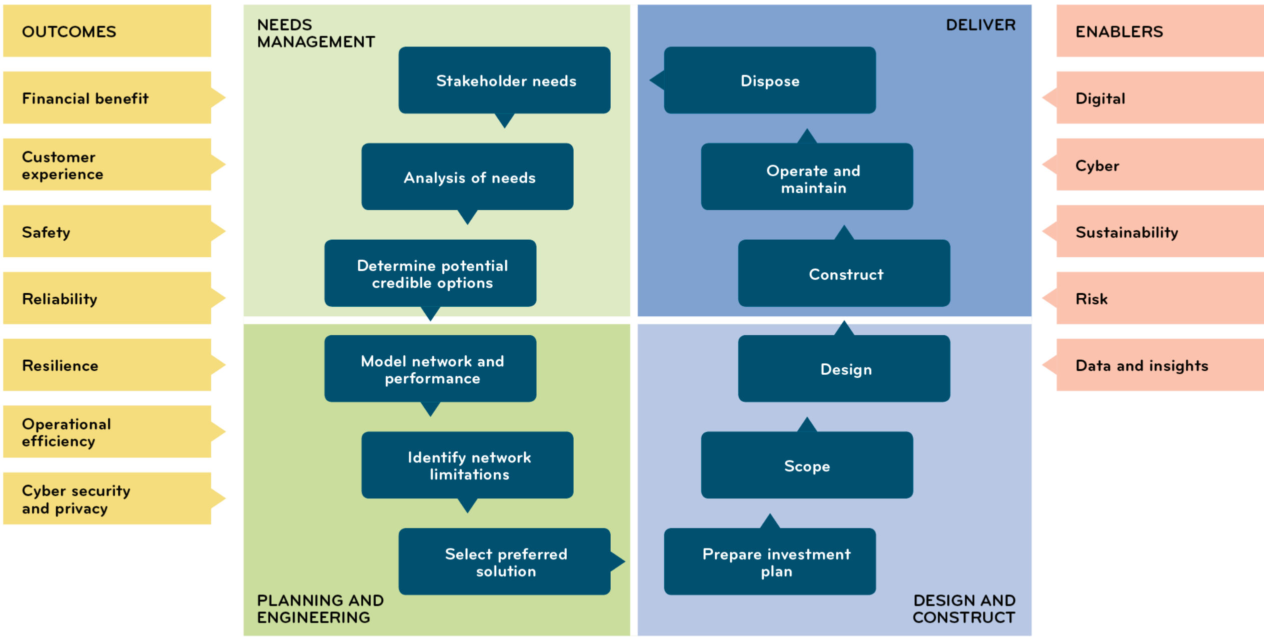

Figure 3-4 Asset investment process

NEEDS MANAGEMENT

This is the formative stage of our asset investment process where the needs of stakeholders are identified and measured against the target outcomes, i.e. customer experience, safety, risk, reliability, compliance, resilience, operational efficiency as well as the financial justification (direct and indirect). During this stage, all stakeholders are engaged to identify and understand the needs, requirements and the target outcomes. By understanding stakeholders' requirements, Vector is able to develop meaningful service level metrics and associated performance targets that are used to assess asset performance. Section 2 provides details of our primary stakeholders and the service levels metrics and targets we use in managing our electricity distribution network assets.

Vector assesses asset performance against the service level targets defined in Section 2. Trends are analysed to identify potential performance issues. Understanding historical performance is key but we also consider the expected future performance, likely influencers, expected changes in the operating environment through advanced data analytics. When actual or foreseen performance gaps are identified, root cause analysis and risks analysis are undertaken to identify the source and significance of any actual compliance or expected service level breaches. External influences, volatility and trends are used to identify any significant systemic performance issues.

The result of this analysis is to identify the need for asset or service related interventions (corrective or preventative) to address actual or expected degradation of service performance. Project proposals are created to address these needs. These proposals specify the need identified, the options considered to address the need and the preferred option. Project proposals are also created through the network planning process (see below), which is responsible for managing the development of the network through a probabilistic planning approach.

All project proposals are approved by Vector's subject matter experts and are then subjected to a portfolio prioritisation and optimisation process as described in Section 6.1. Through the portfolio optimisation process, any conflicting requirements are addressed by assessment to select the option with the greatest overall benefits and least cost. The project proposals for this AMP are provided in Section 5 and the results of selections made through the optimisation process are set out in Section 6.4.

PLANNING AND ENGINEERING

Planning and Engineering involve the development and evaluation of possible options that then culminate in a front-end engineering report and concept. Options may include traditional network solutions such as asset replacement or renewal, accepting the risks of service level breach (do nothing), new technology solutions (e.g. distributed generation, batteries etc.), non-asset solutions or combinations of these options. Each option is developed and a preferred option selected based on the option's economic value, technical feasibility, risk, strategic alignment and on asset management policy considerations including sustainability. Safety in Design forms a critical part of this stage of the asset investment process and is a mandatory consideration that requires collaboration with stakeholders.

Where an asset solution is recommended, functional and performance requirements are specified, lifecycle management plans are developed and a project scope is prepared as the basis of the Design and Construct stage. Where appropriate, we also assess non-traditional solution options which may include distributed generation and batteries to meet the functional or performance requirements expected and a combination of options may be developed to address a particular requirement. Where a non-asset solution is recommended, appropriate specialist processes are engaged to progress the response[3]. In some cases, where no technically or economically feasible option is identified, the front-end engineering design may lead to a revaluation of the identified need.

Under our governance practices, approval of the preferred option is required prior to proceeding to the Design and Construct stage or prior to referral to a specialist non-asset solution process.

DESIGN AND CONSTRUCT

During the Design and Construct stage, Vector translates the selected option into a project scope, functional requirements and performance requirements, a set of design specifications and design drawings.

In accordance with our asset management policy, life-cycle cost minimisation is undertaken during design to ensure that ownership and acquisition costs are minimised. Vector also undertakes assessment of safety, constructability, standards compliance, reliability (i.e. failure modes effects analysis), design standardisation, sustainability, environmental impact and operability during design to ensure that assets can be safely and effectively maintained and operated across the lifecycle. In addition, design is undertaken to align with relevant corporate and asset management strategies.

The outputs of the design process are detailed technical design documentation that is used to guide procurement and construction. During design, essential information is captured in Vector's system of record to enable and support the ongoing management of our assets.

Asset Support forms a further essential part of the Design and Construct stage and provides key links with the Programme Delivery stage. Drawing on service level gap and root cause analysis undertaken in the Needs Management stage, Asset Support develops detailed plans for maintenance, spares holding, data systems, finance and resources that maintain asset performance across the lifecycle. All assets are reviewed annually and a comprehensive set of plans are produced that set priorities to maintain asset performance against the required service levels. These plans are approved under our governance practices before being programmed and delivered by the FSPs.

PROGRAMME DELIVERY

Programme Delivery is a process that involves asset acquisition, construction and commissioning, operations, maintenance and disposal. Construct and Dispose links Design and Construct with Programme Delivery. Through this process, the detailed design documentation produced is translated into network assets. Construction of new assets, testing and verification of "as built" assets and disposal of old assets is undertaken through the Construct and Dispose process to ensure compliance with design documentation, and Vector's standards (see Section 7, Appendix 2). Critical asset data records are created or updated in Vector's systems of record during this process.

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3 The nature of the process for non-asset solutions, and some new technology solutions tends to be bespoke and highly dependent on the type of solution recommended. These are not addressed further in this AMP.

Once in service, assets are maintained across the operational phase of its lifecycle in accordance with our maintenance standards. Asset inspections are also carried out and inspection data is captured in the asset management system to inform asset management practices, service level performance analysis and root cause analysis. This inspection data is also used to identify any network components that require replacement due to an unacceptable failure risk (see risk management below). Operations & Maintenance is also responsible for operating the assets to manage system performance, implement planned changes to the network's static configuration and for providing access to undertake planned or emergency works. Delivery of Operations and Maintenance is contracted to FSPs and is managed under a contract based performance framework.

NETWORK PLANNING PRACTICE

Vector's incremental probabilistic planning practice forms an important specialist aspect of Needs Management that applies across the segment, focusing on network development. Our network planning practice involves processes to manage network peak demand and improving network resilience, delivery of electricity capacity to meet customer's needs and major asset relocations.

The need for asset services initiated directly by customers includes network connections and minor asset relocations. Section 2 describes the service level metrics for connections and asset relocations, and consider the need for these services. In most cases, network connections and minor asset relocations are managed directly by FSPs who undertake design, execute necessary works and maintain associated asset records, in accordance with our standards. Where practical, opportunities to combine network development or asset replacement works with customer initiated works are leveraged to achieve cost savings and other advantages. Vector has also compiled a set of standards and standard designs for customer connections and substations in customer supplied buildings to drive cost efficiencies, standardisation and safety.

Growth in network electricity demand is managed under the SoSS service level discussed in Section 2.5.1. with analysis of the performance of the SoSS service level based on Vector's demand forecast (see Appendix 10 in Section 7). The SoSS service level captures a cost quality trade-off that reflects the ability of our assets to meet the forecast electrical demand without breaching SoSS and to provide restoration capacity that supports planned and unplanned supply interruption events. Performance against the SoSS service level is managed through an annual network planning cycle that involves:

- Development of a network demand forecast in accordance with the Network Load Forecasting Process. An overview of Vector's load forecasting process is provided later in this section
- Ensuring the demand forecast is scenario-based to enable understanding of how the impact of uncertain future technologies (e.g. EV, solar/PV uptake) or lifestyle changes (e.g. energy efficiency) may impact future demand and ultimately, the ten year expenditure profile shown in this AMP. The scenario-based forecast takes a longer term view (30 years) than is represented in the AMP. The scenario methodology is fully described in Section 1
- Ensuring the demand forecast is geographically based, enabling different areas across the network to have different growth rates. Overlaying the 11kV distribution feeders allows the geographical-based demand forecast to be converted to a distribution feeder forecast. Summating feeder forecasts provides zone substation and GXP forecasts
- Individual capacity equipment ratings available from equipment specifications (e.g. transformers, switchgear) or specialised software (e.g. CymCap) being used to calculated cable ratings. Details of the primary plant ratings are set out in Appendix 9 in Section 7
- Circuit ratings being derived by identifying the piece of equipment with the lowest capacity rating thus limiting the circuit overall
- Calculating the impact of climate change on circuit ratings and adjusting the operating thresholds accordingly
- Comparing the feeder demand forecast, circuit ratings and Security of Supply standards to identify potential network security breaches
- Identification of possible SoSS breaches which is initially undertaken using Excel spreadsheets and refined using Digsilent modelling software where required. This models the capacity of both subtransmission and HV distribution networks against various scenarios including contingency conditions or other alternative demand scenarios, and the effectiveness of any proposed reinforcement solutions
- Where a breach of the SoSS service level is forecast, identifying solutions and developing options as outlined under Asset Engineering (see above). Any proposal to respond to an expected breach will be developed to address the breach on a just-in-time basis, and are developed in accordance with corporate and asset strategies and with the System Design Network Parameters standard

The SoSS service level is also taken into consideration when reviewing asset replacement options, and any synergies with network development works are investigated. Moreover, not all breaches of the SoSS service level are addressed through network investment, as in some cases non-network solutions are practical and more economical.

Further information regarding the standards used in our network planning practice are provided in Section 4 and Appendix 2 in Section 7.

NETWORK LOAD FORECASTING PROCESS

The disruptive and growing influence of distributed generation (DG) within the distribution network means that two-way power flows must be factored into a network traditionally designed for one-directional flow i.e. substation to customer. The uncertainty of both volume and timing of EV uptake adds further uncertainty when it comes to forecasting future network demand. Where previously there was strong correlation between population growth and network demand, uptake of DG, EV's, residential energy efficiency gains and home batteries adds complexity to the forecasting process.

Within the current AMP we have adopted a scenario approach to develop the demand forecast using a wide range of inputs to ascertain the sensitivity of each scenario before selecting the most likely one. Inputs used in the scenario include historical half-hourly residential and commercial consumption data, consumer behavioural research, technology uptake data and forecasts (solar, batteries, EV etc), the Auckland Unitary Plan zone plans, population and employment data and forecasts and Statistics NZ census forecasts.

For AMP 2019, we have selected a scenario called Symphony as the basis for the demand forecast. The scenario is based on a growth forecast that facilitates customer engagement and technology uptake. The model, data inputs and scenarios are described in Section 1 and the load forecasts can be found in Appendix 10 in Section 7 of this AMP.

We will closely monitor load growth, particularly DG and EV uptake, and update the Symphony forecast as inputs change or new disrupting factors emerge. The objective is to stay, as much as possible, flexible and agile with our current asset investments so that we can respond to new technologies and customer demands as they emerge. As we recognise changes to the demand profile over time, we are defining network strategies to invest ahead of the technology uptake curve, to encourage customer choice, while improving network reliability, operational cost reductions and customer service excellence.

NETWORK RISK MANAGEMENT

At Vector, we recognise that rigorous risk and opportunity management is essential for corporate stability and performance. To drive sustainable growth, support effective decision making, and ensure business resilience, we must anticipate and respond to risks affecting both our strategic objectives and our operations. As such, our risk management practices form an integral part of the asset management process.

As outlined in our Risk Management Policy, our enterprise risk management (ERM) framework provides a flexible and purpose-built approach to the application of risk management across Vector and reflects the nature of our business as a supplier of critical infrastructure, a leading New Zealand-listed company, and an operator of potentially hazardous material.

Our ERM framework allows for a single, enterprise-wide view of risk, aligning across a number of profiles and contexts (as illustrated in Figure 3-5), to support the achievement of strategic corporate objectives while ensuring key operational activities are appropriately managed and assessed.

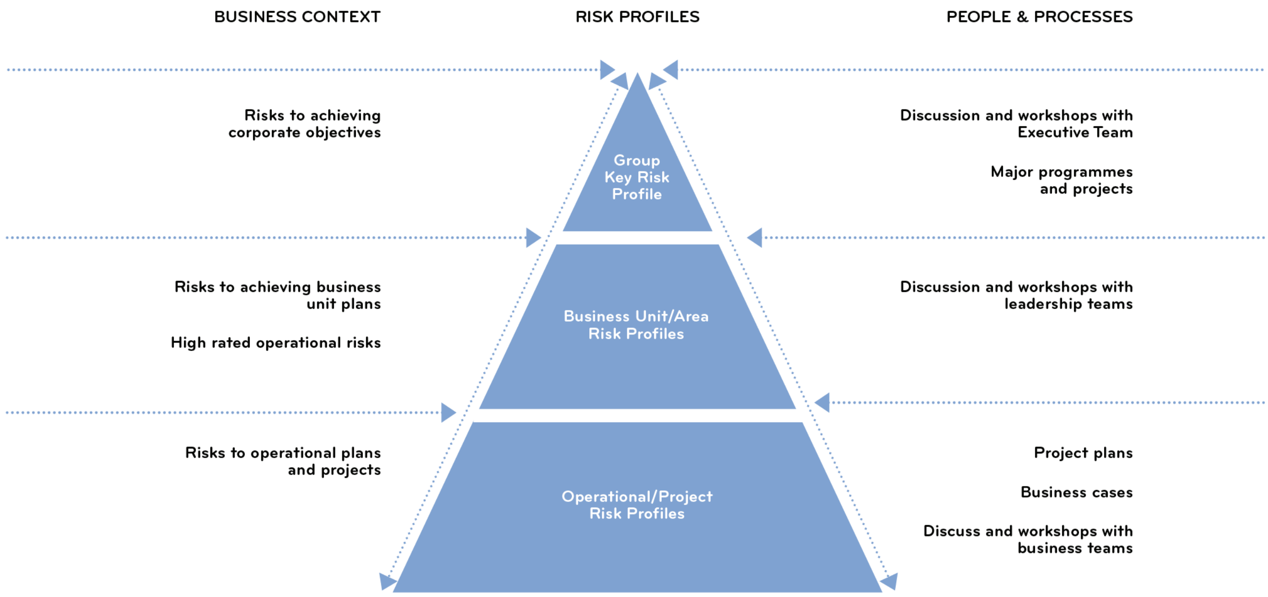

Figure 3-5 Vector's risk profiling structure

The framework is consistent with ISO 31000:2009 "Risk management – Principles and Guideline" and, as illustrated in Figure 3-6, is focused on understanding, monitoring and proactively treating the uncertainty and risks within our business.

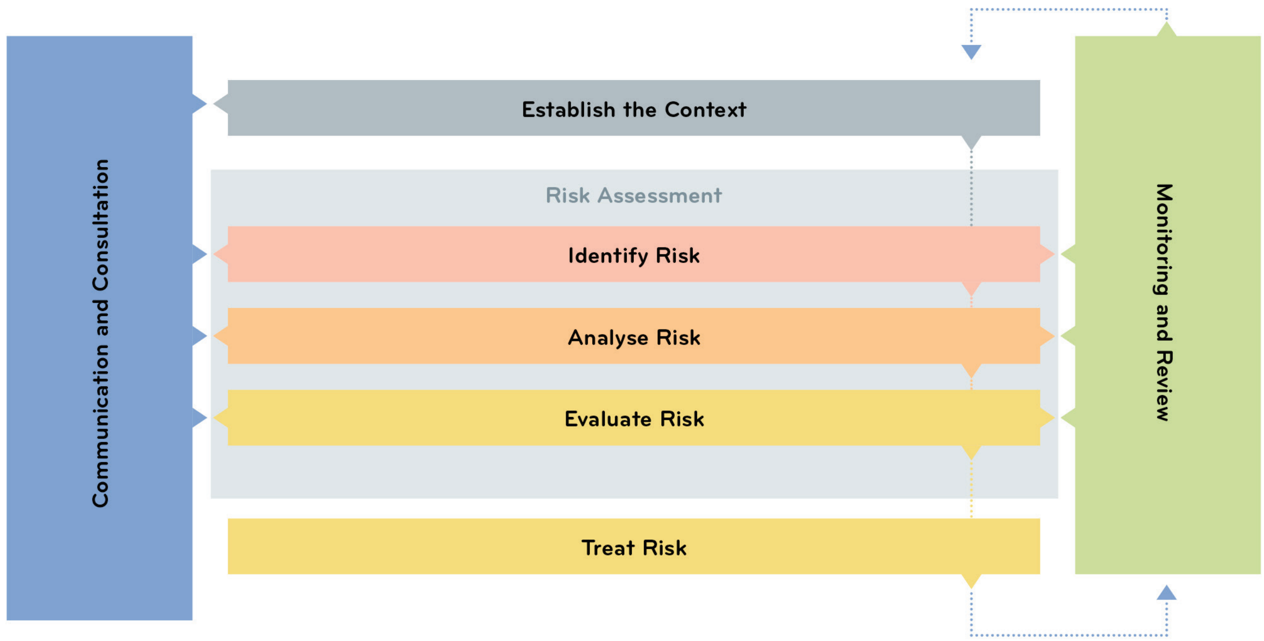

Figure 3-6 Vector's enterprise risk management process

In line with the Three Lines of Defence principle, all Vector people are responsible for applying Vector's ERM framework within their individual roles and are encouraged to proactively identify, analyse, escalate and treat risks, including considering the external trends and drivers that might impact Vector's operating environment going forward.

Under the governance of Vector's Risk Management Policy, the Network Risk Management Process sets out the specific risk management methodologies and processes used within the Network's business and in particular our asset management practice. Quality service metrics, i.e. SAIDI and SAIFI, are recorded in the risk management system and reported to the Vector Board with a specific focus placed on any corrective and remediation activities to address potential deviations from our service level targets.

Identified network risks are assessed on both the likelihood of the risk occurring and the potential impact(s) of the risk. The resulting evaluation informs the asset investment process and the development of asset class strategies, and ensures appropriate treatments plans (which supplement existing controls) are developed and prioritised. This assessment is mapped against the Vector Group Risk Assessment Matrix, which articulates the Board's risk appetite and enables risks from across the business to be raised and discussed using a consistent and transparent approach.

Asset risk management is undertaken using a combination of risk and asset reliability models, including a Failure Mode and Effects Analysis (FMEA), to identify maintenance and other proactive controls, while Bow Tie diagrams enable a comprehensive (and visual) assessment of the causes and consequences of an individual risk and the controls in place to manage the risk. The network-related risk assessment includes identifying potential High Impact Low Probability (HILP) events that could adversely affect the state of the network with specific controls and mitigating activities identified to manage and address the potential consequences. Where appropriate, a visual inspection of the network's health is undertaken post-HILP events to confirm the ongoing resilience of the system.

The management and tracking of identified risks and associated treatment plans is undertaken using Vector's enterprise risk management system, Active Risk Manager (ARM).

To confirm the effectiveness of governance, risk management and internal controls across all business operations, Vector's Group Internal Audit function operates an independent and objective assurance programme. The team follows a co-sourced model, drawing on both in-house and external expertise, and has unrestricted access to all Vector staff, records and third parties as deemed necessary. The team also liaises closely with KPMG, as Vector's external auditor, to share the outcomes of the internal audit programme (to the extent that they are relevant to the financial statements).

3.7 ASSET MANAGEMENT IMPROVEMENT

Periodically, we review our asset management practices using the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT). In addition, Entrust, Vector's majority shareholder (see Section 2.1), biennially conducts an independent review of the state of Vector's network that includes an assessment of asset management. We use these reviews to inform our plans to improve our asset management practice.

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. Appendix 12 provides details of the latest AMMAT self-assessment.

Our latest AMMAT review highlighted the good progress we are making in terms of formalising our asset management practices, and improving our asset management information systems and processes. We recognise the importance of continuous improvement and that this process is ongoing, in our aim of achieving a target score of three on each AMMAT rating criteria. We will continue to develop our CBARM models and formalise our data and information systems to support these models. We have reviewed our operating and contracting models in response to changes in our health and safety policies, potential risks associated with climate change, cyber-security, privacy and data analytics.

In addition, Vector continues to make improvements to our asset management approach and adopt changes as expectations of EDBs change. To this end, Vector welcomes greater clarity and certainty from documents such as the Commerce Commission's DPP Enforcement Guidelines. This information can guide input into our prioritisation and investment modelling.

Set out below is an overview of the primary areas where ongoing improvements of our asset management practice is being implemented.

ISO 55000 FRAMEWORK

We have more recently been consolidating our asset management practice as a basis for improvement. The next step is to revise the key processes so they are in better accord with an ISO 55000 framework. This will involve further development of our asset management framework, assessment and amendment of some of our asset management processes, training and some documentation redevelopment.

It is expected that this initiative will provide benefits through improved skills and more effective and efficient asset management practices. Improvements should become apparent through progressive increases in the self-assessment against the AMMAT model.

ENHANCING STRATEGIC ASSET MANAGEMENT PRACTICE

While we have a range of asset strategies, their effectiveness can be enhanced through the development of a formal strategy framework that improves their alignment and relationship with service level metrics. This initiative involves the review and mapping of current strategies, service levels and corporate strategies, and the development of an appropriate strategic framework. Development and redevelopment of several asset management strategies may also be required. Further staff training in aspects of strategic asset management will also be undertaken.

This improvement initiative will provide benefits through more effective and efficient asset management practices and greater alignment of asset investment. This will be evidenced through progressive increases in Vector's self-assessment against the AMMAT model.

3.8 ENABLING THE ASSET MANAGEMENT SYSTEM THROUGH INFORMATION SYSTEMS

The asset management information systems enable the asset management systems to achieve Cyber-security and privacy outcomes, as well as the targeted customer experience. To achieve this, we have aligned our operational and supporting infrastructure systems with the IEC (International Electrotechnical Commission) network distribution reference model (Section 4.1.13).

VECTOR'S ASSET INFORMATION MANAGEMENT FRAMEWORK

The management of the network asset management information systems follows our Digital lifecycle framework to ensure the information systems are fit for purpose to support and enable the delivery of Network services.

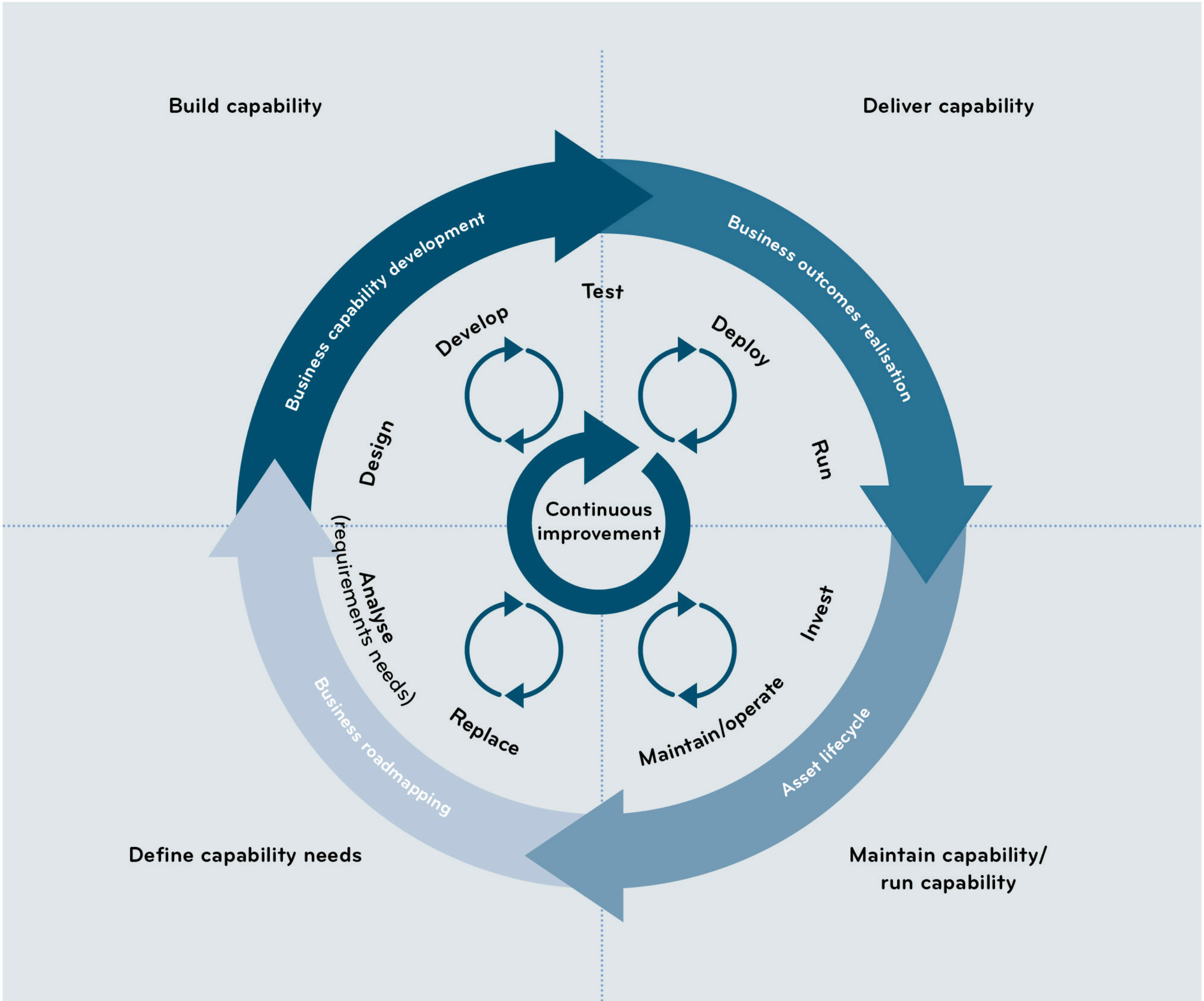

Figure 3-7 Information Systems Lifecycle Management framework

ASSET MANAGEMENT INFORMATION SYSTEMS

Vector has a suite of information systems that support its asset management practice. These, and other critical systems, are described below. The primary systems used by Vector to manage the operation and performance of its network assets, and the related financial and project management activities are shown in Section 5.

PRIMARY SYSTEMS

Many of Vector's information systems operate through an integration layer that extends across these systems and enables the reporting and data analytics that support Vector's asset management processes. Table 3-4 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
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
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
Siemens Power TG	This is Vector's SCADA system and is used to monitor and control operations on the network as well provide data on network loading and other critical asset data
ARM	ARM is Vector's corporate risk management system. Under the Corporate Risk Policy all asset management risks are recorded, prioritised and managed through this system. A supporting system, RIMS is used to record any associated incidents
Stationware	Stationware is Vector's system to record and manage all protection settings in its primary and distribution networks

Table 3-4 Overview of primary information systems

OTHER IMPORTANT SYSTEMS

Vector uses a number of other information systems, computer models and computer based tools in the management of is 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. This optimises asset utilisation through, for example, peak management via community battery storage and ripple control. The system has a 24 hour load forecast across the overall network down to a distribution feeder and will automatically dispatch DERs to overcome network constraints and minimise customer impact. 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
- **Forecast Scenario Model:** this is bespoke load forecasting model used in Vector's load forecasting practice. It is implemented in Microsoft EXCEL and draws data from other corporate systems and databases and third party sources
- **Backstop 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 a zone substation in the event of failure of the subtransmission supply;
- **Digsilent:** is a network modelling tool that provides network power flow and fault levels analysis. It uses information from Gentrack and Smallworld to maintain its network model
- **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 network pinch points. It 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 primary plant in our zone substations and in GXPs. It considers N-1 ratings for winter and summer conditions and identifies points of constraint. It is manually updated on an annual basis

3.9 DATA AND INFORMATION MANAGEMENT

Vector has taken a coordinated approach to the management and governance of its information and data assets. The following four capabilities have been aggregated into a single centre of excellence reflecting the operational, strategic and governance overlaps across the disaggregated functions.

A description of the tools used and strategic approach for each capability is detailed in Section 4.

Enterprise Information Management: This function establishes and administers the data management and governance frameworks applicable to both physical and electronic data and information. In addition, this function oversees the operational application of information management across the electricity network's systems of record for assets and operational activities.

Business Intelligence: Primarily a technical function, this team provides the data integration, visualisation and reporting capability to the business.

Data Platforms: A technical function, this team is responsible for the management and development of the data and analytics platforms

Analytics: 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 and advanced modelling capability.

GOVERNANCE

Vector's Group Data & Information Policy is the foundation document that sets out the governance requirements and operating model for the information lifecycle. This covers both data and information in electronic and physical form. 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[4].

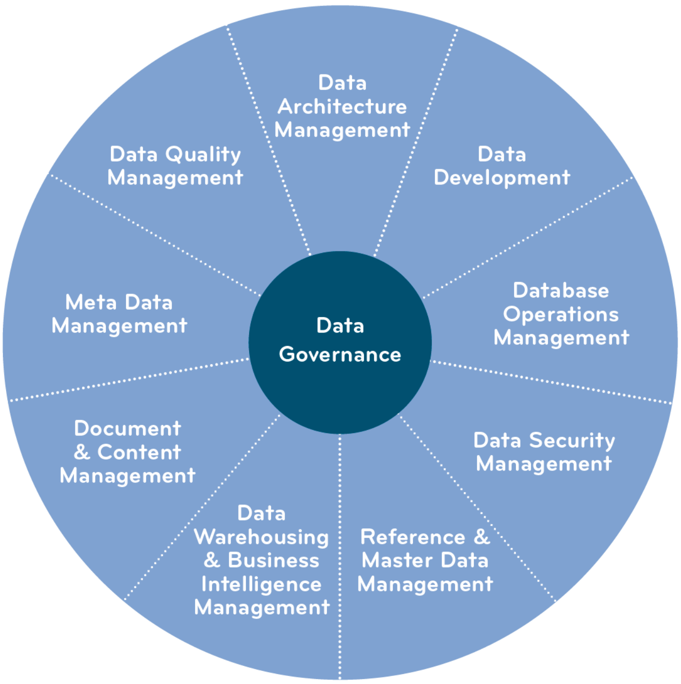

Figure 3-8 Data Management Associations body of knowledge

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

OPERATING MODEL

Vector's data and information management model is represented in the diagram below. Operationally, the Enterprise Information Management (EIM) function within the Information & Insights centre of excellence provides capability horizontally across the different business units. Within each business unit, data stewards have been established to work

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

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 Enterprise Information Manager.

The Group Information Governance Council has responsibility for setting and enforcing the Group Data & Information policy. This includes being the escalation point for data related events and conflict. Importantly the council is made up of the core disciplines and functions from across the business that impact on privacy and data management including, but not limited to, the Privacy Officer, Cyber Security, Digital Architecture, Information Management and Data & Analytics. The council reports directly to our Chief Executive Officer.

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. In addition, 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.

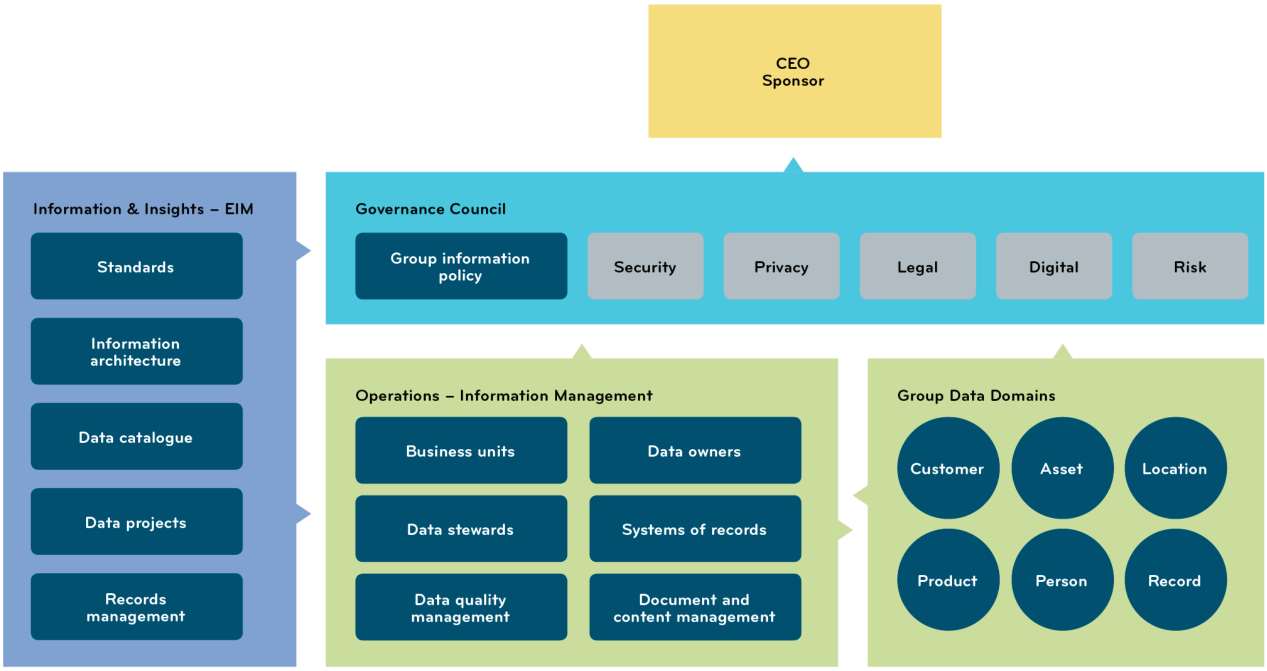

Figure 3-9 Data and Information Management model

3.10 CYBER SECURITY & PRIVACY

In the context of our Asset Management Plan, our strategic intent in regards to cyber security is focused on addressing two key risks:

1. The protection of critical network assets from unauthorised access that could result in disruptions to service/physical damage
2. Safeguarding and restricting access to any personal/customer data that is used for network management purposes

Effectively managing these risks requires the implementation of a combination of technical, process and behavioural controls that will allow us to quickly detect, respond and recover from potential cyber security threats. The security threats, the nature of network assets and the volume of data required to manage the network is constantly evolving. This requires continual re-assessment of the effectiveness of the risk and the corresponding controls.

In this environment, balancing resilience and security provides both challenges and opportunities. These challenges are not new – resiliency and security have always been cornerstone principles of how we deliver our services. However, as the network becomes more open in terms of protocols, communication channels and technologies, and the perimeter of the network extends more into the consumer domain, this will inevitably increase the attack surface and therefore the risk of compromise.

New technologies present a significant opportunity to provide enhanced services and a more robust network for end consumers, however it is important that we also embed appropriate security controls across the network to maintain trust and integrity.

As a major cyber attack becomes increasingly likely (it is not if but when), we must ensure we are appropriately prepared and are able to quickly respond to limit any impacts. Maintaining effective security controls and response strategies is a key priority and an area in which we continue to invest heavily to ensure we appropriately manage this risk. We have improved our ability to prevent and detect potential cyber security treats with our new Security Operations Centre (SOC) which provides 24/7/365 monitoring of our SCADA and Corporate network and continue to improve our preventative and detective controls such as malware detection and our firewalls. In addition, we continue to actively contribute to key NZ industry security forums, across public private sectors and our SOC constantly monitors available threat intelligence feeds for the latest attack trends which are automatically deployed to enhance our perimeter security controls.

We have a clear vision of the level of process and control maturity required to adequately protect the network and data for which we are custodians and a roadmap which supports how this will be achieved.

PRIVACY

As part of managing network assets, privacy must be considered in all things and not just in the cyber security context. The volume and potential sources of data required to effectively manage and operate the network continues to expand. New network and customer devices generate increasingly important information about consumption patterns, faults, performance and resilience which enable us to efficiently and effectively manage the network. This information is also extremely sensitive and this means there is an increased risk that we may be targeted by malicious actors wishing to gain unauthorised access to this information.

Accordingly, we are elevating our internal controls to ensure this information is appropriately protected particularly where Personally Identifiable Information (PII) is involved. Effective management of information is critical to maintaining trust in the network and in Vector as its custodians and we take our obligations very seriously.

The Vector Group Data and Information Policy is the guiding document for the collection, storage, use and sharing of personal information to ensure we only use personal information in a way that is permitted and ethical

3.11 SUSTAINABILITY

SUSTAINABILITY AND THE ASSET MANAGEMENT FRAMEWORK

Responding to sustainability challenges will shape how we develop our electricity infrastructure. Climate change and decarbonisation initiative are obvious opportunities. Other changes that influence how we manage our assets include the adoption of broader sustainability principles – sustainable procurement and better resource efficiency, plus a shift to embedding circular economy thinking that emphasises re-use and minimises waste.

Throughout the planning process, consideration is given to Vector's sustainability policy through the following targeted initiatives:

- Supply chain
  - Reducing exposure to high risk suppliers or products
  - Opportunity to work with suppliers on mutually beneficial sustainability innovation projects
- Adapting for climate change
  - Hardening the network for expected wind speed increases
  - Hardening of the assets forecast to be impacted by climate change, e.g. rising sea levels and land subsidence
  - Developing dynamic asset ratings to compensate for dry and warm spells
  - Respond to bushfire risk by disabling the automatic reclosing function in reclosers
- Enabling energy efficiency (decarbonisation of the economy) options for our customers through our managed integration planning approach
- Starting shift to a circular economy
  - Consider end of life when designing and constructing to avoid expected increases in future landfill costs

GOVERNANCE AND PRINCIPLES OF OUR SUSTAINABILITY APPROACH

Sustainability is overseen at the executive level by the Executive Risk and Audit Committee. The Committee provides a company-wide forum for staff from different disciplines to discuss both the current and emerging risks we face.

Our sustainability policy is based on our sustainability framework explained in Section 1 which has four key guiding principles at its heart – Integrity, Transparency, Inclusive and Kaitiakitanga. Of these Kaitiakitanga, the Māori concept of stewardship and care of the environment, is very relevant when it comes to managing our assets and is a founding principle. It recognises the need to adopt a whole-of-life approach that includes both the upstream (supply chain), downstream (end-of-life), and, very importantly, customer interfacing aspects of asset management.

In order to apply these sustainability principles to asset management Vector utilises appropriate international standards and tools.

ISO 14001 Environmental Management System certification is maintained. This ensures there are competent resources and effective systems in place across the business to manage the interface with and impact on the environment.

The Infrastructure Sustainability Council of Australia (ISCA) has developed a set of ratings tools that provide a useful breakdown of key components to consider in sustainable infrastructure planning, design, construction and operation. The key components headings are Governance, Economic, Environment and Social, and these tools will be utilised within the asset management framework to embed sustainability.

Specifically, the ISCA tool will be applied to the reduction of energy consumption and carbon emissions; climate change adaptation; taking a lifecycle approach to materials, and applying sustainable procurement principles. Eventually all aspects of our asset management will be assessed against the ISCA framework.

Our sustainable procurement strategy aligns with the Flexible Framework[5] for sustainable procurement and draws from frameworks such as BS 8903 and ISO 20400. It is intended to support Auckland's emerging circular economy.

All suppliers of products and services to Vector are required to adhere to our Supplier Code of Conduct. This sets out Vector's expectation on labour / workplace, health and safety, environmental, governance / ethical, community, and supply chain matters.

Sustainability criteria are included in the assessment of all significant purchases made by the business and sustainability is weighted accordingly in tender evaluations.

3.12 EMERGENCY RESPONSE AND CONTINGENCY PLANS

As a "lifeline utility" under the Civil Defence and Emergency Management (CDEM) Act 2002, Vector is required to be able to function to the fullest possible extent, even if this may be at a reduced level, during and after an emergency. In line with our obligations, we have a range of plans (detailed in Table 3-5) governing how we will function under an emergency. These plans, which are reviewed and updated regularly, help support network resiliency by driving effective assessment of and response to disruptive incidents affecting network assets. In addition, we actively participate in the development of a CDEM strategy and are a member of:

- The Auckland Lifelines Group
- The National Engineering Lifelines Committee
- Various lifeline groups throughout New Zealand

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5 The Flexible Framework is a widely used self-assessment mechanism developed by the business-led Sustainable Procurement Task Force, which allows organisations to measure and monitor their progress on sustainable procurement over time.

POLICY	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:
	  • Australian/New Zealand Standard AS/NZ 5050:2010 "Business Continuity - Managing disruption-related risk"
	  • ISO 22313:2013 "Societal security - Business continuity management systems - Guidance"
	  • SAA/SNZ HB 221:2004: "Business Continuity Management"
	  • AS/NZS ISO 31000:2009 "Risk management - Principles and guidelines.

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 it employees, contractors and other stakeholders • Takes account of both the operational response and broader considerations including staff, customer and wider stakeholder engagement and support • Includes the Incident Management Guideline, which provides direction on how to categorise incidents - this categorisation determines the appropriate response team, response plan and escalation hierarchy • Annual crisis management exercises and regular plan reviews are undertaken to ensure usability and understanding and support continuous improvement of the plan
Issue / Crisis Communications Plan	• Standalone plan governing the communications and external relations approach and processes during a crisis, emergency or business continuity events
Incident Response Plans	• Individual business unit / team plans outlining the general procedures for assessing and responding to any disruptive events or incident (below crisis level) within a specific business area
Specific Event Response Plans	• Individual plans covering credible incidents and emergency situations which ensure Vector is prepared for, and responds quickly to, specific-events that may occur on the electricity network
Business Continuity Plans	• Individual business unit / team plans which 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 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, for the purpose of maintaining the electricity security of the grid and avoiding cascade tripping under emergency conditions
Participant Outage Plan	• Describes the actions Vector would take to reduce electricity consumption, as a specified participant under the System Operator Rolling Outage Plan (part of the Electricity Industry Participation Code 2010)

Table 3-5 Overview of emergency response and contingency plans

OUR ASSETS

SECTION 04.

SECTION 4. OUR ASSETS

How we consume electricity is changing fast as we electrify our lives. With this change comes a greater expectation that our energy systems will be reliable. Our dependency on electricity will continue to rise as new technologies enter our lives, especially the electric car. Given this, Vector believes the Symphony scenario it has developed for its future network is the best and most sensible choice. It will grow the network well over the next 10 years and help us meet the challenges we face – and our service-level targets, while also greatly improving the customer's experience. In this section of the Asset Management Plan, we describe our assets, including the various types and volumes, and their functions, and we provide key statistics. But, most importantly, we do this in the context of our range of network management strategies.

4.1 OUR NETWORK MANAGEMENT STRATEGIES

4.1.1 OVERVIEW

We summarise our asset management strategies both at a network-wide level and for specific asset classes. These strategies inform us when we should act, and what actions to take to best manage the lifecycles of our network assets over the course of their useful economic lives. We actively manage our network assets over their whole lifecycle to avoid failures that might harm staff or the public, or damage the environment. We also aim to minimise interruptions of supply for our customers. These strategies are behind the plans set out in Section 5 and align with both statutory and regulatory requirements, and modern design and maintenance standards. A list of key asset strategy documents, along with the design and maintenance standards we abide by, are provided in Appendix 2.

This section describes our asset management strategies for all asset classes, and covers planning, operation and maintenance strategies, as well as specific strategies relating to service-level performance i.e. – reliability, resilience, power quality, sustainability and safety. Our asset-specific strategies are described more fully in our suite of asset strategy documents (from Section 4.3 below).

Section nine of the Default Price-quality Path (DPP) specifies that an Electricity Distribution Business (EDB) must comply with the SAIDI and SAIFI limits the Commission sets for a specific assessment period – or have complied with those set for the two previous years. The Commission derived the targets for 2015 to 2020 using a 10-year historical view to define the SAIDI and SAIFI limits. Vector notes this historical view doesn't address significant recent changes to the operating environment. This, as well as a lack of clear enforcement guidelines around breaching regulatory quality limits, creates significant uncertainty when evaluating options and trade-offs as part of the asset management plan process.

In regard to this, the Health and Safety at Work Act 2015 (HSWA), which came out of the recommendations of the Royal Commission into the Pike River Mine tragedy, and the subsequent taskforce inquiry into general workplace health and safety, has created tougher obligations around keeping staff, contractors and sub-contractors safe. To comply with the new health legislation, new rules have been developed for working on or near lines as a "reasonably practicable" way of minimising the risk posed by live electrical equipment. These new safety rules are incorporated in our live line operating standards. Additionally, from a public safety perspective, Vector has established escalation processes to remotely de-energise reported low or downed lines when an imminent risk is identified.

The new rules make it a challenge to meet the SAIDI and SAIFI targets based on historical performance when rules restricting live-line work were not in place. Nevertheless, Vector monitors its performance in relation to the SAIDI and SAIFI reliability indices, together with the number and duration of 'customer interruptions' metrics, as these are key indicators of how the network is performing. Our current reliability objective is to reduce the number and duration of customer interruptions, and to work back towards SAIDI and SAIFI targets set by the Commission.

We have built a model that enables us to assess the potential impact SAIDI-SAIFI has of the network. This is based on fault rates, network restoration times and network topology. We recognise that SAIDI performance is a function of these three variables, and that an optimal balance needs to be struck between these to deliver the required SAIDI-SAIFI performance. Using our model, we can define the balance required by setting targets for network restoration times and tolerable fault rates. We can also use a number of analytical tools and models to improve our overall SAIDI-SAIFI performance. These targets help us set the priorities for our maintenance and investment plans.

There is a comprehensive set of network reporting tools (including dashboards) that are used to monitor network performance and provide visibility and access to key data and information to help drive performance levels. We also report to the board on service-level performance and focus on how best to remedy any problems that might prevent us meeting our service-level targets.

4.1.2 OUR RELIABILITY AND RESILIENCE STRATEGY

Electricity consumption is changing rapidly as consumers electrify their lives. This is increasing expectations of the energy system's reliability and as a first step we have developed a Reliability and Resilience Strategy that is owned by the Head of Asset Management. Consumer dependency on electricity will continue to rise with the adoption of new technology and the uptake of electric cars. In parallel with this, the impact of climate change is being felt more and more in New Zealand, and across the world. Climate change is increasing the likelihood of adverse weather, and it's clear the number and duration of electricity outages will rise with this.

On any given day, there are likely to be multiple threats to our network's resilience – for example, high winds or a combination of drought and high temperatures. These threats can heighten our resilience risks, create short-term localised damage, along with long-term challenges to electricity supply. The New Zealand electricity system is particularly vulnerable to environmental impact with 80 percent of our electricity coming from climate-dependent wind and hydro generation. Auckland is at risk from a wide range of natural disasters because of its location on a narrow coastal strip poised on top of a volcanic field. Environmental factors, including climate change, in combination with natural hazards, will impact on each part of the electricity system differently, but will, ultimately, have a direct effect on our customers.

While the Vector network currently averages 99.96% availability, as electricity becomes increasingly critical consumers may no longer find this enough. However, in increasing resilience Vector is reluctant to burden future generations with costly solutions that have long-term, regulated cost recovery periods (currently only 10 years certainty on revenue stream) and may only benefit a few. For example, there are resilience threats to generation and transmission, because of drought, natural disasters or equipment failure, and this will have a flow-on impact on the distribution network regardless of any new reliability and resilience measures imposed.

As increased resilience comes at a cost that is ultimately borne by consumers we believe the various options, trade-offs, and costs should be transparent – especially when new technology is creating greater choice, and more household-based resilience options.

Some options, such as household solar and battery storage installations, and Vehicle-to-Home (V2H) electric vehicle technology, provide extra benefits. For example, they can off-set energy costs and provide carbon benefits. These new technologies increase resilience options for consumers and don't require investment in long life network assets. They provide households and businesses with greater control, have shorter financial returns that don't burden future generations and come with a guarantee that consumers will directly benefit from their resilience investments.

A smart, resilient, energy future will embrace multiple solutions. Part of this, in regard to our reliability and resilience strategy is to support consumers so they understand the options available to them, and the necessary trade-offs should they take more direct action with respect to their energy resilience. Previously, only network, transmission or generation-based solutions were available to increase resilience. The emergence of new technology, and the rapidly declining cost curve, is creating new opportunities for customer-controlled resilience options. We have completed various trials with new technology options and will continue to do more during this AMP period. The learnings from these trials are continually informing us of the efficiency and effectiveness of the new technology options in improving the customer's experience during outages and network emergencies.

Vector typically evaluates the trade-offs associated with have the following investment options when it comes to improving reliability and resilience:

- Establishing microgrids using distributed and renewable generation
- Undergrounding or relocating exposed parts of the network
- Using new network storage options
- Using technology options such as aerial bundled conductors (ABC) and/or covered conductors
- Changing the configuration of the network so it is more meshed

- Utilising temporary generation; increasing vegetation cut zones; removing trees that can fall on lines, and limiting third-party assets strikes (these options are under the control of the government, councils and other infrastructure providers, as well as consumers)
- Using emerging technology like fuel cells to improve resilience
- Shared resilience options, where the cost quality trade-off analysis results in options that meet the required resilience through on-premise customer solutions, at a more efficient investment level than a network solution. This can be fully funded by the customers or partially funded by Vector

Microgrids

Ensuring resilience in remote areas using traditional network solutions is often costly relative to the number of customers served. 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, (mainly driven by the exposure of the existing network to climate change effects such as strong winds). A good case to point is Kawakawa Bay in the remote south-eastern edge of Vector's rural network that is supplied via a very lengthy 11 kV overhead line for which an alternative backup supply by means of a traditional network solution would be prohibitively expensive. This is where employing self-sufficient microgrids becomes 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 improves remote communities' resilience in a cost-effective way.

Undergrounding

Even though undergrounding seems to have obvious reliability advantages – such as reduced exposure to lightning, and fewer outages as a result of adverse weather, including falling trees, EDBs cannot simply underground entire networks. The cost would create an unmanageable burden for consumers (an estimated $5.5 billion to underground the remaining 45 percent of Vector's overhead network). An overhead network also has a long economic life – 40 years – and were an EDB to prematurely replace it with an underground network there would be a significant cost impact on future generations since costs are recovered over 40 years.

Undergrounding is not a panacea for all risks either. There are challenges and disadvantages apart from the high cost of such a huge venture. Disadvantages include: replacement is more costly and difficult; fault-finding and repair times for underground cables are much longer (which drives up maintenance costs and duration-based reliability indices) and the cables are at more risk during floods and earthquakes. Sharing roading corridors with other utility services such as water, gas, communication and trees can lead to congestion and cable de-rating.

Distribution Automation

We are increasingly automating distribution with the aid of remotely controllable or automated devices that increase both the visibility and controllability of our distribution system. We have installed devices such as reclosers that are circuit breakers that trip on faults but will automatically reclose if the fault is transient. Remotely controlled feeder switches, used in conjunction with these reclosers, can open and close feeder sections as required to isolate a faulty section of feeder so there may not be a requirement to send out a linesman to undertake manual switching that in turn removes the time associated with driving between isolation points in the network.

Automated distribution is improving our resilience through:

- Sectionalisation – isolating the affected section to minimise the number of customers affected
- Better diagnosis – pinpointing the section affected, so the fault can be found faster
- Restoration – this can be done remotely and automatically

Vector has deployed 136 high voltage auto-reclosers since 2007. We have also deployed 209 remotely controlled feeder switches. This programme of work will continue throughout this AMP period (see Section 5).

Smart Meters

Advanced meters at the customer's premise are essentially a sensor that have the ability to capture a range of information that is useful to Electricity Distribution Businesses (EDBs) to plan, optimise and manage the network. Information regarding voltage levels, network performance and the impact of new technology on the network such as EV and solar are critical to ensuring that the network can continue to support customer choice going forward. In addition, the advanced meters currently installed at customer premises can also provide accurate information regarding which premises are without power.

Vector is currently trying to secure access to the installed base of advanced meters to minimise the investment in its own LV network sensors. We are currently working with the meter owners and the retailers who under the regulations are the only party who contracts for the meters and who by virtue of their contracts, control, to a large extent, access to these meters.

Vegetation Management

Vegetation Management is described in more detail in Section 4.1.8.

Customer Options to Improve Resilience

Customers now have individual ways of improving resilience, thanks to existing and new technologies, whose costs are steadily reducing. These include:

- Mobile on-site generation
- Permanent on-site generation
- Renewable generation with on-site energy storage
- Standalone energy storage
- Solar and battery storage solutions
- Innovative Vehicle-to-Home (V2H) solutions that use the energy stored in an electric vehicle, so customers can supply their home with energy during an emergency such as a storm-caused outage

4.1.3 OUR NETWORK PLANNING STRATEGY

Our planning strategy ensures the network can meet our objectives for creating a new energy future. It takes into account the megatrends affecting the electricity industry, in particular the rapidly evolving technology and digitalisation. To this end, we have engaged in scenario planning to better understand the impact of the uncertainty surrounding the key inputs, influencers and other variables that could affect our future network. At the same, our planning strategy also focuses on meeting our SoSS reliability and resilience objectives, and other service-level obligations – and at optimal cost.

We have also forecast the electricity growth expected to arise from new customer connections that will typically be met through the construction of new zone substations and feeder lines. Where forecasted demand is likely to exceed the capacity of our present assets, resulting in a breach of SoSS, the capacity constraints are being addressed. The timing of the investment is aligned with expected time-frames when capacity in a geographic area, or of an existing substation, is expected to be exceeded.

Our scenario modelling shows the likely growth of our future energy load. Inputs into the Symphony scenario forecast a steady uptake of both solar and battery installations, and a rapid uptake of electric cars over the ten year planning term of this AMP. Ongoing energy efficiency gains (for example, efficient home insulation, LED lighting and the use of heat pumps) is expected to continue. The outcome painted by this scenario forecasts the network peak demand growing by seven per cent over the ten year period.

To meet this increased demand, Vector has looked at increasing the capacity of existing assets or adding new assets such as zone substations and distribution feeder circuits. It has also investigated alternative technology and load control opportunities. Distributed generation and other DERs (with homes that feed energy into the network being one example here), smarter distribution technology and advanced analytics are all providing new options that offer greater choice in how we plan and implement our future network.

Traditional security standards are based on 100% redundancy on urban 11kV distribution networks. In the event of a fault, we can use switching on the network to isolate the faulty section and restore power to the remaining healthy sections. To achieve this level of redundancy, often referred to as deterministic based planning, the network must be constructed to supply not only the primary load, but also the backup load. We follow a different approach, namely probabilistic based planning. Our analysis of fault data shows that the likelihood of a fault at peak times, and the resultant impact on customers, are not the same across the network. By accepting that the likelihood of fault at peak times is small we have adopted a distribution network security standard which offers slightly less than 100% redundancy. By example, through our security of supply standard we offer 100% redundancy on residential urban feeders for 95% of the year (98% for predominantly commercial feeders). This has minimal impact on our customers by way of increased outage frequency or duration, but it has a significant benefit in terms of reducing network expenditure to cover off the few brief periods of the year when we experience peak demand. This approach has reduced investment in the network over the past two decades by deferring reinforcement upgrades without impacting the customer experience. We are continuously refining this approach given new and emerging technologies. As such we now use Incremental Probabilistic based planning, where energy storage is utilised to meet growth in peak demand to further defer subtransmission investments (for example

Warkworth South and Snells Beach battery systems), and Managed Integration, where we enable customer options by integrating and managing on-premise energy storage to defer, or even avoid, investment in traditional network solutions while enabling a much more targeted level of resilience to customers.

4.1.4 OUR EQUIPMENT CAPACITY ASSESSMENT STRATEGY

The policy of using standardised equipment on our network minimises long-term costs and keeps a check on stocks of spare parts. The key factor in deciding the standard capacities (20 MVA and 10 MVA) of power transformers is the load density of the area being supplied. While economies of scale suggest the use of large capacity transformers, higher capacity zone substations result in a larger supply catchment area (for the same load density) and longer distribution feeders. Larger supply catchment areas also mean zone substations are further away from grid exit points (GXPs) so need longer subtransmission feeders.

Deciding on the optimal economic capacity of standard urban transformers requires cable and transformer costs to be balanced, so as to achieve the lowest overall cost per MVA of network capacity. Our scenario analysis (of different transformer capacities and feeder lengths) considered a range of equipment costs and load densities. This supported by our decision to standardise urban transformer sizes at 20 MVA. Other factors considered include how the transformer will be used on the network to ensure resilience (for example, operating transformers in parallel to provide redundancy) and how this reflects back into the selection of the transformer parameters such as impedance, reactive power and tap changer/voltage control.

For power transformers used in rural zone substations, the voltage performance of the network is another important factor. Analysis of these rural areas indicated that 10 MVA was the optimal transformer capacity.

Apart from our variable capacity power transformers, most of our network equipment is standard. The list includes:

- Protection and control equipment
- Zone substation buildings
- Subtransmission switchgear
- Distribution transformers
- Distribution switching equipment
- Distribution cables
- Poles

Asset capacities are specified at the equipment specification stage, before equipment is procured. It is verified through type-testing (for example, switchgear) or individual test results (for example, transformers). For existing equipment, we rely on equipment procurement records or name-plate parameters. Standard distribution cable sizes are nominated to ensure a relatively small range of cables is held in stock. We apply the same principle for overhead conductors, for which standard conductor sizes are nominated to ensure only a small range of stock need be held.

Cable ratings are calculated using the CymCap cable-rating software. These are based on field-tested ground thermal conductivity results and standard cable installation practices. All new subtransmission cables are modelled, including their trench profiles, to ensure the target network rating can be achieved prior to procurement. Circuit ratings are the lowest of the individual asset ratings (e.g. cables, switchgear, transformers, etc.) in the circuit.

Forecast demand is compared to the circuit ratings to confirm all equipment operates within its electrical, mechanical and thermal ratings, adjusted for seasonal variances and the impact of climate changes such as extended long periods of high temperatures, high winds and low rainfall. Where this is not the case equipment is uprated, or replaced.

We are forecasting significant uncertainty around the impact of climate change on this process. We have put the necessary measures in place to mitigate what we have been observing to date but will review asset ratings and associated work practices on a continuous basis to manage climate change.

4.1.5 OUR LOAD DEMAND STRATEGY

We will continue to use our load control system to manage peak load by remotely managing residential hot water. We intend to ensure existing load-control systems are maintained until retired at end-of-life and will continue to roll out our standard load-control systems in new developments. In the Northern network we will deploy a new radio-controlled hot water system.

However, we are in the process of evaluating new load control systems. Some of these (a digital radio-based solution) have recently completed a successful proof-of-concept trial. Once we have settled on a preferred load-management system, it will be rolled out more widely as a replacement for our existing load-control systems during the period of the AMP.

The strategy for planned maintenance to keep our existing ripple plant systems working well includes procuring some key spare components to hold in stock for quick deployment, in case of plant failure when complete plant replacement isn't planned. We will also regularly tune these ripple plants, so they perform at optimum levels to ensure maximum reach of the ripple signal and improve propagation.

We will continue to control that part of Auckland City Council's streetlight population to that hasn't been transferred to their own digital remote-control network as yet.

4.1.6 OUR CBARM, REFURBISHMENT AND REPLACEMENT STRATEGY

Ageing assets remain a challenge, and replacement is sometimes delayed due to uncertainty around cost recovery and replacement choices – especially in light of the 'new energy future' that sees growth at the grid edge increasing. Asset refurbishment and replacement also needs to be considered in the light of a future where the low voltage (LV) network continues to become more important. Our Symphony scenario foresees resilience being shared (see our reliability and resilience strategy above) so we have to be careful not to burden future generations with costly undertakings that have a long-term, regulated cost recovery period. This means full documentation and data on the operational history of our installed asset base will become even more important to understanding and managing them. This will allow us to predict possible issues early and do preventative maintenance or replace the asset.

To do this, we are implementing the CBARM (Condition Based Asset Risk Management) modelling as part of our proactive replacement and refurbishment programme. CBARM first details the age profile of an asset population, then assesses the expected life and condition of individual assets. Resulting asset condition health scores allow us to identify assets that are forecast to exhibit higher likelihood of failure during our 10-year AMP period and beyond. The use of asset condition information and its health score underpins our 10-year forecasted expenditure, and is crucial in moving beyond the traditional time based asset replacement approach.

The CBARM model also contains information about an asset's criticality, that describes the potential consequences when an asset fails. This is combined with an asset's likelihood of failure to derive asset risk. Expenditure is then prioritised during the scoping stage to identify areas of work based on risk at an individual asset level. This ensures that assets at the highest risk are prioritised appropriately. These models will continue to evolve as we improve our understanding of the risks and better network condition data is collected as a result of the new maintenance standards and associated system enhancements.

In dealing with distribution assets, where we have large populations of low-cost assets and components, the optimal investment options (to repair, replace or refurbish) are relatively limited and are readily evaluated. For our more critical distribution and sub-transmission assets, such as power transformers and primary switchgear, where replacement costs are high, the optimal investment options need more complex evaluation, plus business case justification.

Factors that may be considered include:

- The impact and effect of the Symphony future-load scenario on the network and its assets
- The asset's risk and performance history
- Evaluation of alternative network solutions as a permanent answer to the replace or refurbish, or defer, issue
- The maintenance costs over the remaining life of the asset, and whether these will exceed those of replacing it
- If the asset is no longer unsupported technically – software updates aren't practical, and/or spares aren't available
- If the asset has become obsolete; component fabrication is expensive; the asset is likely the last of its kind and continuing with its operation is inefficient
- If low-cost retrofit replacements are available with enhanced ratings and safety features

Asset refurbishment is generally restricted to subtransmission transformers and a certain size of distribution transformer. This is an economic way of extending life. However, we are extending the life of some types of 11 kV switchgear by replacing 1960s' vintage oil-filled circuit breakers (CBs) with modern vacuum CBs as this is more economic.

Going forward when replacing assets, we will also consider new technology options such as Battery Energy Storage Systems (BESS) to defer substation upgrades or transformer replacements or the installation of load control such as Telensa to postpone network reinforcement.

4.1.7 OUR MAINTENANCE STRATEGY

Vector's assets are maintained over their whole lifecycle to avoid failures that pose a hazard to staff or the public. The core practice underpinning this strategy is our schedule of equipment inspections. This is in line with the maintenance standards for each asset class. These inspections are also used to perform minor maintenance tasks and repairs, and to identify and record any non-compliance with maintenance standards. All completed tasks, or requests for follow-up corrective work, are recorded against the asset in a system of record. All outstanding requests for corrective work are held in a work pool and prioritised for remediation based on risk. Vector's new rules for working on or near lines has resulted in a change in how corrective work packs are planned and executed. These work packs are now triggered by a high risk corrective task and the rules for completing other high risk work within the same network section isolation zone are defined.

Vector has a comprehensive suite of maintenance standards that it has developed in-house. These standards have been revised to support Vector's continuous improvement and progression towards becoming more predictive in its approach to maintaining its assets. These define asset inspections, condition testing, failure modes and associated maintenance tasks by the primary asset category. These standards address the purpose, content, frequency, failure modes, data recording requirements and associated treatment criteria. These criteria direct field staff to either repair, refurbish or replace components, or the entire asset. Some assets will need refurbishing or repairing off-site, while others can be dealt with in-situ. The improved condition information, that the revised maintenance standards specify, will support the CBARM initiative described in Section 4.1.6 for the major asset classes. This approach allows Vector to better plan its asset replacements and keep its assets in service for as long as the risk is tolerable. This proactive approach to asset replacement has already been initiated and is described in Section 5. Vector's philosophy is to keep assets in use for as long as they can be operated safely – technically and economically – and, as far as is practicable, for the financial recovery period of the asset too. The maintenance standards support this goal so as to ensure optimal performance. Corrective maintenance is undertaken within specified time-frames, as stipulated in the maintenance standards and in conjunction with the targeted risk approach.

Real-time monitoring using SCADA is used for plant in zone substations and in bulk supply substations. This records key parameters, such as transformer temperature, status of switches, DC system voltage levels, switchgear gas levels, voltage and current levels, trip alarms and fault alarms. Power Quality Meters (PQMs) – see our strategy on PQMs below, allow in-depth analysis of faults, that is, they keep a record of fault currents, time of faults, fault duration and phase relationships, and magnitudes. Analysis of these informs us whether an asset needs refurbishment or replacement.

To improve our service level performance, we deploy proactive maintenance approach with preventative maintenance practices including routine inspections, testing and servicing, and more condition testing in line with our new maintenance standards. This supports the increasing focus on corrective maintenance driven activities, including replacement, targeted at changing the current trend of unplanned events. Reactive maintenance will also focus on improving response times to asset failures when they occur.

We plan to further improve our maintenance practices by:

- Migration of the asset management system of the Auckland Field Service Providers (FSPs) into our Enterprise Resource Planning (ERP) System (SAP) – this project is on-going at the time of writing
- We have already developed the capability to track asset failures in SAP, but further work is continuing to refine the quality of data
- Develop and improve the capability (monitoring and analytics)
- Becoming more condition based and predictive by using acoustic testing across the network
- Improved preventative maintenance and/or testing for submarine cables, distribution cables, power transformers and circuit breakers
- Using the criticality information developed for CBARM – we intend to move to a more risk-based prioritisation of corrective work.

Section 5 has the details of the programmes of work and investment summaries for the maintenance, including associated corrective asset replacement. The improved effectiveness of the targeted risk approach to corrective maintenance will continue.

4.1.8 OUR VEGETATION MANAGEMENT STRATEGY

Effective vegetation management, with changing environmental factors such as climate change, is essential to ensure a safe and reliable network. According to a 2017 NIWA study, extreme rainfall, severe droughts and wildfires could hit Auckland in years to come. A report by Ernst and Young (EY) commissioned by Vector, to look at how the Auckland area network could be impacted by climate change, concluded that occurrences of high wind speeds are likely to increase significantly resulting in trees and tree branches bringing down power lines more often. We have experienced this first hand in recent times.

The challenge for network companies – under the Electricity (Hazards from Trees) Regulations 2003, is that only vegetation in a limited area can be trimmed. Essentially, this is where it is almost directly against power lines – the 'growth limit zone'. This hinders the ability of EDBs to adequately protect the network in adverse weather conditions, when trees from outside the growth limit zone damage power lines. The regulations are highly prescriptive as they focus on set distances between trees and lines. For the vast majority of trees, these distances are grossly inadequate. For example, in some cases no action can be taken until a tree branch is as close as half a metre from a power line. This is a very small physical gap and insufficient to prevent trees swaying in high winds and clashing with lines. Some trees are also very fast growing and might require two trims in a season, which is both costly and inefficient (as mentioned above, growth is exacerbated by climate change). Fast-growing trees also tend to be less resilient to high winds and therefore pose a greater risk to the network.

The regulations take account of only two parties – the power-line company and the tree 'owner'. There can be significant issues identifying the tree owner, who can be different to the landowner or occupier. For example, in the case of forestry, the tree owner might be a Post Office box in Geneva. While tree owners may be difficult to find and communicate with, trees that pose a risk to the network continue to grow. The two parties must follow a complex process involving the measurements of tree distances within various zones, issuance of formal 'cut and trim' notices for every tree, with punitive action procedures to be followed. While the failure to obey a 'cut and trim' notice could result in a theoretical $10,000 fine, there is no record of a fine ever being imposed. Even after a tree is cut the problems can persist. While a newly pruned tree might be physically separated by up to 1.5m from a line, the tree might tower many metres directly above a line, meaning branches can fall across conductors, shorting them or bringing them down.

A reliability and safety-focused vegetation programme, completed during the 2016 and 2017 financial years, surveyed around 20 per cent of the overhead network to risk-assess vegetation that could affect the performance of the associated distribution feeders. Of the sites identified, two-thirds (67 percent) involved trees outside of the growth limit zone – a mixture of trees likely to shed debris onto or fall across the lines, causing an outage or risk to public safety. There is an urgent need to move to a modern, principles-based framework that would allow EDBs to carry out, and act on, risk assessments for trees near power lines and oblige tree-owners to take more responsibility for their trees. The risk assessment could include factors such as customer numbers that might be affected by an outage, tree species, age and condition of tree, overhanging branches and fall distance, and issues of public safety, risk of fire etc.

Service-level performance analysis has identified that outages caused by vegetation contribute to 17% of SAIDI and 12% of SAIFI (reliability indicators). This, in turn, adversely impacts the service level for 'customer interruption breaches'. While 'asset safety incidents' haven't occurred in relation to vegetation, having physical contact between network assets and vegetation poses a significant risk to safety, as well as having the potential to cause fires. Effective vegetation management practice is essential to ensure the safe and reliable operation of the network, and to ensure Vector maintains its regulatory compliance in terms of reliability indices, SoSS and the experience of the customer.

In the meantime, we are focused on addressing the vegetation issue through a proactive programme to identify trees at high risk of causing an outage and affecting our SAIDI, SAIFI or Customer Interruption service levels, as well as the public's safety. This is documented in our Vegetation Management investment programme in Section 5.

Lastly, following a successful trial in 2016, we are embarking on a programme of Light Detection and Ranging (LiDAR) surveys, in 2019, with two of the main deliverables being a series of measurements relating to vegetation:

- Clearances between vegetation and conductors (to monitor growth limit zone encroachment)
- Height of trees when compared to the distance from conductors (to monitor fall hazards)

4.1.9 OUR POWER QUALITY STRATEGY

Vector provides a nominal voltage of 230 V ±6% for single-phase power and 400 V ±6% for three-phase power at the point of supply, as required under the Electricity (Safety) Regulations 2010. Maintaining the network so it operates within the permissible range is proving increasingly challenging. Local distributed generation (for example, solar PV) is pushing the network voltage beyond the upper levels, while winter demand is testing the lower threshold. Access to customer smart-metering data would offer real benefits, allowing for improved identification and response to identification of voltage issues. Currently, and pending access to this data, we are reactive. When we are notified of instances of the network operating outside the regulated voltage range, we investigate and then remedy the problem.

Vector has installed PQMs (power quality meters) at a number of its zone substations, to primarily baseline and trend harmonic[6] levels on the network. Variable speed drives tend to create harmonics and while they have been used by industry for a long time, we are interested in monitoring and understanding the impact of power electronics operating at the residential level, particularly inverters associated with solar PV and electric vehicle and battery charging.

Increasingly, we are being approached by our commercial and industrial customers who have experienced production outages that may have been caused by network disturbances. These disturbances may be caused by depressed voltage whose source is network faults on adjacent circuits, or even by Transpower switching issues. Nevertheless, loss of production and extra costs to the customer are the result. The data from PQMs is analysed to determine the cause of any network disturbances, and changes made to improve our performance to meet regulatory requirements. There are, of course, instances where PQM issues are caused by disturbances in the customer's own electrical installation, in which case we recommend the customer investigates, tests and then takes steps to improve the electrical installation.

4.1.10 OUR CLIMATE CHANGE AND SUSTAINABILITY STRATEGY

A key focus area of our sustainability approach is community resilience. The strategies to address this are already covered in the previous sections on Reliability and Resilience Strategy, and Vegetation Management Strategy.

In addition, when designing, building and operating the various components of the network, sustainability will be a key consideration. Under Vector's sustainability strategy, we are in the process of adopting the framework developed by the Infrastructure Sustainability Council of Australia noted in Section 3.11 to deliver sustainability outcomes through the asset management lifecycle.

Circular economy approach to materials

Along with reducing carbon emissions, we are taking a broader view of materials entering the network, applying the principle of kaitiakitanga (stewardship) to ensure the maximum recovery of materials at end of life. This is a natural progression on from normal practices such as resource efficiency, where we aim to reduce our consumption of resources in the management of the network, generating revenue through the sale of surplus materials, and reducing waste that goes to landfill.

Taking a circular economy approach calls for a different approach to procurement and technical specifications. We have begun and will continue to work with both suppliers and internal teams to pilot the use of new materials and end-of-life approaches, and new service models.

Network components such as transformers, cabling and switchgear contain high percentages of relatively easily recoverable materials which are processed by scrap metal companies. Hardwood poles generally have a second life while concrete poles can be crushed with recovery of any steel reinforcing.

Other items like oil used in transformers is recovered and reused in applications in other sectors where a lower quality product is acceptable.

With increased battery energy storage systems on the network Vector is collaborating with other key players in the value chain for batteries to explore alternative options for end of life disposal. In the near future, we expect our network batteries

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6 Harmonics occur on the network when current and voltage are distorted and deviate from sinusoidal waveforms. Harmonic currents are caused by non-linear loads connected to the distribution system

to be covered by a product stewardship scheme that ensures there is maximum recovery of materials at end of life and safe disposal of any residual materials.

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 follows the processes and procedures, and complies with the relevant regulations and standards, set by this framework. In many instances, this framework provides for Vector's assets and network activities as 'permitted activities'[7].

Where possible, Vector designs, installs, maintains or upgrades the network in a way that ensures this permitted activity threshold applies. Where this is not possible, Vector obtains the requisite resource consents for its assets and related activities, which ensures the environmental effects of these are appropriately avoided, remedied or mitigated.

Carbon reduction

To achieve our commitment of net zero emissions by 2030, we are in the process of developing a carbon reduction strategy that includes setting annual reduction targets; reviewing opportunities relating to transmission losses, business travel, electricity consumption, waste minimisation; and possible investment in New Zealand based carbon offsets.

Through the work on sustainable procurement and the circular economy, the scope of emissions being managed is continually expanded to incorporate more supply chain elements.

In support of this, we are considering the feasibility of applying principles such as the carbon emissions reduction hierarchy specified in the UK Publicly Available Standard for Carbon Management in Infrastructure Verification (PAS 2080). This approach ensures that carbon is considered in the earliest stages of asset management. The greatest opportunities to reduce carbon are during the needs analysis for an asset and these reductions reduce further along the asset management process.

4.1.11 OUR SAFETY IN DESIGN STRATEGY

Safety in Design is a practice that integrates risk-management techniques into the design process early, so as 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 involves 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.

Vector has a Standard for Safety in Design in place. Under the HSWA Act Vector, its designers and all stakeholders have a duty to manage the risks associated with an asset's design throughout the its built life. This requires all parties to consult, co-operate and co-ordinate so as 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.

As part of our strategy, it is a key (obligatory) HSEMS (health, safety and environment management system) requirement that Vector staff complete a formal training module that covers the principles of Safety in Design.

4.1.12 OUR CUSTOMER INSIGHTS AND SUPPORTING DATA AND ANALYTICS STRATEGY

Creating a data driven and enabled organisation is fundamental to the vision of creating a New Energy Future. With a broader lens it is also critical to achieving operational excellence and cost efficiencies over the longer term. Our data and analytics strategy can be represented by three overlapping concepts.

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7 A permitted activity can be carried out without the need for a resource consent so long as it complies with any requirements, conditions and permissions specified in the Resource Management Act, in any regulations, and in any applicable plans or proposed plans

Creating a data culture: At the heart of this is to treat data as an asset, including representing it with an economic value, securing it, maintaining it and having a life cycle management plan. Underpinning this are robust management and governance frameworks cemented by strong alignment to ethical overlays (especially as the regulatory and legal frameworks are not keeping pace with technology and capability in this space).

Systems of intelligence: Here we are utilising digital best practise to develop standardised, re-usable, scalable and secure digital assets. The focus of the systems of intelligence platform is to reduce total cost of ownership (TCO) of the digital systems while utilising emerging and converging technology to deliver enhanced worker and customer experiences and capability. For example, cloud technology, standardised patterns and templates, security, privacy and accessibility by design, utilisation of advanced BI and analytics tools, providing easily accessible and discoverable data and information for decision making and issue identification.

Enable & grow our people: As the complexity of the energy systems (and indeed the world in general) grows, we are working to ensure that our people have the requisite skills and tools to operate in a world where data and information is integral to customer and operational outcomes. As part of this we need to ensure that we are well placed to manage and leverage data as it increases in volume, variety, velocity, veracity and vulnerability.

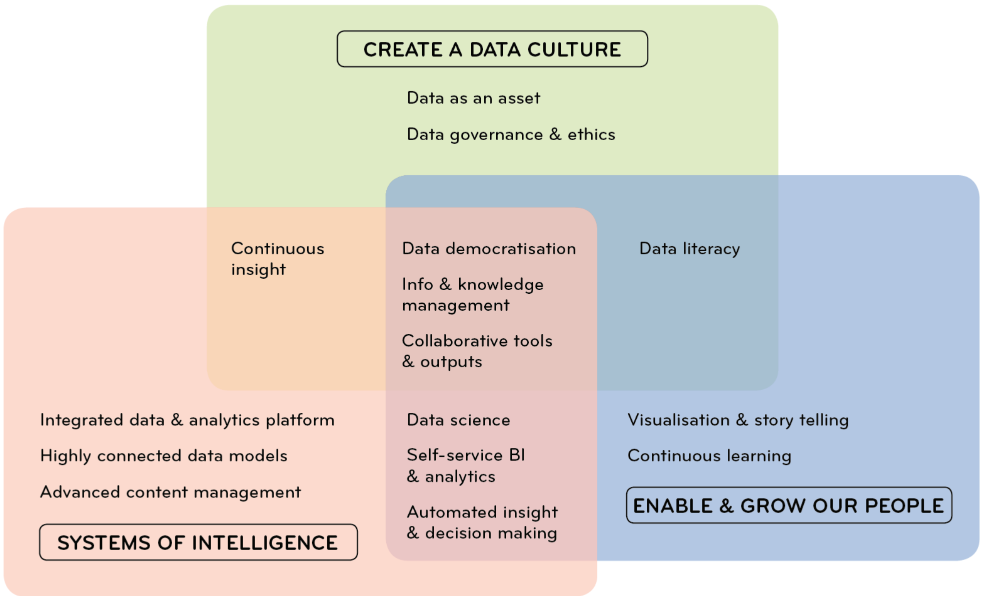

Figure 4-1 Data and Analytics Strategy

Networks Information Management Strategy
The Networks Information Management Strategy is focussed on the following key objectives:

1. Establishment of formal data standards which are fully aligned and support the Engineering Maintenance and Design and Construction standards (this supports the philosophy of needs based data collection) (See Appendix 2 for a list of the current standards).
2. Implementing systems and processes to ensure high quality data is captured and stored, and is aligned with the Networks Data Standards.
3. Implementing Data Quality Management, Master Data Management and Data Governance processes and practices to maximise the quality (and value) of data available for decision making.
4. Ensuring appropriate Business Intelligence and Analytics platforms are established to allow the Networks teams to fully exploit the value of the data to its fullest extent.

Tools Used (WiP)

Figure 4-2 below depicts the data and analytics platform (D&A) logical architecture. As noted in Section 4.1.13, Vector has a digital infrastructure and data platform strategy & roadmap which will implement an integrated, flexible and modern data & analytics platform which can scale to meet the increasing needs of data volume, velocity, veracity and variety.

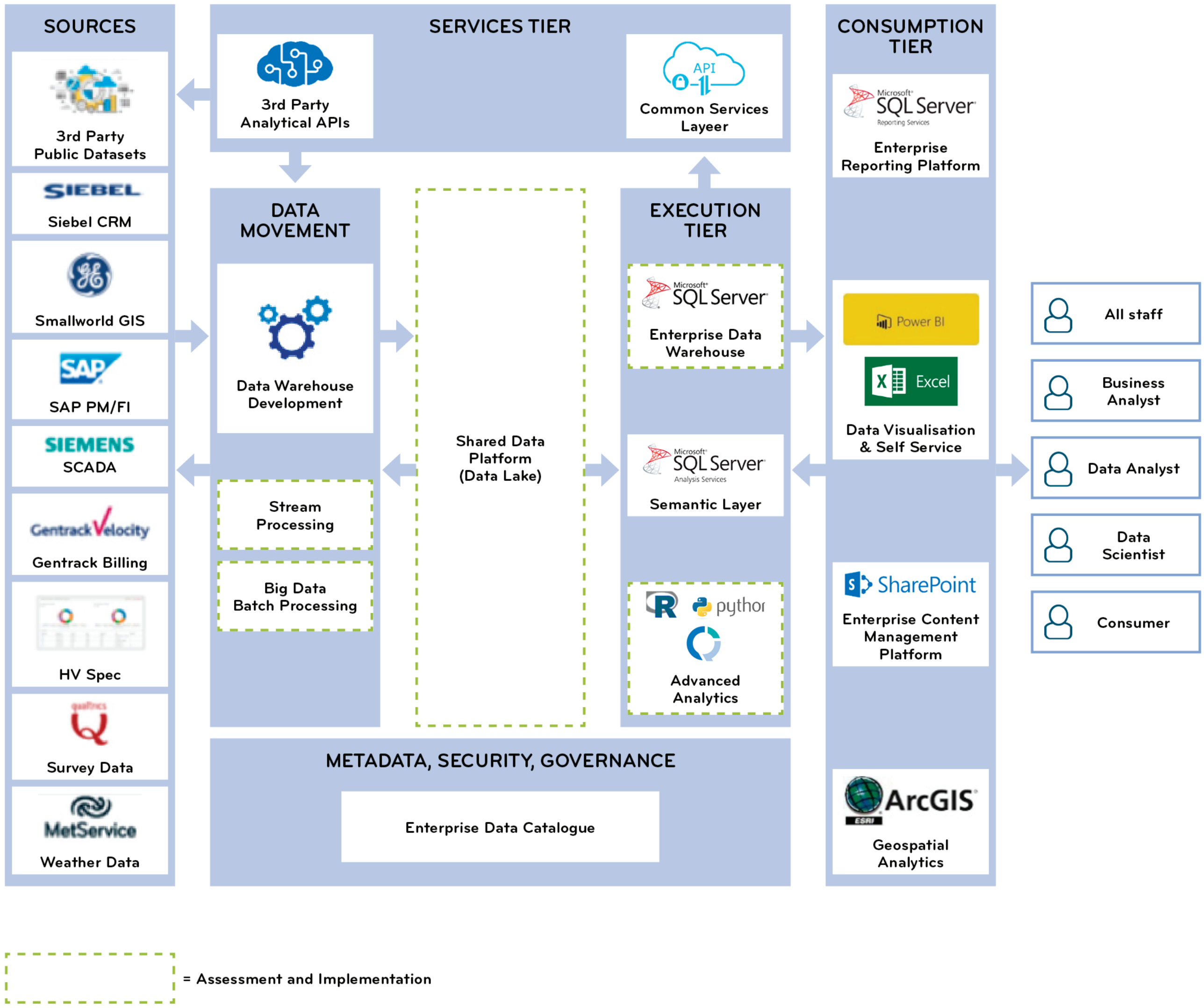

Figure 4-2 Logical Architecture Breakdown

- Data Sources – Data is collected from all core Vector systems as well as external data providers which include public and private subscription data sets.
- Data Movement – Data is extracted or loaded from the data sources in a managed fashion. It is organised, integrated, and loaded into the Data Lake and/or Enterprise Data Warehouse. This can be performed in near real-time or in batch processing as required.
- Shared Data Platform (Data lake) – Used for storing high volume and diverse data sets (aka Big Data). The technology allows more flexibility and greater processing power and performance than traditional systems.
- Execution tier – Responsible for transforming raw data into meaningful and easily understood information.
- Consumption tier – Responsible for providing data visualisation, reporting and analytics tools to all data consumer groups within the organisation and also trusted external parties.
- Services tier – Responsible for integrating/sharing analytical data with digital systems and external organisations through a common platform and method (API).
- Metadata management, security and governance – Supports data governance and security by classifying (security, sensitivity, domain) & cataloguing data across multiple repositories.

4.1.13 OUR INFORMATION SYSTEMS AND DIGITAL TECHNOLOGY STRATEGY

The adoption of new technology by our consumers, as well as the changing role of systems and data under Vector's managed integration approach, requires additional investment in digital capabilities and information systems. To enable the additional needs and requirements of Vector's Asset Management Strategy, our asset information systems strategy will ensure we deliver the required outcomes and options to our customers today, while working towards implementing our roadmap for the network in the future. Further to the introduction in Section 1, below is a list of the key information systems (i.e. system platforms) we are using to deliver for our customers.

- Customer Experience Platform
  Information systems, platforms and digital technology enables us to provide a great customer experience through automation, simplifying their engagement and enabling targeted reporting. Examples of customer engagement include new connection requests, outage management and safety reporting. The objective is to provide more secure and effective engagement across the customer's communication channel of choice.
- The Network Operations Platform (Network Operations & Business Enablement)
  The Network Operations Platform provides the ability for us to invest in technology and solutions that unlock the potential of converging technologies to support Auckland's growth and manage the uptake of new technologies such as electric vehicles in accordance with Vector's strategy. Alongside this, the development of microservices and fit for purpose core business enablement platforms will reduce complexity and risk when Vector's existing legacy, monolithic enterprise platforms begin to reach end of life. This platform improves Vector's ability to complete lifecycle management activity seamlessly when migrating legacy information systems to meet changing customer and technology demands
- The Network Integration Platform
  The increasing instance of customer distributed energy resources (DERs) requires us to improve our ability to connect, control and collect information to gain insights into asset condition and changing customer trends. Through the Network Integration platform this information is delivered to us in a secure way, improving our ability to effectively and safely manage our assets
- Digital Infrastructure and Data Platform
  We deploy practice to develop standardised, re-usable, scalable and secure information and data systems. The focus is on optimising the total cost of ownership (TCO) while utilising emerging and converging technology to deliver enhanced customer experiences. This includes, amongst others, cloud technology, standardised patterns and templates, security, privacy and accessibility by design, informed by data driven decision making through advanced data analytics.

The domains listed in Figure 4-3 under each of the platforms demonstrate how they enable the achievement of the objectives of Vector's Asset Management Plan. To provide clarity and consistency, Vector has developed a standardised reference architecture based on the IEC 61968 reference model to define system, data and integration components in the context of the core and operational information systems. The IEC 61968 reference model as it is utilised by Vector is illustrated in Figure 5-7.

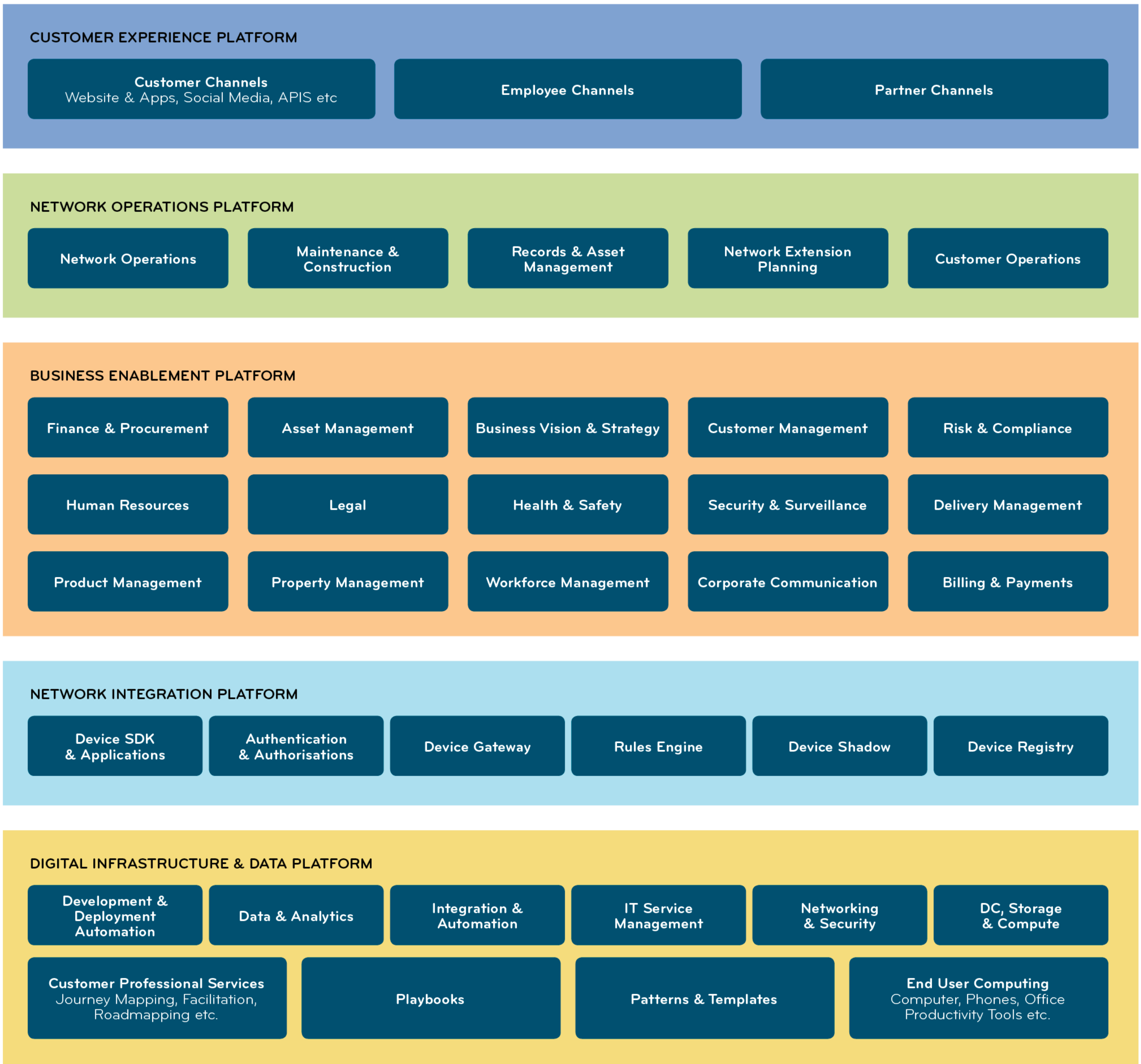

Figure 4-3 Networks Digital Reference Model

NETWORK OPERATIONS

- Network Operation Monitoring (NOM)
- Network control (CTL)
- Power Import Scheduling and Optimisation (IMP)
- Dispatcher Training (TRN)
- Network Calculations – Real-Time (CLC)
- Network Operation Simulation (SIM)
- Operation Statistics and Reporting (OST)
- Switch Action Scheduling/Operation Work Scheduling (SSC)
- Operation Feedback Analysis (OFA)

CUSTOMER OPERATIONS

- Customer Service (CSRV)
- Customer Account Management (ACT)
- Load Control (LDC)
- Trouble Call Management (TCM)

NETWORK EXTENSION PLANNING

- Network Calculations (NCLC)
- Project Definition (PRJ)
- Compliance Management (CMPL)
- Construction Supervision (CSP)

MAINTENANCE & CONSTRUCTION

- Maintenance and Inspection (MAI)
- Field Recording and Design (FRD)
- Work Scheduling (SCHD)
- Construction and Design (CON)

ASSET MANAGEMENT

- Asset Investment Planning (AIP)
- Substation and Network Inventory (EINV)
- Geographical Inventory (GINV)

Figure 4-4 Domain mapping for network streams

4.1.14 OVERVIEW OF OUR NETWORK SUPPLY AREA

Vector's electricity network supply area is centred on the Auckland isthmus and extends north to Mangawhai Heads, south to Franklin, west as far as South Head and Tapora on the Kaipara flats, east to Waiheke Island and south to Papakura. Vector also supplies electricity to a network remote from Auckland outside the network franchise, namely the Fonterra dairy factory at Lichfield in the Waikato. The Vector Auckland supply area is shown in Figure 4-5.

Figure 4-5 Vector's electricity supply region

4.1.15 OVERVIEW OF OUR ASSETS

Vector's network is made up of three main network components: the subtransmission network operated at 110 kV, 33 kV and 22 kV; the HV distribution network operated at 22 kV and 11 kV; and the LV distribution network operated at 400/230 V. Our network connects to the Transpower grid at 15 GXPs from where our subtransmission network conveys electricity to zone substations. Typical load profiles of the network and a list of Vector's large customers that have an impact on network operations, can be found in Appendix 3. A single line diagram of the subtransmission network can be made available on request.

Vector's Asset Strategies for each of its asset classes describe in detail Vector's long-term actions and plans required to deliver specific objectives and network outcomes based on stakeholder requirements and long term service level performance criteria. A list of all of Vector's Asset Strategies is provided in Appendix 2.

Each asset strategy provides an overview of the class of asset, its purpose and information about its population, asset class replacement considerations, its maintenance requirements, failure modes, specific known issues, risks and asset health indicators and refurbishment requirements. These strategies are outlined below in Sections 4.3 to 4.9.

Key statistics of Vector's network are given below.

Customer connections	567,009
No of GXPs	15
No of zone substations	112
Maximum coincident GXP demand - Megawatt (MW)	1,754
Energy delivered through GXPs (GWh)	8,604

Table 4-1 Key statistics for RY18

4.2 SUBTRANSMISSION

The function of the subtransmission network is to transfer electrical energy from GXPs to bulk supply substations and zone substations. The 110 kV subtransmission network emanates from Transpower 110 kV GXPs to connect to Vector owned bulk supply substations in the Auckland CBD, Kingsland and Wairau Valley on the North Shore. The 110 kV subtransmission network consists of cables in the Penrose to CBD tunnel, cables buried in ducts in the ground and overhead lines. The 110 kV subtransmission network is configured as a meshed system with a mix of 33 kV and 22 kV circuits providing backstop to the 110 kV nodes.

33 kV and 22 kV subtransmission circuits run from Vector's bulk supply substations and Transpower GXPs to Vector's zone substations. The 33 kV and 22 kV subtransmission network consists of a mix of underground cables and overhead lines. In the Northern network the subtransmission system is configured as a meshed system. In the Auckland network the subtransmission system is configured mostly as radial line-transformer feeders that can be paralleled at the 11 kV busbars. Vector's overhead subtransmission circuits also accommodate 11 kV and 400 V circuits on the same support structures in many instances.

4.2.1 SUBTRANSMISSION 110 KV UNDERGROUND CABLES

Overview

Key statistics of the 110 kV subtransmission feeder assets are shown in Table 4-2.

No of 110 kV underground subtransmission circuits	14
Length of 110 kV underground subtransmission circuits (km)	31.86
Length of 110 kV underground circuits in tunnels (km)	15.58

Table 4-2 Key statistics for 110 kV subtransmission network

Population and age

The figure below summarises the age of our 110 kV subtransmission cable fleet.

110 KV SUBTRANSMISSION CABLES AGE PROFILE

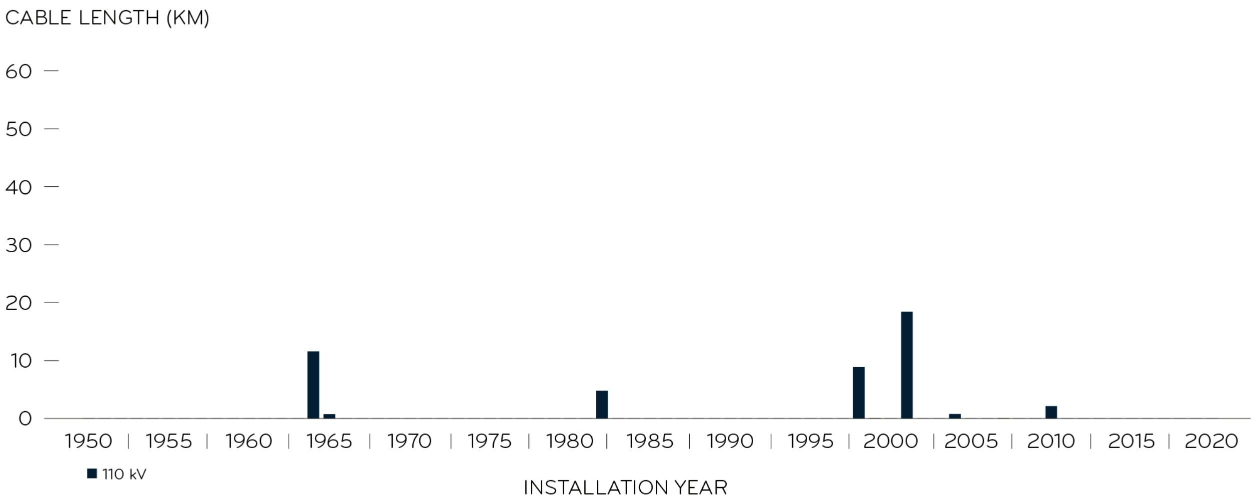

Figure 4-6 Age profile for 110 kV subtransmission cables

Condition and health

The oldest 110 kV cables in Vector's fleet are the two cables from Mt Roskill GXP to Kingsland zone substation and have been in service since 1965, thus 54 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 subtransmission cables and their accessories is 90 years and our fleet is performing well and failures are rare.

Strategy

The 110 kV cable fleet will continue to be maintained as per our maintenance standard. Our CBARM model for this fleet is in progress and is scheduled for completion in FY19 which will further enhance our evaluation of this asset for the future. At present, there are no plans to replace any 110 kV cables but the network in the CBD will be extended as described in Section 5.

4.2.2 SUBTRANSMISSION 33 KV AND 22 KV UNDERGROUND CABLES

Overview

Key statistics of the 33 kV and 22 kV subtransmission feeder assets are shown in the table below. Due to legacy reasons, the data for cable joints are not 100% reliable, so quantities contain a level of estimation.

No of 33 kV underground subtransmission circuits	197
No of 33 kV circuits with undersea/underwaterway sections of subtransmission cables	7
Route length of 33 kV oil-filled subtransmission cable (km)	119
Route length of 33 kV paper insulated lead covered (PILC) subtransmission cable (km)	17
Route length of 33 kV cross-linked polyethylene (XLPE) subtransmission cable (km)	282
Route length of 33 kV subtransmission cable all types that are undersea or underwaterway (km)	12
No of 33 kV subtransmission cable joints	1516
No of 22 kV underground subtransmission circuits	72

Route length of 22 kV gas-filled subtransmission cable (km)	2
Route length of 22 kV oil-filled subtransmission cable (km)	27
Route length of 22 kV paper insulated lead covered (PILC) subtransmission cable (km)	44
Route length of 22 kV cross-linked polyethylene (XLPE) subtransmission cable (km)	64
No of 22 kV subtransmission cable joints	945

Table 4-3 Key statistics for 33 kV and 22 kV subtransmission network

Population and age

The graphs below summarises the population and age of our 33 kV and 22 kV subtransmission underground cables.

33 KV AND 22 KV SUBTRANSMISSION CABLES AGE PROFILE

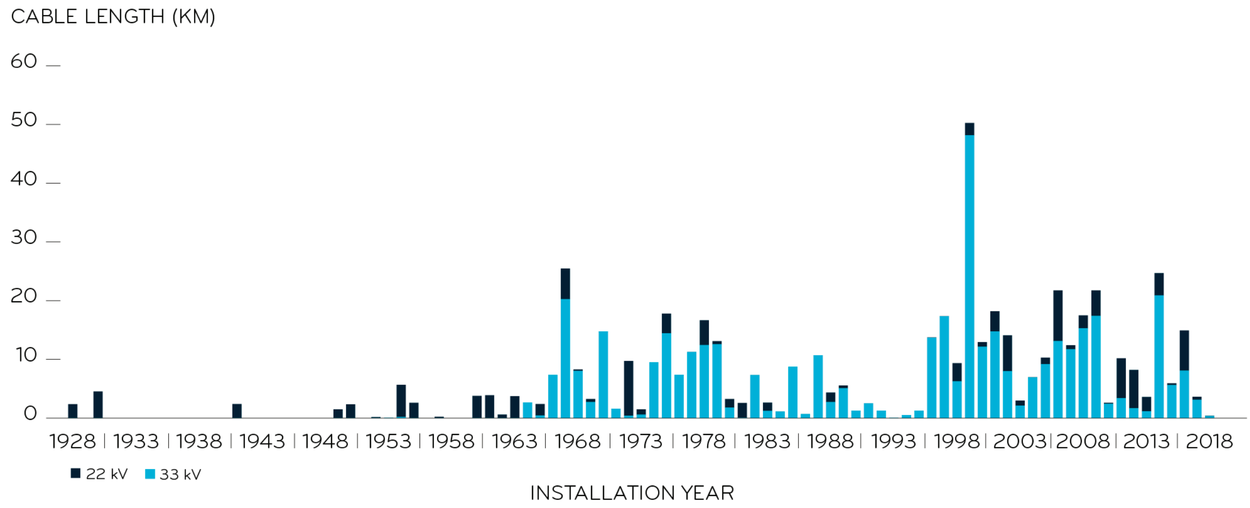

Figure 4-7 Age profile for 33 kV and 22 kV subtransmission cables by voltage

33 KV AND 22 KV SUBTRANSMISSION CABLES AGE PROFILE BY TYPE

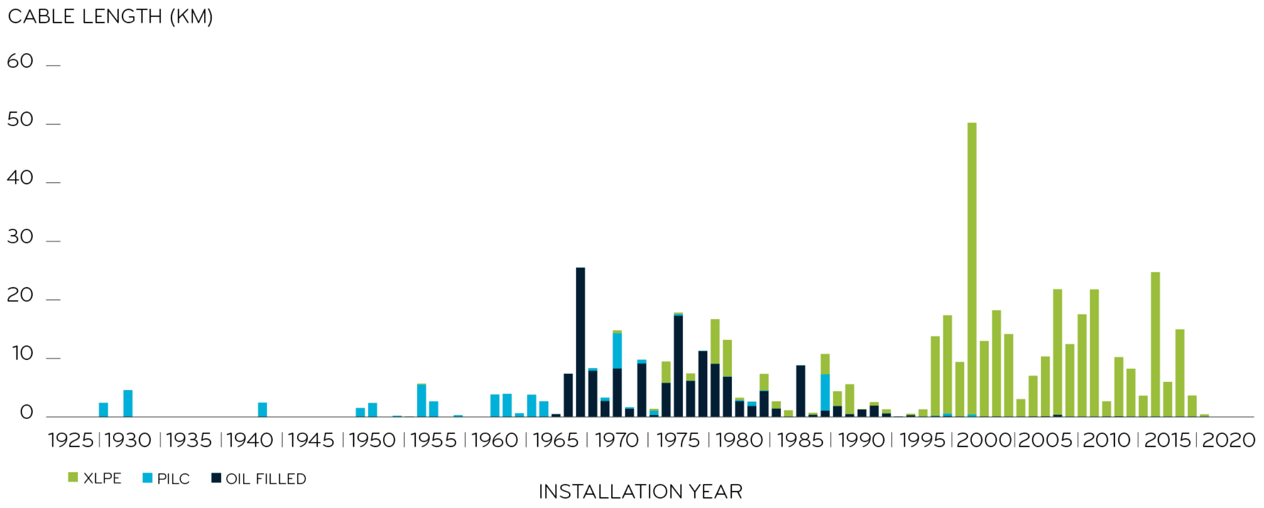

Figure 4-8 Age profile for 33 kV and 22 kV subtransmission cables by type

Condition and health

Our experience and monitoring of condition shows that in terms of underground subtransmission networks, ageing 33 kV and 22 kV PILC cables are currently the worst performing in Vector's subtransmission network. Failures on this type of cable are such that continuous repair and piecemeal replacement are not economical anymore. We are also seeing more failures on some 33 kV oil filled cables.

Strategy

Vector maintains its fleet of 33 and 22 kV subtransmission feeders, some of which are approaching forecast end of life, to provide service for as long as possible into the future without increasing the risk profile of this asset to an unacceptable level. Our experience and monitoring of the condition of 33 kV and 22 kV oil filled cable have shown that with proper and regular maintenance, and continuous condition monitoring, as per Vector's maintenance standard ESM301, the life of this asset can be extended well into the future and in some instances beyond its forecast end of life. The cyclic inspections of oil-filled cables are supplemented by real time monitoring of oil-pressure using SCADA, complete with operational alarms, to alert the Electricity Operations Centre (EOC) of low oil-pressure.

Our replacement programme focuses on the PILC cables but a number of oil-filled cables are also forecast to be replaced in the 10-year AMP period. Our solid insulated XLPE subtransmission cables are performing well, and although some circuits have been in service since the 1970s, there is no need to replace any of this type of cable. Vector still operates a gas-filled subtransmission cable between Kingsland zone substation and Ponsonby zone substation and its condition warrants replacement that is scheduled for completion in FY20.

Our CBARM model for this fleet is being developed and is scheduled for completion in FY19, and will further enhance our capability to plan replacement based on asset health, criticality and risk.

4.2.3 SUBTRANSMISSION 110 KV OVERHEAD LINES

Overview

Vector has three 110 kV overhead subtransmission lines that run between Transpower Albany and Wairau zone substation. Two circuits exist on single poles through the Albany, Unsworth Height and Glenfield areas to Wairau zone substation. A third circuit exists through Greenhithe and Glenfield to Wairau. The three lines supply three 110 kV/33 kV transformers at Wairau zone substation where the transformers are operated in parallel with a 220 kV/33 kV Transpower transformer[8]. Key statistics of the 110 kV subtransmission feeder assets are shown in the Table below.

No of 110 kV overhead subtransmission circuits	3
Route length of 110 kV overhead subtransmission circuits (km)	26.62
No of timber support structures for 110 kV overhead subtransmission circuits	68
No of concrete support structures for 110 kV overhead subtransmission circuits	54
No of steel support structures for 110 kV overhead subtransmission circuits	62
No of support structures that support double 110 kV overhead circuits	63

Table 4-4 Key statistics for 110 kV subtransmission network

Population and Age
98% of the conductors were installed in the 1970s and the present age is 48 years. 2% new conductors were installed in 2011 to 2012 as part the establishment of a new grid exit point at Wairau zone substation. The conductors in the three circuits are all AAC and is a mixture of 265mm² (38%) and 322mm² (62%).

Condition and Health
The life of the conductors is limited 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). The conductors and poles, although ageing, are in reasonable condition.

Strategy
The 110 kV overhead circuits are maintained in accordance with Vector's maintenance standard. These 110 kV circuits will not be refurbished or the conductors replaced but will be maintained and kept in service until a 2nd 220 kV/33 kV transformer is installed at Wairau zone substation which is expected within the first half of the 10-year AMP period.

4.2.4 SUBTRANSMISSION 33 KV AND 22 KV OVERHEAD LINES

Overview
The 33 kV and 22 kV subtransmission overhead line network is constructed with a mix of Copper and Aluminium conductors mostly on concrete poles. The smallest Copper conductor is 70mm² and Aluminium conductors are a mix of ACSR and AAC conductors. The largest Aluminium conductor is 265mm². No covered conductor or aerial bundled conductor is used in the subtransmission network. Key statistics of the 33 kV and 22 kV subtransmission overhead lines are shown in the Table below.

No of 33 kV overhead subtransmission circuits	86
Route length of 33 kV overhead subtransmission circuits (km)	367
No of 33 kV overhead support structures	6,232
No of 22 kV overhead subtransmission circuits	1
No of 22 kV overhead support structures	21

Table 4-5 Key statistics for 33 kV and 22 kV OH subtransmission network

Population and age
The graphs below summarises the population and age of our 33 kV and 22 kV subtransmission overhead line conductors and poles.

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8 Installed in 2011 – 2012 as part of the establishment of a new GXP at Wairau zone substation

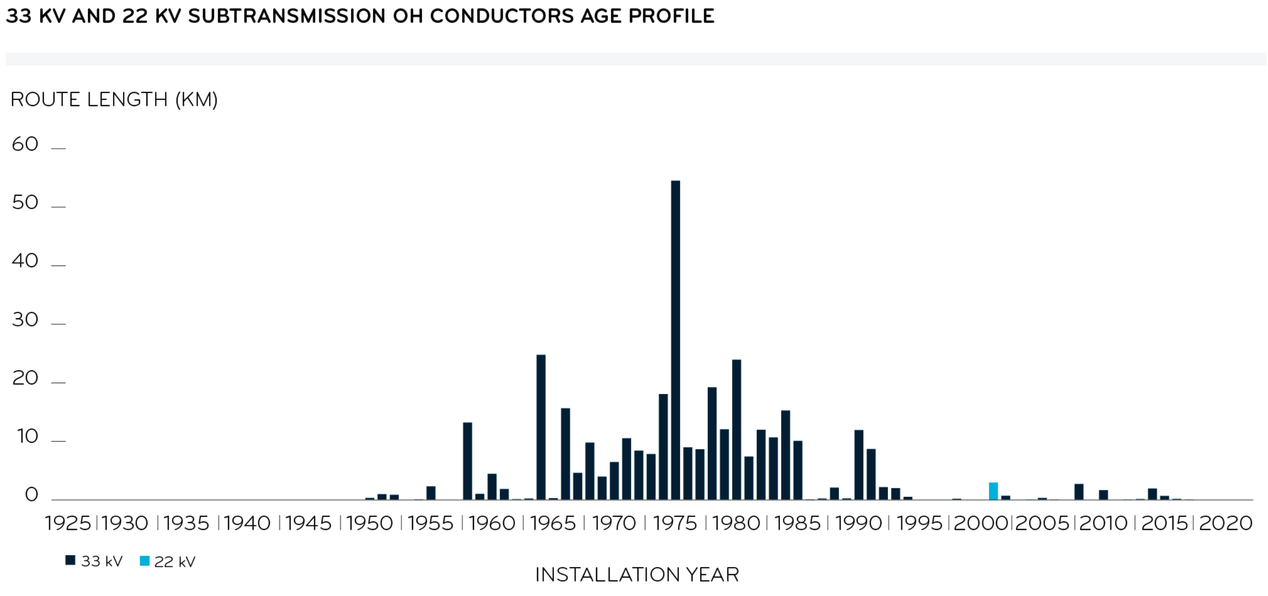

Figure 4-9 Age profile for 33 and 22 kV overhead conductors

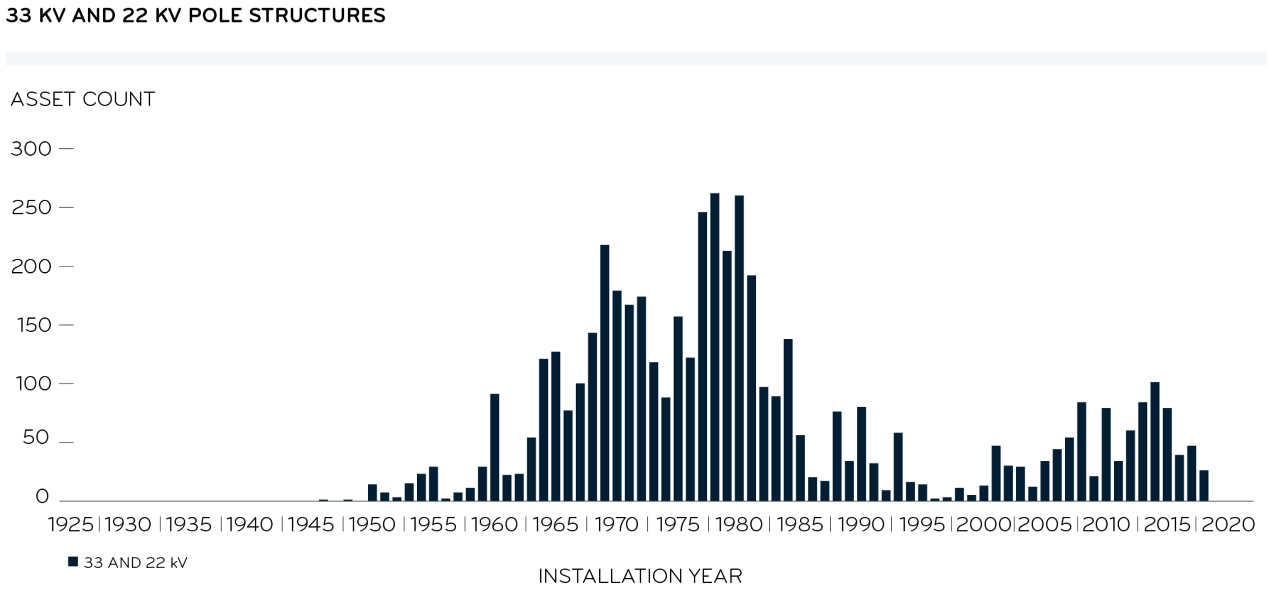

Figure 4-10 Age profile for 33 and 22 kV overhead poles

Condition and health

The 33 kV subtransmission network has a weighted average age of 44 years with over 42% constructed in the 1970s. The 22 kV subtransmission overhead network is relatively young (installed in the early 2000s). Only 2% of 33 kV conductors presently in service has been installed since 1995. There are few performance metrics for overhead conductor. The closest proxy is the number of failures that are listed as overhead conductor. There are no in-service tests on conductors to check condition.

Strategy

Vector has introduced a programme of works for the replacement of overhead conductors that focuses on small sized 11 kV conductors e.g. 14.5mm to 16mm Copper conductors and 22.5mm Aluminium conductors. Further details are given below in Section 4.5. The CBARM model for conductors is fully developed and is used to inform our programme of replacement for the subtransmission overhead network.

The present specification for wooden crossarms requires a life of 40 years. Crossarms are actively replaced based on inspections, age and criticality. The use of composite crossarms is being trialled at present.

4.3 ZONE SUBSTATIONS

Overview

Zone substations are the electrical nodes from which the 33 kV, 22 kV and 11 kV distribution network emanate into Vector's supply areas. Zone substations house Vector's 110 kV, 33 kV, 22 kV, and 11 kV primary switchgear, 110 kV/33 kV, 110 kV/22 kV, 33 kV/11 kV and 22 kV/11 kV power transformers and battery energy storage systems. Zone substations also house the associated ancillary equipment necessary for the primary equipment to function appropriately and to be remotely controlled such as: ripple plant, local supply transformer, auxiliary systems such as the DC system, SCADA systems, and network communications connection equipment, inverters and solar systems to power the AC ancillary services.

In the Northern area, the 33 kV subtransmission network is highly interconnected and a number of zone substations are equipped with a single transformer with N-1 security then supplied from neighbouring zone substations via the 11 kV distribution network. In the Auckland CBD, bulk supply substations are interconnected with 22 kV express interconnectors and 22 kV distribution feeders to provide N-2 security of supply to CBD bulk substations.

Vector also has a transportable 11 kV switchboard that can be moved to different locations as a substitute switchboard when a zone substation is out of service for project work or when a failure occurs at a zone substation. The transportable unit contains 11 kV switchgear and auxiliary systems similar to those found in our fixed zone substations.

Population and Age

Key statistics of zone substations are summarised in the table below. Schedule 12b in Appendix 9 shows the peak loading, capacity and constraints statistics of all Vector's zone substations.

No of 110 kV zone substations[9]	7
No of 33 kV zone substations	85
No of 22 kV zone substations[10]	18
No of BESS zone substations	3
No of transportable 11 kV switchboards	1
No of transportable transformers[11]	2

Table 4-6 Key statistics for bulk and zone substations

Condition and Health

A programme of works to achieve seismic compliance for our zone substation buildings in accordance with NZ seismic standards and the NZ Building Code is nearly complete and the last zone substation to be upgraded, Northcote, will occur in FY19. We have experienced the 'leaky homes' failure mode for a number of zone substations built in the early 2000s and one in particular, Sandringham, required extensive reconstruction. Brick and concrete block substations are ageing but kept in good condition with appropriate and timely maintenance.

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9 Lichfield, Liverpool, Hobson, Quay Street, Kingsland, Pacific Steel, Wairau

10 Highbrook has been included in the list although this is a 22 kV switching station

11 2.5 MVA 400 V/11 kV transformer for the connection of temporary generation

Strategy

Management of our zone substation fleet is undertaken in accordance with Vector's asset strategy EAA701 Network Infrastructure and Facilities and corrective maintenance is used to respond to any asset non-compliance. Wherever practical, standardised design and modular design and construction are used to reduce capital costs and reduce asset stranding risks posed by new energy technologies. Vector's ESE700 suite of design standards describe the standardised design requirements for zone substations.

Security, Air and Fire Management Systems are maintained in accordance with ESM603 (Maintenance of Building Security, Air and Fire Management systems). These inspections are to identify any non-compliance with the afore-mentioned standards and perform minor maintenance tasks. The cyclic inspections are supplemented by real time monitoring of zone substations using SCADA to monitor and record each substation's key parameters (e.g. switch status, temperatures, voltages, etc.) as well as provide operational alarms. In the medium term, condition based maintenance practices will be used more extensively to supplement cyclic maintenance and replace the cyclic inspection practice in the longer term. Data captured through inspection and monitoring of zone substations supports the asset management practice as described in more detail in Section 3.

As part of our drive to improve sustainability we have embarked on a programme titled 'Sustainable Substations' and this includes the installation of solar panels with batteries at zone substations to provide auxiliary AC power. Installations are complete at five zone substations.

Network investments like zone substations require long investment horizons, with much of the costs being carried by future generations. Power generation is shifting from stable, dispatchable resources connected to power transmission to variable, renewable resources connected to power distribution and the planning process needs to shift to address this new reality. Vector thus applies due diligence and scrutiny with regard to investment in a new zone substation to ensure the assets can serve the community throughout their lifetime, whilst avoiding intergenerational inequity. This means increasingly designing and valuing options that are agile, flexible and modular to respond to change. It means for example that we will buy land for a zone substation to secure our options to be able to supply electricity in the future but we might initially install a BESS system for a number of years to provide the peak demand in the area and only install the transformer assets when required. At such time, the BESS will be uplifted and deployed somewhere else for a similar scenario. Details of our future plans to procure land and develop zone substations are in Section 5.

4.3.1 POWER TRANSFORMERS

Overview

Power transformers are used to transform one voltage to another and they are installed either indoors or outdoors at zone substations. Our transformers are a mix of Dyn11 and Dyn1 vector groups except for two 110 kV/11 kV transformers at Lichfield zone substation that are Ynyn vector group. In the Auckland region, zone substations have two and in some instances more power transformers, with most of the transformers radially supplied from a bulk supply substation or GXP.

No of 110 kV/33 kV power transformers	5
No of 110 kV/22 kV power transformers	8
No of 110 kV/11 kV power transformers	2
No of 110 kV/22 kV/11 kV power transformers	2
No of 33 kV/22 kV power transformers	1
No of 33 kV/11 kV power transformers	153
No of 22 kV/11 kV power transformers	45

Table 4-7 Key statistics for power transformers

Population and Age

The age profile of Vector's power transformers is given in the graph below.

POWER TRANSFORMERS AGE PROFILE

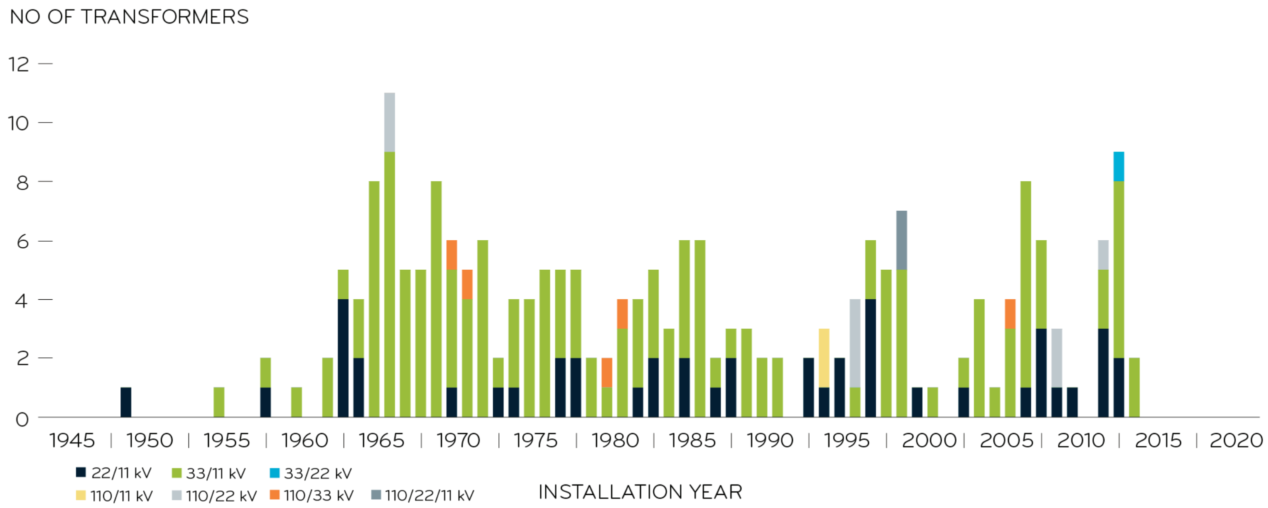

Figure 4-11 Age profile for power transformers

Condition and Health

Our fleet of power transformers consist of 37 different models and types with different makes and models of tap changers but since 2000 we have standardised on a specific range of models that reduces the type and number of spares required. Our transformer fleet is ageing but our active monitoring of the health and condition of these important assets is ensuring that we get the optimum life from this fleet.

Strategy

Power transformers have very long in-service life expectations and are designed to operate at full continuous rating for approximately 25 years. Continuous use at full rating will result in the insulation life of the paper being exhausted and failure will become imminent. Vector, not unlike most utilities worldwide, plans the network with N-1 contingency in its network and as a result the loading on our power transformers is rarely more than 50% of its nameplate rating for the majority of its operating life. At this level of loading we can expect service lives well in excess of 50 years as shown in the graph above.

Through annual oil analysis and insulation testing, the condition of the transformer can be monitored and any developing faults detected so as to ensure continuity of service. Through this process, transformer replacement can be forecast years in advance. However, we are in the process of developing a CBARM model for our power transformer fleet to improve our forward planning of replacement and refurbishment. This model will be completed in FY19. Depending on the condition of a transformer we may also refurbish a transformer if the net present value is more beneficial than the cost of procuring a new transformer.

Transformer replacement is not only driven by condition and criticality but also growth. If and when a transformer needs to be replaced with a transformer of greater capacity the existing transformer will be deployed somewhere else in the network if the remaining life of the unit warrants reuse. Our planning for transformer replacement also considers alternative technology options such as a BESS system and/or load control to defer installation of a new transformer and the Symphony load scenario will be considered as part of our evaluation and business case development with regard to if and when a transformer should be replaced.

We are also planning to trial dynamic ratings as a method to extend the asset life of some of our older power transformers and the business case and planning for proof of concept are presently being prepared. Real time ratings will be obtained from existing measuring devices and this along with the application software will be interfaced with our DERMS. We are also engaged in an initiative with VIA, a US based artificial intelligence start-up, to establish a secure database for transformer data. The aim of this initiative is to take a more proactive approach to transformer management by using machine learning to predict faults before they happen. With secure access to bigger and smarter datasets, transformer maintenance works can be targeted with greater precision. Our replacement plan for power transformers is detailed in Section 5.

4.3.2 PRIMARY SWITCHGEAR

Overview

Our zone substation switchboards and circuit breaker assets comprise oil, SF_6 and air insulated equipment of varying ages and brands. The arc-quenching/circuit interruption technology in our primary switchgear include oil, SF_6-puffer and vacuum. The majority of the switchgear is 11 kV rated followed by 22 kV, 33 kV and 110 kV that generally corresponds to the network topology in that the higher the system voltage, the fewer the number of devices there are on the network. All SF6 and air insulated 33 kV, 22 kV and 11 kV switchgear utilise vacuum technology for current interruption.

All of the 110 kV switchgear are SF_6 insulated with SF_6 puffer circuit breaking technology and are all indoors except for two outdoor 110 kV CBs at Lichfield zone substation in the Waikato. Our 33 kV switchgear is a mix of outdoor and indoor types; outdoor switchgear is a mix of bulk oil type and new generation SF6 units; indoor 33 kV CBs are all SF_6 insulated.

11 kV CBs are a mix of 11 kV oil filled and SF_6 insulated. All 11 kV switchgear in zone substations are indoor units. Where two or more power transformers exist, the 11 kV switchgear comprises two or more bus-sections with incomer CBs to match the number of transformers.

Population and Age

Our Liverpool zone substation 110 kV switchgear is now 18 years old and the Hobson zone substation 110 kV switchgear was commissioned in 2013. Our 33 kV oil filled switchgear are 1960s and 1970s vintage. 22 kV SF_6 switchgear was introduced in the 1980s and 33 kV SF_6 switchgear in the late 1990s. The table and graph below provides key statistics of population and age of primary switchgear in Vector's zone substations.

No of 110 kV indoor SF_6 CBs	20
No of 110 kV outdoor SF_6 CBs	2
No of 33 kV outdoor SF_6 CBs	32
No of 33 kV indoor SF_6 CBs	149
No of 33 kV outdoor oil-filled CBs	85
No of 22 kV indoor SF_6 CBs	101
No of 11 kV indoor SF_6 and air insulated CBs	865
No of 11 kV indoor oil-filled CBs	428

Table 4-8 Key statistics for CBs for Primary Switchgear

PRIMARY SWITCHGEAR AGE PROFILE

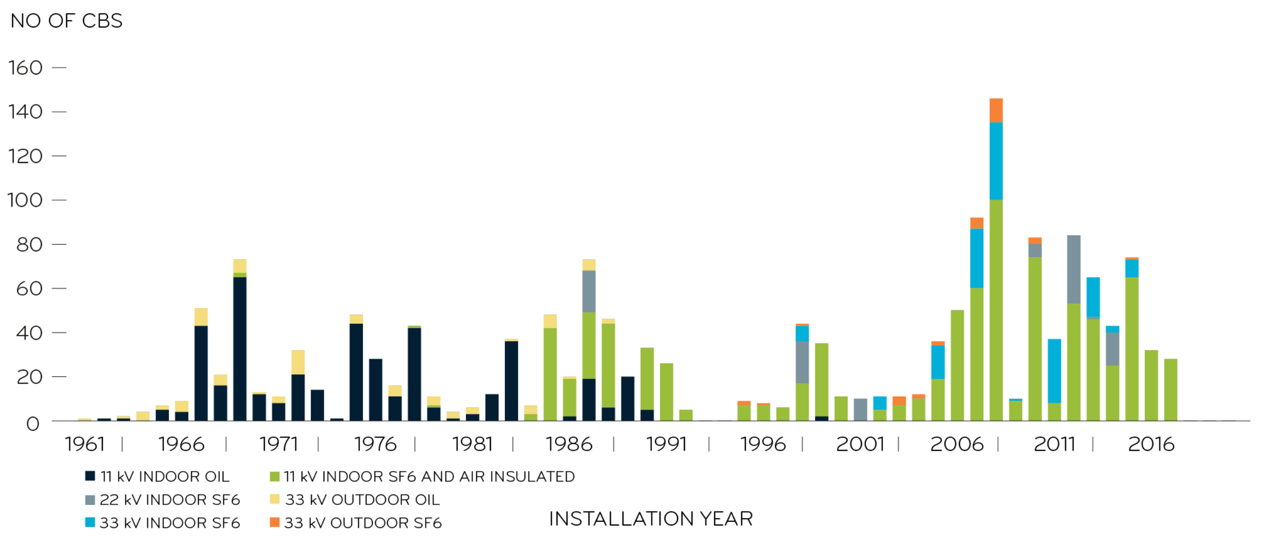

Figure 4-12 Age Profile for Primary Switchgear

Condition and Health

We have undertaken considerable investment on Liverpool 110 kV switchgear in 2014 to improve the health of this highly strategic switchgear in the Auckland CBD. The 110 kV switchgear in Hobson zone substation is only five years old. A number of our 33 kV outdoor oil filled CBs date from the early 1960s and there has been catastrophic failures in this fleet. A number of 11 kV switchgear suites date from the 1960s as well. In the last two years, we have observed failures of 1980s installed 11 kV vacuum breakers – one of which resulted in the failure of the 11 kV switchgear in Mt Wellington zone substation in January 2018.

Strategy

Our 110 kV switchgear is regularly maintained and the Hobson 110 kV switchgear has on-line gas pressure monitoring to our control centre. The Liverpool 110 kV switchgear will be fitted with on-line gas monitoring in the next financial year. 33 kV outdoor oil filled CBs are replaced based on asset health and criticality and the same goes for our 11 kV switchgear. Our 22 kV SF6 switchgear in Quay St zone substation in the CBD is one of our oldest gas insulated switchgear suites and will undergo a mid-life CB mechanism refurbishment in 2019 and circuit breaker fail protection will be installed. We have procured a vacuum interrupter test set and have setup a programme to test all older vacuum current interrupters in our 11 kV fleet.

Our CBARM model, to further assist the evaluation of our switchgear fleet, is presently being developed and will be completed in FY19. The future electricity network and load scenarios are not expected to impact our programme for replacement because age, condition and criticality as well as health and safety concerns will be the primary factors that will impact on and inform our selection and planning of the replacement programme. However, the future electricity network and associated load forecast will be evaluated with regard to how many CBs will be replaced, i.e. a low growth forecast could result in fewer CBs to be replaced and vice-versa.

4.3.3 BATTERY ENERGY STORAGE SYSTEMS (BESS) AND MICROGRIDS

Overview

The 2.3 MWh battery storage system at Glen Innes zone substation has now been in service for nearly three years to supply peak demand. Our second and third battery storage systems were recently commissioned at Warkworth South and Snells beach zone substations (2.0 MW/4.8 MWh and 2.75MW/6.7MWh respectively).

A 1 MW/1.7 MWh storage system is being planned in the remote Kawakawa Bay rural area as part of a microgrid that will provide respite to customers during outages on the long 11 kV rural feeder to this area. Commissioning of the Kawakawa BESS is anticipated in FY20. A 1 MW/2 MWh BESS is under construction at the Hobsonville Point zone substation and will be completed in FY20. A 0.5 MW 1.0 MWh BESS-microgrid is under construction in the remote northern rural area of Tapora (a large avocado growing region) and is scheduled for completion in FY20.

Population and Age

The age of Vector's BESS in service is young as can be seen in the table below.

Glen Innes BESS 1.0 MW/2.3 MWh	3 years
Warkworth South BESS 2.0 MW/4.8 MWh	1 year
Snells Beach BESS 2.75MW/6.7MWh	1 year
Harbour Bridge lights BESS	1 year

Table 4-9 Key statistics for Battery Energy Storage Systems

Condition and Health

Apart from some deterioration of outdoor battery enclosures the BESS population is in good health and condition.

Strategy

Battery energy storage systems are becoming one of the important systems to improve our network resilience especially in areas that are remote and far from zone substations and where it is cost prohibitive to construct additional subtransmission feeders and/or backstopping circuits – such locations are usually at the far reaches of rural networks. BESS will also continue to be deployed in areas where peak demand respite is required for the short term until the installation of additional subtransmission transformer capacity can be economically justified at which time the BESS system will be relocated to another site with the same capacity constraint. For this reason, our BESS systems are designed in a modular fashion that allows easy removal and redeployment. BESS integrated and designed as a microgrid will be rolled out in remote areas where the cost of backstopping is prohibitive. A BESS/microgrid is planned to be installed in the remote western beach settlement of Piha with commissioning expected in early FY20. BESS-microgrid systems are also planned for the remote beach communities in Bethells Beach and South Head.

4.3.4 CAPACITOR BANKS AND STATIC COMPENSATORS

Overview

GXPs that supply Vector's zone substations are equipped with capacitor banks or static compensators to support voltage and provide reactive power to maintain the power factor as defined in Connection Agreements. 150 MVAr is installed across the zone substation network in 3 MVAr step tranches.

Population and Age

Vector has capacitor banks at 27 zone substations and the graph below shows the age of Vector's capacitor banks. Capacitor banks generally have an asset life of 20 years and Vector's capacitor bank plants are approaching this age.

CAPACITOR BANKS AGE PROFILE

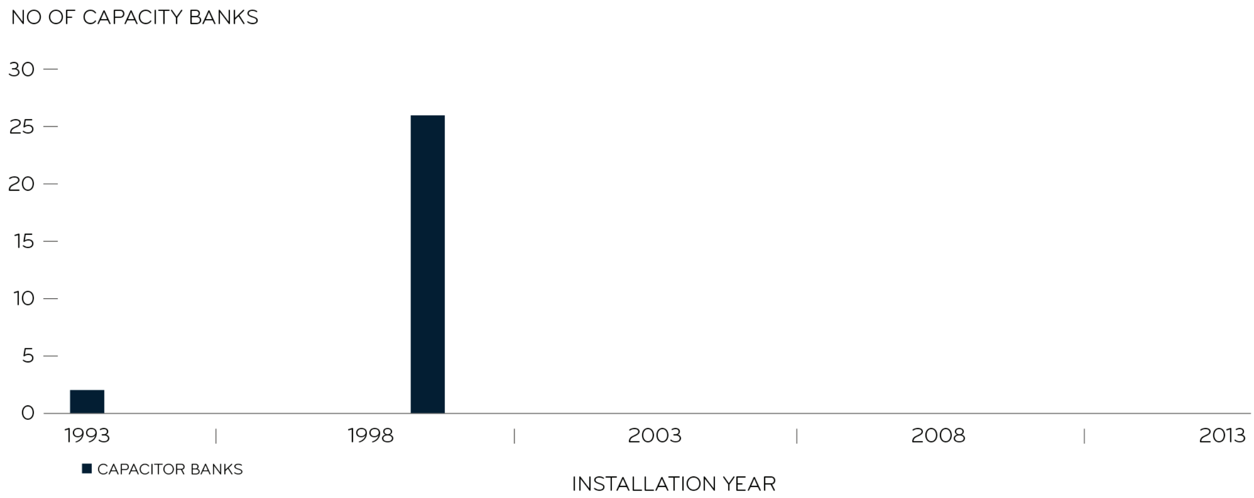

Figure 4-13 Age Profile for Capacitor Banks

Condition and Health

It is clear from the condition and number of faults in our capacitor banks that they are steadily approaching end of life and more intensive and costly maintenance, and remedial works are needed to keep them in service.

Strategy

In terms of power factor there are presently two different requirements applied to different GXPs that supply Vector's network:

- For category A GXPs the Connection Code (Schedule 8 to DTA) specifies unity power factor. However, Vector has an agreement with Transpower on non-compliance with the connection code, subject to following condition: 'Vector maintaining an aggregate Power Factor across all Point of Services in this category during Regional Coincident Peak Demand Periods of not less than 0.96 lagging or 0.97 leading'.
- For category B GXPs the Common Quality Obligations (of the Connection Agreement) specifies that the power factor at any point of service in this category must not be less than 0.95 leading or lagging.

Our Digsilent network modelling tool shows which capacitor banks need to be in service to maintain power factors and provide voltage support and this in turn informs our investment programme (detailed in Section 5). As informed by our model and monitoring of power factors at GXPs some ageing capacitor banks can and will be removed at end of life and used as a source of spares but others will need to be maintained and refurbished as required. Most notable are capacitor banks at zone substations being fed from the Penrose 110 kV GXP and Hobson 110 kV GXP. When both Albany 110 kV and Wairau 33 kV are importing reactive power from the grid the power factor goes low which means the capacitor banks at Wairau zone substation will need refurbishment to ensure their continued operation.

4.3.5 LOAD CONTROL

Overview

Vector uses demand-side load management systems on its distribution network as a customer-centric service to reduce peak demand to limit transmission charges for customers or to help with network congestion. At all other times this load is offered into the wholesale electricity market as instantaneous reserve. Due to the separate legacy power board network philosophies at the time of installation, two signalling systems exist: 'ripple injection' over power lines in the Auckland network and in the Northern network, ripple injection and a 'pilot wire' system. Customers can sign up to a 'controlled' (lesser cost) tariff under either the ripple signal system or pilot cable system. Both these systems signal 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 signalling equipment also switches some streetlights on and off at dusk and dawn on behalf of Auckland Transport.

Population and Age

RIPPLE CONTROL PLANT TYPE	QUANTITY	AVERAGE AGE
GEC Cyclocontrol	2	37
GPT	5	26
SFU-G 120	6	25
SFU-G 200	1	26
SFU-G 30	1	25
SFU-K 203	1	15
SFU-K 503	7	11
Zellweger 1050 Hertz	9	55

Table 4-10 Key statistics for Load Control plant

Condition and Health

The systems on both networks are end-of-life and require upgrading and/or replacement.

Strategy

Vector owns and is responsible for maintaining the load signalling equipment, e.g. the pilot wire system or ripple plant and the Retailer is responsible for installing and maintaining the load control relays. Assisting any replacement strategy is the transfer of Vector's management of streetlights to Auckland Transport as they migrate these to LED luminaries with a new radio-based switching technology. This Auckland Transport programme began in 2014 and is planned for completion in four years (2023). The same systems we use to manage streetlights are used to manage hot water cylinders and so must be retained while Auckland Transport is migrating their streetlights which programme is making good and speedy progress and it is expected that from 2023 control of streetlights via our load control will not be required.

Over the last two years Vector has spent considerable effort to trial and evaluate an alternative load management system to replace the pilot wire system in the Northern network and ageing ripple plants in the Auckland network and a digital radio controlled system has proved successful during field trials. This system will be rolled out over a number of years which means the existing ripple plants will continue to be maintained while some plants will require extensive refurbishment – this is detailed in Section 5. The Auckland network ripple system continues to provide a load management service. The Northern network load management systems (pilot wire system) have been discontinued due to the unreliability of the aged and end of life pilot wire system and the poor condition and lack of technical support for the GEC and Zellweger ripple plant but load control will be reinstated over time once the digital radio system is approved.

4.3.6 FIRE AND SECURITY SYSTEMS

In FY18 Vector's zone substation replacement programme to install CardaxTM security monitoring was completed. This replaced the end of life 1970's control units fabricated by Guardall New Zealand. The intention is also for the zone substation fire detection system to communicate to the local Cardax security system for fire annunciation at Vector EOC, for EOC to then contact the Fire and Emergency New Zealand responder service. Category 1 substations, typically in the Auckland CBD, are also directly annunciated to Fire and Emergency New Zealand.

Recently a sample assessment of the completed Cardax installations has found some sites non-compliant in this regard. A risk assessment has identified that a programme for the balance of zone substation buildings is required. The desktop study has identified 27 Auckland sites and 17 Northern sites, 44 in total. Our strategy includes replacing the old fire monitoring equipment by adding a Cardax fire detection isolation and annunciation panel connected to the existing Cardax security installation, and fire monitoring integration where multiple buildings exist. Connection to the automated fire annunciation service will also be added to the Category 1 Liverpool 110 kV and 22 kV switch rooms, and the three transformer buildings at Auckland Airport. The project will ensure zone substation buildings still have a properly integrated fire safety system. This gives assurance of the correct Fire and Emergency New Zealand response for fire and mitigates a recently identified HILP risk to the zone substation buildings, plant, personnel, customer power supply (potential SAIDI impact), and ultimately the public and our customers.

4.4 DISTRIBUTION FEEDERS HV

Vector's HV distribution network is for the larger part operated at 11 kV. In the Northern supply area, the HV distribution network is predominantly overhead but in new subdivisions HV networks are installed underground. The underground HV network is extensively interconnected via distribution substations. In the Auckland supply area, the HV distribution network is predominantly 11 kV underground but there are pockets of overhead supply most notably the lengthy rural supply to Maraetai and further south to Kawakawa Bay. In the Auckland CBD and in the Highbrook industrial estate, 22 kV networks are utilised for distribution – 22 kV distribution is for the most part underground.

4.4.1 DISTRIBUTION FEEDERS HV OVERHEAD

Overview

Vector has 3776 km route length of 11 kV overhead (OH) distribution feeders. The overhead conductor types and sizes vary across the overhead network and are predominantly copper (Cu), all aluminium conductors (AAC) or aluminium conductor steel reinforced (ACSR) conductors. Aluminium alloy conductors (AAAC) are being utilised for new line construction.

Overhead air break switches and gas-filled overhead switches that can be remote controlled via SCADA exist in strategic locations in the overhead distribution networks to allow automated circuit breaking and controlled remote switching by the EOC to quickly and effectively control the network to limit SAIDI and SAIFI during switching after a fault to restore supply or for planned works.

Population and Age

A breakdown of the 11 kV OH distribution network is given in the table below but it must be noted that due to historical legacy issues, there are deficiencies in the information of the ages of conductors (and poles) for certain areas in the Auckland region. Copper conductors installed in the 1940s through to 1960s are experiencing failures. The table below summarises the population of 11 kV while the graph provides an age profile of 11 kV conductors.

DESCRIPTION	AUCKLAND	NORTHERN
No of 11 kV OH distribution feeders	286	281
Circuit length of 11 kV OH distribution feeders – all conductor types	890 km	2886 km
Circuit length of 11 kV OH distribution feeders Aluminium conductor	248 km	2467 km
Circuit length of 11 kV OH distribution feeders Copper[12] conductor	603 km	405 km

Table 4-11 Key statistics for HV OH conductors

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12 The age data for Copper conductors in especially the Auckland network has historical errors in it and data will remain unavailable. The quantities for conductors in especially the Auckland region contains a proportion of estimation

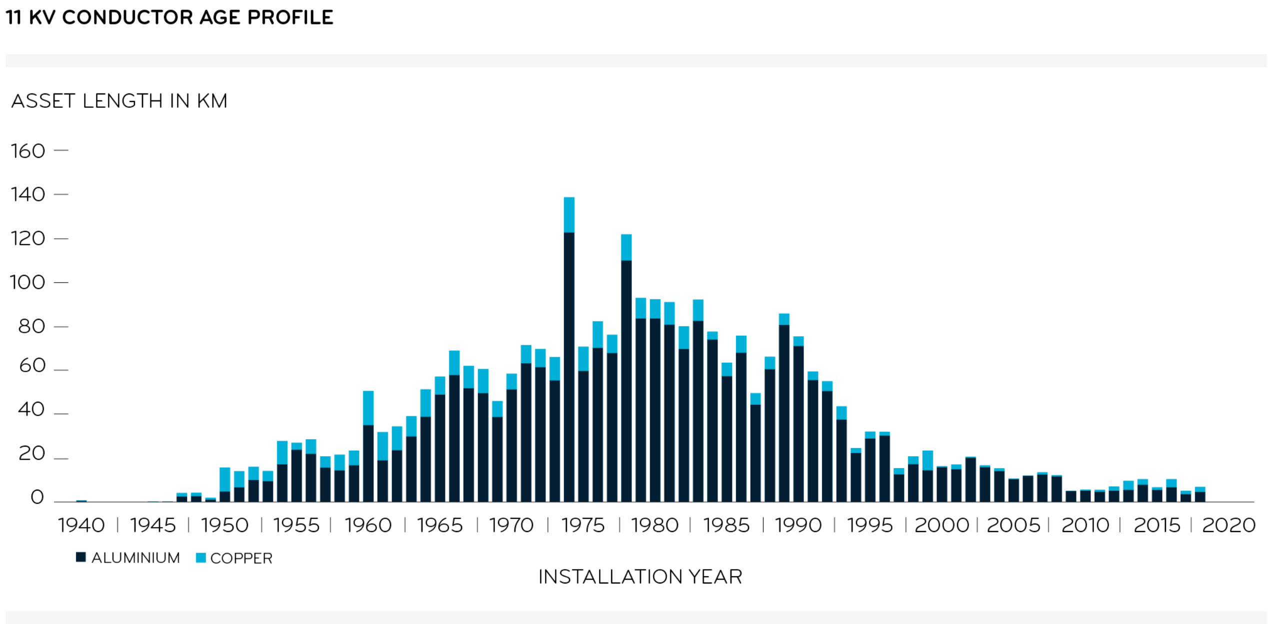


Figure 4-14 Age Profile for Conductors

Condition and Health

Ongoing issues for conductor life is that Vector's network is all relatively close to the sea and therefore subjected to a more corrosive environment. All of Vector's network less than 15 km from the nearest shoreline, and approximately 50% within 3 km of the shoreline. Overhead conductors also harden over time (anneal), becoming brittle due to wind induced vibration, movement and thermal cycling and loses some of its tensile strength.

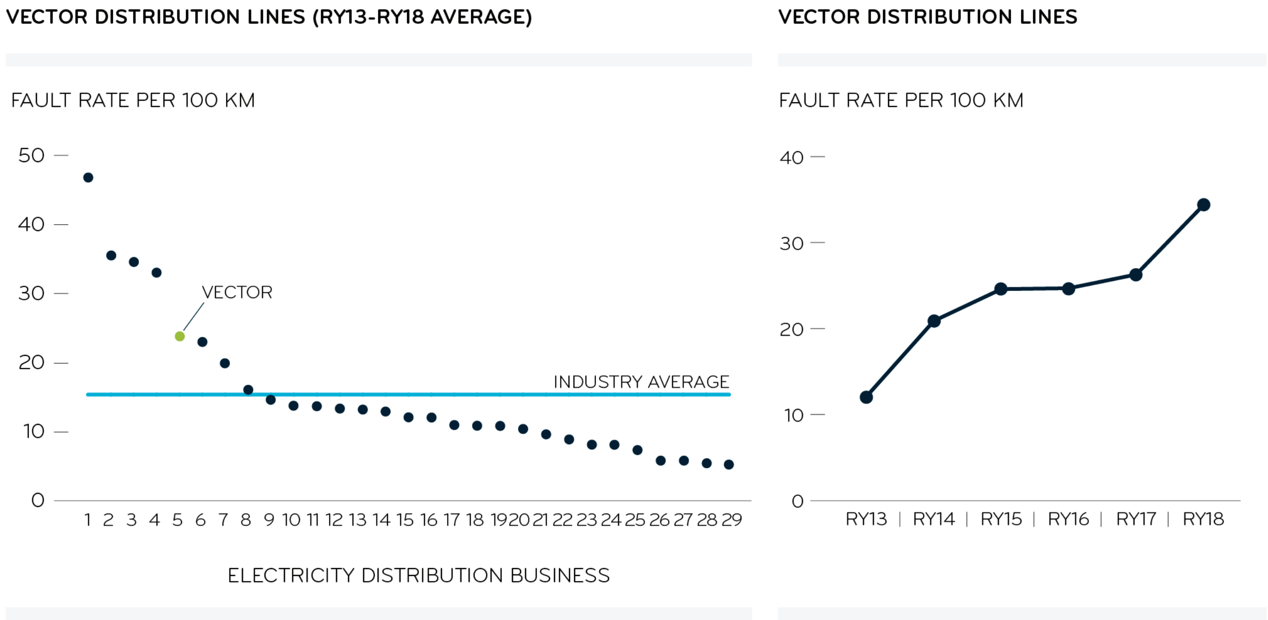


Figure 4-15 Distribution lines fault rates

Our CBARM model to inform our intervention plan for OH conductors is fully developed and the first graph below, taken from our CBARM model for conductors, shows the asset health for conductors in year "0", i.e. the current year. The second graph shows the health index of conductors if no intervention is undertaken in the AMP 10 year period and the conductor route length that will have very poor asset health at the end of the AMP period is evident.

ASSET HEALTH AT YEAR 0 – OH MV CONDUCTOR

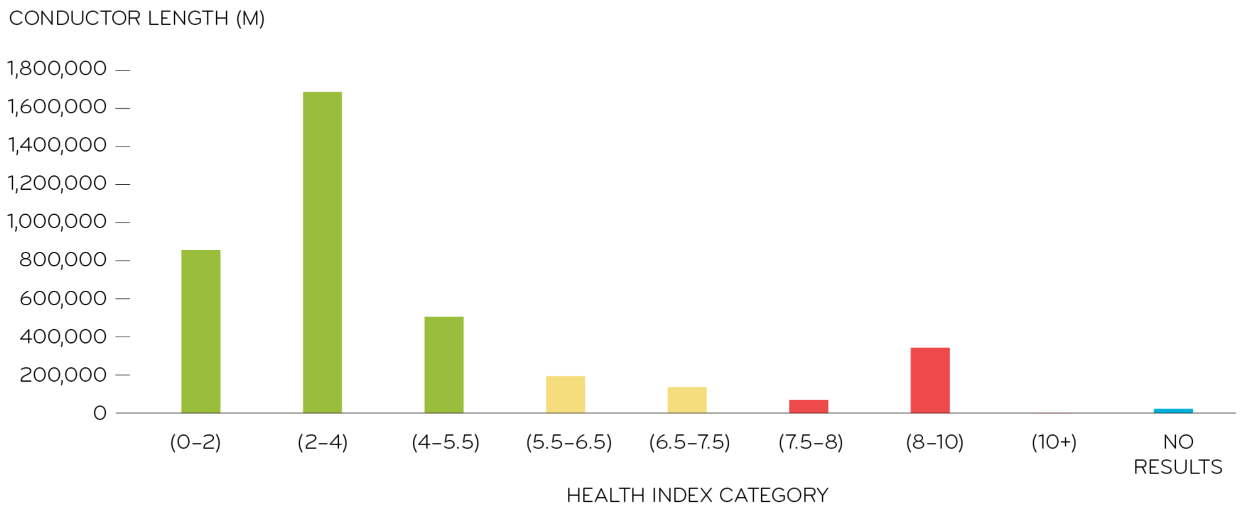


Figure 4-16 Asset Health at Year 0 - OH MV Conductor

ASSET HEALTH AT YEAR 10 – OH MV CONDUCTOR

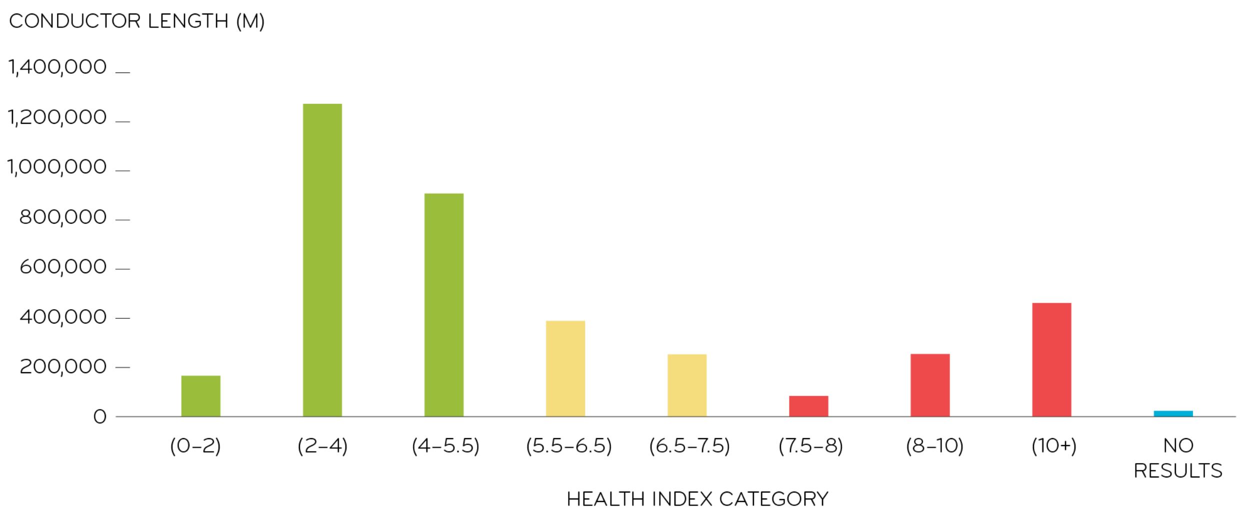


Figure 4-17 Asset Health at Year 10 - OH MV Conductor

Strategy

Maintenance on our OH network will continue as per our revised and updated maintenance standard. However, we have initiated an intervention programme for the proactive replacement of ageing conductors over the AMP period. Where segments of the network have been identified for conductor replacement, based on the asset health in our CBARM model, the same portion of line will undergo general refurbishment and repairs of defects. I.e. crossarms, insulators, connectors will be replaced to extend the asset life.

Our intervention programme to control vegetation to improve SAIDI and SAIFI will continue and be extended. As part of the programme to renew HV overhead feeders, we use acoustic technology to find failed or failing insulators that are then replaced. Conductor sampling is also used to assess condition and to build up a profile and database of the network that contains conductor with poor asset health. As part of conductor condition driven rebuilds, poles, crossarms and stays will be replaced as required.

In rural areas failures of conductors can have disastrous consequences such as electrocution and bush fires and we are investigating the use of alternative overhead technologies such as 11 kV aerial bundled conductors and the so-called Hendrix spaced covered conductor systems. We have also commenced with a targeted sampling and testing plan with a focus on areas where conductors have failed to increase our understanding of the condition, degradation and failure modes of the conductor fleet. This will be used in statistical analysis for our intervention programme to further assist us to better identify and target conductors for replacement.

Further details of our strategy for renewal is described in Vector's asset strategy EAA401 Overhead Lines. Details of the replacement and refurbishment programme and details of the vegetation control programme are given in Section 5.

4.4.2 DISTRIBUTION FEEDERS OH SUPPORTS

Overview

Because many poles in our network share OH lines of different voltages from subtransmission to low voltage, pole data cannot be separated per voltage; hence this section includes overhead supports for 33 kV subtransmission as well – only 110 kV OH supports are excluded and are described in the section for Subtransmission assets. Overhead supports consist of poles, stays and crossarms. Poles for overhead distribution circuits are predominantly pre-stressed concrete with timber crossarms. About 8% of poles in rural distribution feeders are treated softwood timber poles with only a few hardwood poles in the network. Timber poles are extensively used as support structures for connections to customers. Concrete poles in the Auckland region are about 40% as strong as new prestressed concrete poles. Any upgrade or refurbishment of overhead lines utilises pre-stressed concrete poles unless specific locations call for specialised steel poles.

Population and Age

The nominal asset life for concrete poles is 60 years while wooden poles are expected to last from 30 to 60 years depending on type, treatment and installation conditions (traditionally crossarms were expected to typically last between 15 and 30 years but our present specification for wooden crossarms requires a life of 40 years). Due to legacy reasons, the age of all poles in the Auckland network is not available and age dates were estimated based on other factors e.g. the date that an area was established. The table below provides statistics for our pole population.

DESCRIPTION	AUCKLAND	NORTHERN
No of reinforced concrete poles	1758	48848
No of prestressed concrete poles	43108	11742
No of softwood wood poles	2552	1969
No of hardwood wood poles	1822	297
No of steel lattice towers	0	60
No of steel monopoles	4	1
No of U-poles (composite poles)	358	455

Table 4-12 Key statistics for Poles

The graph below shows an age profile for Vector's poles.

POLES AGE PROFILE

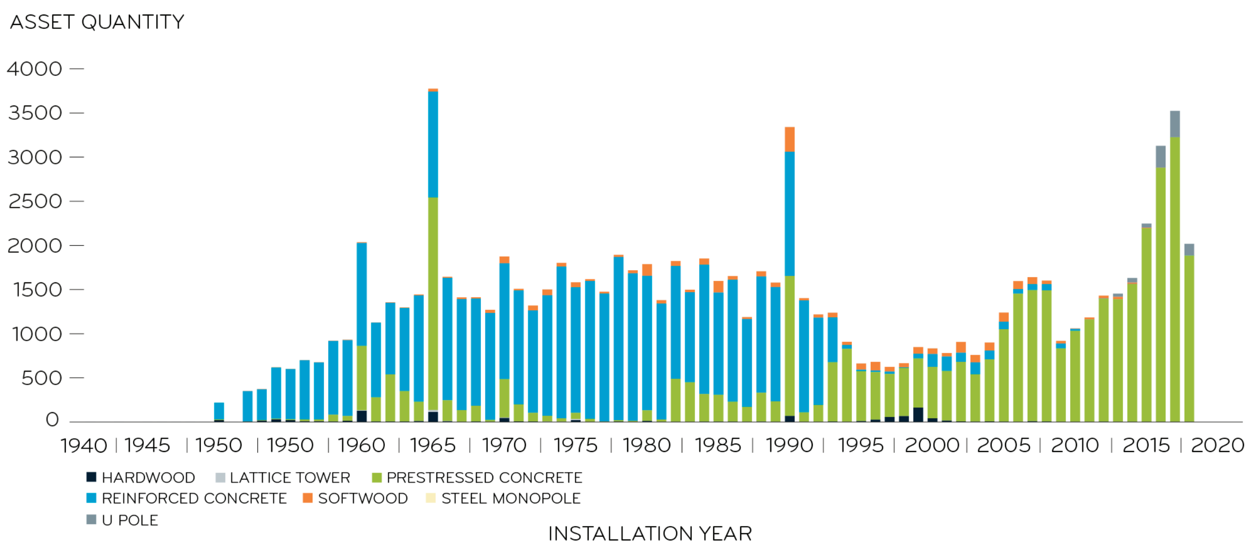


Figure 4-18 Age Profile for Poles (excludes 110 kV poles)

Condition and Health

The average age of poles in the Northern region is 37 years and in the Auckland region it is 11 years. Vector has poles that have gone well past 60 years and are still in good condition. A large number of Vector's concrete poles are the 'Vierendeel' poles – these are prestressed concrete poles that can develop hairline cracks that allow water and air to enter and corrode the steel strands.

Strategy

The failure modes, planned inspections, testing regime and maintenance activities for poles, conductors, crossarms etc. are described in Vector standard ESM401 Maintenance of Overhead Lines for example; before any Vierendeel concrete pole is climbed it is inspected and if showing signs of stress, is not climbed unsupported. Where steel is visible in poles it is red tagged for replacement. Where such poles excessively lean they are replaced. If a crossarm requires replacement the pole is replaced. If such poles exist in a part of the network in which a conductor replacement will take place (as per the programme of works described in Section 5), Vierendeel poles will be replaced.

All new poles in the distribution network are concrete poles and all new poles in rights of way to customer premises are composite poles. Our CBARM model for poles and crossarms is under development at the time of writing and is not yet available to inform and enhance our intervention programme. In the meantime our tagging and replacement of poles based on our inspection and maintenance regime continues. However, where we undertake a conductor replacement, project poles are inspected and strength indexes calculated and replaced under the project if required.

4.4.3 DISTRIBUTION FEEDERS HV UNDERGROUND

Overview

Vector's HV distribution underground cables are a mix of paper insulated lead covered (PILC) cables and XLPE cables. The larger portion of distribution cables are rated 11 kV but in high density load areas such as Auckland's CBD and the Highbrook industrial area the distribution voltage is 22 kV. The bulk of underground cables are in suburban areas but there are small pockets of underground cables in subdivision in more rural areas, e.g. north of Kumeu.

Population and Age

The combined length of 11 kV distribution underground feeders for the Auckland and Northern network is 3536 km of which 285 km will be past end of reliable asset life in 2029. Due to legacy data collection practices, we have about 160 km of 11 kV distribution cables with no age-related data. The table below is a summary of our HV distribution underground cables.

No of 11 kV underground distribution cable circuits	958
No of 11 kV underground distribution cable circuits with underwater/undersea portions	6
Length of 11 kV paper insulated lead (PILC) cables (km)	2125
Length of 11 kV cross-linked polyethylene (XLPE cable (km)	1411

Table 4-13 Key statistics for HV underground distribution cables

The graph below shows an age profile for Vector's HV cables.

DISTRIBUTION HV CABLES AGE PROFILE BY VOLTAGE

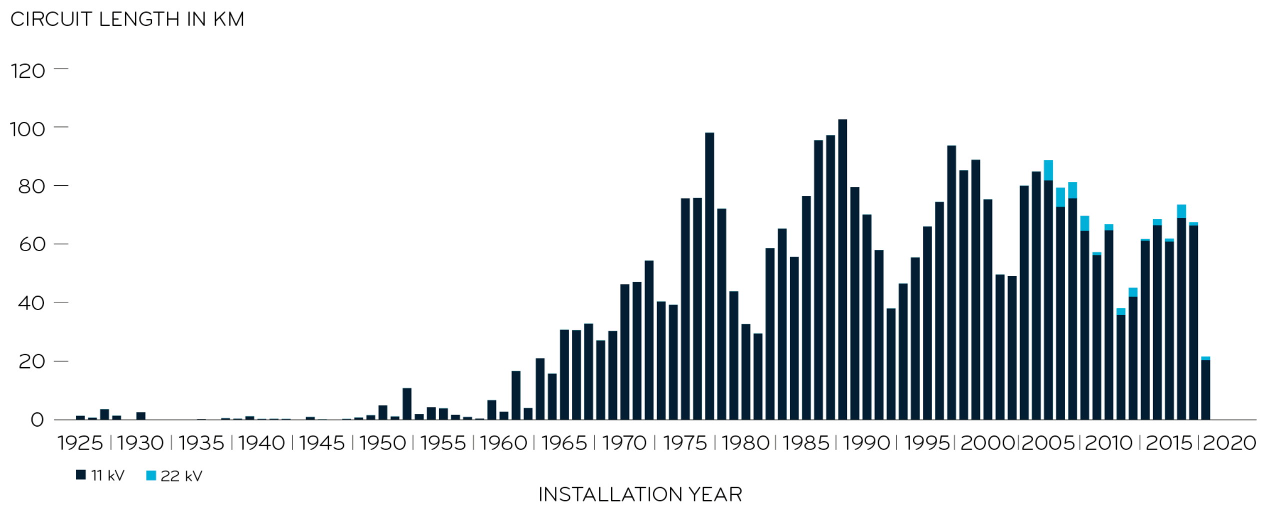


Figure 4-19 Age Profile for 11 kV and 22 kV HV cables by Voltage

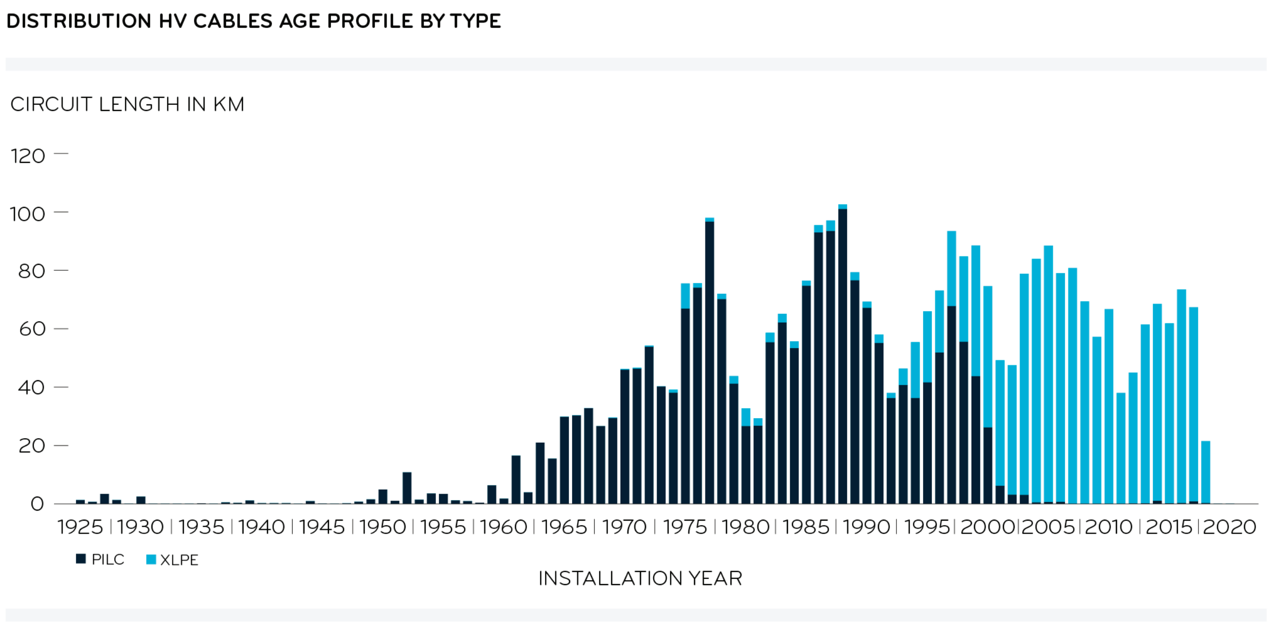
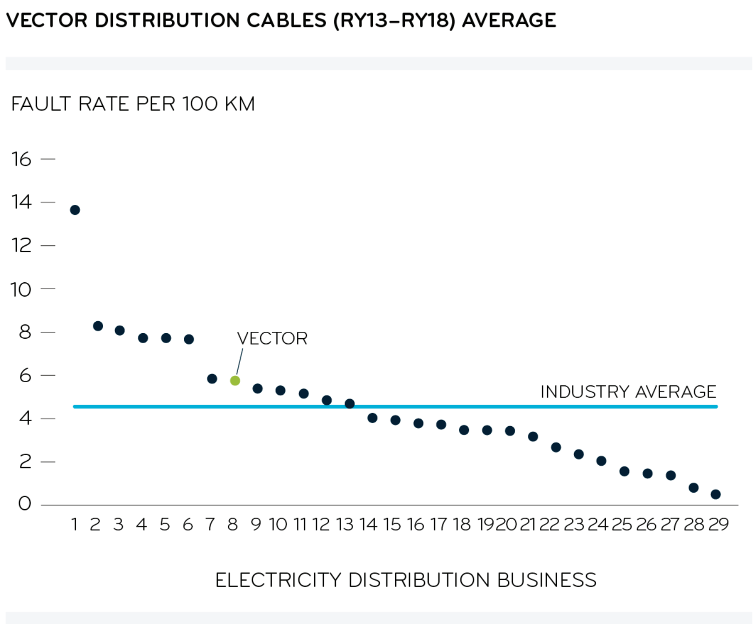


Figure 4-20 Age Profile for 22 and 11 kV Distribution Cables by Type

Condition and Health

We are experiencing an increase in the number of faults on certain sections of cables based on a 5-year rolling window. Tests have also shown a number of cables with very low insulation resistance values and this indicates that we have a certain population of cables that is approaching end of life. Another failure mode that is on the increase and causing outages is deteriorating tinning on tinned aluminium lugs on outdoor 11 kV cable terminations on 11 kV cable risers to OH lines. Age profiles of our 22 kV and 11 kV underground fleet are given below.



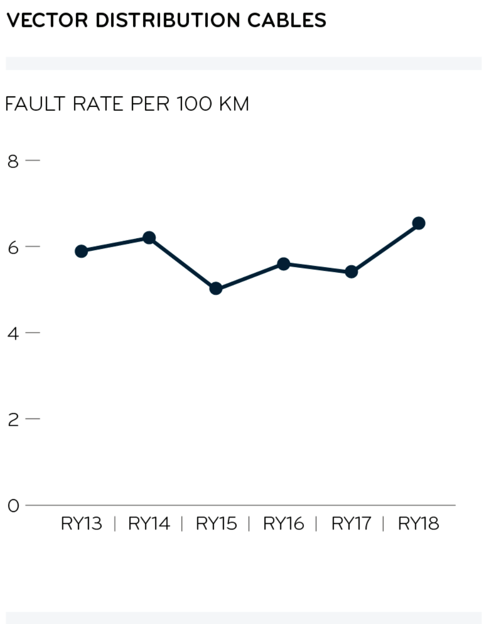


Figure 4-21 Fault rate for 11 kV Distribution Cables

Strategy

Because of high load density and criticality, the HV distribution network in the Auckland CBD has over the last decade and a half been progressively upgraded from the existing 11 kV network to a 22 kV network and subject to the availability of 22 kV cables in a street, all customer capacity upgrades and new connections within the CBD will be at 22 kV. This programme will continue in the AMP period and most likely beyond until all circuits in the CBD are 22 kV – details of this programme is in Section 5. Unless a programme of intervention is undertaken in this AMP period, by 2039, the amount of 11 kV cables at end of reliable life will be triple that at the end of this AMP period, 2029. Our CBARM model for underground HV distribution cables is currently under development and will better inform us to plan our intervention programme of works.

With regard to new electricity networks in suburban areas the Auckland Council Unitary Plan requires urban reticulation for new developments to be placed underground and Vector works with developers and property owners to deliver this outcome. Our development plans for future networks in land defined for suburban development and subdivisions will be based on our Symphony future networks modelling scenario.

A large body of works has already commenced to increase automation of the HV underground network to reduce SAIDI and the positive impact of the increased number of distribution substation sites with automation can already be seen.

4.5 DISTRIBUTION FEEDERS LV

Overview

The LV network is predominantly overhead in the Northern region and consists of mostly bare conductors. The LV network shares HV support structures for extensive parts of the network and on many routes subtransmission circuits exist on the same support structures – Glenfield on the North Shore is a notable example where 110 kV, 33 kV, 11 kV and LV circuits exist on many of the same support structures. In new networks all LV feeders are underground cables. A mixture of above ground pillars and buried service pits are used to tap off to customer connections from our LV underground networks.

For the larger part of the LV network, circuits have limited interconnections and in some cases are not designed for full backstopping if an adjacent distribution transformer should fail. A significant challenge with regard to the LV fleet is that network data is less visible and the geospatial information system (GIS) cannot always provide an up to date view of the LV network.

4.5.1 DISTRIBUTION FEEDERS LV OVERHEAD

Population and Age

Historically, overhead conductors have moved from copper, to AAC and ACSR, through to AAAC. Vector has a large number of different sized conductors with some bare and some PolyVinyl Chloride (PVC) covered, some greased and some not greased. We also have a sizable population of LV ABC conductors. The larger part of the LV network in the Auckland region is underground but 37% of the LV network remains an overhead network. Traditionally, this asset class has been the asset with the least focus in terms of its age and condition, while ironically in the new energy future, will be the asset that will become more important if not the most important as the uptake for EVs, solar and customers' DERs increases. Key statistics of the LV distribution network are stated in the Tables below.

DESCRIPTION	AUCKLAND	NORTHERN
Circuit length of LV overhead distribution feeders (km)	1960	2198
No[13] of LV network poles	28681	18559

Table 4-14 Key statistics for LV Underground Cable Network

Condition and Health

Because of legacy data deficiencies we do not presently have robust data with regard to the condition and health of the LV OH network apart from information that is gained through planned maintenance inspections. 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 OH network as well. The ageing LV network is resulting in the failure of some components such as neutral conductor clamps and this has an impact on customer service levels – a strategy to address this specific topic is in the process of being developed. The increasing importance of the LV network as the

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13 It must be noted that where LV OH circuits are installed on HV poles (i.e. share HV poles), such poles are counted under HV distribution supports and are not shown in the table below.

platform for the flow of energy under the new energy future means that our knowledge of the LV network is already receiving increased focus and this will expand as we go forward.

4.5.2 DISTRIBUTION FEEDERS LV UNDERGROUND

Population and Age

Approximately 63% of the LV network in the Auckland region is underground and in some areas the underground network has been in service for 60 plus years. Pockets of underground LV networks exist in the Northern region but the underground network in the Northern region, where it exists, is generally younger – due to extensive subdivisions in the Northern region the underground LV network is expanding. The table below shows key data for our LV underground cable population, distribution pits and pillars.

DESCRIPTION	AUCKLAND	NORTHERN
Circuit length of LV underground cable distribution feeders (km)	3363	2243
No of LV connection pits	37689	12866
No of LV above ground distribution pillars	59555	27709
No of LV buried distribution link boxes	123	18

Table 4-15 Key statistics for LV Underground Cable Network

Condition and Health

Similar to the LV OH network, the same legacy data deficiencies exist for the LV underground network, except for new underground cable installations. Hence, for the overall population of underground LV cables, Vector does not presently have robust data with regard to its condition and health and an age profile graph is thus not included. Our programme for CBARM models include the development of a model for our LV pits and pillars and the gathering of data for the CBARM model will be undertaken as part of our planned maintenance inspections. We are not experiencing any systemic network failure modes in our LV underground network but we are seeing a slight increase in faults in older parts of the LV underground network, notable in St Heliers and Mission Bay. At this point in time the frequency and number of faults are such that the issue is certainly not viewed as systemic. The biggest threat and cause of faults in the LV underground cable network is damage by third party excavations and vehicle strikes on pillar boxes.

4.5.3 DISTRIBUTION SOLAR AND BATTERY DISTRIBUTED GENERATION

Population and Age

The table below summarises our population of solar panel/battery installations and stand-alone battery installations.

No of solar panel installations complete with storage batteries	460
No of storage battery installations	230

Table 4-16 Key statistics for Solar/Battery installations and stand-alone Battery Installations

The two graphs below show age profiles for solar/batter installations and stand-alone battery installations respectively.

SOLAR PANELS COMPLETE WITH BATTERIES – AGE PROFILE

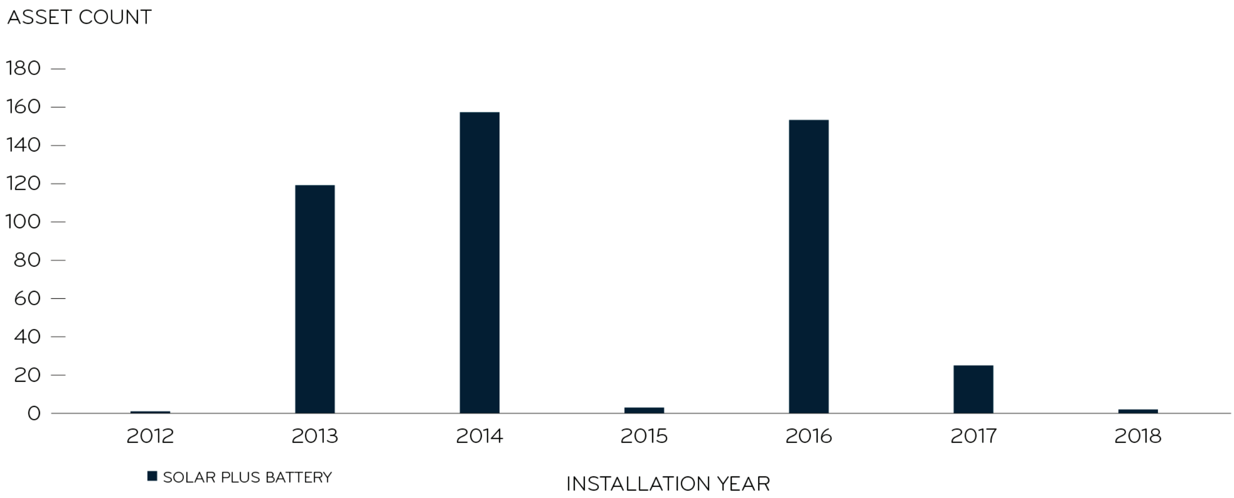

Figure 4-22 Age Profile for Solar Panel/Battery installations

BATTERY STAND ALONE INSTALLATIONS – AGE PROFILE

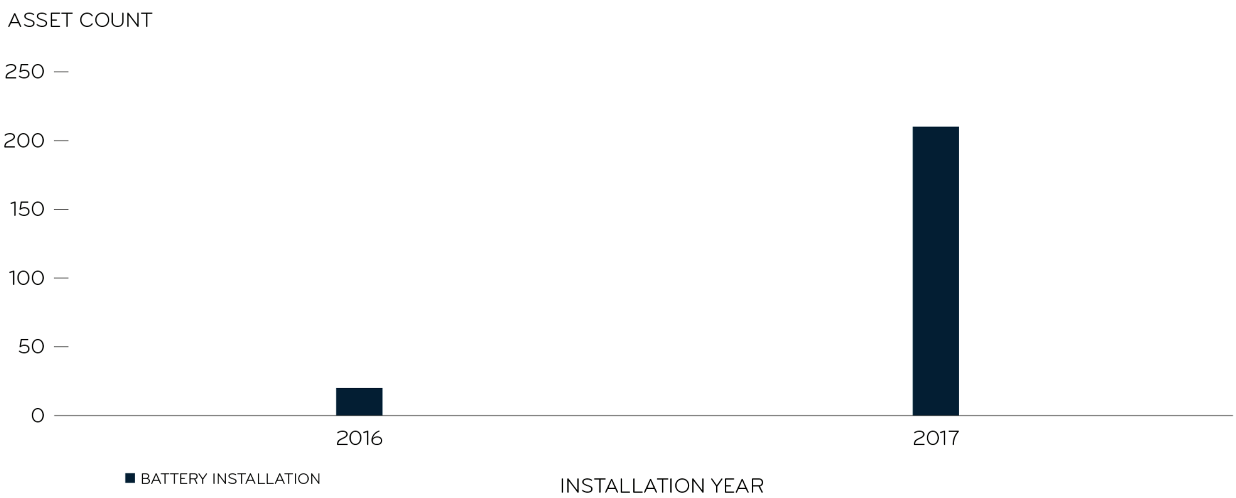

Figure 4-23 Age Profile for Battery Only Installations

Condition and Health

The solar panel and battery populations are relatively young and apart from teething issues with operating software we have not had systemic failures in our solar panel or battery fleets. However, we have experienced deterioration of the invertor steel enclosures where they exist in an outdoor environment or an environment where damp exists – this issue is being addressed under our corrective maintenance programme.

4.5.4 DISTRIBUTION EV CHARGERS

Overview

As of January 2019, 5,394 electric vehicles have been registered on Auckland roads. The availability of public charging infrastructure supports the increased uptake of electric vehicles as it enables the possibility to complete journeys beyond the battery range and reduces range anxiety. In line with the new energy future, in 2016 we commenced a programme to install EV chargers in strategic public locations over the wider Auckland area. The Vector EV charging app was launched in 2017 providing directions to EV chargers making them easier for customers to find. We also have a number of EV chargers in the parking basements of our main office building to charge our own fleet of battery cars.

Population and Age

The table below summarises our population of public EV chargers. The first units were installed in 2016 with the latest installed in 2018.

No of public EV chargers	27
No of EV chargers in Vector's office building	6

Table 4-17 Key statistics for EV chargers

Condition and Health

The EV charger fleet is very young and apart from some teething issues that are oftentimes experienced with a new asset class, the EV chargers are in good health. EV chargers form part of our maintenance regime for which provision is made in our Opex budget.

Strategy

It is clear that the popularity of EVs is on the rise and this forms an important aspect of our Symphony load forecast model. The integration of EV chargers into the electricity network and the potential impact on infrastructure investment needs to be carefully considered to avoid overloading and excessive peaks and this is considered when sites for public charging are selected. Going forward Vector will limit the installation of new EV chargers in the public domain but will continue to maintain its existing fleet of EV chargers.

4.5.5 RESIDENTIAL EV CHARGERS

Overview and Strategy

EV growth in major cities is generally higher than national averages and Auckland is no exception and is the hub of EVs in NZ with 1 out of 2 EVs registered in Auckland. If this trend continues we could see 1 in 15 households with an EV by 2021. Vector is looking to engage with leading stakeholders in NZ to collaborate in research and demonstration programmes, exchange expertise and data and develop a regulatory framework in which EVs can thrive. As part of this programme Vector plans to install EV chargers in 120 private homes spread across Auckland to better understand customers behaviours and response to this new technology. As part of its contract with customers we will maintain the EV chargers for a set period of time.

4.5.6 STRATEGY FOR THE LV NETWORK

Power generation is shifting from stable, dispatchable resources connected to power transmission to variable, renewable resources connected to the distribution network. Our strategy and planning processes need to shift to address this new reality. Going into the future we will maintain the present fleet of solar panels/batteries and the standalone battery fleet and will continue to develop our LV network to suit the requirements of the new energy future.

With the Symphony scenario, 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 the traditional ways to keep the network fit for purpose and fit in terms of H&S requirements but our strategy will now make provision for the new market i.e. we will focus on making the LV network ready for the variable and renewable resources connected to the distribution network to create an LV network suitable for customers to produce, consume, store and sell electricity.

To improve visibility of the LV network we are enhancing and expanding our back-end data systems and improving our analytics and mapping capabilities (linked to the asset information systems, enhanced tariffs, and peer to peer trading). 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. Smart meters and advanced metering infrastructure offer a whole new range of LV supervision capabilities and we are investigating the options offered by smart metering technology to monitor network performance such as voltage and quality of supply to assist with the operation of the LV network and loss of supply to assist with restoration management during storms etc.

In line with the requirements of the Auckland Unitary Plan any new LV distribution feeders in Vector's network will be underground. Where there is a need to replace LV overhead conductors this will be undertaken with either aerial bundled conductors or covered conductors.

4.6 DISTRIBUTION GROUND MOUNTED SUBSTATIONS

Population and Age

There is a mix in terms of what the distribution substations contain; some are switchgear only, others contain switchgear and transformers while others still contain only transformers. The table below provides a view of our total population of all types of distribution ground mounted substations.

DESCRIPTION	AUCKLAND	NORTHERN
No of distribution substations ground mounted all types	7806	9020
No of distribution substations in a concrete block, blockwall or brick building	1895	27
No of distribution substations with steel, aluminium, fibre glass or other canopies	5904	8993
No of underground distribution substations	7	0

Table 4-18 Key statistics for Distribution Ground Mounted Substations

The graph below provides a view of the age of distribution ground mounted substations.

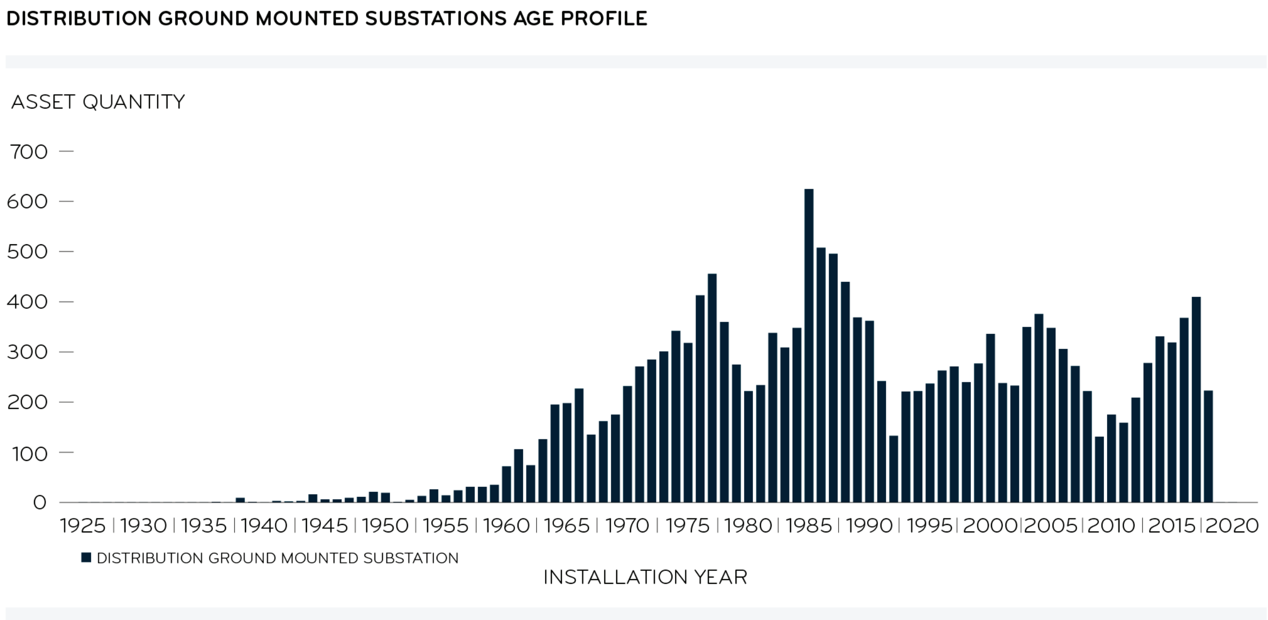

Figure 4-24 Age Profile for Distribution Ground Mounted Substations

Strategy

Distribution ground mounted substations are maintained in accordance with ESM503 Maintenance of Ground Mounted Distribution Equipment and Voltage Regulators. To deliver to this, extensive routine and operational preventive activities are implemented that include cyclical inspections, planned maintenance, asset inspections, maintenance servicing and condition testing. These preventive tasks uncover non-compliant or serviceability asset observations which are then treated as a corrective maintenance action or an asset renewal action depending on the extent and risk with regard to performance and safety.

The identification of serviceability or non-compliant asset observations consider generic performance and safety consequences. These consequences are used to determine the treatment criteria. The timeframes for treatment are strongly driven by the likelihood of the hazard. The applied maintenance approach has developed from a pure condition-based maintenance strategy to incorporate risk elements but the adoption of a more formal CBARM framework is in progress.

4.6.1 DISTRIBUTION GROUND MOUNTED SWITCHGEAR

Overview

The function of HV distribution switchgear is to connect underground HV cable circuits together to form functional circuit rings that can be switched from two or more ends. Our distribution switchgear comprises varying ages and types of gear including oil-filled, SF6 and a small population of epoxy resin insulated equipment. One of the challenges facing Vector is an ageing 11 kV RMU population but we do not yet have evidence of systemic failures. However, we have experienced catastrophic and highly visible failures of oil filled switchgear in recent years. Some of the older brands and models of our ageing oil-filled ring main population also do not adhere to the latest Health and Safety codes of practice for the protection of operating personnel and the public against the risk of arc flash.

Population and Age

The table and graphs below describe the population and age of Vector's 22 kV and 11 kV RMU population in distribution substations.

DESCRIPTION	AUCKLAND	NORTHERN
No of 11 kV distribution ground mounted oil filled switches	6121	1433
No of 11 kV distribution ground mounted switches with solid insulation	0	106
No of 11 kV distribution ground mounted SF_6 switches	883	594
No of 22 kV distribution ground mounted SF_6 switches	195	0

Table 4-19 Key statistics for Distribution Ground Mounted Switchgear

DISTRIBUTION SWITCHGEAR 11 KV AND 22 KV AGE PROFILE AUCKLAND

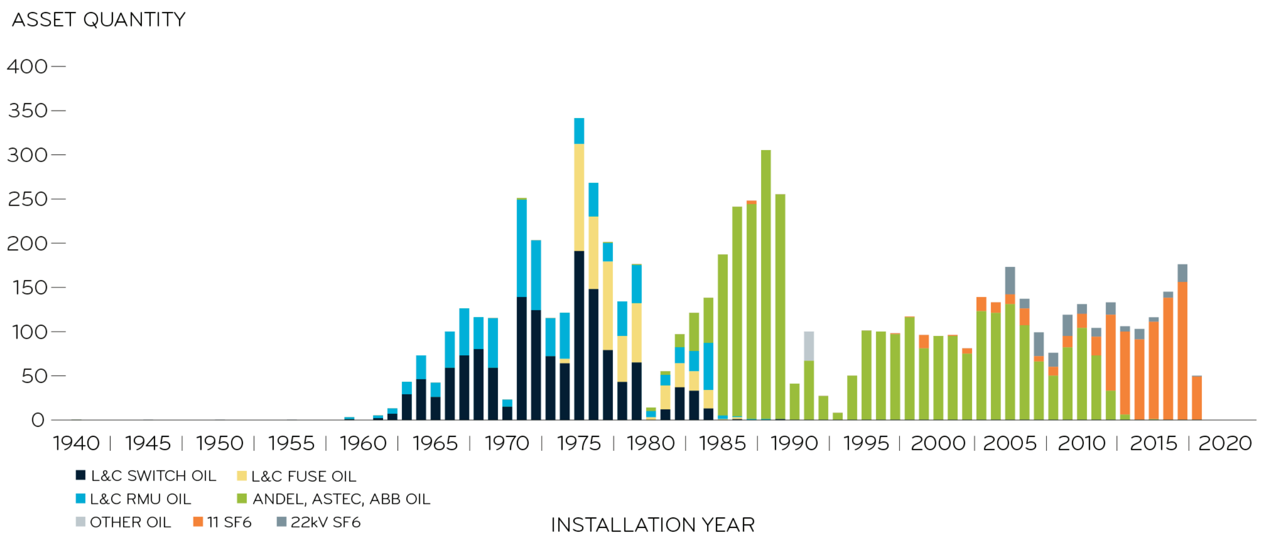

Figure 4-25 Age Profile for Distribution Ground Mounted Switchgear Auckland

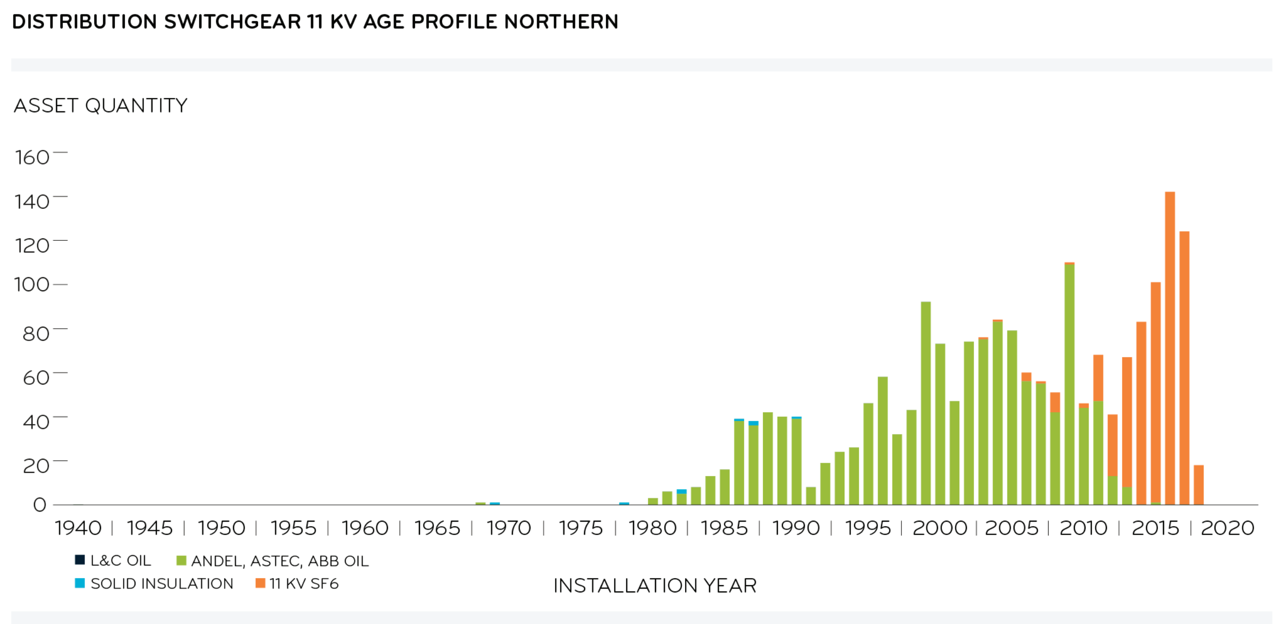

Figure 4-26 Age Profile for Distribution Ground Mounted Switchgear Northern

Condition and Health

The distribution switchgear population is ageing and while our maintenance regime is succeeding in keeping the fleet operational it does not remove the risks posed by the ageing fleet in terms of arc flash capability and ageing internal components that are not replaceable (i.e. spares are simply not available), nor will our maintenance regime extend the asset life indefinitely. We have thus embarked on a replacement strategy as expanded below under the Strategy heading and in our Asset Strategy document, EEA500 Asset Strategy Distribution Systems. Our CBARM model to inform our intervention plan for ground mounted switchgear is fully developed and the first graph below, taken from our CBARM model for distribution ground mounted switchgear, shows the asset health in year "0", i.e. the current year. The second graph shows the health index of ground mounted switchgear if no intervention is undertaken in the AMP 10 year period.

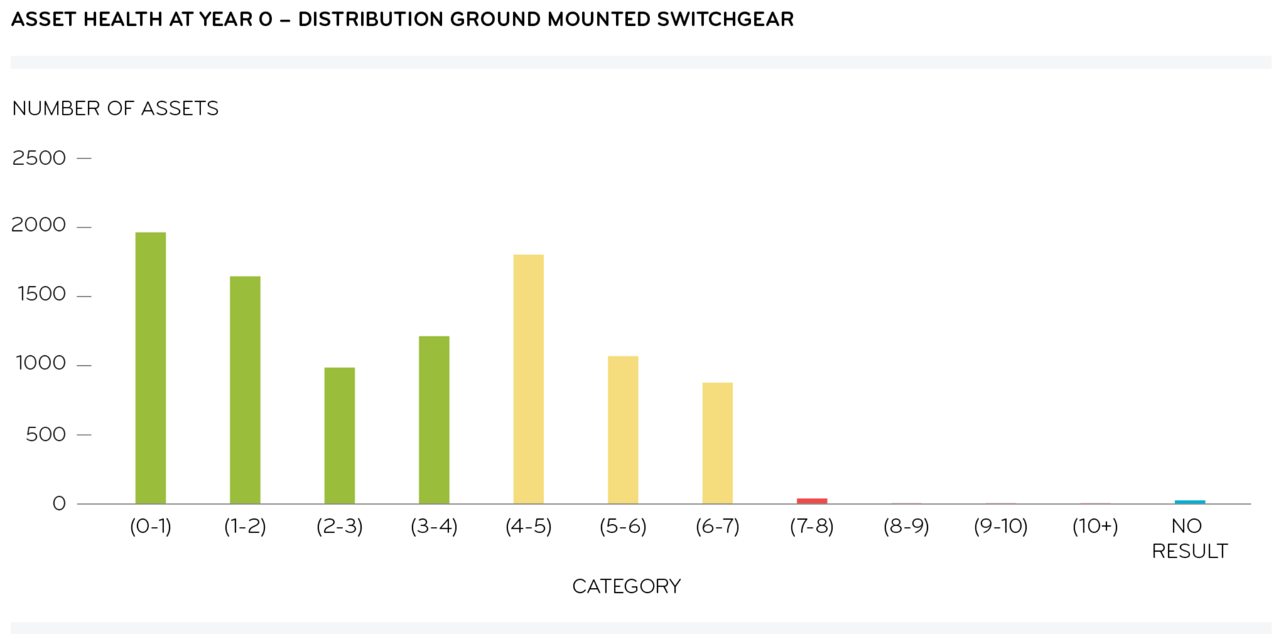

Figure 4-27 Asset Health at Year 0 - Distribution Ground Mounted Switchgear

ASSET HEALTH AT YEAR 10 – DISTRIBUTION GROUND MOUNTED SWITCHGEAR

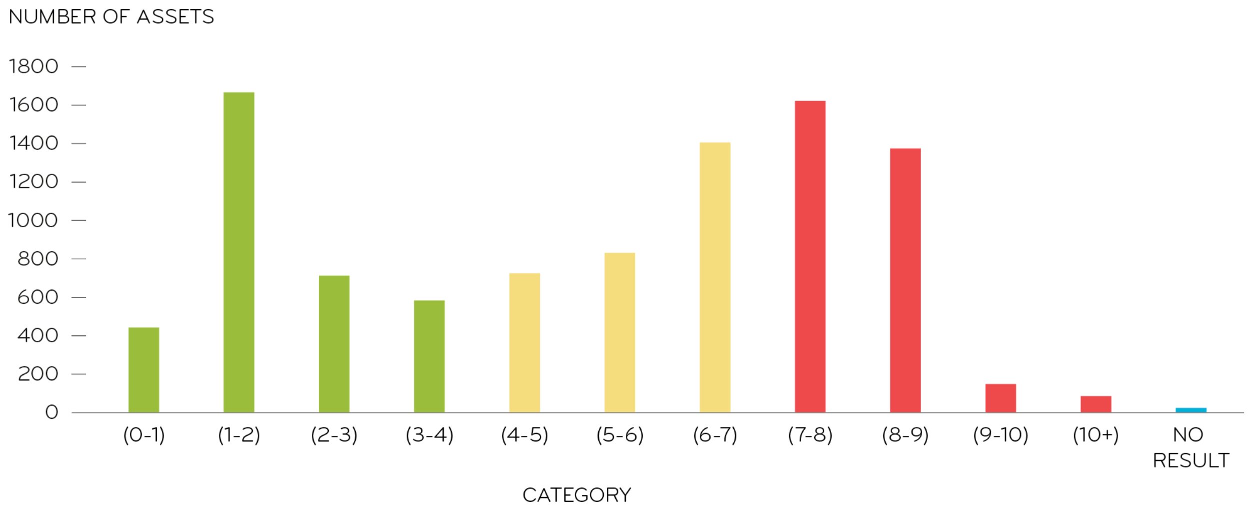

Figure 4-28 Asset Health at Year 10 - Distribution Ground Mounted Switchgear

Strategy

Our strategy for distribution switchgear relies on a deterioration in condition being identified by routine maintenance inspections and replacement undertaken as required by the risk under a corrective maintenance programme. Our concern is that the population has a similar age profile with large numbers approaching the end of expected service life simultaneously and a sudden increase in deterioration / asset failures becomes a higher probability and may encompass a greater number of assets that can be attended to under the budgeted corrective maintenance programme. The replacement strategy is to undertake a scheduled programme over a number of years, replacing oil-filled ring main units, with priority based on asset health, criticality and risk, including the lack of arc flash protection. Our CBARM model for this asset class is fully developed and is informing our replacement programme. Details of the replacement programme can be found in Section 5.

We have also commenced with a programme of works to enhance our HV feeder automation by adding more remote controlled switches at cross feeder ties, mid-feeder segregation and cross zone ties. Vector is targeting critical feeders first and areas where reliability will be enhanced the most (high SAIDI feeders – high criticality feeders) and add telemetry devices to the HV network at critical points to provide network visibility and links for Vector's Energy IoT. The additional network switches will also enhance the resilience of our HV distribution network in the sense that power will be able to be restored quicker.

4.6.2 DISTRIBUTION GROUND MOUNTED TRANSFORMERS

Overview

Whether in infrastructure systems, industrial and commercial areas or in suburban areas, transformers play a key role in the reliable distribution of energy to customers. For the future energy network distribution transformers will become even more pertinent as one of the major components for the flow of energy from distributed energy resources to customers. Our transformers are all oil filled and where we have to comply with environmental requirements due to oil volume, a transformer will be installed in a bund. For a very small number of transformers the windings are contained in a tank of synthetic organic ester and these transformers are used in situations where fire safety or protection of the environment (where other containment measures are not practical) are primary considerations, e.g. close to waterways. All transformers are fitted with manual tap changers.

Population and Age

Our ground mounted distribution transformer fleet ranges from small compact stand-alone transformers, transformers integrated as part of package type substations to ground mounted transformers as large as 1500kVA for high-rise buildings and large commercial or industrial customers. In the Northern network, the distribution voltage is 11 kV and in the Auckland area there are both 11 kV and 22 kV with 22 kV utilised in high density areas such as the CBD and Highbrook industrial estate. The Northern area has a large population of ground mounted transformers up to 250 kVA. The Auckland area on the other hand is more densely developed and hence has a larger population of transformers 300 kVA and above as is evident from the age profile graphs below. The table and three graphs below provide data for our 11 kV and 22 kV distribution ground mounted transformers.

DESCRIPTION	AUCKLAND	NORTHERN
No of distribution ground mounted transformers 11 kV / 415 V, 10 kVA to 250 kVA	2417	6020
No of distribution ground mounted transformers 11 kV / 415 V, > 250 kVA to 500 kVA	3364	1071
No of distribution ground mounted transformers 11 kV / 415 V, > 500 kVA to 750 kVA	542	157
No of distribution ground mounted transformers 11 kV / 415 V, 750 kVA	331	125
No of distribution ground mounted transformers 11 kV / 415 V, 1000 kVA	6	2
No of distribution ground mounted transformers 11 kV / 415 V, 1500 kVA	2	0
No of distribution ground mounted transformers 22 kV / 415 V, 250 kVA	1	0
No of distribution ground mounted transformers 22 kV / 415 V, 500 kVA	64	0
No of distribution ground mounted transformers 22 kV / 415 V, 750 kVA	54	0
No of distribution ground mounted transformers 22 kV / 415 V, 1000 kVA	53	0
No of distribution ground mounted transformers 22 kV / 415 V, 1500 kVA	5	0
Total no of distribution ground mounted transformers	6839	7375

Table 4-20 Key statistics for Distribution Ground Mounted Transformers

11 KV DISTRIBUTION GM TRANSFORMERS AGE PROFILE – AUCKLAND

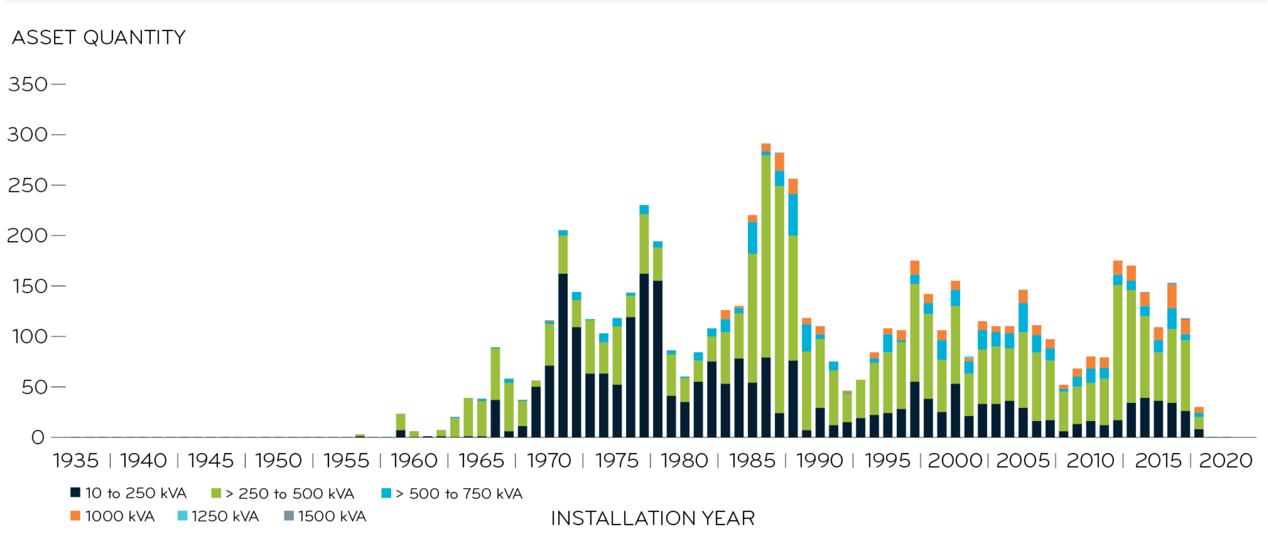

Figure 4-29 Age Profile for 11 kV Distribution Ground Mounted Transformers - Auckland

11 KV DISTRIBUTION GM TRANSFORMERS AGE PROFILE – NORTHERN

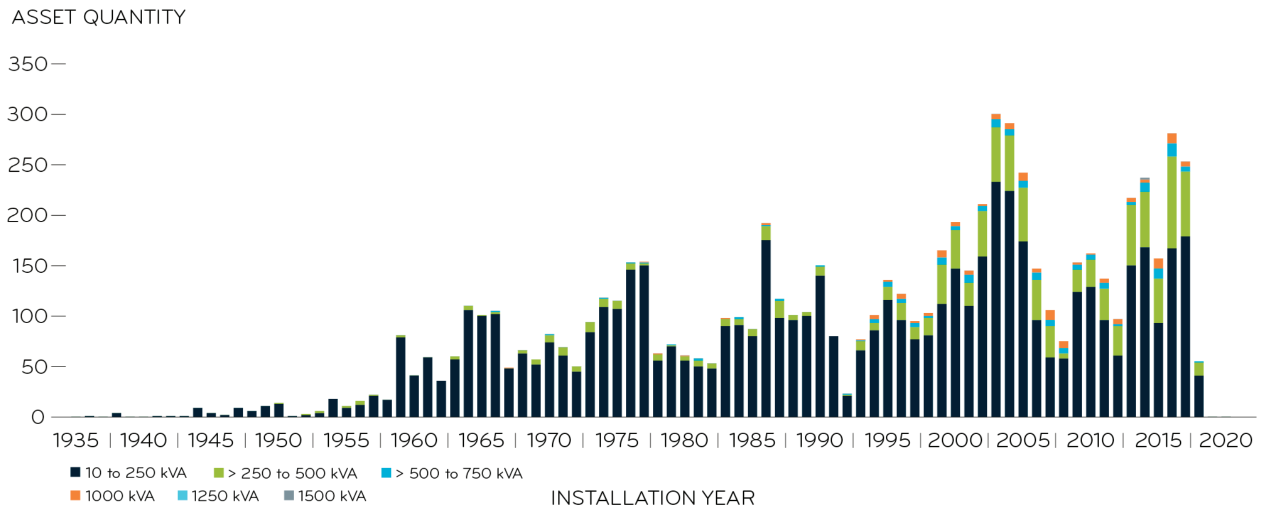

Figure 4-30 Age Profile for 11 kV Distribution Ground Mounted Transformers - Northern

22 KV DISTRIBUTION GM TRANSFORMERS AGE PROFILE – AUCKLAND

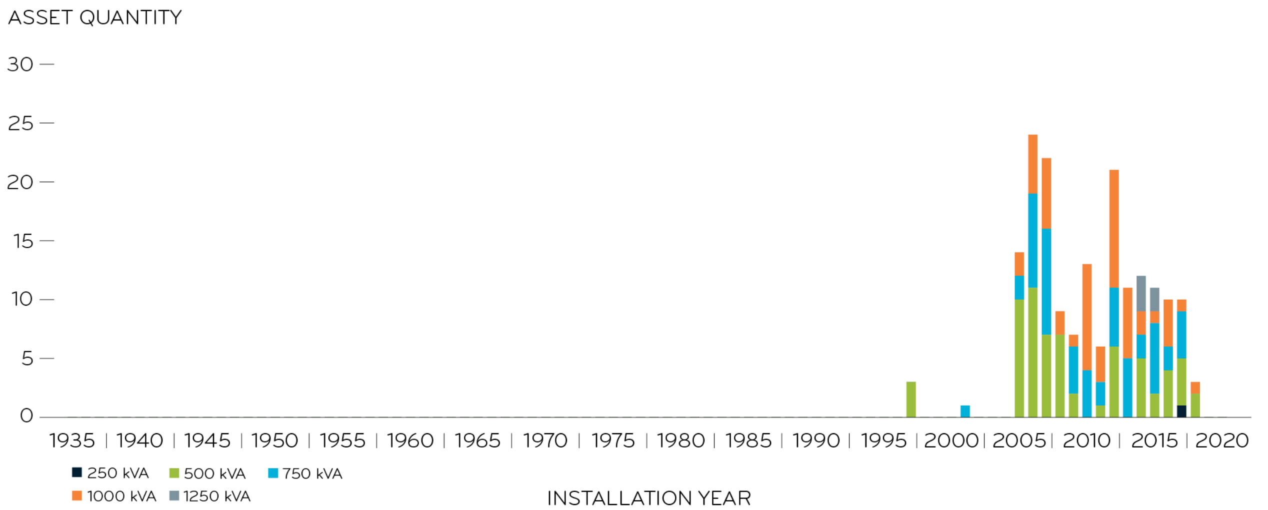

Figure 4-31 Age Profile for 22 kV Distribution Ground Mounted Transformers - Auckland

Condition and Health

Our CBARM model to inform our intervention plan for ground mounted transformers is fully developed and the first graph below, taken from our CBARM model for distribution ground mounted transformers, shows the asset health in year "0", i.e. the current year. The second graph shows the health index of ground mounted transformers if no intervention is undertaken in the AMP 10 year period.

ASSET HEALTH AT YEAR 0 – DISTRIBUTION GROUND MOUNTED TRANSFORMERS

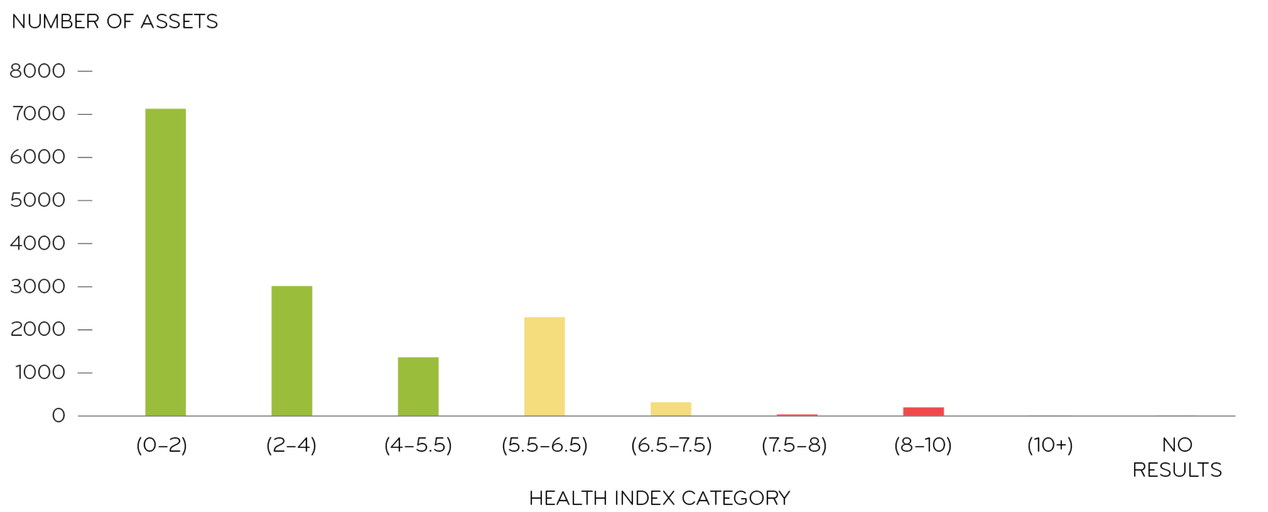

Figure 4-32 Asset Health at Year 0 - Distribution Ground Mounted Transformers

ASSET HEALTH AT YEAR 10 – DISTRIBUTION GROUND MOUNTED TRANSFORMERS

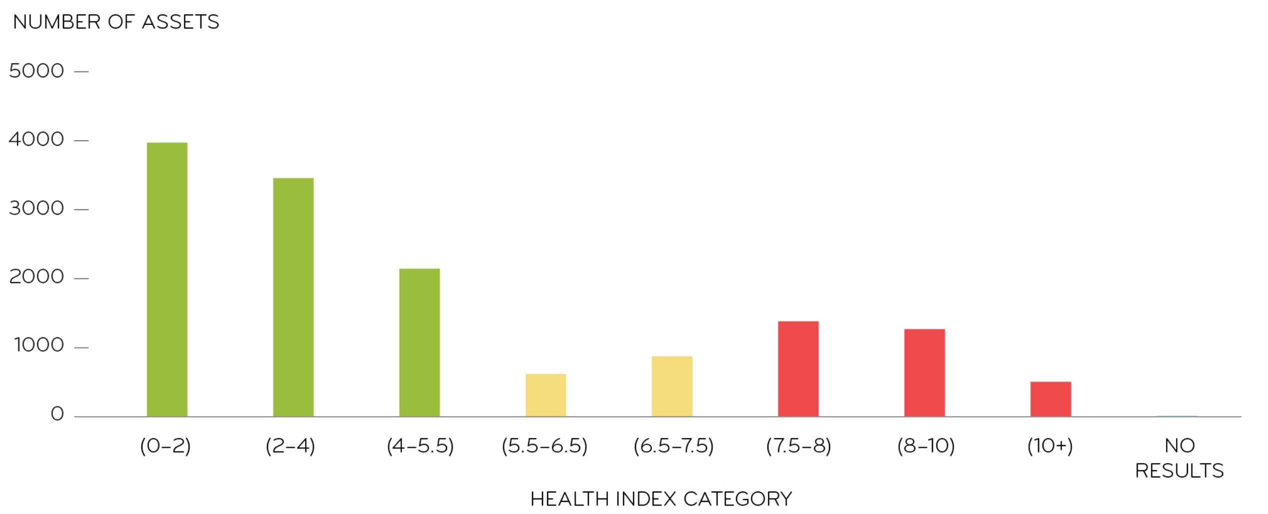

Figure 4-33 Asset Health at Year 10 - Distribution Ground Mounted Transformers

Strategy

Distribution transformers are maintained in accordance with Vector maintenance standard ESM503, Maintenance of Ground Mounted Transformers. Our present strategy is to replace transformers on failure. Transformers will not last indefinitely and have a stated asset life of 45 years and notwithstanding that there is no evidence of systemic failures, we will embark on a programme of targeted replacement using our CBARM model for this asset class in FY20. Transformer replacement is of course driven by network growth as well and as a result of overhead to undergrounding projects.

We have seen growth in distributed energy resources connected to the LV network and as DERs supplement (and in the future even start to replace) generation, the LV network and distribution transformers will require increased attention and focus. As noted previously, the lack of visibility of the LV network and distribution transformers is being overcome thanks to advanced metering infrastructure and digital equipment and we have developed a LV visibility and development roadmap. Trials are on-going at the time of writing, of equipment that will improve the visibility and controllability of distribution transformers.

The strategy also includes all new installations with transformers larger than 500 kVA having appropriate and fast acting arc flash protection in place on the high current, i.e. LV side.

4.6.3 DISTRIBUTION SUBSTATIONS LV FRAMES

Vector has a sizeable population of old style DIN-type vertical fuse disconnect LV frames. This style of LV frame holds a higher risk of arc-flash to operators when a fuse is pulled under energised conditions. Vector will undertake a risk-based assessment for a programme to upgrade to modern LV frames that for larger transformers (larger than 500 kVA) will include a CB to further reduce the risk and consequences of arc-flash. At the time of writing, this strategy is to be developed. Risks are covered by operational instructions.

4.6.4 DISTRIBUTION POLE MOUNTED TRANSFORMERS

Overview

Our population of pole mounted transformers are either 11 kV / 415 V three-phase or 11 kV / 230 V single phase transformers and they are the mainstay in our rural networks - we have no 22 kV pole mounted transformers. Pole mounted transformers are installed on either single or double poles depending on its kVA rating but because of seismic risks, pole mounted transformers larger than 300 kVA are not installed on poles.

Population and Age

The table and graphs below provide details of our pole mounted transformer population and age.

DESCRIPTION	AUCKLAND	NORTHERN
No of distribution pole mounted transformers 11 kV, 5 kVA to 30 kVA	431	4148
No of distribution pole mounted transformers 11 kV, > 30 kVA to 100 kVA	369	1451
No of distribution pole mounted transformers 11 kV, > 100 kVA to 300 kVA	988	23

Table 4-21 Key statistics for Distribution Pole Mounted Transformers

11 KV DISTRIBUTION PM TRANSFORMERS AGE PROFILE – AUCKLAND

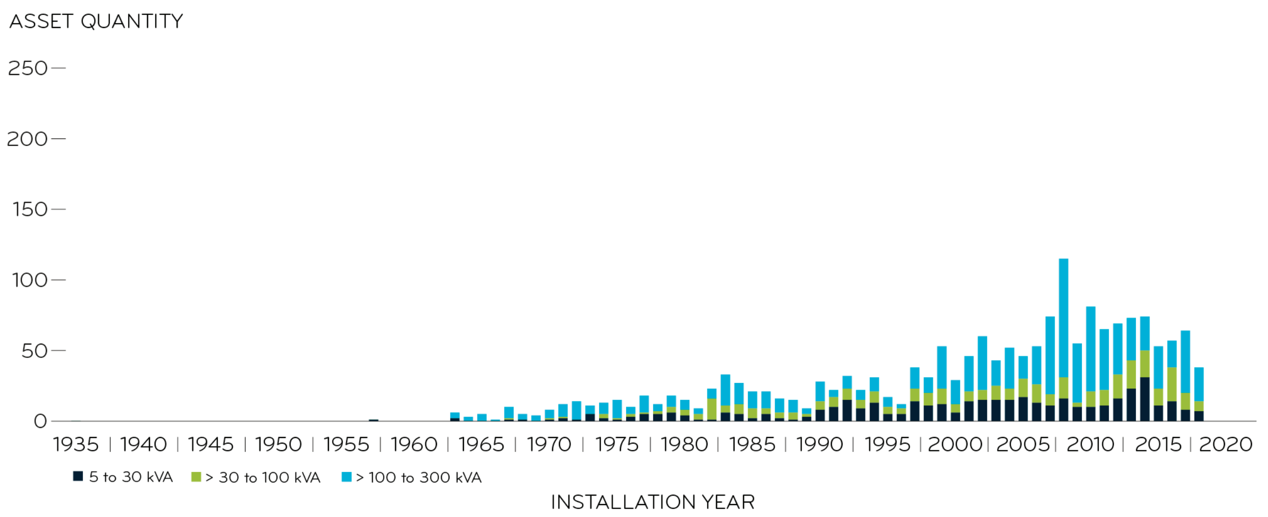

Figure 4-34 Age Profile for Distribution Pole Mount Transformers – Auckland

11 KV DISTRIBUTION PM TRANSFORMERS AGE PROFILE – NORTHERN

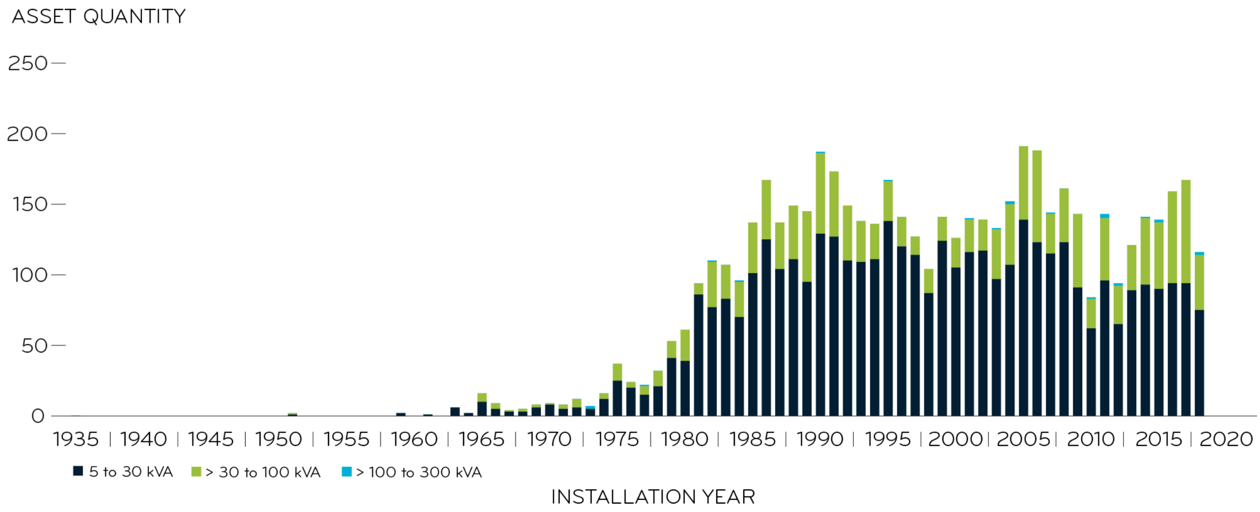

Figure 4-35 Age Profile for Distribution Pole Mount Transformers – Northern

Condition and Health

Our CBARM model to inform our intervention plan for pole mounted transformers is fully developed and the first graph below, taken from our CBARM model for distribution pole mounted transformers, shows the asset health in year "0", i.e. the current year. The second graph shows the health index of pole mounted transformers if no intervention is undertaken in the AMP 10 year period.

ASSET HEALTH AT YEAR 0 – DISTRIBUTION POLE MOUNTED TRANSFORMERS

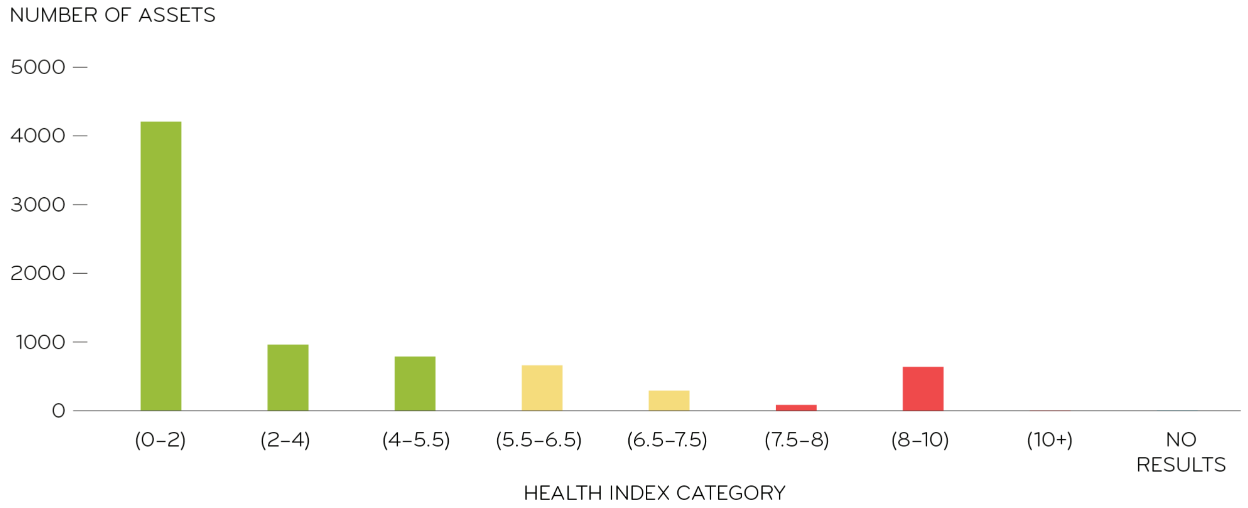

Figure 4-36 Asset Health at Year 0 - Distribution Pole Mounted Transformers

ASSET HEALTH AT YEAR 10 – DISTRIBUTION POLE MOUNTED TRANSFORMERS

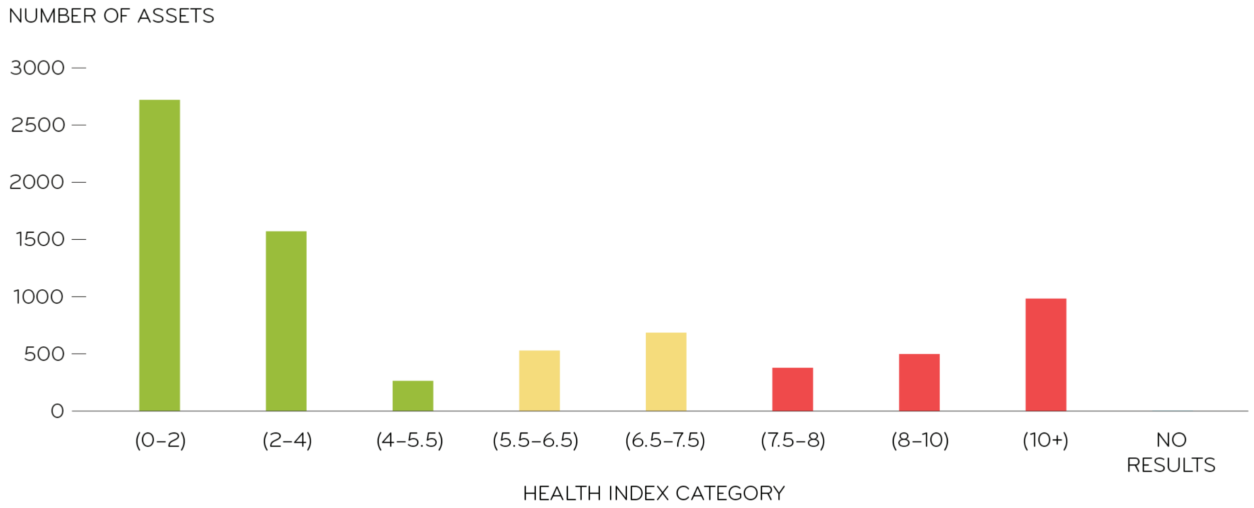

Figure 4-37 Asset Health at Year 10 - Distribution Pole Mounted Transformers

Strategy

Our pole mounted transformer fleet is maintained in accordance with ESM502 Maintenance of Pole Mounted but replacement on failure is done reactively and fault analysis has not warranted a programme of replacement. However, we have a number of transformers in this fleet that have exceeded the stated asset life for this asset class and we are planning an intervention programme based on asset health and criticality – our CBARM model will inform this strategy.

Smaller size pole mounted transformers in rural areas that are not meshed via an LV network will be less impacted by the future energy network and its management in terms of distributed energy resources. However, for larger distribution transformers in meshed suburban areas the same issue will apply as for ground mounted transformers, i.e. lack of visibility but this will be overcome by utilising advanced metering infrastructure and digital equipment as well as the installation of transformer sensing/monitoring devices to inform us in terms of energy flows and control as distributed energy resources gain mass in the network.

4.6.5 DISTRIBUTION VOLTAGE REGULATORS

Overview

Voltage regulators are normally used in long rural, and sometimes remote feeders to boost the voltage. Essentially, they are tap-changing autotransformers that maintain network voltage within desired limits and automatically produce a regulated output voltage from a varying input voltage.

Population and Age

Vector does not have a large population of voltage regulators in its network: only nine are installed and they exist on lengthy rural feeders in the Auckland and Northern networks.

Condition and Health

Our voltage regulators are in good condition, relatively young with no systemic issues.

Strategy

Voltage regulators will be installed as and when required to maintain the network supply voltage within statutory limits and to maintain service levels at Vector's customer service level standards. However ,to resolve network voltage quality of supply issues and/or service level issues preference will be given to the rollout of new technology options, e.g. microgrids, that will provide more than just voltage regulation improvement as a solution for remote areas. Before the rollout of a voltage regulator network, studies will be undertaken to select the optimum solution that will provide the best outcome to customers.

4.7 SECONDARY SYSTEMS

Secondary systems are those systems that do not carry load current but are crucial for the safe and reliable operation of the distribution network and its current carrying components. In most instances, secondary systems will exist in zone substations and in some cases in distribution substations. This asset fleet consists of protections systems, SCADA and communications, DC supplies, RTUs and power quality metering.

4.7.1 PROTECTION SYSTEMS

Overview

Protection systems are systems that take action during a fault, i.e. detects fault current, trips a circuit to remove the supply after a fault has started to remove the risk of damage to plant, operators and the public. Protection systems are needed to remove as speedily as possible any element of the power system in which a fault has developed. Protection systems include preventive systems such as a gas operated relay that detects gas accumulation produced by an incipient fault in a power transformer or a surge arrestor that prevents a dangerous rise of potential.

Population and Age

Our fleet of protection relays consist of modern numerical relays, static/electronic relays and electro-mechanical relays. Although electro-mechanical protection relays in Vector's subtransmission network are reliable, they have no data storage or computing capability to allow engineers to undertake proper and in-depth fault analysis or to analyse the impact on service levels. They are only able to provide trip alarms to the EOC. We have a wide range of electro-mechanical line differential protection schemes that date from the 1960s and in terms of skill sets to maintain these, it is becoming a challenge to employ personnel that are able to maintain and repair these schemes.

Our numerical IED protection schemes are based on standardised and modular designs that are laid out in the ESE800 suite of design standards and EDE8000 suite of standard design drawings. Vector has standardised on the IEC 61850 internet based communications system that allows for easy integration of new IEDs into its network. This standard also allows easy communications from SCADA to IEDs and between IEDs.

Our population for protection relays is shown in the table below.

No of numeric protection relays	1709
No of static/electronic protection relays	724
No of electro-mechanical protection relays	900
No of auxiliary protection relays	380
Total no of protection relays	3713

Table 4-22 Key statistics for Protection Relays

The graph below shows the age profile for our protection relays but due to legacy data issues there are inaccuracies in our data set especially for the older population of relays and our dataset include some estimates up to 1990.

PROTECTION RELAYS AGE PROFILE – AUCKLAND AND NORTHERN

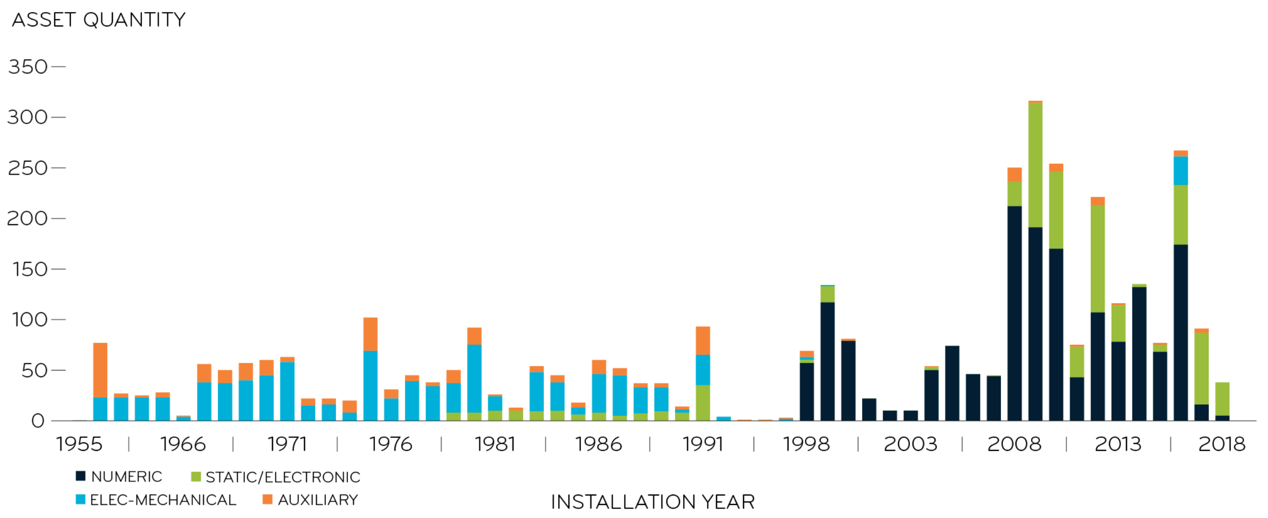

Figure 4-38 Age Profile for Protection Relays

Condition and Health

The population of numeric relays is relatively new and we have not experienced any systemic failures. The electromechanical relay population is reliable but the relays in this population that provides differential protection functions are at the mercy of an ageing and failing Copper pilot network.

Strategy

Vector's asset strategy for protection systems is described in strategy EAA801 Protection Systems. The power system is continually becoming more complex and this commensurate with higher expectations from customers to have a network with improved reliability and higher resilience has prompted Vector to invest in protection systems with advanced analytic and advanced protection functions. This programme commenced in the late nineties and is continuing.

Many of our OH lines share 33 kV subtransmission circuits with 11 kV distribution circuits and this has led to erroneous tripping because of mutual coupling for faults in the distribution lines with a commensurate risk to SAIDI and service levels. We have embarked on a programme of works to install numeric differential protection together with fibre optic communications channels to improve reliability and resilience. To improve SAIDI we are also embarking with a programme to replace electro-mechanical feeder protection relays with numerical relays on rural feeders to achieve fast clearance for switching onto faults, implement broken conductor alarming, improve our ability to have distance to fault information and to provide historical summaries and trends. Numeric relays are also more granular in their pickup settings and fault response timing.

4.7.2 TRANSFORMER MANAGEMENT SYSTEMS

Overview

Power transformers are a vital part of the electrical distribution network, but they are also large and expensive assets usually without spares readily available and with a very long lead time for replacement. As result of this, monitoring and diagnostic technologies focused on power transformers, are essential to provide a means to monitor transformers, predict failures, and proactively manage their performance. Transformer management systems(TMS) have migrated over time from various discrete electro-mechanical relays performing specialised functions such as voltage regulation and thermal protection to modern numerical relays that provide all the functionality in one device, e.g. voltage regulation on variable tap transformers, monitoring of key health conditions, monitor and control cooling systems and fans, and provide condition alarms and trips with advanced control, reporting and analysing functions.

Population and Age

Around 52% of TMS on power transformers have been replaced with modern numerical systems. Due to legacy issues, the age-related data for TMS especially in the Northern network is not reliable and hence an age profile graph is not included.

No of modern numerical transformer management systems	112
No of programmable logic controller transformer management systems	20
No of electro-mechanical transformer management systems	85

Table 4-23 Key statistics for Transformer Management Systems

Condition and Health

Technical and spares support for older electro-mechanical systems is becoming a challenge and older PLC TMS are technically unsupported but are being kept in service through our maintenance programme.

Strategy

The strategy for this asset is described in EAA802 Transformer Management Systems. Because of the fact that there is no spares available for both the electro-mechanical population and there is no technical support for the PLC based systems, in order to maintain service levels and reduce the risk of loss of supply, a programme is in place to replace all electro-mechanical and PLC based TMS in the next five to six years. This programme is described in Section 5.

As mentioned under the section on power transformers we are also preparing for a trial to implement dynamic ratings on a number of power transformers to extend the asset life and use of power transformers. If this trial is successful, the use of dynamic ratings as a tool to extend the life of power transformers will be rolled out further.

4.7.3 POWER QUALITY METERS

Overview

The future energy network in which distributed generation is gaining mass and the expectations of customers for a reliable and resilient network of high quality increase, combined with regulatory requirements, leads to the power system becoming more complex. This requires network monitoring equipment that provides high speed monitoring of electrical parameters with a given number of seconds before and after a trigger event. About two decades ago Vector embarked on a programme to install power quality meters to improve its visibility of the performance of the electricity network. PQMs assess the quality of power, identify the causes of any problems and check the effectiveness of remedial measures. Power quality is defined by a group of performance attributes and the four main functions are:

- Monitoring of harmonics;
- Detections of voltage sags and swells;
- Detection of transients; and
- Electricity supply compliance checking

In addition, we utilise a power quality metering system as a check of energy consumption at GXPs as measured by revenue meters. PQM also assist with the analysis of faults and our fleet of PQMs provide data to a separate PQM server at the EOC.

Population and Age

The age of the PQM population is approaching 18 years. The table and graph below summarises the population and age profile of the PQM fleet.

No of PQMs in the Auckland region	101
No of PQMs in the Northern region	34
No of PQMs in the Lichfield area	10

Table 4-24 Key statistics for PQM

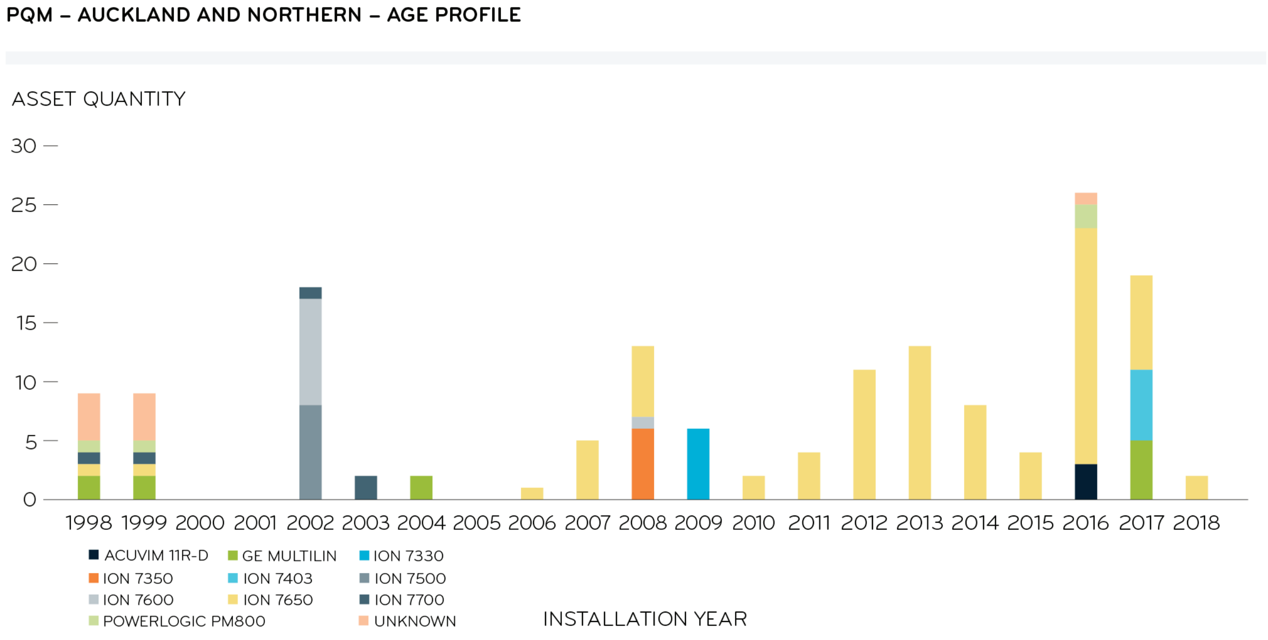

Figure 4-39 Age Profile for PQM

Condition and Health

Although we are not experiencing any systemic failures or issues with this asset class the software in the older versions are technically unsupported and cannot be upgraded to the latest PQM reporting software. Notwithstanding that the fleet is not in poor health there are other factors that drive replacement as described below under Strategy.

Strategy

Vector uses a standardised and modularised design for PQM panels, allowing easy interchange or replacements. To ensure continued technical support of the hardware and software, older models of our PQM fleet are being replaced. Furthermore, going into the future the regulatory regime will require more detailed reporting on under frequency events and in the new energy future the penetration of DERs will place a higher priority on this reporting - the PQM fleet will be used for this purpose amongst others. Any replacement PQMs will have rapid capture functionality to comply with the regulatory requirements of the New Zealand generation market to provide high speed monitoring of electrical parameters for a period with a given number of seconds before and after a trigger event. The PQM fleet is also used to trigger interruptible load (hot water load shedding via ripple plants) in the Auckland region.

4.7.4 NETWORK AUTOMATION SYSTEMS

Overview

Communication and network visibility are the backbones of the automation system and the RTUs in the network form a highly critical and essential part of the SCADA system. They collect information on the status of the network and allow remote control from Vector's EOC of a large variety of plant in our zone substation and numerous sites in the suburban and rural networks The LANs and RTUs also provide visibility to the control centre of the status of the network and provide metrics of a large number of parameters. It also provides alarms when plant is reaching or exceeding capacity. Furthermore, data that pertains to access, security, fire detection and unlawful access are all dependant on RTUs.

POPULATION AND AGE

The asset life of an RTU is 20 years but Vector still has RTUs from the late eighties in operation. The table below is a summary of our RTU population and the graph shows an age profile.

No of RTUs in the Auckland region	237
No of RTUs in the Northern region	156
No of RTUs at Lichfield	3

Table 4-25 Key statistics for RTUs

RTUS AGE PROFILE – AUCKLAND AND NORTHERN

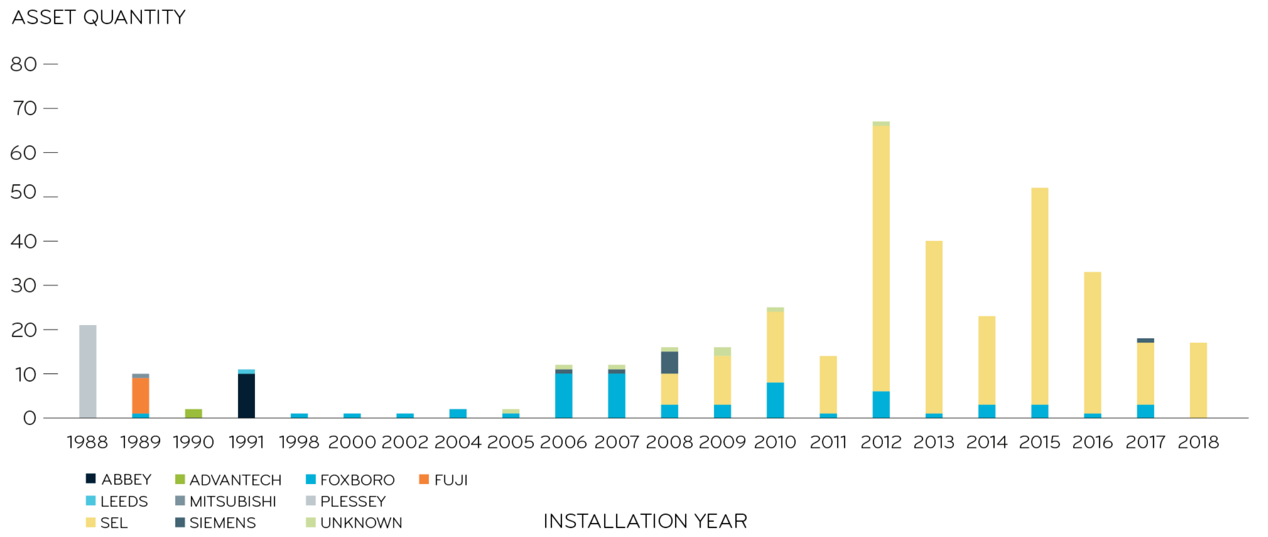

Figure 4-40 Age Profile for RTUs

Condition and Health

Our 1980s to late 1990s RTU fleet is reaching end of life and is not technically supported anymore with no spares available from suppliers. Failure of RTUs in load control installations results in loss of load control and loss of control of streetlights. Failure of other RTUs result in loss of visibility of substation plant and loss of remote control with commensurate health and safety risks as well as a risk to the reliability of the system.

Strategy

Vector has a standardised and modular design for substation LAN systems that is described in design standard ESE802, Automation and Control in Zone Substations and the EDE8004 suite of design drawings. These modular designs are used for zone substation refurbishments and new zone substations.

To ensure continued control and visibility of substations and continued load control there is a programme to replace technically unsupported RTUs over a number of years. The new units will be suitable for the transfer of large volumes of data and will also be suitable for our new initiatives that will include on-line transformer gas analysis, cable partial discharge, temperature sensing and will offer optimal scalability for the number of interfaces and signals required for the future energy network. The Asset Strategy for zone substation automation systems is detailed in Vector's asset strategy EAA805 Automation Systems.

4.7.5 DC SUPPLIES

Overview

The proper functioning of protection systems and the reinstatement of electricity in the zone substation after a fault are reliant on able and trustworthy DC systems. The DC system is continuously charged as a back-up power supply in the event of an AC outage on site. DC auxiliary systems provide supply to the protection, automation, communication, control and metering systems, including power supply to the primary equipment motor driven mechanisms in zone substations.

In our zone substations we have standardised on 110 V DC systems but utilise 30 V DC in distribution substation sites. The battery chargers simultaneously supply 110 V DC to the zone substation protection and control systems and float charging to the 110 V DC station battery bank(s), (aka 'strings'). For an alternating current (AC) failure event of the battery charger the battery banks provide an unswitched 110 V DC supply to the protection and control systems, i.e. as an uninterruptable DC supply. Battery monitoring is essential to ensure battery systems continue to have the capacity to operate equipment during a supply outage and to enable restoration of supply once any contingency has been rectified. Battery voltages are alarmed to the SCADA system to alert the EOC to low battery voltage.

Population and Age

We have a total of 331 DC systems in service in zone substations, communications sites and a number of distribution substations. The table below provides a view of our DC system population (due to legacy data deficiencies a population age graph is not provided).

No of Autoamp 30 V DC chargers	5
No of Benning 110 V DC chargers	62
No of Century Yuasa DC chargers	1
No of Cordex DC chargers	80
No of Innovative Energies DC chargers	127
No of MHS Technologies DC chargers	7
No of Powernet DC chargers	1
No of Santon DC chargers	28
No of Switchtec DC chargers	1
No of Westhinghouse DC chargers	3
No of unknown brand DC chargers	16

Table 4-26 Key statistics for DC Systems

Condition and Health

Vector's zone substation battery chargers are progressively reaching end-of-life and are now showing an increasing failure rate compounded by limited replacement stock availability.

Strategy

Vector has standardised and modularised its design for DC systems and the modular designs are in accordance with Vector's design standard ESE601 DC Systems. Vector's asset strategy for DC systems is described in strategy report EAA601 Auxiliary Systems.

The risk for Vector customers is that without a reliable charger supply the zone substation will fail within the 24-hour capacity of the 110V battery string. To ensure continued reliable provision of DC in zone substations and other sites in which a reliable DC supply is required we have commenced a programme of works to replace certain types of DC chargers. Most of the units that will be replaced are from our ageing fleet of Benning-type chargers and this programme has commenced in RY19. With regard to battery strings, as a general rule DC strings are replaced every 12 years under a rolling replacement programme. Sites will be prioritised by the criticality of connected customers and the age, condition and failure history of the charger.

4.7.6 EARTHING SYSTEMS

Overview

Earthing systems are required to minimise the risk of electric shock, limit earthing system related over-voltages on the network, ensure the operation of protection and carry earth fault currents safely. Earthing is normally specifically designed to meet established performance criteria. Every zone substation has an earth grid, 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 together via bare copper conductor. Copper is both an excellent electrical conductor and mechanically resistant to in-ground corrosion.

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 resistivity and covering (e.g. metal chip and asphalt) must be included in the overall analysis of earth system performance and are covered by step and touch voltage measurement.

Condition and Health

The condition and health of earthing systems are essentially determined by visual inspection and testing. Theft of copper earthing conductors has been an ongoing issue for some time. The problem with earthing conductors is that they can be removed without causing an outage and therefore without raising an alarm to the EOC via SCADA. This can present a hazardous situation when there is a fault and the earthing system is no longer able to perform as it is designed – hence a rigorous regime of visual inspection. Some of the earthing arrangements for lightning arresters in our network are sub-optimal and may result in poor performance of the arresters – we have initiated a project to investigate lightning arrestor earth banks and voltage coordination in general.

Strategy
Earthing systems for zone substations are installed in accordance with Vector engineering standard ESE704 Zone Substation Earthing. Earthing systems for the distribution network are installed in accordance with Vector engineering standard ESE506 Distribution Earthing. Vector's asset strategy for earthing systems is described in strategy report EAA600 Auxiliary Systems. Earthing systems are maintained and tested in accordance ESM603 Maintenance of Earthing Systems to ensure the integrity of earthing systems and its capability to carry fault currents and limit step and touch potentials. Zone substations and distribution earthing have a thorough testing regime that is performed every five years.

LV pillar earthing is only to improve (lower) the overall MEN system resistance and is not installed to limit step and touch resistances and as such it is not tested but visually inspected as part of the maintenance regime. 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. Over more recent times Vector has switched to copper-bond steel earth rods and copper-clad steel conductor.

Earth studies and measurements are undertaken for every new zone substation or BESS project to provide the necessary baseline information to design the new earthing system to ensure quick and efficient operation of protection systems and ensure safe step and touch potentials.

4.8 COMMUNICATIONS NETWORKS
Vector operates an open communications architecture based on industry standards. The deployed technologies range from copper based buried cables to first generation optical fibre multiplex systems, to modern digital microwave systems and Ethernet based optical fibre networks. Vector's communications network also consists of differing architectures and technologies, some of which are based on proprietary solutions. The physical network infrastructure consists of a mix of optical fibre, copper wire telephone type pilot cables and third party radio communication systems.

4.8.1 PILOT CABLES
Overview
In the Northern network, around 70% of the pilot cables used for operational communications are installed overhead and are prone to damage by the environment and lightning. The mostly copper pilot cables in the Auckland region are all installed underground. They are used for operational communication services and differential protection and alarms.

Population and Age
The copper pilot population is 50 plus years old. The pilot cable population in our dataset consists of many thousands of lines and it is not practical to compile age profiles or a key statistics table.

Condition and Health
Our Copper pilot cables have experienced some failures and their health is deteriorating. Fault finding on LV pilot cables is difficult, cumbersome and expensive.

Strategy
Copper pilot cables simply do not have the bandwidth to cope with the data communications requirements of the future energy network and our population is not in sufficient health to ensure reliability and resilience into the future. Hence, we have gradually been replacing Copper pilot cable with fibre optic cables and since 2006 we have been implementing an internet protocol (IP) based communications network.

In light of the deterioration of the Copper pilot cables we are also systematically replacing subtransmission differential protection schemes with modern numerical protection schemes that use fibre optic communications channels (see the section above on protection relays). This replacement programme will continue for the first half of the AMP period. Not only will this improve the reliability of line differential protection schemes and SCADA but make provision for the expected increase in communications bandwidth as part of the Distributed Energy Resource Management System (DERMS).

4.8.2 RADIO LINKS
Overview
Several digital microwave radio links were installed about 10 years ago to extend the IP operational WAN to zone substations in the Northern region. There are 295 overhead 11 kV network switches with SCADA remote control ability on

our 11 kV overhead network. Of these units, 56 use Very High Frequency (VHF) radio for communications and the remainder use 2G cellular communications. For communication to distribution substations Vector uses commercial cellular 2G/3G networks. Distribution substations that are remote controllable is equipped with an IP based layer 3 wireless router. The Northern region legacy radio system is based on six (6) base stations and one repeater to cover most of the area. It is used for voice, data communication and demand side management applications. In the Auckland region, a similar radio network was installed which consists of two base stations and three repeaters and one zone substation and five distribution substations are connected to the master station via this radio network. Data and communications between the EOC and the communications modules on 11 kV network switches are via the Conitel protocol and VHF analogue radio.

Population and Age

The expected life for digital mobile radio equipment is about 10 years. This has now been reached and the equipment is planned to be replaced over the next five years.

Condition and Health

The Digital Mobile Radio (DMR) network is performing well given its age. To date there have been only very few failures. There are no systemic issues with the wireless 2G/3G routers but a hardware refresh will be required in the next three years. Furthermore, the 2G cellular network does not provide sufficient coverage and this will also drive an upgrade of the 2G network.

The VHF radio system has reached its end of life and the Conitel protocol is obsolete and firmware and software cannot be updated. Intermediate protocol convertors are required and this has resulted in loss of information and loss of SCADA visibility in the EOC of the status of 11 kV switches.

Strategy

The network is continually adapted to meet Vector's specific needs and this has resulted in the adoption and deployment of Ethernet and IP based communication technology. 2G and 3G will become redundant in the 2020s and Vector will migrate to 4G and 5G. The Auckland radio network is performing satisfactorily but will become obsolete and is to be retired in the next five years.

The subtransmission supply between Albany GXP and Coatesville zone substation is prone to mutual coupling and erroneous tripping – this issue can be solved with unit differential protection but the installation of a fibre optic cable to this remote zone substation will be prohibitively expensive. In FY19/20 we will undertake the first installation of its kind in our network where we will use a digital micro wave link between zone substations for line differential protection to improve the reliability of the subtransmission to this rural area.

4.8.3 NETWORK ROUTER REPLACEMENT PROGRAMME

Overview

The Zone Substation's Local Area Network (LAN) is able to communicate with the Vector Wide Area Network (WAN) by means of Routers. The Routers ensure that SCADA data traffic is prioritised and relayed across the Vector WAN to the appropriate destinations. Routers also use dynamic routing techniques to help to reduce network traffic. The substation LAN is based on a resilient optical ethernet architecture compliant to IEC 61850 Standards.

Population and Age

The routers in in our zone substations are the Cisco 2811 model for which Cisco has made an end-of-sale and end-of-life announcement in 2013. Hardware and software support for the Cisco 2811 ended in 2014. Cisco has stopped all support for the Cisco 2811 in November 2018.

Condition and Health

The population of Cisco 2811 routers is approaching end-of-life and is unsupported.

Strategy

Our strategy is to undertake a programme of replacement of the Cisco 2811 routers with the new standard CGR2010 routers – see Section 5 for full details of the replacement programme. This programme of works will be coordinated with the replacement of Copper pilot cables with fibre optic communications channels.

4.9 OVERVIEW OF OUR DIGITAL NETWORK ASSETS

To enable us to support the objectives of the Asset Management Plan through our information systems and digital platform reference model discussed in Section 4.1.13, we have classified our data and information systems, associated capability statements, strategy and lifecycle management approaches according to the functional areas they enable. This enables clear, functional assessment of core capability and consistent terminology and classification across the business internally and externally.

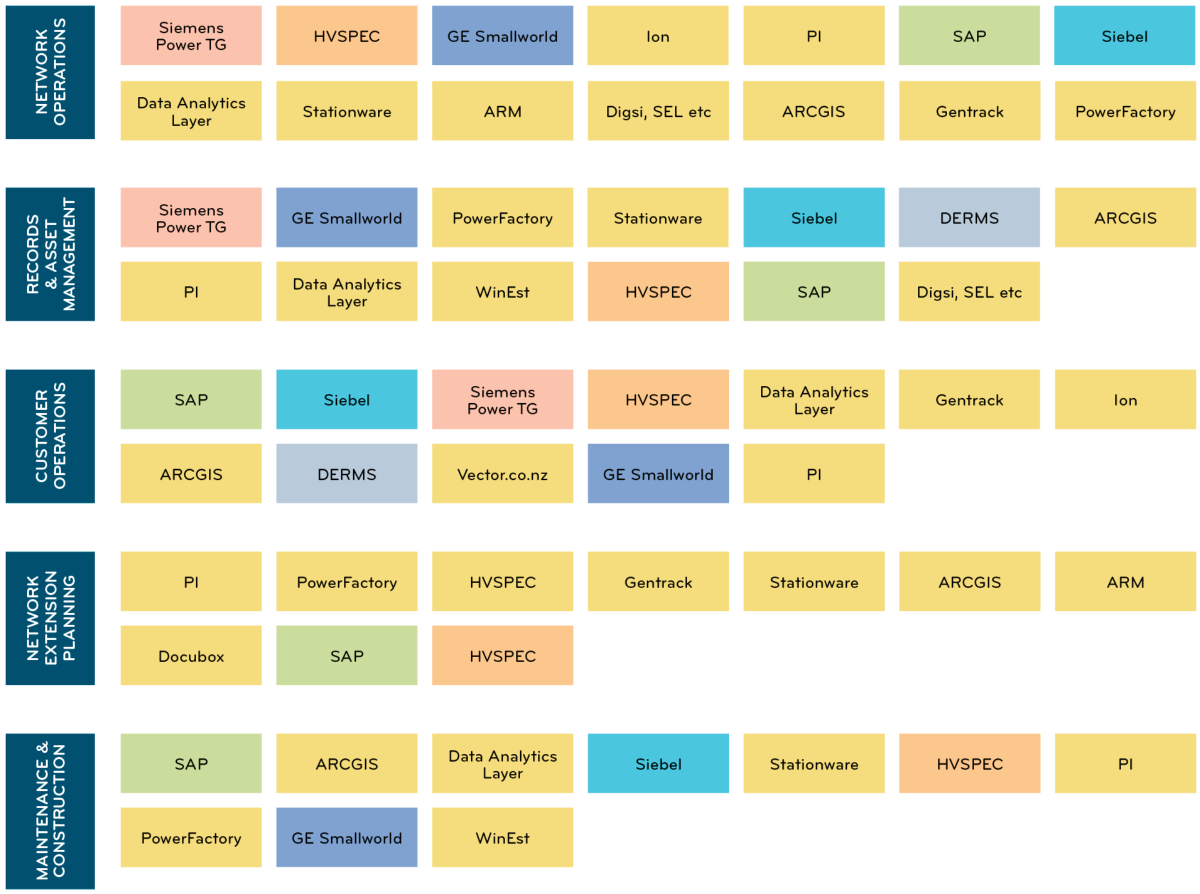

Figure 4-41 Network asset information systems mapping

4.9.1 NETWORK OPERATIONS

Overview

The Network Operations domain reflects the need to both actively and passively monitor, manage and optimise the assets to deliver our targeted outcomes. This includes core capabilities such as network control, monitoring, reporting, switching, real time operations and simulation.

The Electricity Operation Centre (EOC) monitors the network 24/7 using Vector's SCADA system, ensuring real-time monitoring and control of Vector's electricity network. As more customer-side Distributed Energy Resources (DERs), such as solar and battery installations and rapid EV chargers appear on our network, managing the impact of these DERs on our network is presenting challenges which must be overcome to ensure the best outcome for our customers and the network itself. Also of key importance is outage management, which includes planned and unplanned outages as well as fault management and analysis, and the feedback and analysis needed to ensure network architecture, processes and systems are being improved after faults and other incidents occur. Due to changing weather patterns and higher incidence of extreme weather in recent years as discussed in Section 1, we now need to take live weather feeds into account when planning and operating the electricity network rather than only use historical information.

Current state & stage in application lifecycle

The system landscape is dominated by Siemens Power TG as the SCADA system and the Vector DERMS platform which gives increased visibility of the DERs on the network. A further central server enables access to the data from the Power Quality meters deployed (see Section 4.7.3) for post fault and incident investigations, and customer enquiries.

Some legacy systems like SCADA, Historian and HV Spec are nearing at the end of life or will need significant changes to meet the evolving needs of our customers or the network. The rising importance of the LV network due to increasing numbers of DER's and the electrification of the transport network requires a step change in system sophistication and capability.

We are focusing our efforts in the outage management space, following the severe April 2018 storm, to make use of new options available to enable us to improve the customer's experience during emergencies. Our key focus is to create capabilities that allow us to pivot and adjust to the changing environment we are operating in. If there is a sudden update or advancement of PV, battery or EV technology, we need to react quickly to integrate and manage the change to meet customer expectations to avoid having to invest heavily in traditional assets as a potentially short-term solution.

The graphic below shows the layers of sophistication in the network operations and network planning environment which need to be met.

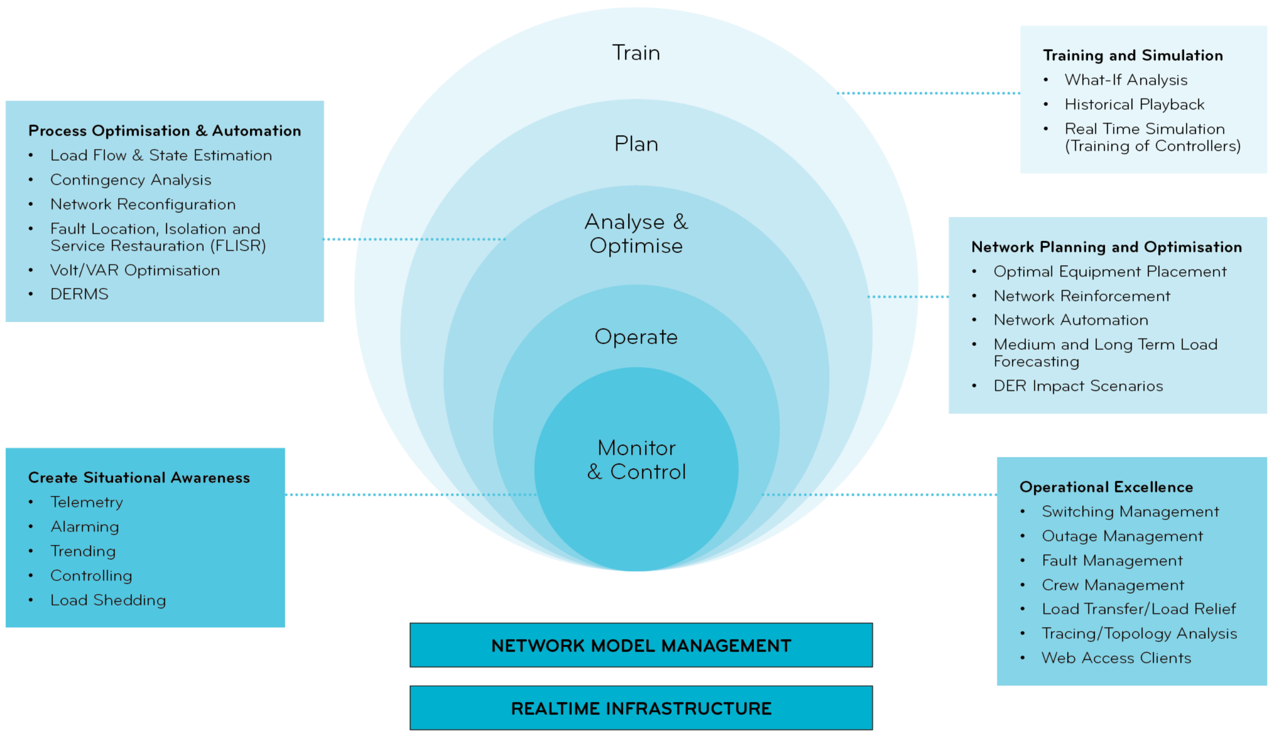

Figure 4-42 Levels of Sophistications in the Network Operations stream

A key enabler for our Asset Management Strategy is network connectivity and topology management. Traditionally, the GIS is a non-operational system, mainly used for asset management, planning and engineering purposes. Our strategy requires the GIS to become an operational system and the central repository of data for network topology, on which systems like SCADA, Outage Management and DERMS are heavily reliant for providing accurate and timely information.

Strategy & Plan for period

Our strategy, when evaluating options for the SCADA system, revolves around outage management and electronic switching capability. A more integrated and automated outage management system will provide visibility of outages during major events and will enable Vector to integrate fully with outage data from smart meters and LV sensors. We are exploring the benefits of Advanced Distribution Management Systems (ADMS) capabilities to further enhance our network operations by integrating with SCADA and DERMS.

To be able to improve our management of power flows in the LV network, especially in terms of outage management and reinstatement of the network to enable us to manage customer service levels, more information and visibility of the LV network is needed. This will require Vector having access to data from the fleet of smart meters in the network in the first instance. It could also include the installation of sensing devices in the LV network to inform our assets management systems.

At an 11kV distribution level Vector is considering the following options to manage the impact of the increasing uncertainty in customer behaviour and the take-up of new technology:

- 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. This is 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).

4.9.2 CUSTOMER OPERATIONS

Overview

Customer Operations is a core capability to enable Vector to deliver services to its customers, partners and stakeholders. The customer operations capability fundamentally relies on our ability to provide accurate, relevant and timely information into all our customer channels, at the optimised cost to serve. The multi-channel service capability that delivers this will give customers more choice on how they engage with us and allows us to balance our mix of channels – direct, indirect, online, contact centre and face to face.

Customer Operations defines the capability we have to respond and react to network issues that impact our customers. It is how we manage customer concerns and feedback, billing and connections and customer records. We continue to enhance our customer experience and give customers more choice on how they engage with us by adopting more engagement channels and a digital first approach in support of more self-service channels. We are therefore continuing our implementation of additional customer channels (such as conversational 'bots', voice recognition and pro-active outbound multi-channel communications). In support of our continuous improvement strategy, we are enabling customers to provide real time feedback on our performance.

Current State & Stage in application lifecycle

Our approach to customer support evolves around alignment with customer expectations and will drive more investment in digital-first and self-service channels over the period covered by the AMP. This will necessitate investment in digital system providing this capability such as Siebel (Customer Account Details and trouble ticketing), SAP, Gentrack (Customer Billing and Invoicing) and to a lesser degree HV Events.

Strategy & Plan for period

Our strategy is to invest in new, enabling capability to meet our customers' preference for more self-service and need for accurate and timely information. As such, we will continue to develop multi-channel customer engagement capabilities over the period of the AMP. Investment in customer channels will reduce from RY24 onwards, except for allowances for continuous improvement based on customer feedback.

With Vector's field work outsourced to our Field Services Partners (FSPs) and other external parties, we maintain a significant engagement model to ensure a secure and reliable information exchange with Vector. There are multiple points of interaction with the various service providers, ranging from direct access to our information systems to alternate indirect means for accessing and providing information. The development of secure, scalable and reliable interfaces with our service providers is therefore a key focus for the initial period of the AMP.

4.9.3 MAINTENANCE & CONSTRUCTION AND RECORDS & ASSET MANAGEMENT

Overview

In line with our stated objectives and to enable Vector to deliver on its asset management strategies as per this AMP, a number of digital system and applications are used to inform asset management, with the three primary systems used for this purpose being SAP-PM, GIS and CBARM. These systems are used to plan and inform both capital investment and maintenance investment.

Current state & stage in application lifecycle

SAP-PM holds records of our regulated assets, their financial value, depreciation, procurement history, accounting data and financial control history. SAP-PM is also used as the repository for planned maintenance by our FSPs and enables auditing of planned maintenance activities by Vector engineers.

CBARM is informed by our SAP-PM database and provides a view of the risk of condition based failure of network assets. It contains indices that measure health and criticality and is our tool for making decisions for our programme of works to replace assets in the AMP period. We currently have fully developed CBARM models for the following asset classes: overhead conductors, distribution transformers and 11kV ring main units. Development of CBARM models for our other asset classes (power transformers, primary switchgear and cables) is in progress.

GIS provides the geospatial view of our regulated assets and informs the day to day planning of our asset management as well as our long-term asset and network strategies. This system includes data of electrical attributes of assets, connectivity, land base data, topological maps and photographs. It is also the primary repository that additions and deletions of assets.

Strategy & Plan for the period

We will continue the granularity of our assets data, historical and new, in the SAP-PM database into the CBARM models, addressing gaps identified in the SAP platforms used by our FSPs. This stems from historical paper-based record keeping, which in many cases had incomplete data.

We are continuing our focus on data cleansing within the GIS system to ensure that the geospatial views and layouts that inform asset management, maintenance planning and investment are accurate.

The investment strategy during the period covered by this AMP for these key systems is anchored by the planned investment in the plant maintenance module of SAP (SAP-PM). This will enhance our asset replacement, planning and maintenance capabilities by centralising operational history, providing additional auditing capability for planned and corrective maintenance activities and incorporating financial transactions. Operational data will be captured and updated directly for each asset through the mobile devices our service providers use.

We will continue to complete our fleet of spreadsheet-based CBARM models for our different asset classes, however they will be systemised in the longer term as part of SAP-PM; this means that an up to date and live version of the model will always be available.

4.9.4 NETWORK EXTENSION PLANNING

Overview

Data, information and insights that enable the planning process for activities such as demand forecasting are mainly stored in the Historian (OSI-PI) system.

Data from PI is used as an input into the network modelling tool (DigSILENT PowerFactory). In addition to the data from PI, the network model is kept up-to-date with network connectivity and characteristic data (e.g. cable length, size, composition, etc) from GIS (GE SmallWorld). Regular downloads from GIS ensure the quality of the information used for modelling.

Current state & stage in application lifecycle

PowerFactory is expected to remain as our key modelling tool, but with ongoing investment to ensure appropriate software modules developed by DigSILENT are added to the current system. DigSILENT is also used as a modelling tool by our protection engineers for grading field protection.

Modern SCADA systems include Historian functions so with the planned investment in the SCADA replacement and the newly built data lake there is no need for a dedicated Historian in the long term. This is will be confirmed through the planned SCADA replacement project.

Strategy & Plan for Period

The introduction of new technologies (e.g. Solar PV and storage batteries) could lead to the injection of energy into the LV network from external sources. This was not envisaged when the LV network was designed. To manage this risk, we are increasing our visibility of the LV network by the following:

- Increased demand and voltage monitoring capability of the LV network
- Improved analytical tools. Field data providing demand and voltage information needs to be filtered to identify those parts of the network likely to breach regulatory or ratings limits. This will enable remedial works to those targeted areas.
- Improved capability, since our network model needs to cater for new technologies to be modelled

MANAGING OUR
ASSET'S LIFECYCLE

SECTION 05.

SECTION 5. HOW WE MANAGE THE LIFECYCLE OF OUR ASSETS

There will be a need for traditional assets across our network for many years to come but we are continually seeking to embrace better ways to grow and improve the network to meet Auckland's needs, while balancing growth, costs and network resilience. There are powerful forces shaping the energy sector, both here in New Zealand and around the globe. Enveloped in continuous change, planning long-term network investments is more challenging than ever before lending itself to a scenario-based forecast described in Section 1. This section describes our investment proposals for the next 10 years by way of the 'needs management' process as described and illustrated in Section 3.

Climate change is making network resilience and sustainability more of an imperative in everything we do. We must mitigate and adapt to the physical impacts of climate change as well as the economic impacts associated with decarbonising the economy. Various studies point to the high likelihood that extreme rainfall, severe droughts, wildfires and strong winds could hit Auckland in years to come. Those parts of the network whose resilience is doubtful will need investment to ride out these storms and this particularly applies to ageing overhead networks in areas known to be exposed to high winds. We also have an issue with small-diameter conductors that are showing an increasing rate of failure. Our investment proposals will help us achieve our service-level targets by addressing both current and forecasted performance issues[14] and they will help us realise our network vision as described in Section 1. The capital investment proposals in this section also align with our asset management strategies as described in Section 4. Furthermore, our focus will move from a reactive approach to proactive approach where replacement and refurbishment are undertaken as proactive programmes of work informed by our CBARM models, condition assessments and criticality.

Our projects are categorised in this section as three main groups namely: Network Development programmes, Operate, Maintain, Renew and Replace programmes and Non-Network (Information Systems or Digital) projects and programmes of work. Projects comprise both standalone projects, where investment is focused on a specific asset and need, and programmes of work where a series of projects address the same need in different locations in the network or deliver an enabling need. Our proposals for capital investment are described in the following way in this section:

Need: The need sets out how the project is aligned with our service-level targets (see Section 2). It also addresses any shortfalls in performance and strategies (see Section 4) or specific needs. Any risks relating to the network's ongoing performance are also highlighted. The close alignment with service levels ensures projects are in accordance with our asset management objectives.

Targeted Outcomes: The targeted outcomes describe seven drivers/outcomes that our projects and programmes of work should address and support. Each project or programme of work contained in the section below has a table in which the drivers and targets that relate to that project are clearly marked.

Options considered: Viable options to address individual needs are set out in an options table for each proposed capital investment project or programme of work. Where applicable, options consider non-network solutions and innovations, and investment deferral. The options table includes the expected cost of the preferred option and the reason for choosing it, and rejecting others, plus the post-investment risk.

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14 See Section 2 for details of performance issues

Investment summary: Our investment summary table shows our expenditure forecast for the project or programme for the next 10 years in New Zealand dollars. The forecast annual expenditure is expressed in financial years and all amounts are shown in millions of dollars.

5.1 NETWORK DEVELOPMENT

Auckland is the largest urban area in New Zealand. It is also one of the fastest growing cities in the world, and accounts for a substantial part of New Zealand's economy with the largest GDP by region in New Zealand[15] - Auckland's share is 37.5%. A safe, reliable, economically competitive and environmentally sustainable electricity network is a cornerstone of a strong and prosperous Auckland economy.

At the same time, our customers' preferences and expectations are changing. They want fewer carbon emissions, greater choice and real-time interaction. They also want a sharing, always-on connection, along with greater transparency, a personalised experience and opportunities to learn – through services more than products.

To meet both our existing and our future customers' needs, we are aligning our network planning approach to the Symphony model described in Section 1. We aim to be both more diverse and customer-centric. Our new approach promotes a lower cost, smarter, more decentralised but more connected network. One that enables customers' DERs to actively participate in providing resilience and improving network asset use.

Network development project proposals for the next 10 years that relate to the expansion and interconnection of the network take into account Auckland's growth, suburban areas becoming denser and rural areas becoming more urban, as well as the need to improve resilience for more isolated rural communities. Needs Statements are included for all projects and programmes.

Network development costs often need a long investment horizon, with much of the cost being carried by future generations. This is why we scrutinise our investments closely, so we can be sure our assets will serve our community throughout their lifetime while avoiding inter-generational inequity. Increasingly, this means designing (and valuing) distribution networks that are agile, flexible and modular. This allows them to respond to change as we navigate an era of uncertainty. Accordingly, our investment strategy places value on flexibility and the ability to switch options, and use the latest technology, along with data analytics and advanced operational practices. This will enable us to meet the challenge Auckland's fast growth represents, and optimise outcomes for our customers.

Auckland's projected growth is based on the Future Urban Land Strategy laid out in the Auckland Unitary Plan. Under this plan, the network will need to expand into new greenfield areas (for example, Takanini and Wainui) and become denser in sparsely developed regions (for example, Whenuapai). These areas are currently supplied by low-capacity rural feeder lines, so, as they intensify to urban residential levels, investment in new zone substations will be needed, along with all the associated distribution infrastructure.

To account for the possible high uptake of DERs (for example, solar, batteries and electric cars charging into and out of the network) all new zone substation investments are designed to be flexible.

The first such new design zone substation is Hobsonville Point zone substation. This new substation design also means the sub-transmission network can be skinnier, as demand peaks are reduced either because of increasing local DER availability or the possibility of reducing peaks with the aid of BESS.

In the following sections, we group our network development projects by geographic region. The aim here is to provide visibility of those areas where growth will overtake existing capacity and investment is needed. For all the projects described below we looked for the optimal solution before deciding on the investment choice (and continue to do so). Whether this is through the use of network or non-network solutions, or customers' DERs, in all cases, we identify the solution that will deliver the best outcome for our customers.

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15 Refer to the Stats NZ website, Regional Gross Domestic Product statistics page

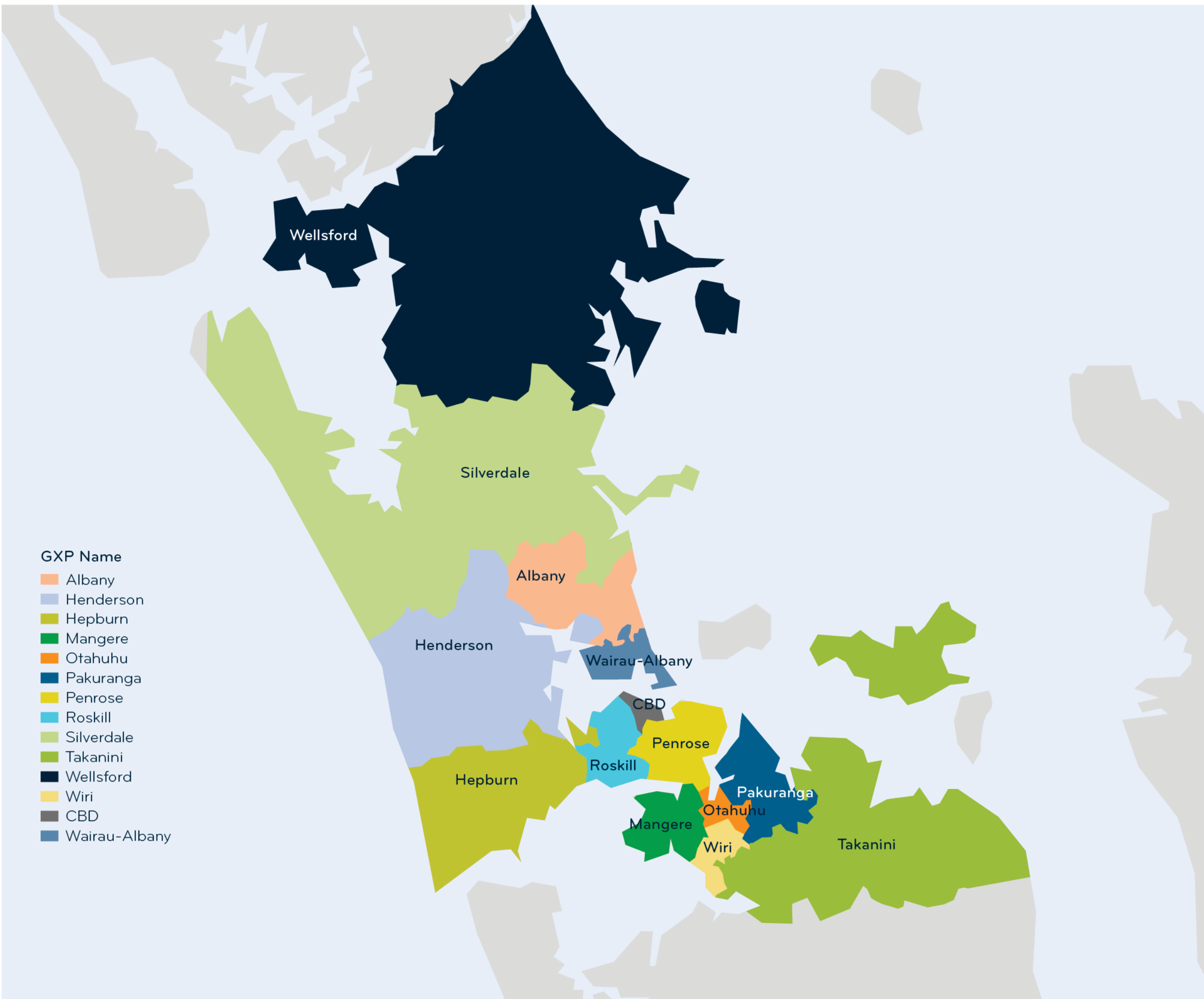

Figure 5-1 Geographic areas as basis of Needs statements

NEEDS STATEMENT - WELLSFORD

Increasingly, whether for reasons of lifestyle or affordability, customers are choosing to live further from Auckland's city centre. Demand growth is forecast in the Warkworth, Snells Beach, Matakana, and Omaha areas, and is expected to accelerate with the completion of the SH1 motorway extension to Warkworth. Travel times to Auckland CBD will be significantly shortened, increasing the attractiveness of this locality as a place to live. The increasing demand will threaten network security at Warkworth, Snells Beach and Omaha. Two new zone substations are planned at Omaha (Omaha - new zone substation) and Warkworth (Warkworth South - new zone substation) respectively, allowing load to be redistributed across Snells Beach and Warkworth substations.

Supply to Warkworth/Snells Beach/Omaha area comes from Transpower Wellsford GXP, some 19km to the north. The two subtransmission lines between Wellsford and Warkworth are nearing capacity. Steps have been taken to reduce the loading on these circuits, delaying the need for costly reinforcement. These include the installation of network batteries at Snells Beach and Warkworth to flatten the demand profile while a third project is planned to upgrade the load control to enable load shifting (Warkworth - implement load control). Ultimately a more substantial upgrade may be required comprising an additional subtransmission circuits between Warkworth and Wellsford. At this time, the 33kV subtransmission switchyard will need to be upgraded at Wellsford zone substation (Wellsford - 33kV switchboard upgrade).

NZTA are undertaking a Safer Roads programme on SH1 between Wellsford and Warkworth to improve traffic safety. We have an opportunity to install ducts (Warkworth - future-proofing ducts (Wellsford - Warkworth (NZTA), Wellsford GXP -Wellsford 33kV upgrade) along this section of road in anticipation the need for future subtransmission reinforcement. The installation of cables in the ducts can be delayed until needed in the future (Warkworth - new 33kV cable (Wellsford-Warkworth)).

A new zone substation is planned for Omaha to capture the growth in the Matakana and Omaha areas, while improving network resilience by shortening 11kV distribution feeders (Omaha – new zone substation). To address the forecast demand increase for Warkworth and to reduce the dependence on Warkworth substation, a new zone substation is planned for Warkworth South (Warkworth South – new zone substation).

We have two 11kV feeder upgrade projects planned, one at Snells Beach and the other at Warkworth (Matakana Link Rd). Two additional 11kV feeder reinforcement projects have been included to improve network resilience of the network (Puhoi and Tomorata).

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Forecast capacity constraints on the subtransmission circuits between Wellsford and Warkworth	Option 1: Install ducts for future subtransmission circuits. NZTA are undertaking a safety improvement programme that will enable us to install cable ducts along SH1 from Wellsford to Warkworth, sharing the cost of traffic management and civil works. The ducts will be populated with subtransmission cables when capacity limits are met on the existing overhead circuits (Option 2)	$21.2M	Selected
	Option 2: Install a subtransmission cable from Wellsford to Warkworth in the ducts installed on Option 1. This will also require a rebuild of the 33kV switchgear at Wellsford.	$7.6M	Selected
	Option 3: Install a subtransmission cable from Wellsford GXP to Wellsford zone substation: This will increase the capacity to both Wellsford zone substation and Warkworth (Option 2)	$7.6M	Selected
	Option 4: Upgrade the 33kV switchboard at Wellsford zone substation: The installation of additional subtransmission circuits to Wellsford (Option 2) will initiate an upgrade of the 33kV switchboard at Wellsford	$2.0M	Selected
	Option 5: Implement DSM measures to reduce load. Network batteries have been installed at Snells Beach substation and in Warkworth township to reduce the maximum demand on the subtransmission lines. A project to upgrade the load control across the Warkworth region (see below) will be implemented in 2020/21. This will enable non-critical load shifting into off-peak periods. These three measures will defer the investment of Option 2	Batteries already installed Load control $3.8M	Selected
	Option 6: Defer installation of the ducts as proposed in Option 1 until the additional subtransmission circuit is needed. The cost of the installing the ducts in the completed highway with median barrier is estimated to be more than double that of Option 1 due to loss of benefits arising from the shared works	$25M	Rejected
	Option 7: Install a new supply along the SH1 motorway from Silverdale GXP. Silverdale is further away from Warkworth, and there is no opportunity for shared civil		Rejected

	works with NZTA roading projects making the project significantly more expensive than Option 1		
	Option 8: Install a new supply through Kaipara Flats from a new GXP near Tauhoa. The distance is similar to Option 1, and it avoids SH1. There is no opportunity for shared civil works with NZTA roading projects. The need for a new GXP makes the project significantly more expensive than Option 1		Rejected
	Option 9: Upgrade the existing lines. Upgrading the existing subtransmission circuits will provide extra capacity and defer the installation of a third subtransmission circuit (Option 2) for 4 years. However, these lines are mostly on private property without easements, and the cost and feasibility of an upgrade is not certain – the lines may need to be completely rebuilt. Even under a very optimistic cost estimate, the NPV of the return on this option is poorer than Option 2 without deferral	$3M	Rejected
Warkworth and Snells Beach substations are approaching capacity.	Option 1: Omaha zone substation. Growth in the Matakana/Omaha area is increasing the load on Warkworth and Snells Beach substations. Establishing a zone substation at Omaha reduces the 11kV load these two substations, freeing up capacity for further growth. Omaha will also sectionalise two long 11kV feeders improving the resilience while reducing SAIDI, and improve voltage performance on the more remote rural sections of the Warkworth network	$2.7M	Selected
	Option 2: Build a second 11kV circuit to Matakana. This option will supplement the capacity to Matakana but will place the extra load onto the 11kV network advancing the reinforcement of Warkworth and Snells Beach substations. The original plan for this feeder was for a second circuit on the existing Matakana overhead line, but this is mostly on private property without easements and may not be feasible. A new overhead line following the road would cost nearly as much as option 1. An underground circuit would cost more.	$2.5M	Rejected
Load growth in Warkworth is exceeding the capacity of Warkworth substation	Option 1: new zone substation at Warkworth South. To relieve the forecast capacity constraints at Warkworth substation and provide supply diversity a new substation is proposed at Warkworth South. Omaha substation will defer this solution.	$8.9M	Selected
	Option 2: upgrade the capacity at Warkworth substation: Warkworth substation is located 3km from the load centre so any additional capacity installed here would need be supplemented by new 11kV cables to convey the capacity into Warkworth. Further it lacks the diversity offered by an additional zone substation (Option 1). Including feeder reinforcement, this option more expensive than Option 1		Rejected
11kV security shortfall at Snells Beach and Warkworth	A new NZTA link road is proposed connecting SH1 and Matakana Rd at Warkworth. We intend to install a new feeder in this new road when constructed. New commercial load is proposed on Sandspit Rd necessitating the reinforcement of the Sandspit Rd 11kV feeder	$1.7M	Selected
SAIDI reduction initiatives	11kV feeder upgrade – Puhoi: Connecting the Kaipara and Satellite feeders has the potential to save 0.8 SAIDI-min per annum	$0.7M	Selected
	11kV feeder upgrade – Tomorata feeder: Linking the Te Hana and Tomarata feeders will save approximately 1 SAIDI minute per year	$0.3M	Selected

FORECAST INVESTMENT SUMMARY

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Install cable ducts along SH1, Wellsford - Warkworth	9.6	11.60									21.20
Subtransmission cable installation along SH1, Wellsford - Warkworth						0.20	7.44				7.64
Subtransmission cable installation Wellsford GXP – Warkworth zone substation								0.20	7.46		7.66
Implement load control in Warkworth/Snells Beach areas	2.60	1.20									3.80
Upgrade 33kV switchboard at Wellsford zone substation							0.20	1.80			2.00
Establish Omaha zone substation		1.69	1.00								2.69
Establish Warkworth South zone substation				0.50	4.00	4.40					8.90
New 11kV feeder – Link Rd, Warkworth	0.40	0.40									0.80
11kV feeder extension – Sandspit Rd	0.85	0.85									1.70
11kV feeder extension – Puhoi			0.70								0.70
11kV feeder extension – Tomorata			0.30								0.30
Total CAPEX	13.45	15.74	2.00	0.50	4.00	4.60	7.64	2.00	7.46	0.00	57.39

NEEDS STATEMENT SILVERDALE

The Silverdale area extends from Albany in the south to Waiwera in the north, west to Helensville and the west coast. The highest population density is to the east of SH1 and comprises Whangaparaoa, Gulf Harbour, Orewa, Millwater, Red Beach and Silverdale areas. New developments are expanding westwards from Millwater towards Wainui and Dairy Flat. To meet the growing electricity demand caused by this urbanisation, an 11kV switchboard upgrade is planned for Orewa increasing the capacity from this substation, while a new zone substation at Millwater is planned to accommodate the new residential development on the western side of SH1 towards Wainui.

Larger capacity transformers will be installed in Helensville substation (Helensville - 33/11kV transformer capacity upgrade (T2)) in conjunction with asset replacement works, while a second transformer will be installed in Spur Rd substation to improve the supply security at this site (Spur Rd - second 33/11kV transformer and new 11kV and 33kV switchboards).

Towards the west, areas such as Helensville and Kaukapakapa were badly impacted by the storm events last year. A new zone substation at Kaukapakapa and three 11kV feeder projects at Helensville (2) and Orewa (1) that link remote ends of the radial feeders will greatly improve the network resilience by providing alternative supplies to six feeders.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Forecast security shortfall arising from residential growth at Millwater and Wainui	Option 1: Upgrade the 11kV switchboard at Orewa substation. The incomer rating of the switchboard is 800A (15.2MVA) which is below the capacity of the subtransmission circuits, transformers, and current peak load. Replacing the switchboard with one of higher rating will release available capacity	$3.10M	Selected
	Option 2: Construct Millwater Zone substation. To support the forecast growth in Wainui and Millwater, a new zone substation is proposed	$8.28M	Selected
	Option 3: Defer the expansion of Orewa substation by constructing Millwater zone substation (or vice versa). Orewa substation is a long way from the face of the residential development, requiring the installation of additional long 11kV feeder cables to deliver the capacity to new growth. This is costly and inefficient. It is preferable to have the substation located at the future load centre i.e. Millwater substation. Installing a new switchboard at Orewa and a new substation at Millwater allows the redistribution of load on Orewa substation supplying new growth to the north of Orewa, and has a lower NPV cost		Rejected
	Option 4: Hibiscus Coast 11kV reinforcement. Feeder and backstop capacity will be exceeded between Orewa and Red Beach substations. A new cable will resolve the constraint.	$2.0M	Selected
	Option 5: Delay primary asset investment through DSM or new technology solutions. Hot water load control is estimated to deliver 1.4MW or approximately two years growth at present rates. The NPV calculation based on the installation of HLC followed two years later by Millwater substation (or Orewa) favours Millwater as the best option	$0.6M	Rejected
Improve the resilience of the network in the Helensville area	Option 1: Kaukapakapa zone substation: Construct Kaukapakapa substation and segment feeders. This will reduce the number of customers per feeder thus improving SAIDI, reducing the length of the feeders and enabling closer protection. Kaukapakapa substation will also support Helensville substation	$7.5M	Selected
	Option 2: Helensville zone substation: The existing transformers are scheduled for replacement. When replaced they will be upgraded from the current 2 x 12.5MVA to 2 x 15MVA units	$1.7M	Selected
	Option 3: Install additional 11kV feeders to provide backup support. The construction of Kaukapakapa substation under Option 1 will initiate 11kV reinforcement to ensure maximum resilience benefit is gained. However, without the substation, the equivalent resilience benefit can only be achieved by substantially increasing the investment in extending the 11kV. This option is unnecessarily costly and ultimately ends up with asset stranding		Partially selected (some 11kV reinforcement included in Option 1)
	Option 4: South Head micro-grid: The 11kV feeder from Helensville to South Head is over 50km long and lacks a back-up supply. It is one of the worst performing feeders caused in part by its length, proximity to westerly weather events and remoteness. Installation of a micro-grid towards the end of the feeder will allow supply to be maintained to some of the more remote customers when an outage occurs		Under analysis

	Option 5: A 6km undersea cable from the Tapora peninsula to South Head is an alternative to Option 3. This has the potential to reduce SAIDI on the W39PORT and W13SOUT feeders from 45 SAIDI minutes since 2001 to a figure less than 24 SAIDI minutes		Under analysis
Support growth west of Silverdale	Option 1: Install a second transformer at Spur Rd substation: Forecast load increases to the west of Silverdale along Dairy Flat Highway and Pine Valley Rd. has initiated this reinforcement project. The existing substation is nearing network security limits and the second transformer will restore increase the capacity headroom. A new switchroom will also be installed. This substation will backup Kaukapakapa zone substation once constructed	$7.8M	Selected
	Option 2: East Coast Road 11kV reinforcement. Two feeders out of Spur Road substation are constrained by small conductor size – the lines will be upgraded	$1.5M	Selected
	Option 3: DSM solutions. A trial of Telensa hot water control technology was made in this area. While the trial was successful the requirement for reinforcement remains		Trialled
SAIDI Improvement Initiatives	Makarau SAIDI Improvement: Connecting Kaukapakapa and Kaipara feeders offers a reduction of nearly 4 SAIDI-min per annum.	$1.3M	Selected
	Kaipara Flats SAIDI Improvement: Connecting Limeworks and Kaipara feeders may save up to 2 SAIDI-min per annum	$0.8M	Selected
	Wainui SAIDI Improvement: Connecting Orewa and Waiwera feeders may save up to 0.27 SAIDI-min per annum	$0.2M	Selected

FORECAST INVESTMENT SUMMARY

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Upgrade 11kV switchboard at Orewa zone substation	3.10										3.10
Establish Millwater zone substation							0.50	3.89	3.89		8.28
11kV feeder reinforcement – Hibiscus Coast										2.00	2.00
Establish Kaukapakapa zone substation								0.50	3.40	3.40	7.30
Upgrade transformers at Helensville zone substation						0.20	1.50				1.70
Install a second transformer at Spur Rd zone substation	4.74	2.50									7.24
11kV feeder extension – East Coast Rd		1.50									1.50
11kV feeder extension – Makarau/Kaukapakapa			1.30								1.30
11kV feeder extension – Kaipara Flats		0.80									0.80
11kV feeder extension - Wainui			0.20								0.20
Total CAPEX	7.84	4.80	1.50	0.00	0.00	0.20	2.00	4.39	7.29	5.40	33.42

NEEDS STATEMENT - ALBANY

As with Silverdale, growth investment is being driven by the conversion of rural areas into more intensive residential urban areas. A second transformer is planned for Waimauku substation (Waimauku - second 33/11kV transformer) while an upgrade of the subtransmission is planned in conjunction with NZTA's Safer Roads programme along SH16 (Waimauku - future-proofing ducts (SH16 - Waimauku)). This project allows the installation of cable ducts for future subtransmission network upgrades as the Waimauku load increases exceeds Security of Supply thresholds.

A second transformer is planned for Coatesville substation (Coatesville - second 33/11kV transformer), again to address the extra load caused by urbanisation of rural areas towards the southern end of the Dairy Flats Highway (northern end captured under Silverdale).

An 11kV feeder project is proposed linking two 11kV feeders that supply Muriwai Beach area, to improve the resilience of the network in this area.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Forecast security shortfall arising from residential growth at Waimauku	Option 1: Upgrade the transformers at Waimauku. Greenfields residential growth is extending from Hobsonville along SH16. The capacity in the existing substation at Waimauku will need to be increased to maintain security. One transformer is being replaced due to end-of life, the other due to insufficient capacity	$1.8M	Selected
	Option 3: DSM or network batteries: The load is increasing at an average rate of 250kVA/annum. The existing transformers are rated at 7.5MVA and 10MVA respectively, supplying a winter peak load of 11.1MVA. The current shortfall in N-1 security is provided by 11kV feeders connected to adjacent substations. As the load increases through new local developments the predominantly rural feeders run out of capacity to provide the necessary level of security. Hot water load control will provide 3 years of deferral. Installing a network battery will allow peak shaving but the most economical approach is to install larger transformers (Option 1)	$0.6M Load control	Rejected
	Option 4: Cable ducts – SH16. NZTA are upgrading SH16 as part of their safety improvements programme. We will install cable ducts along SH16 from Waimauku to Huapai in conjunction with these works to enable a future 33kV cable connection into the Riverhead subtransmission circuits and reinforce 11kV connection to Huapai, Kumeu and Riverhead. The 33kV cable will double the subtransmission capacity to Waimauku and improve the resilience of the substation to subtransmission faults. The ducts will be installed leveraging off existing roadworks to minimise disruption to the public	$4.2M	Selected
	Option 5: Defer the ducts along SH16 until the cables are required. This approach increases the risk that the cables will not be in service when needed, compromising network security. In addition to the disruption caused to the public by a separate major state highway civil project, the additional costs of not sharing the civil works with the NZTA project are prohibitive		Rejected
SAIDI Improvement Initiative	Feeder upgrade at Muriwai. This project is to improve the resilience to customers on the end of the Muriwai beach feeder by linking two radial spur lines.	$0.8M	Selected

Improve network security at the southern end of the Dairy Flats development area	Option 1: Install a second transformer at Coatesville. This project is to add capacity to Coatesville to supply the new residential load to the north-west of Coatesville, and address a shortfall in backstop capacity. A transformer will be relocated from a substation upgrade project	$1.25M	Selected
	Option 2: DSM options. The backstop shortfall is increasing at 750kVA/annum. Hot water load control will provide less than 2 years of deferral	$0.5M	Rejected
Northern Corridor Improvements	NZTA Northern Corridor Improvement- duct installation: The establishment of a new NZTA interchange at Constellation Dr/SH1 intersection will close off the opportunity to access our Albany – Wairau Rd transmission corridor. Installing ducts during the civil construction phase will provide a degree of future-proofing	$0.12M	Selected

FORECAST INVESTMENT SUMMARY

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Upgrade transformers at Waimauku zone substation					0.20	1.60					1.80
Install ducts under SH16 – Waimauku - Huapai	1.40	1.40	1.40								4.20
11kV feeder upgrade – Muriwai		0.80									0.80
Install a second transformer at Coatesville zone substation					0.20	1.05					1.25
SH1/Constellation Dr - ducts	0.12										0.12
Total CAPEX	1.52	2.20	1.40	0.00	0.40	2.65	0.00	0.00	0.00	0.00	8.17

NEEDS STATEMENT – WAIRAU RD

Modest growth in the Wairau Valley area is driving brown-fields investment. Highbury is a single transformer substation in the middle of two adjacent single transformer substations, Northcote and Balmain. Housing New Zealand redevelopment in Northcote coupled with the reliance on the supply from adjacent substations is contributing to the need for this project. A second transformer and subtransmission circuit upgrade is planned for Highbury (Highbury - second 33/11kV transformer and new subtransmission cable) to improve local network security as well as that to Northcote and Balmain substations.

Takapuna substation is a single transformer zone substation, supplying the important and growing Takapuna commercial area. It also serves as a backup to adjacent Hauraki substation and is critical for the supply to Belmont and Ngataringa Bay in the event the Belmont subtransmission circuits are out of service. A second transformer and subtransmission upgrade is proposed for Takapuna substation (Takapuna - second 33/11kV transformer and new subtransmission cable).

A separate project has been included to address a flooding risk at low-lying Ngataringa Bay substation (Ngataringa Bay Zone Substation flood mitigation). This risk is expected to increase under forecast climate change scenarios.

An 11kV feeder upgrade is proposed at Hillcrest substation.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Forecast security shortfall arising from residential growth at Highbury	Option 1: Install a second transformer and new sub-transmission cable to Highbury substation. Highbury substation is supported by single transformer substations comprising Balmain and Northcote, and with the proposed Housing NZ redevelopment in Northcote additional capacity is required. A second transformer and subtransmission cable are proposed	$4.45M	Selected
	Option 2: Upgrade adjacent substations of Balmain or Northcote in preference to Highbury. Both Balmain and Northcote are supported by dual transformer substations of Hillcrest and Birkdale respectively, and so the security improvement is less than for upgrading Highbury. Upgrading either of Balmain or Northcote is more costly than Option 1, due to the longer subtransmission circuits needed		Rejected
	Option 3: 11kV load transfer. Transferring load to the adjacent substations (Balmain or Northcote) immediately causes a security shortfall at the neighbouring substation. This in turn initiates a reinforcement project as per Option 2 above but with the added cost of reinforcing the connecting 11kV feeders		Rejected
	Option 4: Non-network solutions. The forecast load increase on Highbury cannot be offset by load management or by sensible battery solutions. Even with hot-water load control there is a capacity shortfall from 2019 onwards following the loss of either the Northcote or Highbury transformers at peak times		Rejected
Forecast security shortfall arising from the common-mode failure risk of the Wairau-Belmont double circuit, and insufficient backstop capacity for Takapuna ZSS	Option 1: Install a second transformer and new sub-transmission cable to Takapuna substation. Takapuna substation is a single transformer substation supplying the Takapuna CBD. It is also a critical substation providing backup to Belmont, Hauraki and Ngataringa Bay upon loss of the double-circuit Belmont subtransmission lines. Apart from the criticality of this substation for the backup security of the Devonport Peninsula, growth in Takapuna is reducing spare capacity. A second transformer supported by a second subtransmission cable from Wairau Rd GXP is proposed	$7.3M	Selected
	Option 2: Non-network solutions. Network security cannot be delivered by these solutions		Rejected
Address the inundation risk associated with Ngataringa Bay substation	Option 1: Ngataringa Bay substation rebuild. Ngataringa Bay substation is a low-lying coastal substation and has been inundated in the past on a number of occasions by king tides. Forecasts indicate the frequency and severity of these events is likely to increase. The proposal is to rebuild the substation to avoid this risk	$9.5M	Selected
	Option 2: Abandon Ngataringa Bay substation and supply load from adjacent Belmont substation. This substation supplies the Naval Base, residential load in Devonport and Stanley Point and supports Belmont substation. Transferring this load onto Belmont would immediately initiate an upgrade of Belmont as this substation is already to N-1 capacity, whereas replacing Ngataringa Bay with a new substation could be used to alleviate Belmont loading		Rejected

	Option 3: Non-network options. The load is too large to benefit from sensible battery solutions or load control		Rejected
Improve distribution network security between Hillcrest and Northcote ZSS	Option 1: 11kV feeder upgrade. A shortfall in backstop capacity for Northcote ZSS and for several Hillcrest feeders, due in part to the Housing New Zealand development, will be alleviated by 11kV reinforcement.	$2.0M	Selected
	Option 2: DSM options. Hot water load control for Hillcrest and Northcote is under investigation		Under analysis

FORECAST INVESTMENT SUMMARY

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Install a second transformer and subtransmission cable at Highbury zone substation						2.45	2.00				4.45
Install a second transformer and subtransmission cable at Takapuna zone substation	3.00	3.00	1.30								7.30
Ngataringa Bay Zone Substation - flood mitigation		0.50	4.50	4.50							9.50
11kV feeder upgrade – Northcote/Hillcrest				2.00							2.00
Total CAPEX	**3.00**	**3.50**	**5.80**	**6.50**	**0.00**	**2.45**	**2.00**	**0.00**	**0.00**	**0.00**	**23.25**

NEEDS STATEMENT – HENDERSON

The Henderson area is one of the major growth areas in the Auckland region with major residential greenfields developments at Hobsonville Point extending towards Whenuapai, Riverhead, and Kumeu to the north and Westgate and Red Hills to the west.

A project to install load control (Riverhead - implement load control) in the Riverhead area will forestall the need for a transformer upgrade at Riverhead zone substation until the latter part on next decade (Riverhead - 33/11kV transformer capacity upgrade). An 11kV feeder upgrade is forecast for Kumeu (Kumeu - 11kV feeder upgrade).

A new zone substation (Redhills - new zone substation) is proposed west of Westgate substation to support the green-fields residential growth. This substation is expected to be supplied via subtransmission circuits from Westgate. Ducts are being installed along SH16 motorway corridor (Westgate - future-proofing ducts (Henderson- Westgate (NZTA)) in conjunction with NZTA's motorway widening project. Subtransmission cables will be installed when the security of supply to Westgate substation is compromised.

A new substation at Hobsonville Point (Hobsonville Point - new zone substation) currently under construction, is scheduled to be completed in 2019. To support this substation two 11kV feeder projects are proposed. These are the installation of ducts along SH18 and the installation of another 11kV feeder connection to Greenhithe across the Greenhithe Bridge.

The transformers are to be upgraded at Te Atatu zone substation (Te Atatu - 33/11kV transformer capacity upgrade) to provide additional capacity, and an upgrade of the 11kV feeder into Lincoln Rd.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Forecast security shortfall arising from residential growth at Riverhead	Option 1: Install load management. The installation of hot water load control at Riverhead will defer a major upgrade of the Riverhead substation 2027/28	$1.45M	Selected
	Option 2: Upgrade the Riverhead substation transformers. By 2028 the deferral benefits arising from the installation of load control will have been exhausted, requiring the provision of additional capacity at Riverhead substation. Two new transformers are proposed at this time	$0.5M	Selected
	Option 3: Earlier installation of two larger capacity transformers at Riverhead. The NPV calculation based on the two projects proposed in Options 1 and 2 is $3.26M compared to Option 3 which delivers an NPV of $3.01M		Rejected
	Option 4: 11kV feeder upgrade – Kumeu: This feeder will expand the capacity available to provide for the forecast growth in the Kumeu/Huapai area	$0.4M	Selected
Forecast security shortfall arising from residential growth at Redhills	Option 1: Establish a new zone substation at Redhills. Greenfields residential growth to the west of Westgate if forecast to exceed the capacity available from Westgate substation. A new 2 x 20MVA substation is proposed at Redhills	$6.35M	Selected
	Option 2: Expand Westgate substation to supply Redhills. Westgate substation supplies Westgate commercial centre and east towards Hobsonville. This substation is forecast to be at capacity by the end of the next decade. The area to the west towards Redhills Rd is expected to contribute a further 15.4MVA of residential load. This is in addition to the forecast load on Westgate and beyond the capacity of Westgate substation to supply		Rejected
	Option 3: Non-network solutions. No practical solutions will offset the need for a new zone substation		Rejected
Forecast security shortfall arising from residential growth at Westgate	Future-proofing ducts to Westgate zone substation: Westgate substation will be a key subtransmission distribution site providing connections to Hobsonville and Hobsonville Point. Future subtransmission connections to this substation will include the future Redhills and Whenuapai substations. NZTA are upgrading SH16 and the installation of ducts in conjunction with this project is important to support future subtransmission requirements	$1.4M	Selected
Forecast security shortfall arising from growth at Hobsonville	Option 1: Establish a new zone substation at Hobsonville Point: This project is already underway and is expected to be commissioned in 2019. The budget allows for completion of this project	$1.4M	Selected
	Option 2: Future-proofing duct SH18: To enable the capacity from Hobsonville Point substation (Option 1) to be distributed, ducts will be installed SH18 as part of NZTA motorway upgrade	$1.0M	Selected
	Option 3: Future-proofing duct - Greenhithe Bridge: As for Option 2, this project extends the ducts across the Greenhithe Bridge to enable the connection of the Hobsonville Point network to that of Greenhithe substation	$1.9M	Selected
Forecast security shortfall arising from growth at Te Atatu	Option 1: Install new transformers with increased capacity. The substation load exceeds the N-1 capacity of the existing transformers by 8MVA and relies on 11kV load transfer for network security. Backup capacity is limited, advancing the need for early replacement of the existing transformers	$3.4M	Selected

	Option 2: Install a third transformer. The existing transformers are 1966 vintage. Installing a third transformer instead of replacing the existing two transformers will require extension of both the 33kV and 11kV switchboards with additional switchgear as well as civil works associated with the additional transformer enclosure. To achieve a break-even point an additional 18 years life is required from the existing transformers. This is unlikely to be achieved		Rejected
	Option 3: Move load to adjacent substations. The distribution backup to Te Atatu substation is from the single-transformer Woodford substation. Loss of a transformer at Te Atatu at peak times results in both the remaining transformer at Te Atatu and the Woodford transformer being overloaded; the constraint is transformer capacity		Rejected
	Option 4: Non-network solutions: A network battery can afford a short term solution but the demand forecast margins are quite tight. If demand grows by more than 1.5MVA over the next ten years then based on cost, Option 1 is preferable.		Rejected
	Option 6: 11kV feeder upgrade – Lincoln Rd: The feeder is to be upgraded in conjunction with adjacent SH16 motorway widening works	$0.8M	Selected

FORECAST INVESTMENT SUMMARY

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Load control - Riverhead			0.60	0.70	0.03	0.03	0.03	0.03	0.03	0.03	1.48
Upgrade transformers at Riverhead zone substation										0.50	0.50
11kV feeder upgrades – Kumeu							0.38				0.38
Establish Redhills zone substation									0.50	5.85	6.35
SH16 Henderson – Westgate – future-proofing ducts							0.20	1.20			1.40
Establish Hobsonville Point zone substation	1.44										1.44
SH18 Hobsonville Point – future-proofing ducts			1.00								1.00
11kV feeder upgrades – Greenhithe	1.00	0.88									1.88
Upgrade transformers at Te Atatu zone substation			3.40								3.40
11kV feeder upgrades – Te Atatu				0.80							0.80
Total CAPEX	**2.44**	**0.88**	**5.00**	**1.50**	**0.03**	**0.03**	**0.61**	**1.23**	**0.53**	**6.38**	**18.63**

NEEDS STATEMENT – HEPBURN

The Hepburn area extends from Te Atatu and Ranui to New Lynn, extending westwards out to the coast. Relatively low growth is forecast except for pockets of re-development around the old Brickworks site in New Lynn and Sabulite areas. New transformers are proposed for Sabulite substation (Sabulite - 33/11kV transformer capacity upgrade) to increase their capacity.

One of the key areas of focus is the resilience of the network towards the western coast. Two projects have been included, namely the installation of a micro-grid at Piha (Henderson Valley - new micro-grid (Piha)) and the linking of two remote 11kV feeders (Piha/Scenic Drive feeders)

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Forecast capacity constraint at Sabulite	Option 1: Upgrade the transformers to larger capacity units at Sabulite substation.	$3.6M	Selected
	Option 2: Hot-water load management may have been an alternative to defer Option 1, but it would need to be deployed very soon. The higher priority for Vector's first large-scale roll-out is the Warkworth area, which will defer much greater expenditure. The age of the transformers also favours their replacement		Selected
Resilience improvement project	Option 1: Micro-grid at Piha. A battery-powered microgrid is being investigated as a solution to improve the resilience of supply to this remote community	$4.4M	Selected
	Option 2: Generation at Piha. An alternative to the battery microgrid is onsite diesel generation		Rejected
	Option 3: Reinforce the 11kV network to Piha. While duplication of the 11kV supply to Piha is prohibitively expensive, extending the Scenic Road feeder will allow connection to the Piha feeder, providing a backstop. This solution also reduces the size of micro-grid solution proposed in Option 1	$1.3M	Selected

FORECAST INVESTMENT SUMMARY

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Upgrade the transformers at Sabulite zone substation						0.20	3.40				3.60
Piha microgrid	0.20	2.00	2.20								4.40
11kV feeder extension - Piha	1.30										1.30
Total CAPEX	**1.50**	**2.00**	**2.20**	**0.00**	**0.00**	**0.20**	**3.40**	**0.00**	**0.00**	**0.00**	**9.30**

NEEDS STATEMENT – CBD

The Auckland CBD is undergoing a transformation driven largely by the redevelopment of existing commercial sites. Overlaid on this are significant infrastructure projects such as the City Rail Link (CRL), the Auckland Light Rail (LRT) and Streetscape improvement projects (e.g. Quay St). While these projects do not add significant load to the Auckland CBD, they nonetheless consume considerable resource protecting or moving existing network without compromising security of supply.

The America's Cup is scheduled to be held in March 2021 while APEC is programmed for November 2021. Again, these events will not contribute significantly to CBD demand, but supply security is vital during these international events.

The projects in the CBD are focussed mainly around the three key substations, namely Liverpool, Hobson and Quay St. Switchboard replacement projects (see later in section 5) have been identified for both Hobson and Quay St and these need to be coordinated with a number of growth related projects. At Liverpool substation we are extending the 110kV switchboard (Liverpool - 110kV switchboard extension including bus-zone protection upgrade) to remove operational constraints on the 110kV supply to Quay St substation while reducing the common-mode failure risk of multiple 110/22kV transformers out-of-service at the same time. To increase the electrical capacity from Liverpool substation, we are looking at installing reactors on the 110/22kV T3 transformer (Liverpool - 110/22kV transformer capacity upgrade (T3)) to enable better load sharing with the two other transformers on this site.

A new 110kV transformer feeder is to be installed from Hobson substation to Quay St substation (Hobson - new 110kV cable (Hobson - Quay St)). This new feeder will supplement the existing 110kV cable from Roskill GXP via Liverpool substation. Ducts have been installed between the Hobson and Quay but the challenge is to secure a window when the cable can be installed and jointing completed. Currently the Quay St Streetscape and the CRLL tunnelling project are preventing this work being carried out.

The investment plan shows a number of projects designed to increase the capacity of the distribution network within the CBD. The most significant one is the progressive roll-out of a 22kV network that will, over time, replace the lower capacity 11kV network in the CBD. Its focus is to ensure sufficient coverage with the 22kV network such that redeveloped sites can connect directly to the new network. To supply this expanding 22kV network, additional distribution switchgear is required at both Quay St (Quay - second 22kV switchboard) and Hobson (Hobson - additional 22kV feeder circuit-breakers) substations and new 22kV distribution feeders from Liverpool and Hobson substations.

A new 11kV feeder is required from the Freemans Bay substation.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Relieve capacity constraints at Liverpool substation	Option 1: Upgrade 110/22kV transformer T3 at Liverpool. Installing a transformer with the same electrical characteristics as the other transformers on this site will make additional capacity available to the network	$2.7M	Rejected
	Option 2: Installation of a 22kV reactor on the existing T3 110/22kV transformer. This option addresses the issue of load sharing with the other onsite transformers, but with added complexity associated with the management of Electromagnetic Fields (EMFs). This is potentially a lower cost solution	$1.2M	Selected
	Option 3: Reconfigure the 22kV network to constrain the load on Liverpool at current levels. By transferring load to adjacent Hobson substation, we will advance a major reinforcement at this substation. This option also requires an upgrade to the network connectivity with the installation of new 22kV distribution feeders to enable the load transfer. The cost of this option is expected to exceed the solutions proposed above.	$5.0M	Rejected
Address HILP security risks associated with the Liverpool 110kV switchboard	Option 1: Extend the 110kV switchboard at Liverpool substation. The design of the 110kV switchboard at Liverpool may require adjacent panels to be electrically isolated for intrusive maintenance of repair works. This will compromise the security of supply to the CBD should this situation arise. Secondly the supply from Roskill GXP is	$2.7M	Selected

	paralleled with the supply to Quay St substation at Liverpool. Operationally and from a risk-reduction perspective these two circuits need to be separated. This project will be completed with the upgrade of the Liverpool T3 transformer		
Reinforce the supply to Quay St substation	Option 1: Install a 110kV cable between Hobson and Quay St substations. Quay St substation achieves its N-2 security through a combination of the 110kV cable from Liverpool substation and the 22kV network from Hobson substation. Through a combination of load increase on Quay St substation, and reducing spare capacity backup from Hobson, there is a forecast security shortfall on Quay St substation. The installation of the 110kV cable in Quay St is part of the long term plan for this part of the CBD	$3.0M	Selected
	Option 2: Upgrade the 22kV circuits to Quay St substation. As the ducts have been installed in anticipation of the 110kV circuit, reuse of these ducts for 22kV circuits will deliver only 20% of the electrical capacity to Quay St that an equivalent 110kV circuit would supply for approximately the same cost		Rejected
Increase distribution feeder capacity from Quay St substation	Option 1: Install a new 22kV switchboard at Quay St substation. Additional 22kV distribution feeders are required out of Quay St substation. The existing 22kV switchboard cannot be extended. This project proposes installing an additional switchboard to supplement existing outgoing 22kV feeders.	$2.2M	Selected
	Option 2: Replace the existing 22kV switchboard incorporating the additional outgoing feeder circuit-breakers. This solution is more expensive than the proposed solution.	$3.5M	Rejected
Increase distribution feeder capacity from Hobson substation	Option 1: Install additional 22kV switchboard at Hobson substation. Additional 22kV distribution feeders are required from Hobson substation. The existing 22kV switchboard is to be replaced as an Asset replacement project. This project makes provision for extra distribution feeders as part of the replacement project. A new switchroom will also be added	$3.0M	Selected
Increased distribution capacity within the CBD	Option 1: Continuation of the 22kV cable rollout with in the CBD. This is a programme to progressively roll-out the 22kV distribution network across the CBD. The programme commenced in 2004, initially to address overloaded 11kV distribution cables. The second phase is well underway to achieve 22kV feeder coverage of the CBD to allow the connection of new/redeveloped buildings to 22kV network. The third phase is the conversion of existing 11kV substations to 22kV when asset replacement or capacity upgrades are required.	$29.1M over 10 years	Selected
	Option 2: New feeders 22kV distribution – Hobson to Nelson St: To address forecast feeder capacity constraints	$1.6M	Selected
	Option 3: New feeders 22kV distribution – Hobson substation to the Waterfront: To address forecast feeder capacity constraints	$1.0M	Selected
	Option 4: New feeders 11kV distribution – Freemans Bay: To address forecast feeder capacity constraints	$2.0M	Selected

FORECAST INVESTMENT SUMMARY

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Upgrade 22kV capacity at Liverpool zone substation	0.20	1.00									1.20
Extend the 110kV switchboard at Liverpool zone substation	2.32	0.36	.								2.68
Install a 110kV cable between Hobson and Quay zone substations	2.65	0.35									3.00
Extend the 22kV switchboard and new switchroom at Hobson zone substation	1.20	1.80									3.00
22kV network roll-out	1.50	2.00	3.20	3.20	3.20	3.20	3.20	3.20	3.20	3.20	29.10
11kV feeder upgrade – Hobson - Waterfront								0.98	0.08		1.06
11kV feeder upgrade – Hobson – Nelson St	1.64										1.64
11kV feeder upgrades – Freemans Bay						2.00					2.00
Extend the 22kV switchboard at Quay zone substation			0.20	2.00							2.20
Total CAPEX	**9.51**	**5.51**	**3.40**	**5.20**	**3.20**	**5.20**	**3.20**	**4.18**	**3.28**	**3.20**	**45.88**

NEEDS STATEMENT – PENROSE

Although Penrose GXP is Vector's largest GXP there are surprisingly few projects forecast over the next ten years. Penrose GXP supplies a large, well-established area in central Auckland. Unlike the greenfields areas on the Northern network, the Symphony forecast suggests only moderate brownfields growth, offset in part, by technology-driven energy efficiencies.

The upgrade of the Newmarket substation (Newmarket - substation upgrade) is the most significant project, driven largely by commercial developments in the Newmarket area.

A project already in the construction phase is to install a new 22kV switchboard at Penrose (Penrose - new switchroom and 22kV switchboard). The switchboard is containerised and intended to see out the residual life of the 22kV subtransmission cables supplying Onehunga and Westfield substations. When the subtransmission cables to these substations are replaced they will be uprated to 33kV and connected to the Penrose 33kV bus. The switchroom will be moved to one of the Northern network zone substations as a permanent replacement for an end-of-life outdoor switchyard.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Address a forecast security shortfall on Newmarket substation	Option 1: Newmarket substation upgrade. Growth within Newmarket is forecast to compromise the security of Newmarket substation. This project establishes a second substation on the existing Newmarket substation site	$7.7M	Selected

	Option 2: Build a second substation within Newmarket remote from the existing substation. The added expense of land purchase significantly increased the cost of this option above that of the preferred option.	$14.6M	Rejected
Switchboard replacement at Penrose GXP	Option 1: Replace the 22kV switchboard at Penrose GXP. Due to the presence of asbestos, the 22kV switchboard at Penrose GXP had to be replaced. Within ten years the 22kV supply from Penrose will be retired. The proposal is to install a "containerised" switchroom to supply the 22kV circuits until their retirement at which time the switchroom will be uplifted, relocated and used as a replacement for a 33kV switchboard at one of Vectors substations.	$1.0M	Selected
	Option 2: Transpower replace the switchroom/switchboard. Transpower's practices require the switchroom/switchgear to be installed on the basis of achieving full technical life. This imposes additional unnecessary costs on our customers as these assets will be stranded within a ten year timeframe	N/A	Rejected

FORECAST INVESTMENT SUMMARY

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Upgrade Newmarket zone substation				0.16	5.00	2.50					7.66
Install a new 22 kV switchboard at Penrose GXP	1.00										1.00
Total CAPEX	1.00	0.00	0.00	0.16	5.00	2.50	0.00	0.00	0.00	0.00	8.66

NEEDS STATEMENT – PAKURANGA

Pakuranga covers established areas of East Tamaki, Pakuranga and Howick and the greenfields growth areas of Flat Bush to the south. The Flat Bush zone substation was established in 2015 in anticipation of the current development. The next stage is to overlay the area with backbone 11kV distribution feeders to enable connection to the various separate developments. Where practicable ducts are being installed along the major arterial routes during the roading construction phase including Link, Chapel and Murphys Roads, followed by cable installation in Ormiston and Chapel Roads.

A new commercial feeder is proposed for Cryers Rd in East Tamaki.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Forecast capacity shortfall on the distribution network at Flat Bush and East Tamaki	Option 1: Reinforcing 11kV feeders in Flat Bush and East Tamaki. Greenfields residential growth in the Flat Bush area has resulted in the need to reinforce the 11kV distribution network. A number of future-proofing duct and cabling projects in Chapel, Link, Ormiston and Cryers Rd's address this issue.	$3.5M	Selected

FORECAST INVESTMENT SUMMARY

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
11kV feeder reinforcement - Flatbush	0.49			1.49							1.98
11kV feeder reinforcement – East Tamaki	0.75										0.75
Future-proofing ducts - Flatbush	0.80										0.80
Total CAPEX	**2.04**	**0.00**	**0.00**	**1.49**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**3.53**

NEEDS STATEMENT – MANGERE

Mangere covers the Mangere township and surrounding residential areas, extending south to the developing commercial areas out by the airport. Watercare have forecast significant demand growth associated with their treatment plant and when coupled with the greenfields commercial growth in the Ihumatao area, capacity constraints are forecast for the Mangere West substation. Eventually a new zone substation (Mangere South - new zone substation) will be required in the Ihumatao area but to forestall this investment a third transformer is being installed in Mangere Central substation (Mangere Central - third 33/11kV transformer) to enable load transfer from Mangere West.

Distribution feeder reinforcement is required on the Ascot Rd, Mangere Bridge and Oruarangi Rd feeders out of Mangere Central substation and Robertson Rd feeder out of Mangere East substation to enable the load transfer and accommodate the new load

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Capacity shortfall in the Mangere area	Option 1: Install a third transformer in Mangere Central substation. Growth in the Ihumatoa area by the airport is forecast to cause constraints on the Mangere West substation. To defer the upgrade of this substation or construction of a new substation this project proposes the installation of a third transformer at Mangere Central substation. This substation was previously a three-transformer substation so previously install but subtransmission cables will be reinstated	$1.16M	Selected
	Option 2: Upgrade Mangere West substation. This substation is located on private Watercare land with current upgrades to the wastewater network, significant demand increases are forecast for this substation. Expanding this substation for further commercial usage is not the best long term option	$5.3M	Rejected
	Option 3: Construct a new substation in south Mangere. The rapidly expanding commercial area surrounding the airport will require a new substation to meet the forecast capacity. The timing of this will be determined by when the additional supply security gained by the reinforcement proposed under Option 1 is again compromised by the growth. In the interim we will secure land for the future substation	$16.9M	Under analysis

	Option 4: Non-network options. Growth in this area is predominantly commercial where a single customer's supply requirements may offset the capacity delivered by a non-network solution such as a network battery solution. Similarly for demand side management (DSM) solutions such as hot-water load control		Rejected
Forecast capacity shortfall on the distribution network at Mangere	Option 1: Distribution feeder upgrades: Reinforce the 11kV distribution network at Ascot, Robertson and Oruarangi Rds, and Mangere Bridge	$4.5M	Selected

FORECAST INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Install a third transformer in Mangere Central zone substation	1.16										1.16
Establish Mangere South zone substation						1.00	7.95	7.95			16.90
11kV feeder reinforcement – Mangere Central (Mangere Bridge)				1.76							1.76
11kV feeder reinforcement – Mangere East (Robertson Rd)					2.62						2.62
11kV feeder reinforcement – Mangere West (Oruarangi Rd)	0.16										0.16
Total CAPEX	**1.32**	**0.00**	**0.00**	**1.76**	**2.62**	**1.00**	**7.95**	**7.95**	**0.00**	**0.00**	**22.60**

NEEDS STATEMENT – WIRI

Wiri covers the established areas of Manukau, west to commercial area of Wiri and south to the residential area of Clendon. Growth is being driven by the greenfields commercial developments to the west of Roscommon Rd. Wiri zone substation is nearing capacity, initiating construction of Wiri West substation in Jerry Green St (Wiri West - new zone substation).

A new 11kV feeder is proposed from Manukau substation

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Forecast security shortfall arising at Wiri substation	Option 1: Construct a new substation at Wiri West. This solution will provide additional capacity for greenfields commercial growth along Roscommon Rd while providing additional security to Wiri substation.	$11.6M	Selected
	Option 2: Non-network solutions. This is a commercial area making currently available non-network solutions impractical		Rejected
Forecast capacity shortfall on the distribution network at Manukau	Option 3: 11kV feeder reinforcement – Great South Rd. A feeder reinforcement to address forecast capacity constraints	$1.8M	Selected

FORECAST INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Establish a Wiri West zone substation	0.20	2.70	4.34	4.34							11.58
11kV feeder reinforcement – Great South Rd									1.76		1.76
Total CAPEX	**0.20**	**2.70**	**4.34**	**4.34**	**0.00**	**0.00**	**0.00**	**0.00**	**1.76**	**0.00**	**13.34**

NEEDS STATEMENT – TAKANINI

Takanini covers the urban areas of Manurewa, Takanini and Papakura townships, extending east to the more remote areas of Clevedon, Maraetai, Beachlands and Waiheke Island.

Waiheke Island has a relatively static load of about 12MVA, supplied via two 33kV subtransmission cables from Maraetai. These cables can 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. Provision has been made for the installation of third cable between Waiheke and Maraetai to lessen this asymmetric risk but project as presented represents an upper cost threshold for delivering a workable solution. The intention is to look at other local solutions that may deliver a similar outcome but utilising new technology and at a lower cost

11kV distribution feeder upgrades are planned for Whitford Rd, Papakura and Waiheke.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Address the risk of both undersea sub-transmission cables to Waiheke incurring concurrent damage	Option 1: Install a third subtransmission cable to Waiheke. The 12MW electrical demand on Waiheke is delivered by two undersea subtransmission cables. The load can be supported by one cable but repairs to the faulty cable may take many weeks stretching to months. Having a circuit out-of-service for an extended period of time increases the likelihood of a second cable failure within that outage interval. The existing cables are 1970/1987 vintage PILC cables. A third cable across the marine portion of the route would largely mitigate this risk	$7.5M	Under analysis
	Option 2: Non-network solution. The cost of a cable to provide N-2 security across the marine section for a HILP event is significant. The implementation of a multi-facetted local solution comprising large-scale solar generation, load management, network batteries supported by a diesel backup may be a more cost effective solution. However a viable solution needs to cost less than the cost of Option 1.		Under analysis

	Option 3: Install temporary generation on an as-needed basis. The generation connection points at the zone substation will be retained but because of the cost, this option will be considered as a backup to other options		Rejected
Forecast capacity shortfall on the distribution network at Maraetai, Papakura, and Waiheke	Option 1: 11kV distribution feeder upgrades at Maraetai, Papakura and Waiheke Island to accommodate localised growth	$4.9M	Selected

FORECAST INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Waiheke Island – improve resilience of subtransmission circuits			1.00	3.25	3.25						7.50
11kV feeder reinforcement – Maraetai					2.62						2.62
11kV feeder reinforcement – Papakura	0.16										0.16
11kV feeder reinforcement – Waiheke				2.11							2.11
Total CAPEX	0.16	0.00	1.00	5.36	5.87	0.00	0.00	0.00	0.00	0.00	12.39

NEEDS STATEMENT – LV NETWORK REINFORCEMENTS

Increasing demand whether due to incremental increases in load by existing customers or through infill in existing subdivisions sometimes initiates reinforcement of the LV network. Most of these projects are small in nature and consequently identified less than one year in advance. Planning, design and delivery is generally reactive and in most cases will consist of traditional network reinforcement. The budget for future years is estimated from historic trends and load forecasts.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓	✓		

OPTIONS CONSIDERED

Options are summarised below.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Address LV capacity shortfalls	Option 1: Do Nothing. Increasing demand on established network either results in overloaded assets or voltage issues if not addressed. 'Do nothing' approach is not practical		Rejected
	Option 2: To maintain the operational functionality of the LV network investment is required to address impending voltage and loading issues on the LV network. The budget for future years is based on historic trends – an average of $1M is forecast for each network ($2M pa) for the 10 year AMP period	$20.0M	Selected

FORECAST INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Northern network – LV reinforcements	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	10.00
Auckland network – LV reinforcements	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	10.00
Total CAPEX	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**20.00**

NEEDS STATEMENT – SYMPHONY SCENARIO OUTCOMES

The primary difference between the Symphony and the Pop forecast scenarios is based on the level of 'control' that is exercised to manage the demand uptake. The underlying growth, using population as the proxy, is the same in both scenario's but the differences arise primarily in the size and timing uptake of new technology.

The key differences between the two scenarios is illustrated in Table 5-1.

SCENARIO INPUT (IN 2028)	SYMPHONY	POP
Efficiency gains	80%	50%
Residential solar uptake	20%	4%
Residential battery uptake	6%	2%
EV uptake	88,000 vehicles	88,000 vehicles
EVs plugged in at winter peak	10%	50%
Efficiency gains	80%	50%

Table 5-1 Key differences between the Symphony and Pop scenarios

The impact each of the input parameters has on the network investment portfolio is briefly described below.

Energy efficiency: This impacts by lowering peak winter demand and is captured in the demand forecast. No additional investment is required although the network needs to be monitored for under-utilised assets that may be economically moved to another, more productive location

Residential solar uptake: The inverters attached to each of the solar installations are configured to reduce their output when the network voltage exceeds pre-set conditions (as defined in AS/NZS 4777). This condition occurs when the LV is lightly loaded and high solar irradiance conditions (e.g. midday during summer). One of the noticeable effects of solar uptake is the tendency towards 'clustering' resulting in pockets of solar installations. As the penetration of solar increases, the same solar customers on the end of LV feeders have their solar output curtailed with increasing frequency as more solar/PV is added to the LV feeder. We have included a budget to address this issue at a network rather than individual level. Solutions may involve moving LV open-points, upgrading conductors, changing or adding transformers and a budget has been included for this work. Each situation will be evaluated on a case-by-case basis.

Residential battery uptake: The relatively low level of uptake is expected to have minimal impact on the network. No budget has been included for control at this time.

EV's connected during winter/summer peak: The uptake of EV's is the same for both the Pop and Symphony scenarios but the difference is based on the numbers of EV's charging over the peak period. In the Symphony scenario it is assumed that no more than 10% of the EV fleet will charge at customers are incentivised to charge off-peak. In contrast, the Pop scenario allows for 50% for the EV fleet to be charging at peak times. While the Symphony scenario requires a greater investment in EV charger control infrastructure, the Pop scenario requires greater investment in primary LV/MV assets.

Even allowing for investment in control devices for 90% of the EV fleet, additional investment is required in primary assets to provide additional network capacity for the 10% of the fleet which is not controlled and charging at peak times. Budget has been included for smart EV chargers to be installed across 90% of the EV fleet out to 2024, after which mandated control of EV chargers may be required, or incentives or tariffs could be introduced to encourage consumer behaviour. Separate budget is also included for the 10% of the EV fleet that is not controlled.

OPTIONS ASSESSMENT

For major projects, i.e. above $4M (level to be confirmed), include the following in this section: Technical feasibility, economic analysis, OPEX and CAPEX costs, net present value or net present cost, service levels, risks, etc.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Address the emerging impact of solar/PV on the network[16]	Option 1: Do nothing. As solar/PV penetration increases the numbers of customers unable to fully utilise their investment in solar/PV will increase, leading to increased complaints to Vector		Rejected
	Option 2: Symphony scenario. Upgrade the network to relieve voltage and capacity constraints forecast by the Symphony scenario	$43.5M	Selected
	Option 3: Pop scenario. Upgrade the network to relieve voltage and capacity constraints forecast by the Symphony scenario. Note that although the expected cost due to solar-related issues is lower than the Symphony scenario, other POP expenditure is higher making the overall POP scenario more expensive over the ten years	$12.0M	Rejected
Address the emerging impact of EV charging on the network	Option 1: Do nothing. As EV penetration increases the impact on the network will be increased incidence of low-voltage complaints and increased incidences of network overloading. These need to be addressed		Rejected
	Option 2: Symphony scenario. Apply control to 90% of the EV installations to reduce the impact of peak-time EV charging. We have assumed that we will invest in control devices until 2024, after which EV charger control will be mandatory	$12.2M	Selected
	Option 2: Symphony scenario. Additional investment in primary assets to provide extra network capacity for the 10% of the EV fleet charging over peak times	$5.5M	Selected
	Option 3: Pop scenario. Apply control to 50% of the EV installations to reduce the impact of peak-time EV charging. We have assumed that we will invest in control devices until 2024, after which EV charger control will be mandatory	$6.8M	Rejected
	Option 3: Pop scenario. Additional investment in primary assets to provide extra network capacity for the 50% of the EV fleet charging over peak times	$43.1M	Rejected

FORECAST INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Network investment specifically related to residential solar/PV	0.11	0.27	0.57	0.85	2.68	3.59	6.02	7.44	10.21	11.77	43.51
Investment in EV charger control	1.94	1.94	1.94	1.94	4.46						12.22
Network investment specifically related to EV chargers	0.29	0.09	0.30	0.23	0.34	0.62	0.78	1.41	0.71	0.74	5.51
Total CAPEX	**2.34**	**2.30**	**2.81**	**3.02**	**7.48**	**4.21**	**6.80**	**8.85**	**10.92**	**12.51**	**61.24**

NEEDS STATEMENT – UNSPECIFIED REINFORCEMENT PROGRAMMES

Within the growth area most of the major projects are identified and budgets assigned within the AMP process. While all care is taken to identify projects, some of the smaller reinforcement projects and those projects that arise during the year

16 Although in this instance the Pop scenario is lower cost than the Symphony scenario, overall Pop is the more expensive option

cannot be foreseen in advance. An annual provisional budget has been included for HV projects that may arise during the year that need to be carried out with urgency but for which no specific budget has been allocated.

As with the provisional budget for HV projects, we have included a similar non-specific budget for the opportunistic installation of cable ducts for future reinforcement projects. Where we know road reconstruction works will be undertaken and we have forecast future network reinforcement requirements, we will install ducts in anticipation of the future needs. Civil works are the most expensive component of installing cables so by installing ducts during roading alterations we can reduce our overall project cost, and we can avoid the cost, public disruption and adverse PR of future civil works when the reinforcement project is ultimately required. Where these ducting opportunities are foreseen we can include them as stand-alone projects with specific provisional budgets (e.g. City Rail Loop ducts, Warkworth – Wellsford ducts, etc).

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓	✓	

OPTIONS CONSIDERED

Options are summarised below.

DESCRIPTION	OPTIONS	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Allow for HV network reinforcement un-foreseen at the time the AMP was prepared	Option 1: Do nothing. Funding for unforeseen HV reinforcement projects would have to be sought from existing budgets already "committed" to existing projects or additional funding sought		Rejected
	Option 2: Unspecified HV reinforcement budget - To ensure we carry out necessary network reinforcement for projects that arise during the year	$2.5M (over 10 years)	Selected
Allow for the installation of cable ducts un-foreseen at the time the AMP was prepared	Option 1: Do nothing. Loss of opportunity resulting in substantially higher future costs		Rejected
	Option 2: Unspecified cable duct budget. Prudent installation of ducts in conjunction with other roading works to lower present - day costs, avoiding higher future reinforcement costs	$2.5M (over 10 years)	Selected

FORECAST INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Unspecified HV reinforcement provision	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	2.50
Unspecified duct installation provision	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	2.50
Total CAPEX	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	5.00

EXPANDING NETWORK MONITORING CAPABILITY

NEEDS STATEMENT

The increasing societal dependence on high speed communications, automation (and EV's,) and computer-based devices across wider aspects of our life is making us increasingly dependent on an uninterrupted supply electricity and lowering our tolerance to outages. To meet this demand, we need to extend our monitoring capability of the network to quickly identify those parts of the network susceptible to overloads which, if not attended to, can lead to outages, and where outages do occur, instigate remedial action to restore power as quickly as possible.

We will need smart instrumentation to monitor the performance of network elements and provide data to enable us to understand asset health, network loading, energy flows, and when the power goes off, outage locations. This needs to be supported by back-office analytics capability that can sift through the data to identify those items needing attention.

We are initiating a programme to selectively install measuring sensors on the LV terminals of distribution transformers with a focus on areas of high DER penetration, and/or poor network performance. We need to establish the software platforms to capture, analyse and filter the field data.

Together with two Metering Equipment Providers (MEPs) we are trialling the use of smart meters at customer premises to provide outage and restoration notification to speed up identification of the location and magnitude of outage area. Current practices require customer calls to be logged by the service centre, service requests raised, and the FSP service crew dispatched, a very manual process. Our target using smart metering information will have the fault location identified within ~5 minutes, system-generated service requests and a crew despatched to the fault location and our outage app updated with current information, much faster that is currently the case.

We have established power-quality (PQ) monitoring capability across approximately half of our zone substations and all GXPs. The purpose behind this programme is to monitor long-term trending of power-quality deterioration, especially as the next ten years will see an increase in the connection of solar/PV inverters and EV chargers, both of which have the potential adversely impact power quality. By trending we can observe PQ changes over time so remedial steps may be taken to halt the deterioration advance if necessary. The existing PQ monitoring capability has been found to be beneficial in identifying causes of customers plant mal-operation. Relating plant outage times to voltage sags/swells on the network aids customers by identifying a cause of the plant outage and allows them to install equipment to minimise the impact of future events. Progressively extending the PQ programme so we can monitor power quality across the remaining zone substations is the long term plan, so we can extend the benefits gained from the existing PQ monitored substation to the whole network.

Because of our increasing dependence on the LV network we are investigating opportunities for improving its resilience and reliability. This will involve trialling "new" network equipment to ensure it delivers cost-effective solutions that can be extended for wider use across the network. This area is increasingly important as it allows emerging network problems to be identified, workable solutions found and incorporated into standard network designs before they become significant.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓		✓	✓	✓	

OPTIONS CONSIDERED

Options are summarised below.

DESCRIPTION	OPTIONS	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Improve monitoring capability on the LV network	Option 1: Do nothing. Growth on the LV network particularly with increased penetration of distributed generation and electric vehicles together with higher expectations from customers means that 'Do-nothing' is not an option		Rejected
	Option 2: Installation of instrumentation on the LV network. The installation of metering within distribution substations offers the ability to monitor the load and condition of the distribution substation and also flag when operating outside accepted limits	$10.0M	Selected
Increase our PQ monitoring capability	Option 1: Do nothing. With increased penetration of distributed generation and electric vehicles we should be increasing our PQ monitoring capability, rather than		Rejected

	maintaining the status-quo which a "Do-nothing" option would deliver.		
	Option 2: Expand PQ monitoring capability. Progressively extend the PQ monitoring capability to zone substation not already monitored, focussing initially on the remaining commercial/industrial substations. This will allow us to continue the "trending" objective and provide customer support for PQ-initiated plant outages	$1.5M	Selected
Improve LV resilience capability	Option 1: Do nothing. It is important we find cost-effective and timely solutions to emerging network problems. Failure to do so will place us in a costly reactive mode delivering unsatisfactory long-term solutions		Rejected
	Option 2: Develop LV resilience solutions. Develop network-wide solutions to emerging network problems in a timely and cost-effective manner	$10.0M	Selected

FORECAST INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Core digital services for network monitoring	0.75	0.75	1.00	0.50		0.50		0.50			4.00
LV monitoring – Auckland network	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	5.00
LV monitoring – Northern network	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	5.00
Power Quality monitoring	0.10	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.45
LV resilience development	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	10.00
Total CAPEX	**2.85**	**2.85**	**3.15**	**2.65**	**2.15**	**2.65**	**2.15**	**2.65**	**2.15**	**2.15**	**25.45**

NETWORK RESILIENCE INITIATIVES

NEEDS STATEMENT

One measure of network resilience is the length of time taken to restore supply following a fault. The standard performance measure is SAIDI as it combines the fault duration with the number of customers affected by the fault. To improve SAIDI Vector intends to accelerate its programme of works to improve the utilisation of existing remote control devices and install new remote control devices in the underground and overhead 11 kV distribution network. The intention is to install remote control at key locations on the 11 kV network that will enable faster isolation and restoration of supply to customers that are not within the faulty section of the network. This programme of works commenced in AMP 2018 and will continue over the AMP 2019 period, culminating in an increased in the number of existing and new switches with remote control capability. Priorities are 11 kV feeders associated with single transformer zone substations, feeders that experience frequent faults, and those feeders that supply large numbers of customers and incur high SAIDI during an outage.

We are targeting a reduction in the maximum number of customers between network isolation points to less than 500. A network outage results in those customers between isolation points being without power until the necessary remedial work is completed. Reducing the number of customers between isolation points not only reduces the number of customers without power but also reduces the SAIDI impact. We commenced a programme in 2018 and will continue over the AMP 2019 period, to increase the number of network isolation points to achieve this outcome.

Distribution feeders to some of the more remote parts of the Vector network are without redundancy. That is, a fault on the network needs to be repaired before power can be restored. In most cases, the cost of building in network redundancy is prohibitive but we have identified a number of locations where a short extension to an existing distribution feeder allows connection to an alternate feeder, providing at least partial network backup to customers on both feeders. Specific resilience initiatives have been included as specific projects. A provisional budget has been included for continuation of this initiative from 2023 onwards. Specific projects will replace this provisional budget as they are identified, scoped and costed.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓	✓	

OPTIONS CONSIDERED

Options are summarised below.

DESCRIPTION	OPTIONS	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Improve network resilience and reduce outage times for customers	Option 1: Install remotely operated switchgear. This is a continuation of an existing programme to improve and expand our ability to remotely operate distribution switchgear across the network. This programme will reduce feeder switching times to isolate faulty section and/or to restore healthy sections after a fault. It will result in reduced SAIDI and improved service levels for customers	$28.0M	Selected
	Option 2: Increasing the number of isolations points on the network. The targeted installation of additional isolation points on the network allows us to reduce the number of customers between isolation points. In the event of a fault the number of customers without power while the fault is repaired is reduced. This also reduces SAIDI	$14.75M	Selected
	Option 3: Increase feeder backstopping capability. Extending distribution feeders to enable connection into other feeders provides backstopping capability and reduces the number and duration of customers without power when a fault occurs	$17.5M	Selected

FORECAST INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
11 kV feeder remote control – Auckland network	1.50	1.50	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	11.00
11 kV feeder remote control – Northern network	2.50	2.00	2.00	1.50	1.50	1.50	1.50	1.50	1.50	1.50	17.00
11 kV feeder isolation points – Auckland network	0.25	0.50	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	7.15
11 kV feeder isolation points – Northern network	0.40	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	7.60
11kV feeder meshing – Northern network				2.50	2.50	2.50	2.50	2.50	2.50	2.50	17.50
Total CAPEX	**4.65**	**4.80**	**4.60**	**6.60**	**6.60**	**6.60**	**6.60**	**6.60**	**6.60**	**6.60**	**60.25**

5.1.1 ZONE SUBSTATION AND DISTRIBUTION FEEDER PROGRAMMES

ZONE SUBSTATION FIRE AND SECURITY IMPROVEMENTS

NEEDS STATEMENT

Within the framework of the safety precautions applied to electricity zone substation, fire protection is one of the essential features. While fires in zone substations are rare the consequences of a substation fire can be very serious. The objectives of fire protection in our zone substations are clearly defined in Vector guideline "ENG-0028, Fire protection in zone substations". A number of our fire and security systems are now reaching end of life and do not comply with Vector's latest design standards, is unsupported technically by vendors, placing the safety of zone substations and their equipment at risk. As part of our programme of continuous improvement we are installing card-access security and improving fire monitoring systems across all zone substations - this includes replacing the core infrastructure for these systems. The intention is to bring all zone substations up to the same standard to ensure that operationally and functionally they are the same. This improves operational familiarity and maintenance requirements.

Our security system improvement will also involve the installation of improved and more secure fencing and gating as and where required with a focus on zone substations that supply critical loads e.g. the fuel depot in Wiri. In certain instances, as and where warranted and required, we will install cameras for remote monitoring – an initiative that will also apply to more strategic zone substations that supply critical load.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓	✓	✓	✓

OPTIONS CONSIDERED

DESCRIPTION	OPTIONS	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Our fire and security systems in a number of zone substations are reaching end of life and is not supported technically any longer. A 'Do nothing' approach will put zone substations and its equipment at risk and this option is rejected		Rejected
Option 2: Undertake a programme of replacing fire and security systems in zone substations Upgrade of core infrastructure for security and fire monitoring	Although zone substations fires are rare their consequences are very serious. End of life fire and security systems must be replaced to ensure the continued safety of our zone substations. To be able to integrate and manage all security and fire monitoring systems, core infrastructure has been deployed which will also need to be upgraded to comply with latest Cyber Security requirements.	$6.40M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland network zone substations - fire system and security upgrades	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	3.20
Northern network zone substations -fire system and security upgrades	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	3.20
Total CAPEX	**0.64**	**0.64**	**0.64**	**0.64**	**0.64**	**0.64**	**0.64**	**0.64**	**0.64**	**0.64**	**6.40**

5.1.2 CUSTOMER CONNECTIONS

The interface with the customer is managed by Vector's Customer Excellence Team. Requests for new connections or changes to existing connections are forwarded to the Customer Excellence Team from our FSPs for small projects and from developers or consultants for subdivision and customer substation works. Provisional budgets are then developed. Work on customer connections also include the connection (and disconnection) of smaller customers to Vector's network as well as minor extensions to the LV mains to allow connection and installation of service pillars. The service main inside the customer's property is the responsibility of the customer. Activities also include the livening of the service on receipt of a Certificate of Compliance. Expenditure on each service is variable depending on the complexity and scope of the works to be carried out. For the purposes of estimating the budget for the investment summary the average cost of a connection has been applied to the expected connection numbers for the year and regulatory period.

NEW CUSTOMER CONNECTIONS

NEEDS STATEMENT

Auckland's population is growing at a rapid rate. The demand for new housing is outstripping available supply resulting in construction of new high density subdivisions in previously greenfields areas (residential subdivisions) or refurbishing and intensification of existing established areas. The connection forecast for the next ten years is shown in Section 2. Vector is keen to support this growth by investing in reinforcing our network to support subdivision reticulation enabling the connection of these new customers (new connections).

Commercial growth differs from residential growth by virtue of the size of the load presented to the network and the way in which we deliver the capacity to meet the customer's needs. The solutions focus more on the installation of substations, whether new (customer substations) or capacity upgrades of existing substations (capacity changes). Smaller commercial customers may be supplied from street reticulation (business subdivisions) much the same as for residential subdivisions. As part of the reticulation we may be asked to install streetlighting circuits. Vector also takes into consideration the changing energy needs of both residential and commercial customers, such as the predicted increase in the number of Electric Vehicles for private and commercial use, in the design of networks for subdivisions.

OPTIONS CONSIDERED

The following options are considered for new customer connections.

DESCRIPTION	OPTIONS	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Vector is keen to support growth in Auckland. Do nothing is not a viable option for the development of Auckland into a world class city.		Rejected
Option 2: Install new connections and new subdivisions	The supply and installation of infrastructure for new connections to customers is part of Vector's core business	$56.94M p.a. average	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland Network Streetlighting	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	2.90
Northern Network Streetlighting	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	5.90
Northern Subdivisions - Business	0.75	0.65	0.65	0.65	0.59	0.59	0.59	0.59	0.59	0.59	6.24
Auckland Subdivisions - Business	0.88	0.76	0.76	0.76	0.60	0.60	0.60	0.60	0.60	0.60	6.76
Northern Customer Substations	5.20	4.40	3.60	3.34	3.02	3.02	3.02	3.02	3.02	3.02	34.66
Northern Capacity Changes	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	14.80
Auckland Capacity Changes	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.07	30.70
Auckland Customer Substations	7.80	6.60	5.40	4.99	3.94	3.94	3.94	3.94	3.94	3.94	48.43
Northern New Connections	6.64	6.61	7.00	7.00	7.00	7.00	7.00	7.63	7.63	7.63	71.14
Auckland New Connections	9.32	9.27	8.83	8.83	8.83	8.83	8.83	8.11	8.11	8.11	87.07
Auckland Subdivisions - Residential	11.33	11.33	10.07	9.44	8.81	8.18	8.18	7.55	6.48	6.48	87.85
Northern Subdivisions - Residential	19.88	19.88	17.67	16.56	15.46	14.36	14.36	13.25	11.36	11.36	154.14
Customer Substations Major					1.00	1.00	1.00	1.00	1.00	1.00	6.00
CRL Supplies	2.78										2.78
Auckland Airport third supply	0.20	4.80									5.00
America's Cup village	1.00										1.00
Elliot Tower 22 kV supply	0.50	1.00	0.50								2.00
WRR Lincoln Rd interchange to Westgate	0.06										0.06
Light Rail transit station supply		0.50	0.50	1.00							2.00
Total CAPEX	**71.77**	**71.23**	**60.41**	**58.00**	**54.68**	**52.95**	**52.95**	**51.12**	**48.16**	**48.16**	**569.43**

5.1.3 RELOCATIONS

OUTDOOR TO INDOOR SWITCHGEAR CONVERSIONS AT TRANSPOWER GXPS

NEED STATEMENT

Transpower is undertaking a program to convert ageing outdoor 33 kV bulk oil CBs at GXPs in Auckland. The Transpower owned and operated bulk oil CBs have been in service since the 1960s and there has been a number of catastrophic failures of the bulk oil CBs. Under agreement with Transpower, Vector will undertake the relocation of its subtransmission circuits to the new indoor switchgear.

OPTIONS CONSIDERED

To ensure continued reliability at GXPs to Vector's subtransmission zone substations Transpower will replace all ageing bulk oil filled CBs at GXPs. No other viable options exist to address the H&S risks and/or risks to reliability of supply. Description

DESCRIPTION	OPTIONS	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1	Do nothing: this option has been discounted because of the on-going risks posed by the ageing bulk oil subtransmission CB population. Obtaining spares for the 1960s vintage CBs is becoming an increasing challenge to Transpower	N/A	Rejected
Option 2	Because of the risks posed by ageing bulk oil CBs Transpower has elected to embark on a nationwide programme of works to removed such CBs from the network and replace them with maintenance efficient SF6 fixed pattern switchgear. This switchgear contains the latest arc flash technology to remove the risk of harm to operators and the public.	$7.80M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Mangere Transpower 33 kV switchboard	3.00										3.00
Wellsford Transpower 33 kV switchboard				2.00							2.00
Wiri Transpower 33 kV switchboard			2.50								2.50
Mt Roskill Transpower 33 kV switchboard	0.30										0.30
Total CAPEX	3.30	0.00	2.50	2.00	0.00	0.00	0.00	0.00	0.00	0.00	7.80

ASSET RELOCATIONS REQUESTS

NEEDS STATEMENT

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. Depending upon the third party making the relocation request, Vector is obliged to relocate its assets by Sections 32, 33 and 35 of the Electricity Act, 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 required by these Acts often occur when infrastructure projects are initiated by road or rail corridor managers, particularly Auckland Transport, NZTA, Kiwirail and other utility providers such as Chorus. The process and funding of such relocation work is governed by the relevant Acts. The investment summary below covers a number of anticipated relocation projects that are consolidated into two lines items namely Auckland and Northern, reflecting their location on Vector's network. However, the Auckland Light Rail project is shown as a separate line item in the investment summary table below because of the very high level of projected relocation cost to Vector. It will be noted that the Auckland Light Rail project has a significant impact on raising the forecast spend for relocations from AMP 2018 to AMP 2019.

The timing and scope of relocation projects are driven by the third party concerned. Consequently, Vector often has less advance notice of relocation projects and / or detailed scope, compared to projects initiated from within Vector. This makes the accurate forecasting of relocation costs difficult.

OPTIONS CONSIDERED

DESCRIPTION	OPTIONS	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Because Vector is required by various Acts to undertake relocation projects when reasonably requested, 'Do nothing is not an option.		Rejected
Option 2: Invest capital in customer relocations projects and programmes of work	Relocation projects occur when infrastructure projects are initiated by other utilities and Vector will oblige in terms of the Acts to undertake such works	$218.1M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland relocations	3.18	6.90	8.55	6.00	5.05	5.00	6.50	6.50	6.50	6.50	60.68
Auckland Light Rail Project		12.00	21.00	21.00	21.00	8.00					83.00
Northern relocations	15.60	13.16	8.20	4.50	4.50	4.50	6.00	6.00	6.00	6.00	74.46
Total CAPEX	**18.00**	**28.96**	**37.75**	**31.50**	**30.55**	**17.50**	**12.50**	**12.50**	**12.50**	**12.50**	**218.14**

5.2 OPERATE, MAINTAIN, RENEW AND REPLACE

The safe and reliable operation of the network relies upon renewal and replacement of assets together with a sound maintenance regime. Vector's ultimate aim for operations and maintenance is to meet the service level targets set out in Section 2. Our approach includes provision of a safe workplace for staff and safe networks for the community, delivering customer service and network performance to meet the required standards and service levels and maintaining an efficient and sustainable cost structure. Network refurbishment programmes of work are developed to identify and restore or replace assets based on asset health and criticality. These programmes factor in the benefits of future reductions in operating costs and are based on a technical assessment of the serviceability of the asset and the economic costs of replacement or refurbishment. This includes ensuring asset safety and ensuring assets meet any associated environmental requirements.

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 current gap in the reliability indices, with SAIDI and SAIFI exceeding targets, is currently a main focus area of our renew / replace programme. In addition, there is an emphasis on improving the safety of network assets through improving visibility of assets.

Programmes of work have been created where expenditure is planned across a number of years. We are accelerating our rate of replacement of certain assets from a safety and reliability perspective. An example among others, described in the section below, is the replacement of small diameter OH conductors for which there is a potential trend of increasing failure (details of the rate of failure is given in Section 4). Another example described below is our programme to replace certain types of oil filled ring main units where there is evidence of a trend of poor asset health some of which are in high criticality locations.

Vector's forecast expenditure for Routine and Corrective Maintenance and Inspections is set out in Forecast Operational Expenditure (Schedule 11b) in Appendix 7 as part of the disclosure Report on Forecast Operational Expenditure. Asset replacement and renewal is forecast in Forecast Capital Expenditure (Schedule 11a) in Appendix 6 as part of the disclosure Report on Forecast Capital Expenditure. A typical breakdown of Vector's expenditure on Routine and Corrective Maintenance and Inspections across the primary asset categories is shown in Table 5-2, reflected as a percentage of the value forecast in Schedule 11b.

ROUTINE AND CORRECTIVE MAINTENANCE AND INSPECTIONS	FY19 – FY28
Distribution feeders	61%
Distribution substations and transformers	13%
Secondary systems	5%
Subtransmission feeders	6%
Zone substations	15%

Table 5-2 Routine and corrective maintenance and inspections expenditure allocation

NETWORK MAINTENANCE NEEDS STATEMENT

Achieving the corporate objectives will require the balancing of cost, risk and performance outcomes to gain optimal value from assets without compromise to service levels, reliability indices and the experience of customers. To achieve the required network performance efficiently the condition of individual assets must be maintained in a serviceable operating state over the period of its useful life. To deliver on this Vector implements extensive routine and operational preventative activities. Equipment is inspected at scheduled intervals for physical indications of degradation exceeding a threshold that is predictive of a potential failure. Typical examples of inspection and condition monitoring activities include: analysis of power transformer oil to monitor for trace gasses produced by internal faults; inspection of service lines; acoustic inspections to identify partial discharge; assessing the extent of decay in timber power poles to determine residual strength and; inspection of timber cross-arms to detect visible signs of degradation. Pole and/or crossarm replacement occurs through a combination of failed inspections and proactive replacement where age, type, location, risk and criticality are considered. Proactive pole and crossarm replacement is also undertaken in conjunction with reconductoring projects. However, analysis of our service levels and reliability indices show that a number of performance issues are developing within our asset base that requires Vector to take a different approach and/or additional programmes of maintenance to prevent service level gaps from deteriorating any further. Our performance gap analysis and root cause analysis shows that:

- The failure of components of overhead lines contribute significantly to interruptions on distribution feeders
- There could be a potentially increasing trend of failure of underground 11 kV cables and joints that contribute to interruptions on distribution feeders
- Third party damage to our assets is contributing significantly to poor service level outcomes.
- Pole mounted 11 kV cast iron pothead cable boxes were found to be a primary contributor to interruptions on distribution feeders
- Vegetation in the proximity of our overhead power lines is a major factor in network outages especially during storms and high winds (additional maintenance spend will be directed at Vegetation – see separate Needs Statement further below)

In general, there is an increasing number of open, high risk corrective notifications in our inspections database and the number of unplanned events are rising and needs to be addressed (refer to Section 4.1.7). To reduce our open, high risk corrective notifications and improve our service levels we will undertake the following as part of our corrective maintenance investment:

- Fully implement the proposed changes to SAP-PM to support the new maintenance standards. This will enable the collection of better condition data and the improved management of planned and corrective work.
- Increase focus and investment to remediate open, high risk corrective notifications
- Traditionally conductor clearance to ground issues have been identified primarily as part of planned inspections of poles structures. This method is too time consuming and does not address in a timely manner the legislative risks with regard to low conductors. We will increase our use of light detection and ranging (LiDAR) to speed up the survey of OH line clearances
- Increase the level and skill set of reactive response field staff
- Increase the use of diagnostic measurement techniques such as ultrasonic partial discharge surveys on our network.
- Increase and improve our diagnostic testing on our subtransmission and 11 kV distribution cable fleet
- Increase partial discharge and acoustic surveys on switchgear

Our maintenance regime and frequencies of inspection for planned maintenance are described in our suite of maintenance standards for our different asset classes. Each maintenance standard addresses the purpose, content, frequency, record requirements and associated treatment criteria. The treatment criteria and resulting actions generally direct field staff, to repair, refurbish or replace components, replace entire asset, and for some assets refurbish entire asset off-site or refurbish oil in-situ. Maintenance frequencies are not stated in this Needs Statement.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓	✓		

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – do not increase the investment in maintenance	Our service levels and reliability indices show that a number of performance issues are developing within our asset base that requires Vector to take a different approach and/or additional programmes of maintenance to prevent service level gaps from deteriorating any further. A business as usual approach will simply not suffice going forward		Rejected
Option 2: Alter our maintenance practices and undertake additional proactive investment	Corrective maintenance must be increased and adapted to increase works volumes to target the root causes of the identified service level gaps and to undertake additional and alternative maintenance initiatives to address the increasing number of open, high risk actions. This is needed address the existing service level gaps and correct performance to re-establish and maintain the expected service level	$982.37M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

Our operational expenditure as per the investment summary below is a combination of core maintenance, i.e. all FSP reactive, planned and corrective maintenance activities, management of strategic spares, storage. It also contains non-core maintenance activities relating to exceptional and extreme network events, specialist contractor or extraordinary maintenance activities over and above that provisioned through core maintenance services. It also includes all reactive, planned and corrective work associated with the Penrose-Hobson tunnel and covers cost recovery associated with reactive third party damage activity.

MAINTENANCE CAPEX

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Corrective maintenance (CAPEX)	34.00	34.00	34.00	34.00	33.16	33.02	32.78	32.34	33.19	33.59	334.08
Reactive maintenance (CAPEX)	16.27	16.43	16.60	16.77	16.94	17.12	17.29	17.47	17.65	17.83	170.37
Total CAPEX	50.27	50.43	50.60	50.77	50.10	50.14	50.07	49.81	50.84	51.42	504.45

MAINTENANCE OPEX

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Planned maintenance (OPEX)	16.48	17.27	17.49	18.58	22.73	22.92	18.07	18.02	18.11	18.24	187.91
Corrective maintenance (OPEX)	12.64	13.42	13.56	13.7	13.84	13.79	13.64	13.77	13.91	14.06	136.33
Reactive maintenance (OPEX)	13.90	13.53	13.65	13.78	13.91	14.04	14.17	14.29	14.43	14.55	140.25
Total OPEX	43.02	44.22	44.70	46.06	50.48	50.75	45.88	46.08	46.45	46.85	464.49

VEGETATION MANAGEMENT

NEEDS STATEMENT

Vegetation encroaching within minimum clearances of OH power lines creates safety risks for the public and to Vector and Vector contractor workers. Vegetation in the proximity of OH power lines is a major factor in network outages especially during storms and high winds. Gap analysis between service level performance and target performance levels has identified outages caused by vegetation contribute 15% of SAIDI and 13% of SAIFI on distribution feeders (see Section 2). According to a NIWA study on the impact of climate change, the climate over the Auckland region will become more volatile over the next century and there is a real risk that this item will have a further negative impact on service levels. The report outlines that Auckland would be impacted amongst others with storm surges with more frequent strong winds and the April 2018 storm was a classic example where trees and branches caused outages to thousands of customers in Auckland. There is clear indication that faults due to 'out of zone vegetation' are on the increase (see the figures below), and Vector will place greater focus on managing 'out of zone vegetation'.

What Vector can do about trees is governed by 15 year old regulations which also set out what private landowners should do. The challenge for Vector is that under the current Hazard from Trees Regulations that only vegetation in a limited are can be trimmed. The MBIE has initiated a dialogue with distribution lines businesses and other interested parties for a full review of the Electricity (Hazards from Trees) Regulations of 2003. Notwithstanding the limitations for EDBs under the current regulations, Vector will continue and increase its programme of work to control vegetation (within the current rules in the Hazards from Trees Regulations). To achieve this we will deploy a leading approach to focus on controlling vegetation by SAIDI criticality. We will also work with Auckland City Council to reduce future conflicts between trees and power lines and initiate agreements to remove existing unsuitable trees and replace with power line 'friendly' trees. We will have done a LiDAR survey of our network by the end of FY19 and will utilise the data to identify trees close to powerlines a project planned for FY21 is to make further use of this data plus utilising data analytics tools to create a vegetation prediction model.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓		✓	✓		

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Continue with current level of investment to control vegetation. This option will not address the existing service level performance gaps and the network will continue to be impacted by vegetation and in light of the prediction that storms and high winds will increase such gaps in the service level will increase		Rejected
Option 2: Proactively identify trees that are high risk and increase the investment to control vegetation. Utilising data analytics and create a vegetation prediction model.	This solution will address the service level gaps that exist and will correct performance of the network to re-establish and maintain expected service levels. The significant contribution by vegetation to reliability indices will be reduced.	$78.8M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Vegetation management (OPEX)	7.57	8.16	8.25	8.36	8.46	8.57	7.10	7.19	7.28	7.37	78.31
Vegetation prediction model (CAPEX)		0.50									0.50
Total	**7.57**	**8.66**	**8.25**	**8.36**	**8.46**	**8.57**	**7.10**	**7.19**	**7.28**	**7.37**	**78.81**

CONSOLIDATED AREA FAULT REDUCTION PROGRAMME

NEEDS STATEMENT

In addition to planned, corrective and reactive maintenance we will embark on a programme that we titled 'consolidated area fault reduction programme'. The intention with this programme of works is to focus on areas with poor service levels and a poor experience of Vector's electricity network and to address issues in a consolidated manner - in other words rather than undertaking reactive repair and reactive maintenance in such areas, a consolidated effort will be undertaken in predetermined areas to have a large shutdown and then undertake the reactive repairs that are required but also repair all other outstanding defects in the specific area in on go, to reduce the number of outages and, to improve service levels in a consolidated and coordinated effort repair effort. Areas with poor service levels will form the target of this programme of works.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓		✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Continue with current level of investment to control vegetation. This option will not address the existing service level performance gaps and the network will continue to be impacted by vegetation and in light of the prediction that storms and high winds will increase such gaps in the service level will increase		Rejected
Option 2: Proactively identify areas which has poor service levels and undertake a consolidated effort to repair all faults in the targeted area	As society becomes more dependent on technology the expectation is that the tolerance for loss of power and poor service levels will reduce	$48.0M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland consolidated area fault reduction	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	24.00
Northern consolidated area fault reduction	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	24.00
Total CAPEX	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**4.80**	**48.00**

CONDITION BASED ASSET RISK MANAGEMENT (CBARM)

NEEDS STATEMENT

An asset health indicator is a measure that represents an asset's stage within its overall life cycle. Asset age has traditionally been used for this purpose and while useful for evaluating population level strategies in circumstances where reliable statistics are available, use of age alone can produce misleading conclusions. In addition to that we rely on asset condition as identified by routine maintenance inspections and replacement undertaken as required based on the identification of risks under the corrective maintenance programme.

Asset health is a measure of the condition of an asset and the proximity to the end of its useful life. As the health of an asset deteriorates the likelihood that it will fail due to condition increases. Presently our process to determine the risk and associated weighting for prioritisation of works is rather ad-hoc. To this end Vector is developing CBARM models for its major asset classes to inform our replacement and refurbishment programmes of work and strategies. The key outputs from the CBARM models are evaluation of the probability of failure and the consequence of failure. This will provide a current health score as well as a future health score which is capped at 10 – the higher the score the poorer the asset health and the higher the probability of failure. Any asset with a score higher than 8 requires replacement as soon as possible.

The models will enable us to plan and forecast programmes of work to be undertaken on the assets with planning horizons of 1 to 2 year schedules and 2 to 5 year options. The CBARM models provide a bottom up risk priorities plan which allows assessment of investments on a common basis and tests decisions of deferrals as well as expediting work on a risk versus cost basis. Our CBARM models for OH 11 kV conductors, 11 kV ring main units and distribution transformers are mature and we plan to complete CBARM models for other major asset, e.g. power transformers, subtransmission switchgear, poles and crossarms, 11 kV cables, and subtransmission cables – a total of 12 CBARM models will be developed. As we move forward in time our CBARM models will be extended to other smaller asset classes e.g. protection relays, RTUs, PQM meters, and the like.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓	✓	✓	

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do not undertake this initiative – Do nothing	Without CBARM models our decision making will remain ad-hoc and inefficient. Deteriorating asset condition invariably leads to deteriorating network performance and increases safety risk and an ad-hoc approach will simply not achieve the efficiencies to manage ageing asset populations.		Rejected
Option 2: Implement condition based asset risk models for all major asset classes	Condition rather than age will allow better decision making to plan replacements and refurbishment programmes of work. Being informed in a structured way about the condition of asset classes is essential to address issue with escalating failure rates and poor SAIDI and SAIFI performance.	$0.50M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
CBARM	0.50										0.50
Total CAPEX	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50

5.2.1 SUBTRANSMISSION FEEDERS

While subtransmission feeders currently make up a relatively small proportion of network interruptions, failure of a subtransmission feeder can result in a large impact to SAIDI, particularly for underground circuits with low physical accessibility. It is therefore important to closely monitor the condition of subtransmission feeders and maintain risk profiles to an acceptable level.

The following section describes the project and investment proposals for subtransmission cables.

SUBTRANSMISSION CABLE REPLACEMENT PROGRAMME

NEEDS STATEMENT

Vector's subtransmission cable population is ageing but presently with a consistent trend of failures. Notwithstanding that the failure rate is not presently showing an increasing trend, in terms of design life, certain types of subtransmission cables especially PILC cables, are nearing the third part of the 'bathtub curve' namely, the wear out failure period where if enough units from a population of assets remain in use long enough, the failure rate begins to increase as materials wear out and degradation failures occur at an ever increasing rate. We are experiencing degradation failures and the concern is that with a population of similar age profiles approaching the end of design life that a sudden deterioration of subtransmission cables could result in loss of supply to large areas. In many instances, the two or three subtransmission cables that run to a zone substation are of the same age and hence the risk of concurrent failure is real. If one subtransmission cable to a zone substation should fail we will in many instances be able to backstop the shortfall in supply capacity via the 11kV distribution networks from neighbouring zone substations. However, if both or more subtransmission cables should fail there will likely be large and lengthy outages.

Our XLPE fleet of subtransmission cables have the largest number of cable faults but is also the largest population of this asset. Vector also has a large number of ageing oil filled cables of similar age but the construction of this type of cable is such that they can be retained in service for a number of years to come under Vector's existing maintenance regime (maintenance requirements are described in Vector standard ESM301 Maintenance of Cables). The population most at risk is our PILC subtransmission cable fleet where there is real concern that this part of the fleet is entering the wear out failure period of the bathtub curve.

For certain subtransmission cables it is not the health of the cable(s) that is a concern but their location: over time with the development of new road corridors certain subtransmission cables or portions of cables can only be accessed with difficulty or not at all. In some instances, excavations of up to 4m deep are required to reach cables – this results in very lengthy outages during which time the supply to large areas of network is at risk. Such cables or portions of cables must be replaced.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Continue with current level of investment to maintain subtransmission cables and accept the risk that the wear out period as per the bathtub curve might be approached for certain populations of the subtransmission cable fleet. This option will not address the risk of complete loss of supply to a large area should both or more subtransmission cable circuits to a zone substation fail.		Rejected
Option 2: Use new network technology options to offset the requirement to replace subtransmission circuits	Under the Symphony load forecast model a 7% demand increase is forecast by 2028. For certain areas the installation of a new network technology installation, e.g. a large scale BESS system, will provide respite for peak demand in the event of loss of one subtransmission supply but this option will not suffice for any of the subtransmission projects in the summary of investment list below		Rejected
Option 3: Undertake a staged and scheduled programme of works to replace subtransmission cables that are approaching the end of design life	This solution will address the risk as per the bathtub curve where cable population of the same age is approaching the end of their design life.	$43.19M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Glen Innes subtrans replace	10.00										10.00
Ponsonby subtrans replace	3.70										3.70
Takanini subtrans replace	3.18										3.18
Onehunga subtrans replace	0.20	6.00	2.70								8.90
Chevalier subtrans replace			2.00	4.59							6.59
Westfield subtrans replace				1.10	5.72						6.82
Northern subtrans replace						0.50	0.50	1.00	1.00	1.00	4.00
Total CAPEX	**17.08**	**6.00**	**4.70**	**5.69**	**5.72**	**0.50**	**0.50**	**1.00**	**1.00**	**1.00**	**43.19**

5.2.2 ZONE SUBSTATIONS

Similar to subtransmission feeders, zone substations do not currently have a significant impact on SAIDI due to their N-1 design criteria. Zone substations are subject to regular inspections as set out in Section 4 and use SCADA for real time monitoring. Through this inspection and monitoring regime, several projects have been identified that could impact on SAIDI in the future that is mainly due to the fact that a large population of zone substation assets are of the same age and as for subtransmission cables above, this population will reach end of their design lives at the same time. This means the bathtub risk of curve of 'wear out failure rate' comes into play. This risk applies to oil-filled switchgear and zone substation power transformers where there is a substantial population that dates from the 1960s. Age profiles are included in Section 4.

The following sections set out the project proposals for different assets in zone substations:

33 AND 22 KV PRIMARY SWITCHGEAR REPLACEMENT

NEEDS STATEMENT

Vector has made inroads with renewing its fleet of 1960s and 1970's 33 kV and 22 kV oil-filled switchgear but a number of sites with bulk outdoor oil filled switchgear still remain – the population and age profile is shown in Section 4. In RY18 no failure occurred in our 33 kV CB bulk oil fleet but a chunk of this asset population is of the same age and nearing the end of its design life – this can be attributed to a rigorous maintenance schedule and high standard of maintenance.

Furthermore, this fleet of CBs is not technically supported by vendors but we recovered similar CBs from previous conversion projects and these have been retained to be cannibalised for spare parts. It must be noted that if a 33 kV oil-filled CB fails it is usually catastrophically and they do present a risk to maintenance personnel as well as personnel that undertake inspections in close proximity to this plant. Because of the volume of oil that these CBs contain they also present a risk to the environment. We also have a number of first generation 22 kV SF6 switchboards that are showing signs of poor health. One 22 kV switchboard in particular is the Yorkshire SF6 switchgear suite in our Hobson zone substation in the Auckland CBD. The asset health in this switch presents reasons for concern and a programme of replacement needs to be undertaken – we will start this replacement programme by extending the existing switch with a number of new panels[17] - with a gradual transfer of 22 kV CBF feeders to the extension.

The replacement programme for 33 kV and 22 kV switchgear will not result in a visible and immediate impact or improvement to SAIDI but will rather reduce the risk of catastrophic failure and prevent the high levels of SAIDI that will go hand in hand with a failure of this plant, from happening in the first instance.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment: Continue with current level of investment to maintain ageing 33kV bulk oil CBs.	The existing fleet of 60s and 70s vintage CBs require extensive maintenance to keep them operational and safe. At present a number of 33kV bulk oil CBs that were recovered from previous conversion projects, are available to be cannibalised for spare parts and this enables Vector to maintain its current fleet of 60s and 70s vintage bulk oil CBs. However this stock of CBs will be depleted in the not too distant future. During maintenance, personnel work in close proximity to in service 60s and 70s vintage oil CBs and they present a risk to the H&S of personnel. The risks associated with this switchgear is of high consequence and high likelihood and failure will have a high impact on SAIDI		Rejected
Option 2: Use new network technology options to offset the requirement to replace subtransmission circuits	New technology options are not suitable as an alternative for the risk posed by ageing bulk oil filled CBs		Rejected
Option 3: Undertake a staged and scheduled programme of works to replace 33kV outdoor bulk oil CBs	This solution will address the risk as per the bathtub curve where outdoor bulk oil CBs of the same age is approaching the end of their design life. This option removes the risks associated with the 'Do Nothing' option	$16.47M	Selected

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17 The works at Hobson ZSS are described in a separate Needs Statement

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

AMP19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Belmont 33kV SWBD ODID	1.62										1.62
Browns Bay 33kV SWBD ODID	0.65										0.65
New Lynn 33kV SWBD ODID	0.20	2.30									2.50
Sabulite 33kV SWBD ODID		0.15	1.23								1.38
Henderson Valley 33kV SWBD ODID			0.20	1.73							1.93
James St 33kV SWBD ODID					0.20	2.00					2.20
Hobsonville 33kV SWBD ODID						0.20	2.00				2.20
Sunset Rd 33kV SWBD ODID								0.20	1.80		2.00
Waikaukau 33kV SWBD ODID										2.00	2.00
Total CAPEX	2.47	2.45	1.43	1.73	0.20	2.20	2.00	0.20	1.80	2.00	16.48

HOBSON ZONE SUBSTATION UPGRADES AND REPLACEMENTS

NEEDS STATEMENT

Hobson zone substation is one of three bulk supply (zone) substations in Auckland's CBD (the other two bulk supply zone substations in the CBD are Liverpool and Quay St). Hobson ZSS is supplied from the NAaN 220 kV cable via a 250 MVA 220 kV/110 kV transformer. The voltage is stepped down to both 11 kV and 22 kV to supply the lower to mid CBD and the 22 and 11 kV nodes provide backup supply to the 11 and 22 kV networks from Liverpool and Quay zone substations. Because of the increasing load density, a long-term programme exists in which the distribution network in the CBD is being changed from an 11 kV network to a 22 kV network but this programme of works is expected to take at least another three decades to complete. This means that the 11 kV switchboard at Hobson ZSS will be required for the same amount of time.

The 11 kV switchboard at Hobson consists of two sections: A Reyrolle switchboard that was installed in 1984 and a Brush switchboard that dates from 1969. This critical switchgear ZSS is approaching the end of its asset life and the risk profile offered by this plant is increasing. Failure of ageing 11kV oil-filled CBs can result in catastrophic explosions with accompanying flaming oil and shrapnel. International records exist of catastrophic and deflagration failures of similar oil-filled Brush 11kV switchgear and this holds risk of injury as well as risk of collateral damage. A number of oil-filled switchgear failures that resulted in deflagrations and extensive outages have occurred in Vector's network in recent times most notably at Parnell zone substation (ZSS), Browns Bay ZSS and Spur Rd ZSS. Thus far catastrophic failures have negatively impacted SAIDI and SAIFI but not resulted in injury or worse. Older generation oil-filled 11kV switchgear does not provide the level of protection to personnel against the risk of arc-flash that is provided by modern gas-filled switchgear. An arc-flash has the potential to do serious harm and Vector is obliged under the Health and Safety in Employment Act and the Electricity Act to consider this risk. Both the replacement switchgear and the retrofit switchgear will provide arc-flash protection to improve the safety of personnel.

The asset life of the existing 1984 vintage 11kV oil-filled Reyrolle switchgear can be extended by the installation (retrofitting) of vacuum CB trucks and the replacement of its electro-mechanical protection systems with modern numerical protection relays. A retrofit option does not exist for the 1969 vintage Brush switchgear and it will have to be replaced in its totality.

Furthermore, the 22 kV Yorkshire switchgear in Hobson ZSS has been in service since 1975 and the operational performance and maintenance requirements did not quite meet expectations and a start will be made to replace this switchgear by installing a number of replacement 22 kV CBs. A staged replacement will take place with the complete suite replaced over the longer term.

Before refurbishment of the 11 kV switchgear or replacement of the 22 kV switchgear can take place, a seismic upgrade is required for the switchgear building and cable basements to bring it up to seismic standard for importance level 3 buildings as required in the NZ Seismic standard and as required by Auckland Council. The 22 kV switchroom must also be extended to house the replacement 22kV switches and this civil work is also enabled by the seismic compliance works.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – Do nothing	Failure of switchgear in Hobson ZSS will result in lengthy loss of supply to many (high profile) customers (and the associated negative impact on SAIDI and SAIFI). Failure of the switchgear also means that the security of the supply to the lower and mid CBD will be compromised and any further network contingencies will result in a complete loss of supply.		Rejected
Option 2: Undertake the seismic building compliance work, refurbish the 11 kV switchgear and commence with replacement of the 22 kV switchgear	The civil and structural works to make the old switch building seismically compliant and extend the 22 kV switchroom on this space constrained and operational site will be complex, costly and not without risk but has to be undertaken to ensure the integrity of the facility. The 11 kV switchgear must be replaced to ensure the continued reliability of supply to the CBD. The same holds true for the 22 kV switchgear for which partial replacement must commence to ensure continued reliability.	$14.50M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Hobson 11kV SWBD replace	2.80	3.55	3.35								9.70
Auckland Seismic Rebuild Hobson	3.80										3.80
Hobson 22kV SWBD Extension		0.50	0.50								1.00
Total CAPEX	**6.60**	**4.05**	**3.85**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**14.50**

11 KV SWITCHGEAR REPLACEMENT

NEEDS STATEMENT

11kV Primary switchgear in zone substations is among the most critical assets for lines companies. Vector's large population of 11 kV oil-filled switchgear dates from the 1960s and 1970s and due to our rigorous maintenance regime, we have managed to maintain the reliability of this ageing 11kV fleet with very low impact to SAIFI and SAIDI. However, a failure mode is being observed in 1970s vintage New South Wales and Reyrolle switchgear in which bushings manufactured with synthetic resin bonded paper are failing increasingly. The 60s and 70s vintage oil filled switchgear designs are based on withdrawable CBs and do not provide the protection against the risk of arc flash as with newer generation switchgear where the switchgear is designed to withstand arc faults and is physically segregated to safely withstand internal arc faults and eliminate the risk of widespread damage to an entire installation. For most of our Reyrolle fleet of oil filled CBs we are able to retrofit vacuum CBs and have made good progress with this programme but a few substations still need to be completed. However, the Brush and New South Wales 11kV switchgear fleet are not able to be retrofitted and require a complete replacement.

We have also recently, Nov 2017 and Jan 2018, experienced failures of 1980s vintage vacuum CB interrupters in our GEC VMX CB fleet and in response we procured a test set specifically for the testing of vacuum interrupters and have now completed tests on all 1980s vintage vacuum interrupters. Tests have shown that 1980s vintage vacuum interrupters, especially in the GEC VMX CB fleet, should be replaced in the next two to three years and our investment programme makes provision for this replacement.

Further to the above, there is no vendor product support for 60s and 70s vintage oil filled 11kV CBs and obtaining spare parts is a challenge. However, we have prudently retained 60s and 70s vintage oil-filled switchgear from previous replacement projects and these are cannibalised for spares. To ensure the reliability of our zone substations we will undertake a programme of works to replace our fleet of Brush and New South Wales oil filled CBs with modern arc flash rated and arc flash segregated switchgear, replace oil filled CBs in our Reyrolle fleet with modern vacuum CB trucks and arc flash doors and replace vacuum interrupters in GEC VMX 11kV CBs.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment: continue with current level of investment to maintain ageing 11kV zone substation switchgear	Maintaining the fleet of 60s and 70s vintage oil-filled 11 kV switchgear is becoming an increasing challenge with no vendor/supplier product support available and no availability of spare parts apart from spares that can and are cannibalised from 11kV CBs that were recovered from previous replacement projects in the past by Vector. 60s and 70s vintage oil filled switchgear also pose a H&S risk to maintenance and inspection personnel. Failure of oil filled CBs is usually catastrophic and spectacular with a commensurate risk of fire and thus a risk of complete loss of a zone substation. This vintage switchgear also do not provide mitigation against the risk of arc flash as found in new generation switchgear that is fitted with arc chutes that guide arc flash products away from the equipment user.		Rejected
Option 2: Use new network technology options to offset the requirement to replace subtransmission circuits	New technology options are simply not suitable as an alternative for the risks posed by our ageing fleet of 11 kV zone substation switchgear		Rejected
Option 3: Undertake a staged and scheduled programme of works to replace primary 11 kV zone substation switchgear	To ensure the continued long-term reliable performance of the primary 11 kV CB fleet in our zone substations and ensure the safety of maintenance and operational personnel we have selected to undertake a programme of works to replace 60s and 70s vintage oil filled switchgear, install vacuum CBs in our Reyrolle fleet and replace vacuum interrupters in our GEC VMX fleet.	$93.03M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Mangere Central 11 kV SWBD Replace	1.50										1.50
White Swan 11 kV SWBD replace	1.00	3.48									4.48
Warkworth 11 kV SWBD replace	0.20	3.40									3.60
Mt Wellington 11 kV SWBD Replace	0.08										0.08
Otara 11 kV SBWD arc flash doors	0.20										0.20
Freemans Bay 11 kV SWBD replace		1.00	3.48								4.48
Pakuranga 11 kV SWBD Replace		1.00	3.18								4.18
Wiri 11 kV vacuum CBs retrofit and upgrade protection		0.50	2.18								2.68
Papakura 11 kV vacuum CBs retrofit		0.50									0.50
Sandringham 11 kV SWBD Replace			1.50	3.50							5.00
Manukau 11 kV SWBD Replace			1.00	2.56							3.56
Hobsonville 11 kV SWBD Replace			0.80	2.76							3.56
Ponsonby 11 kV vacuum CBs retrofit			0.50								0.50
New Lynn 11 kV SWBD replace				1.20	2.80						4.00
Te Papapa 11 kV SWBD Replace				1.00	3.28						4.28
James St 11 kV SWBD Replace				1.00	3.00						4.00
Quay 11 kV SWBD Replace					0.20	3.54					3.74
St Heliers 11 kV vacuum CBs retrofit					0.80	1.48					2.28
Rockfield 11 kV vacuum CBs retrofit						1.00					1.00
Rosebank 11 kV vacuum CBs retrofit						0.70					0.70
Hillcrest 11 kV vacuum CBs retrofit						0.61					0.61
Kingsland 11 kV vacuum CBs retrofit						0.50					0.50
Papakura 11 kV SBWD replace						1.20	3.00				4.20
Sunset Rd 11 kV SWBD replace							1.20	4.00			5.20
Henderson Valley 11 kV SWBD replace							1.20	3.00			4.20
Victoria 11 kV SWBD replace							1.00	4.50			5.50
Woodford 11 kV SBWD replace							0.70	2.00			2.70
Manly 11 kV SWBD replace								1.00	3.20		4.20
East Coast Rd 11 kV SWBD replace								0.40	1.00		1.40
Mt Albert 11 kV SWBD replace									0.50	1.00	1.50
Newton 11 kV SWBD replace									1.50	4.00	5.50
McLeod Rd 11 kV SWBD replace									0.60	1.10	1.70
Waikaukau 11 kV SWBD replace										1.50	1.50
Total CAPEX	**2.98**	**9.88**	**12.64**	**12.02**	**10.08**	**9.03**	**7.10**	**14.90**	**6.80**	**7.60**	**93.03**

GAS MONITORING INSTALLATION LIVERPOOL 110 KV SWITCHGEAR

NEEDS STATEMENT

The 110 kV switchgear at Liverpool zone substation in the Auckland CBD has been in service since 1998. The switchgear is fitted with two stage gas density switches per SF6 gas compartment and these are signalled to Vector's EOC at bay level but there is no visibility of a compromised gas compartment until alarm levels are reached.

The switchgear is reaching a stage in its asset life where accelerated gas leaks can develop rapidly with weaknesses in seals over time. To avoid unexpected shut-downs manual inspections are undertaken every two months as part of the station maintenance regime where the gas is checked to be above the alarm points. Manual inspections are labour intensive and readings from inspection to inspection do not provide any trends due to the macro scale of the fitted pressure gauges with slow leaks being virtually imperceptible between periods.

In 2012 a refurbishment project was undertaken on the Liverpool Merlin Gerin 110 kV switchboard to replace the most vulnerable components through which gas was leaking (e.g. switch position indicating windows and fragile carbon disk pressure relief devices) as well as overhauling the hydraulic systems of all CBs. The opportunity offered by the refurbishment was utilised to install milliampere output pressure transducers to make the switch ready for a comprehensive gas monitoring system to be installed.

The layout of the 110 kV switch is such that a gas monitoring system can be installed and this needs to be undertaken. Without such a system, the switch could be shut down unnecessarily resulting in a negative impact to SAIDI/SAIFI and Security of Supply in the CBD.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: do nothing and continue to rely on the single global gas alarm	A lack of gas-trending and reliance on a single alarm means there is a risk that the whole switch could be shu7.85tdown unnecessarily and this will have a negative impact on the SAIDI/SAIFI reliability index, security of supply to Auckland's CBD and will impact Vector's reputation. This strategic switch is ageing and the reliance on a global gas alarm requires intensive manual monitoring and there is no visibility of gas trending		Rejected
Option 2: install a gas monitoring and trending system	A system that provides comprehensive reporting on gas-trending and gas-alarms will provide full visibility to the EOC and negate the need for constant manual monitoring. This system will reduce the risk of high impact on the SAIDI/SAIFI index and reduce the risk of a high impact on the security of supply to the Auckland CBD	$0.20M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Liverpool 110 kV gas monitoring system	0.20										0.20
Total CAPEX	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20

POWER TRANSFORMER REPLACEMENT PROGRAMME

NEEDS STATEMENT

Zone substation power transformers are the key items to enable the transfer of energy from the subtransmission network to Vector's distribution network. We have 216 power transformers in service and the oldest dates from 1950: the average age for the fleet is 32 years. Forty transformers are 50 years and older with the oldest 68 years of age. Full details of our existing fleet of zone substation power transformers and their age profiles are given in Section 4. The insulation system of power transformers consists primarily of mineral oil, paper and pressboard that has a finite life even under ideal operating conditions and ageing of the paper insulation depends primarily on the operating temperature of the oil and the length of time for operation at high oil temperatures. Moisture and the presence of oxygen are other factors that will accelerate the ageing of transformers. Another key factor in the life expectancy of a power transformer is the history of downstream faults that a transformer has been subjected to: high fault levels will cause winding and core deformation that will lead to unintentional shorts in the insulation of which a high number are not repairable. Depending on the condition of transformers, mid-life refurbishment is an option to extend the lives of transformers.

We take care not to subject our transformers to excessive loading and they undergo regular testing in accordance with our maintenance regime. The availability of spare parts especially for tap changers, will impact our decision on whether to refurbish a transformer or to replace a transformer. We are finding replacement parts for certain older generation tap changers almost impossible to source. Notwithstanding our maintenance and testing regime, the asset health of a number of older power transformers has now reached a stage where mid-life refurbishment is not an economical option.

Development of our CBARM model for power transformers is in progress at the time of writing. Notwithstanding, our 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 investment summary below is our current view to replace power transformers but this will continue to be informed by on-going condition monitoring that might change priorities.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment: continue to retain ageing power transformers in service	The replacement of a large power transformer is a challenging and time consuming task that can take months rather than weeks at which time the supply will be on 'N' security. Any further failures could mean that load cannot be serviced with a commensurate risk of high SAIDI and reputational damage. This option is not recommended		Rejected
Option 2: Use new network technology options such as a BESS system to offset the requirement to replace zone substation power transformers	Our 'Symphony' modelling scenario shows that there will be natural load growth to which EV charging will contribute. Modelling also shows that there will be a decrease in demand due to efficiencies and small scale batteries and solar distributed generation. However ,modelling shows that new technology options will not reduce peak demand in the AMP period to such an extent that it will negate the need for power transformer replacement. A BESS system will assist during peak demand but will not improve or provide security of supply for failure of a power transformer in this AMP period. This option is not recommended		Rejected
Option 3: Undertake a staged and scheduled programme of works to replace zone substation power transformers	To ensure continued long-term reliability at zone substations a programme of works should be undertaken to replace power transformers with the worst asset health and highest criticality. This will ensure that security of supply standards and service levels to customers will continue to be met and will also reduce the risk of injury due to for example a failed tap changer	$34.12M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Parnell 22/11kV TX Replace and TX Refurb	0.08										0.08
Helensville 33/11kV TX replace T1	1.50										1.50
McNab 33/11kV TX Replace T1	0.20	1.08									1.28
Takanini 33/11kV TX Replace T1	0.15	1.31									1.46
Takanini 33/11kV TX Replace T2			1.46								1.46
Triangle 33/11kV TX Replace T1				1.64							1.64
Triangle 33/11kV TX Replace T2					1.64						1.64
Waimauku 33kV TX Replace T1				1.12							1.12
McNab 33/11kV TX Replace T2			1.28								1.28
McNab 33/11kV TX Replace T3				1.28							1.28
Mt Wellington 33/11kV TX Replace T1						1.04					1.04
Mt Wellington 33/11kV TX Replace T2							1.04				1.04
Otara 33/11kV TX Replace T1		1.15									1.15
Otara 33/11kV TX Replace T2			1.15								1.15
Auckland ZSS TX Refurb & Replace	0.25	0.25	0.25	0.25	0.75	0.75	1.50	1.50	1.50	1.50	8.50
Northern ZSS TX Refurb & Replace	0.25	0.25	0.25	0.25	0.75	0.75	1.50	1.50	1.50	1.50	8.50
Total CAPEX	2.43	4.04	4.39	4.54	3.14	2.54	4.04	3.00	3.00	3.00	34.12

ZONE SUBSTATIONS CIVIL AND STRUCTURAL UPGRADES

NEEDS STATEMENT

A number of ageing zone substation buildings exist in our network and although these are maintained in accordance with a rigorous and structured maintenance regime there are instances where normal maintenance is simply not sufficient to remedy larger civil and structural defects. In such cases a capital project must be undertaken to remedy any issues. Examples of larger defects are seismic non-compliance and deterioration of a building due to soil movement where structural strengthening is then required. A typical example of a zone substation that is not seismically compliant is The Drive zone substation where the switchroom was constructed in 1930 and is seismically at-risk due to its construction methodology of the time – this building was also identified as a potential risk during a recent safety audit in terms of NZS7901, Public Safety, but has now been vacated and screened with fencing. The existing 11 kV switchroom at The Drive zone substation, now vacant, is currently listed as a Historic Place Category 2 protected building, and its historic façade will be incorporated into any civil/structural upgrade. There are also instances where deficient construction methodologies, e.g. improperly installed monolithic construction, was used in the not too distant past to construct some of our substations and these now require extensive repair work beyond normal maintenance.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓		✓		

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing – do not undertake civil and structural upgrades	By postponing or not undertaking the works will result in further deterioration of buildings and structures and this will in turn result in remedial works becoming more extensive and more costly to remedy. Apart from the afore mentioned, Vector is obliged to comply with Council seismic standards within a certain time frame		Rejected
Option 2: Undertake civil and structural remedial capital works	Timely remedial capital investment will remove the risk of further deterioration of zone substation facilities and will also reduce the risk of failure of primary and/or secondary plant inside a zone substation(s) due to failing facilities. Selecting this option also means that we will comply with regulatory and Council seismic requirements to mitigate the risk posed by non-compliant facilities during a seismic event and will then also remove the commensurate risk to operating and maintenance personnel	$3.83M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland civil structures upgrades	0.30	0.54	0.54	0.14	0.14	0.14	0.14	0.14	0.14	0.14	2.36
Northern civil structures upgrades	0.20	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	1.46
Total CAPEX	0.50	0.68	0.68	0.28	0.28	0.28	0.28	0.28	0.28	0.28	3.82

NEUTRAL EARTHING RESISTOR INSTALLATIONS IN ZONE SUBSTATIONS

NEEDS STATEMENT

Our larger commercial and industrial customers have come to depend more and more on reliable electricity as an essential resource for their enterprises and we have had specific requests for 11kV bus sections at certain zone substations to be operated closed (in parallel) to ensure that supply to a customer is uninterrupted in the event of failure of one of Vector's zone substation transformers, 11 kV bus sections or failure of one of the customer's 11 kV supply circuits. Because of the fact that we still have a sizable population of older generation 11kV distribution cables with low rated earth screens parallel operation of 11 kV zone substations busbars is not possible at such zone substations due to the risk of more extensive damage to 11kV cables with low rated earth fault currents.

On some urban 11 kV systems earth fault currents are up to 15% higher than phase fault currents and can be higher than the 250 MVA (13.1 Kiloampere) rating of typical ring main units. Neutral earthing resistors are used to limit earth fault currents in power systems. The primary effect of the installation of neutral earthing resistors is a very large decrease in the fault current when an earth fault occurs on the system. To be able to provide uninterrupted supply to large customers in the event of 11 kV bus, power transformer or 11 kV supply cable failures there is a need to install neutral earth resistors at such zone substations. Not all zone substations where this plant might be required have been identified yet so this is a capital provision that will be used as and where required.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing – do not invest in the installation of NERs	Taking a do-nothing approach means that where ageing 11kV cables with low earth fault ratings exist, parallel operation to ensure uninterrupted N-1 supply to commercial and industrial will not be possible.		Rejected
Option 2: Use new network technology options such as a BESS system to provide the required security of supply or let the customer make provision for security of supply	A BESS system will provide respite of peak demand but will not provide security of supply, and thus not provide uninterrupted supply, in the event of failure of a power transformer or 11kV bus section at a zone substation. Most large customers and building facilities have emergency generation that will provide electrical energy to essential services but there are large commercial and industrial enterprises that have N-1 supplies that require continued uninterrupted supply for failure of one leg of a supply. This option will not provide this function		Rejected
Option 3: Undertake a programme of works to install neutral earthing resistors in zone substations as and where required	This option will allow continued supply without the risk of extensive damage to 11 kV cables with low earth fault rated screens during cable earth faults or if a 3rd party construction crew accidentally damages an 11 kV cable	$3.86M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland neutral earthing resistors	0.10	0.18	0.20	0.20	0.20	0.20	0.20	0.25	0.25	0.20	1.98
Northern neutral earthing resistors	0.12	0.16	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	1.88
Total CAPEX	**0.22**	**0.34**	**0.40**	**0.40**	**0.40**	**0.40**	**0.40**	**0.45**	**0.45**	**0.40**	**3.86**

5.2.3 DISTRIBUTION FEEDERS (HV & LV)

The following sections set out the project proposals for HV and LV distribution feeders, with a particular focus on overhead conductors. In addition to these specific projects and programmes, there will be some further expenditure on distribution feeders as part of the general Network Maintenance programme.

OVERHEAD CONDUCTOR RENEWAL

NEEDS STATEMENT

Vector's 11 kV overhead network for the combined Auckland and Northern networks is 3,776 km in route length of which over 600 km consists of small diameter conductors. A substantial portion of the network is in excess of 60 years old[18] and there is increasing failure in older and ageing small conductors in the 11kV network most notably the population of 16mm² Copper conductors but we are also starting to see failures of older 21mm² ACSR conductors. The increasing rate of failure of small diameter 11 kV conductors has impacted reliability (see Section 2) and its poor health is also starting to pose a risk to operational staff and the public. Many portions of the network with small diameter conductors exist in high density urban areas with a high congregation of people and the risk of conductor failure and then, falling to ground presents a hazard to the public. Furthermore, according to a National Institute of Water and Atmospheric Research study in 2017 extreme rainfall, severe droughts, wildfires and wind with increased speeds could hit Auckland in years to come and conductors in poor condition and little resilience will result in further outages and thus an increase in SAIFI unless investment to renew conductors is undertaken. Our CBARM model shows that to meet our service level standards and to reduce the health and safety impact of conductors we will need to replace most of the 600 km of small diameter 11 kV conductor in the AMP period.

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18 Due to legacy issues there are gaps in the data for the age of overhead conductors and assumptions had to be made based on other statistical data, e.g. the date that subdivisions were developed, the dates imprinted on poles, etc.

It is highly likely that in areas that have been identified for conductor replacement that some poles will need to be replaced especially in some parts of the Auckland area where lower strength poles were used in years gone by. Standard AS/NZS7000 requires that engineering assessments of major overhead line components be undertaken when the mechanical load is being altered. The need for replacement of some or all poles will be determined during detail design of conductor replacement projects. All crossarms and insulators will be replaced as part of reconductoring projects.

Our Conductor CBARM model was used to inform our programme of works to select which conductors to replace in the AMP period. To prevent the probability of failure to increase over the AMP period to unmanageable levels an intervention programme as per the investment summary below must be undertaken - that will result in a health index at the end of the AMP period (2029) as shown in the graph below. The present health index at the start of this AMP period, i.e. 2019 health index (referred to as year 0 in our models), is shown in Section 4, Our Assets. The health index at the end of the AMP period if no work is undertaken, i.e. 2029 (referred to as year 10 in our models), is also shown in Section 4.

ASSET HEALTH AT YEAR 10 WITH INTERVENTION – OH MV CONDUCTOR

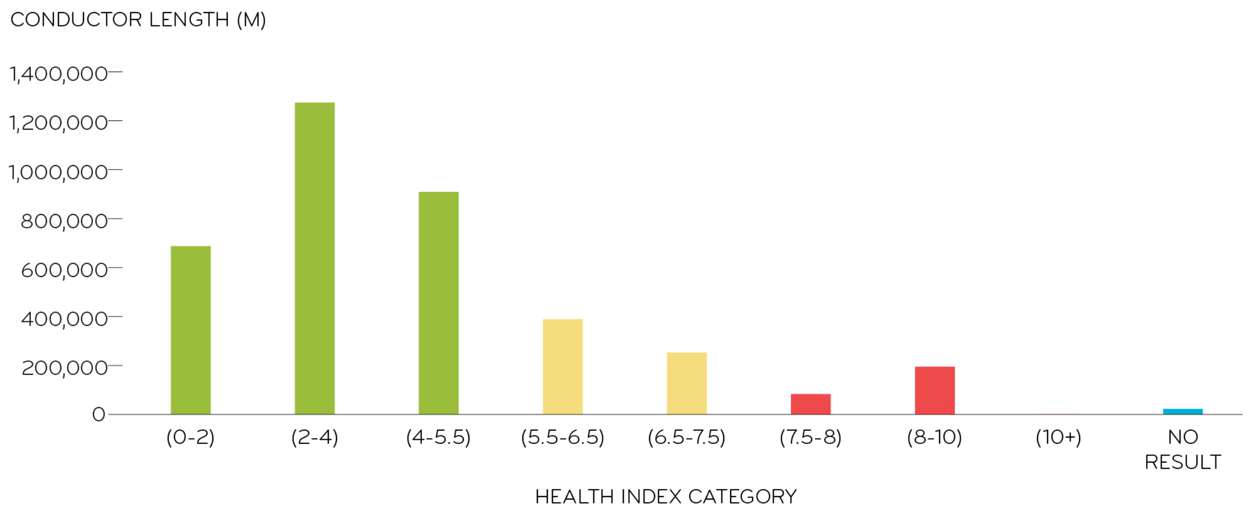

Figure 5-2 Health index at year 10 with Intervention – OH MV Conductor

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing – do not address the need to replace conductors	Not undertaking a replacement programme will exacerbate the increasing trend of failure of smaller conductors with a commensurate increase in the risk of harm posed to the public of falling conductors as the population continues to age over the AMP period. The volume of conductors with poor health and high probability of failure will continue to increase and reach a point where it will be difficult to maintain the population of OH conductors to an asset health score below 7[19]. Selecting this option will also result in an increase in SAIFI, reduction in service levels and the customer's experience of the quality of Vector's electricity supply will further deteriorate.		Rejected
Option 2: Underground the network	There are certain areas in which undergrounding is a more effective cost option than OH line refurbishment and reconductoring but in most cases undergrounding is considerably more expensive, up to four times more, than refurbishing and reconductoring an OH line. However, each project is considered on a case by case basis and where undergrounding is the better option it will be implemented		Rejected as a blanket option but will be used if it is practical
Option 3: Replace small diameter conductors based on asset health and criticality	To prevent the risks posed by the 'Do nothing' approach a long term proactive programme of works must be undertaken to replace conductors with a high probability of failure. The investment programme as proposed below will replace over the AMP period conductors that presently (at the start of the AMP period) has a health index of 7 and above	$116.50M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland overhead conductor renewal	2.00	3.00	4.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	51.00
Northern overhead conductor renewal	2.00	4.50	5.00	7.50	7.50	7.50	7.50	8.00	8.00	8.00	65.50
Total CAPEX	**4.00**	**7.50**	**9.00**	**13.50**	**13.50**	**13.50**	**13.50**	**14.00**	**14.00**	**14.00**	**116.50**

AUCKLAND AND NORTHERN NETWORK RESILIENCE IMPROVEMENTS

NEEDS STATEMENT

Vector's approach to asset management recognises that climate change poses a risk to our assets and operation. Wind gusts up to 215 kilometres per hour were recorded during the intense April 2018 storms. The level of damage across our network was unprecedented and offered a stark reminder of the type of event that may become more frequent with climate change, and that could threaten the reliability of electricity distribution in the future. According to a National Institute of Water and Atmospheric Research study in 2017, environmental events such as extreme rainfall, severe droughts, wildfires and wind with increased speeds could hit Auckland in years to come. Environmental factors including climate change in combination with natural hazards is forecast to impact each part of the electricity system differently but is more pronounced on OH networks and will ultimately affect customers directly. As sustained wind speeds on the Vector network exceeds 70 km/h there is a significant increase in the duration of outages, customer minutes lost and the number of customers affected. There is a need for capital investment that specifically targets resilience aspects to make the network more reliable during severe environmental events.

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19 Refer our CBARM model for an explanation of health index scores

The capital investment described in this 'Needs Statement' will target the improvement of network resilience with a focus on our OH network. This will involve amongst others improving the insulation coordination in areas that are prone to outages caused by lightning by undertaking a detailed insulation coordination study to ensure the network is properly protected against overvoltages. It will involve installing additional lightning arrestors at strategic locations to remove overvoltages due to lightning and switching surges. We will trial the installation of a variety of equipment to make the network more resilient against strong winds and falling branches and tree bark e.g. improved stays and/or additional stays, the use of 11 kV aerial bundled conductors, spaced covered conductors and, grouped covered conductors. Vector will actively investigate with equipment vendors equipment and installation methodologies that might improve resilience. The active control of vegetation is another major programme but this is described under a separate 'Needs Statement' further above in Section 5.

We regularly liaise with City Power in Melbourne and Western Power in Perth on their asset management strategies for OH lines in adverse environmental conditions and the lessons that they have learnt.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓		

OPTIONS CONSIDERED

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	A do-nothing approach is not an option and will continue to result in poor SAIFI and SAIDI indices, poor experience by customers of Vector's electricity network, poor service levels and risk to Vector's reputation. In light of the predicted impact of climate change and environmental events this option is not viable and is rejected		Rejected
Option 2: Use new network technology options such as microgrids, solar panels and domestic on-site batteries	New technology options such as Microgrids are a viable alternative option to improve resilience especially to remote rural parts of the network. Solar panels and on-site batteries are options by customers themselves to improve resilience but notwithstanding that customers can and will use these as options to improve their own resilience there are feeders and supplies where it is not practical to rely on either new technology options or customer initiated options to maintain service levels and capital investment is needed to improve the reliability of the network to acceptable service levels. Section 5 contains a number of Microgrid projects and is only rejected as an option for this specific programme.		Rejected as a solution for this specific programme
Option 3: Invest capital to improve the reliability of the network	Investing capital to improve network reliability is necessary to maintain service levels to customers and to maintain SAIDI and SAIFI reliability indices levels to regulatory levels. This investment is necessary to make the Vector network ready for the anticipated impacts of climate change and environmental events.	$10.50M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland resilience improvements	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	5.50
Northern resilience improvements	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	5.00
Total CAPEX	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	10.50

OVERHEAD 11 KV SWITCHGEAR RENEWAL

NEEDS STATEMENT

Vector's overhead network includes 715 rocking-post type air break switches of various designs. Of these, approximately two thirds are on the Northern network, with the remainder in the Auckland network. Until the year 2000 rocking-post type air break switches were the primary type of switch used for field switching. From 2000 to 2015 fully enclosed (SF6 gas) switches were predominantly used. Since 2015, air break switches with integral arc-interrupting devices are now the Vector standard because they are more robust and simpler to maintain.

Some of the switches failed during operation by field technicians that resulted in molten metal falling onto the ground in close proximity to operators. Apart from the target to improve performance, this programme will also have safety as a targeted outcome. To address this issue, at least 365 overhead switches need to be replaced over the 10-year AMP period to prevent a deterioration of service levels. However, analysis undertaken in 2017 of air break switches against the SAIDI benefit they offer, showed that a number of switches are no longer in optimal locations in the network to offer optimum SAIDI benefit. Therefore, it is expected that rather than replacing all 365 switches, improved SAIDI benefit can be obtained by replacing 265 switches in optimum locations in the network.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Looking forward we are expecting that the overhead network air break rocking-post type switches will continue to deteriorate and have a continued negative impact on SAIDI and asset safety incident rates. Failure of air break switches, most likely during operation, will continue to present a Health and Safety risk and as the switches age this risk will increase.		Rejected
Option 2: Undertake a staged and scheduled programme of works to replace aging air break rocking-post type switches	Undertaking a staged and scheduled programme of works to replace ageing air break switches will remove the risks associated with the do-nothing option. It will also allow safe and ease of sectionalising and segmentation of the network during contingency events and during maintenance	$3.63M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland overhead 11 kV switch renewal	0.04	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	1.12
Northern overhead 11 kV switch renewal	0.08	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	2.51
Total CAPEX	0.12	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	3.63

OVERHEAD IMPROVEMENT PROGRAMME

NEEDS STATEMENT

Vector has a deed in place with its major shareholder Entrust, to provide Energy Solutions Programme Investment. This programme is focused on improved energy efficiency and visual amenity around Vector's assets. Projects have largely focused on undergrounding of overhead lines which reduces the exposure of assets to environmental risks such as vegetation, third party damage and lightning. Other projects undertaken under the deed with Entrust have included: (i) Sustainable substations: where solar panels and battery packs have been installed in a number of zone substation to displace or reduce energy consumption and dependence on the grid at a number of our zone substations; (ii) Energy efficiency community programmes: where battery packs have been installed in the community to reduce their monthly power bills. Energy audits have been conducted at the residential homes and these installations have resulted in energy efficiencies.

The Entrust deed requires Vector to invest an average of $10.5m annually on these energy solutions. This ties in with Vector's commitment to improving the environmental impact of our assets.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Do nothing is not an option as this is a requirement of Vector's deed with Entrust and an obligatory spend		Rejected
Option 2: Undertake a programme of works to underground overhead lines; Undertake community based new technology projects	Notwithstanding that this programme of works is a requirement of Vector's deed with Entrust and is thus obligatory, the programme will reduce the risk of SAIFI and SAIDI because the undergrounded portions will be less prone to the effect of lightning, vegetation or the impact of third party events on OH line poles.	$105.00M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland various overhead to underground improvements	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	105.00
Total CAPEX	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	105.00

LIGHT DETECTION AND RANGING (LIDAR) TO DETECT LOW LINES AND VEGETATION

NEEDS STATEMENT

Low lines and vegetation have proved to be major contributors to faults and thus major contributors to SAIDI and SAIFI. This was highlighted during the recent storms in Auckland and surrounding areas. The vegetation problem is greatly magnified during high winds as was experienced especially during recent storm events. Traditionally overhead lines would have been surveyed from the ground but this method is expensive and time consuming and will not suffice for the large volumes of data that are needed to plan and prioritise the programme of work to rectify low lines and control vegetation.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Taking a do-nothing approach means that Vector will not be able to prioritise and plan its works programme to control vegetation. This option will also result in continued risk to the public presented by low lines and risk continued and increasing outages due to vegetation. This will in turn result in continued and increasing SAIDI and SAIFI indices and impact negatively on service levels and the customer's experience		Rejected
Option 2: Undertake ground based survey of overhead lines and measurement of clearances	A ground based survey to measure overhead line clearances will be time consuming and expensive.		Rejected
Option 3: Undertake a staged and scheduled LiDAR programme to measure clearances	A staged LiDAR survey will provide information with regard to network clearances in a quick and effective manner for large tracts of the network in short period of times. This data will inform Vector's proactive programmes of work to refurbish OH assets as well as further inform our maintenance programme. This will in turn improve our SAIDI and SAIFI caused by 'switching for low lines'.	$6.60M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland overhead network LiDAR survey	0.30			1.00			1.00			1.00	3.30
Northern overhead network LiDAR survey	0.30			1.00			1.00			1.00	3.30
Total CAPEX	**0.60**	**0.00**	**0.00**	**2.00**	**0.00**	**0.00**	**2.00**	**0.00**	**0.00**	**2.00**	**6.60**

RIGHT OF WAY POLES

NEEDS STATEMENT

In mid-2014, an increasing rate of deterioration and failure of non-Vector owned assets deployed along Rights of Way within the Auckland region was identified. Poles and conductors make up the majority of these assets and can cause significant damage and harm to people and property when they fail.

Vector has experienced an increase in costs and customer outages as a result of these customer assets being in poor condition. Customers often do not realise they are responsible for these assets or call Vector for advice. This incurs an increase in operational costs including the costs of sending a reactive crew to confirm the state of the asset and whether it is part of our network. Additionally, when Vector is made aware of an immediate safety issue, our safety procedures require us to immediately de-energise the area remotely until we can physically attend and assess whether the asset is safe. This is done at the HV level as there is currently no way to remotely de-energise the LV network. This results in increased outages to customers, negatively impacts quality measures such as SAIDI and SAIFI and incurs costs to manage and inform customers who are affected by the resulting safety outage.

In addition to information gathered from attending sites that have resulted in failure, Vector has inspected a number of properties across the region to assess the size of the problem. We have estimated that there are approximately 5,000 shared driveways in the Auckland region that have non-Vector overhead assets and that there could be approximately 15,000 structures in the urban area, with another 5,000 structures expected in rural areas. Based on these survey results Vector has assessed that the majority of these are likely to be well beyond their economic life and in poor condition.

Vector estimates that the total cost to remediate and make safe customer owned service lines would cost up to $94m. The cost of repairs at each site can vary substantially, but it is not uncommon for costs to exceed $3,000 and can go as high as $15,000. Our experience to date is that many property owners cannot afford these costs which could expose them to protracted disconnection. In addition, when there is an issue it is often complicated by absentee land owners.

This problem of unmanaged and unsafe customer structures is an industry problem and is not isolated to urban areas. Vector has engaged with a number of other electricity lines businesses who have confirmed they have similar concerns and issues across their network footprints. On 14 February 2018, the Electricity Networks Association held a workshop to highlight industry concerns to a number of government agencies including MBIE, the Electricity Authority and Energy Safety. At this workshop, Vector indicated that if it was given the right liability protections and confirmation of an increase in its regulated allowable CAPEX and OPEX, that it would be prepared to proactively identify and remediate structures down shared right of ways to ensure public safety. Once the assets were up to network standards Vector would take ownership and assume maintenance responsibilities.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	In mid-2014, an increasing rate of deterioration and failure of non-Vector owned assets deployed along Right of Ways within the Auckland region was identified. Poles and conductors make up the majority of these assets and can cause significant damage and harm to people and property when they fail. A Do-nothing approach means that this risk will continue to exist and as these assets age the risk of failure will increase.		Rejected
Option 2: Continue with the programme of works to remediate right of way poles to bring all assets up to present design standards, and inclusion into business as usual processes.	Vector has experienced an increase in costs and customer outages as a result of these customer assets being in poor condition. Customers typically do not either realise they are responsible for these assets and/or call Vector for advice. This incurs an increase in operational costs including the costs of sending a reactive crew to confirm the state of the asset and/or whether it is part of our network. Continuing this programme of works will remove the risks and H&S concerns associated with this asset, although this level of investment would see assets operating at a balance of cost/risk/performance not comparable with the rest of the Vector owned LV network.	$93.9M	Rejected
Option 3: Continue with the programme of works to remediate right of way poles to address high risk assets, and inclusion into business as usual processes.	As option 2, but this programme addressing high risk right of way assets only and the remainder of works being included in our business as usual maintenance investments. This level of investment would see assets operating at a balance of cost/risk/performance comparable with the rest of the Vector owned LV network.	$42.60M	Selected

	Note an additional corresponding increase in maintenance replacement expenditure is associated with this option (refer need statement for Network Maintenance)

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland right of way hardware replacement	3.80	2.50	2.50	2.50	2.50	2.30	1.00	1.00	1.00	1.00	20.10
Northern right of way hardware replacement	6.20	2.50	2.50	2.50	2.50	2.30	1.00	1.00	1.00	1.00	22.50
Total CAPEX	**10.00**	**5.00**	**5.00**	**5.00**	**5.00**	**4.60**	**2.00**	**2.00**	**2.00**	**2.00**	**42.60**

11 KV UNDERGROUND CABLE REPLACEMENT

NEEDS STATEMENT

Vector's 11 kV distribution underground cable network for the combined Auckland and Northern networks is 3,542 km in route length of which about 285 km will be past end of reliable life at the end of this AMP period – see Section 4 for details of the existing 11 kV underground distribution cable population. There is a further 160 km of cables for which there is no age data (a legacy data issue for older asset populations). Underground 11 kV cables have a long asset life but our 11 kV cable population is ageing and over the last two years Vector has observed an increase in the number of 11 kV cable failures. Another failure mode that is on the increase is deteriorating tinning on tinned aluminium lugs on outdoor 11 kV cable terminations on 11 kV cable risers to OH lines. We could continue to repair faulted cable but for certain sections of cable the fault history, frequency of faults together with diagnostic testing means that replacement should be undertaken. We have commenced with a programme to test cables with suspected poor asset health and have found a number of 11 kV cables have very low insulation levels which is an indication that this portion of the fleet is approaching end of life.

Unless a programme of intervention is undertaken starting in this AMP period, our prediction of asset health is that by 2039, the amount of cables at end of reliable life will be triple the amount in 2029 – see the graph below. An increasing cable failure trend will impact negatively on SAIFI, SAIDI, and on customer service levels.

DISTRIBUTION HV CABLES: WITH POOR ASSET HEALTH

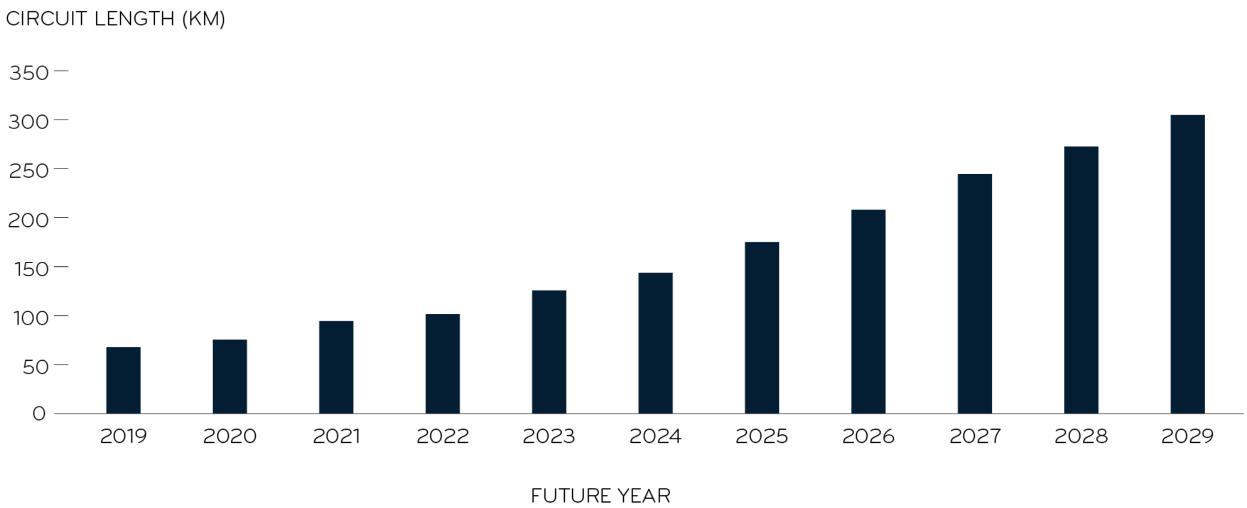

Figure 5-3 11 kV underground cable population with poor asset health

Our CBARM model of 11 kV underground cables is under development at the time of writing the AMP. In the mean-time we will focus our efforts on cables with known fault history with high criticality load and cables with poor test results to inform and prioritise our replacement programme.

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓			

OPTIONS CONSIDERED

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	A 'Do nothing' approach means that this asset class will deteriorate further and by 2039 our prediction of cable population with poor asset health will be triple that at the end of this AMP period – 2029.		Rejected
Option 2: Undertake a programme of works to replace 11 kV underground distribution cables with poor health	This option will remove the risks associated with the 'Do nothing' approach and ensure that the network is ready for the longer term future. This option will ensure that the population with poor asset health remains stable	$32.25M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland 11 kV cable replacement	1.00	1.20	1.44	1.73	2.07	2.49	2.99	3.58	4.30	5.16	25.96
Northern 11 kV cable replacement	0.50	0.53	0.55	0.58	0.61	0.64	0.67	0.70	0.74	0.78	6.30
Total CAPEX	**1.50**	**1.73**	**1.99**	**2.31**	**2.68**	**3.13**	**3.66**	**4.28**	**5.04**	**5.94**	**32.26**

LV NETWORK REPLACEMENT

NEEDS STATEMENT

The LV distribution network is the stalwart asset to distribute electricity to customers and is becoming more critical as people increasingly rely on electricity. In the previous century the LV distribution network predominantly supplied power to radios, fridges, freezers, lighting and then televisions and washing machines. In the 1980s computers, microwaves and security systems were added. More and more devices will use and be reliant on electricity e.g. autonomous home management systems, mobile phones, modems, induction hobs, EVs etc. To this end, we need to replace certain components of the LV network e.g. ageing LV PILC cables, that date from the 1950s for which we are starting to see an increase in failure rates in our network. There are also portions in the LV OH network that needs replacement. Rather than replacing the network with bare conductors, LV aerial bundled conductors can be used that will provide increased visual aerial amenity, increased safety and will reduce the need for aggressive and extensive tree trimming.

At the time of writing this AMP, the CBARM model for our LV network is still to be developed and substantial data gathering and model building are required to forward plan our LV replacement programme. At this point in time, we undertake routine inspections are still reactive in our planning approach of replacement of the LV network. Our LiDAR initiative will also assist to plan our programme of works for the LV network.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	A Do-nothing approach means that the LV network will not be suited to the ever increasing reliance of customers on the electricity network. As society becomes more dependent on technology and the techno-dexterous population ages, the expectation is that the tolerance for loss of power will be reduced		Rejected
Option 2: LV Network Replacement	Undertake the replacement of certain components and portions of the LV network as required that will include ageing PILC LV cables and ageing and poor performing sections of the OH network	$12.00M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland LV network replacement							1.50	1.50	1.50	1.50	6.00
Northern LV network replacement							1.50	1.50	1.50	1.50	6.00
Total CAPEX	0.00	0.00	0.00	0.00	0.00	0.00	3.00	3.00	3.00	3.00	12.00

5.2.4 DISTRIBUTION SUBSTATIONS AND VOLTAGE REGULATORS

The following sections set out the project proposals for distribution substations and voltage regulators.

GROUND MOUNT DISTRIBUTION SWITCHGEAR (OIL) RENEWAL

NEEDS STATEMENT

Vector's population of ground mounted oil filled distribution switchgear is approximately 7,331 tanks (discrete oil tanks). These tanks make up 4,100 distribution substation sites of which 80% are in the Auckland network. As of 2019, approximately 506 units are already older than 50 years. The oldest unit dates from 1959 and a number of units date from the early 1960s. By 2029 another 1743 units will be 50 years old. Additionally, there are presently 1,230 SD Series 1 units in service on the network which have a known risk of failure inherent with their original design (see Section 4 for more details).

In the past, our strategy relied on asset condition being identified by routine maintenance inspections and replacement undertaken as required based on the identification of risks under the corrective maintenance programme. Approximately 1% of the ground mount distribution oil switchgear population is replaced annually due to customer initiated growth or projects. Our concern was that with a population of similar age profiles all approaching the end of expected service life together that this will result in a bathtub curve scenario where there is a risk of a sudden increase in deterioration of a large population group that is likely to encompass a greater number of assets that can be attended to under the budgeted corrective maintenance programme, resulting in increased asset failures. In general, it is highly questionable that we can continue to stretch the service life of our ageing distribution switches beyond 60 years through the existing maintenance programme, due to the risk of material fatigue leading to equipment failure - especially as there are parts in the switches which cannot be maintained or replaced individually. The exception to this is the population of 1,442 J4, GF3 and T4GF3 switch units dating from 1973 onwards where we are investigating a refurbishment option in conjunction with an UK based organisation that offers after-market support options for these switch units. We are aware that a similar refurbishment approach is being utilised by a number of the distribution network operators in the UK in order to extend the life of these units by up to 20 years. Of the 2,249 units expected to exceed 50 years old within this AMP period, 956 units may be able to be refurbished rather than replaced.

To embark on a long-term strategic programme to modernise our ground mount distribution oil switchgear population we fully developed a CBARM model for this asset class in the first instance to inform our replacement programme. Our planned programme will see the replacement or refurbishment of ~ 1,500 RMUs with poor asset health, high probability of failure and high criticality over the 10 year AMP period. The CBARM model has also been calibrated to factor in the poor design SD series 1 units which suffer from low phase clearances within the small tank, and therefore pose additional risk in terms of failure especially during operation (on some models we have to use 'lanyard' (remote) switching to ensure the safety of operating personnel).

The graph below taken from the CBARM model for this asset shows a view of asset health at the end of the AMP 10 year period if an intervention programme is undertaken. Graphs of the current health and health at 10 years if replacement is not undertaken are included in Section 4.

YEAR 10 TARGETED INTERVENTION HI PROFILE

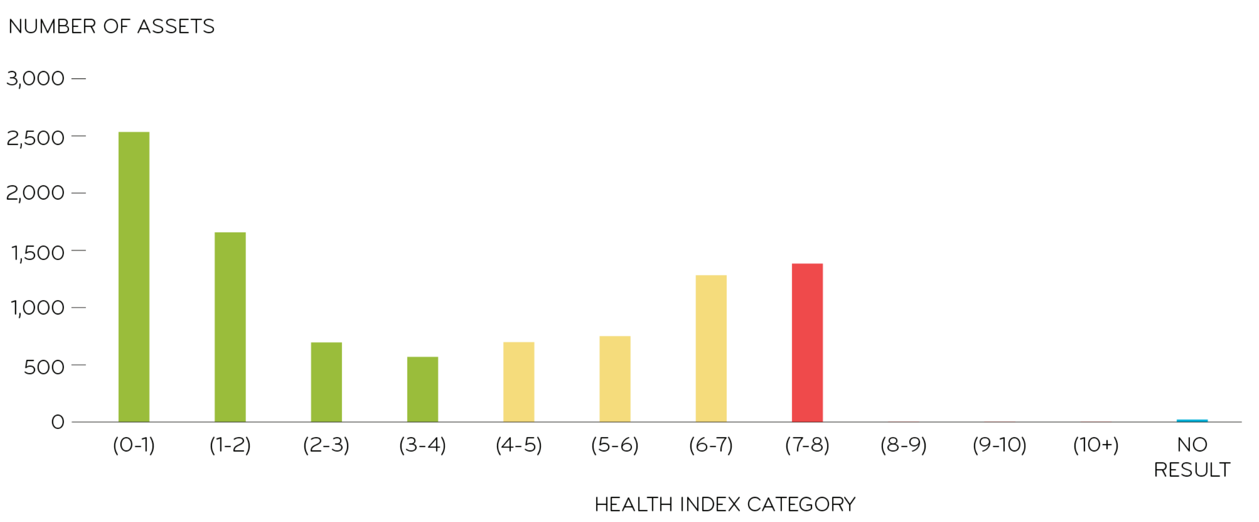

Figure 5-4 Asset health at year 10 with Intervention – Ground Mount Distribution Switchgear

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	There is a high risk that a bathtub curve scenario could eventuate where a sudden increase in deterioration / asset failures are likely and may encompass a greater number of assets that can be attended to under the budgeted corrective maintenance programme. This will have a negative impact on SAIDI and Asset Safety Incident rate service level. A 'Do nothing' approach is rejected		Rejected
Option 2: Undertake a staged and scheduled programme of works to replace or refurbish distribution oil switchgear prioritised by condition and criticality	The preference would be to replace all RMUs with a health index of 6 and above in the AMP period but such a programme will lead to an estimated capital spend of $213.94M over the AMP period which is not tenable within the DPP constraint. This selected programme of works will see at least those units with a health index of 8 and above replaced within the 10 year AMP period. This calculates to ~ 1500 units replaced or refurbished.	$114.60M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland RMU replacement	6.40	7.00	8.50	9.50	9.50	9.50	10.00	10.00	10.00	10.00	90.40
Northern RMU replacement	1.60	1.60	2.00	2.00	2.50	2.50	3.00	3.00	3.00	3.00	24.20
Total CAPEX	**8.00**	**8.60**	**10.50**	**11.50**	**12.00**	**12.00**	**13.00**	**13.00**	**13.00**	**13.00**	**114.60**

DISTRIBUTION TRANSFORMERS REPLACEMENT

NEEDS STATEMENT

There are approximately 7,600 pole mounted distribution transformers operating in Vector's network. Almost three quarters of this population is in the Northern network that is a predominantly OH network. With respect to the age of the equipment, almost two thirds of the population are installed in the 1990s or thereafter. Some of the oldest units have been in service since the 1950s. Given the design life expectancy of a distribution transformer typically ranges from 30 to 40 years, the transformers installed in 1980s and prior – approximately 2,700 units – will reach the end of design life by 2029.

There are approximately 14,200 ground mounted distribution transformers operating in Vector's network. The population is evenly split between the Auckland and Northern networks. With respect to the age of the equipment, half of the population were installed in the 1990s or thereafter. The oldest units have been in service since the 1950s. Ground mounted distribution transformers have a similar life expectancy as pole mounted units namely in the range of 30 to 40 years. This means that ground mount transformers installed in the 1980s and prior – approximately 6,400 units – will reach end of design life by 2029.

Vector's current maintenance strategy for this equipment class relies on regular visual inspections to identify any noticeable deterioration in exterior of a transformer, and then undertaking replacements as required. Due to practical constraints, no testing is performed as part of the maintenance regime on an in-situ transformer to assess the electrical performance and properties of its insulation. In addition to the condition-based replacements, approximately 1.6% of the population is replaced annually for other purposes, such as new customer connections, network reinforcement etc.

Our concern with the existing population is that there is a large number of transformers of similar ages approaching expected end of service life in the coming decade, and if we continue to allow this situation to develop unabated, it could result in a scenario where the incidence of simultaneous transformer failures in the network rises suddenly and in considerable quantities that will create a large burden on all resources, such as field staff, corrective budgets, and the ability of equipment manufacturers to respond effectively to the failures. Such a scenario will have a commensurate negative impact on reliability indices and on service level targets. To address this we need to adopt a different asset management approach to manage Vector's distribution transformer population rather than continuing to rely on the traditional time based maintenance approach. Hence, we have developed a CBARM model as a tool to help us identify distribution transformers that need to be replaced based on asset health, probability of failure and criticality factors.

The outputs of our CBARM model are going to be used in the development of a comprehensive maintenance and replacement programme for distribution transformer for the next 10-year AMP period. This programme of works will require the replacement of 1,556 pole mounted transformers and the replacement of 1,680 ground mounted transformers over the AMP period. By undertaking this long-term strategic plan for pole mount and ground mounted transformers, it not only ensures continuous reliability of this asset class but also reduces the risk of unexpected transformer failure to a manageable level.

The following graph shows the expected asset health profile at the end of the 10-year AMP period if the proposed replacement programme is undertaken for pole mounted distribution transformers.

ASSET HEALTH AT YEAR 10 WITH INTERVENTION – DISTRIBUTION POLE MOUNTED TRANSFORMERS

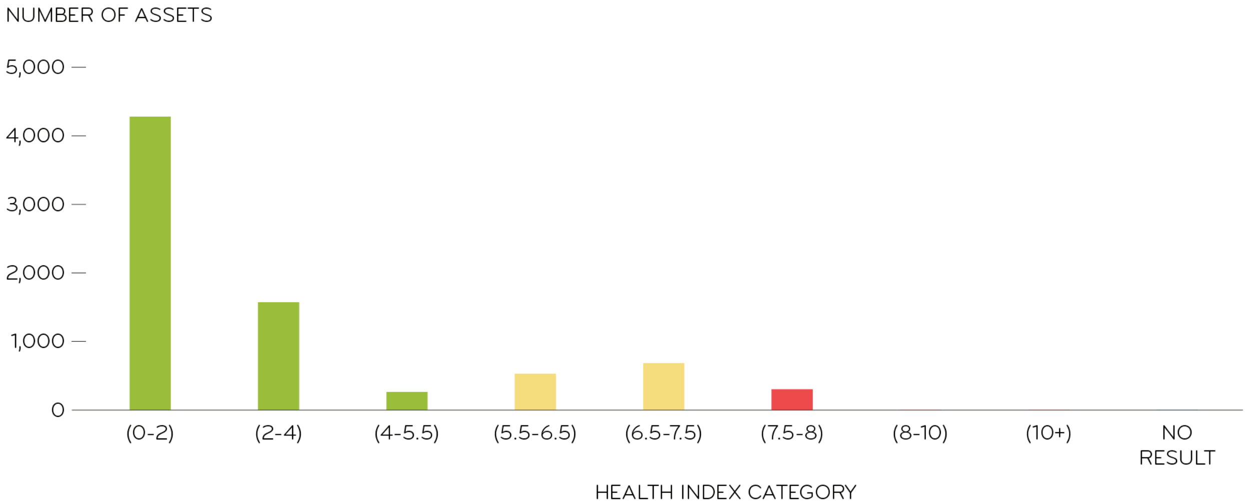

Figure 5-5 Asset health at year 10 with Intervention – Distribution Pole Mounted Transformers

The following graph shows the expected asset health profile at the end of a 10-year period if the proposed replacement programme is undertaken for ground mounted distribution transformers.

ASSET HEALTH AT YEAR 10 WITH INTERVENTION – DISTRIBUTION GROUND MOUNTED TRANSFORMERS

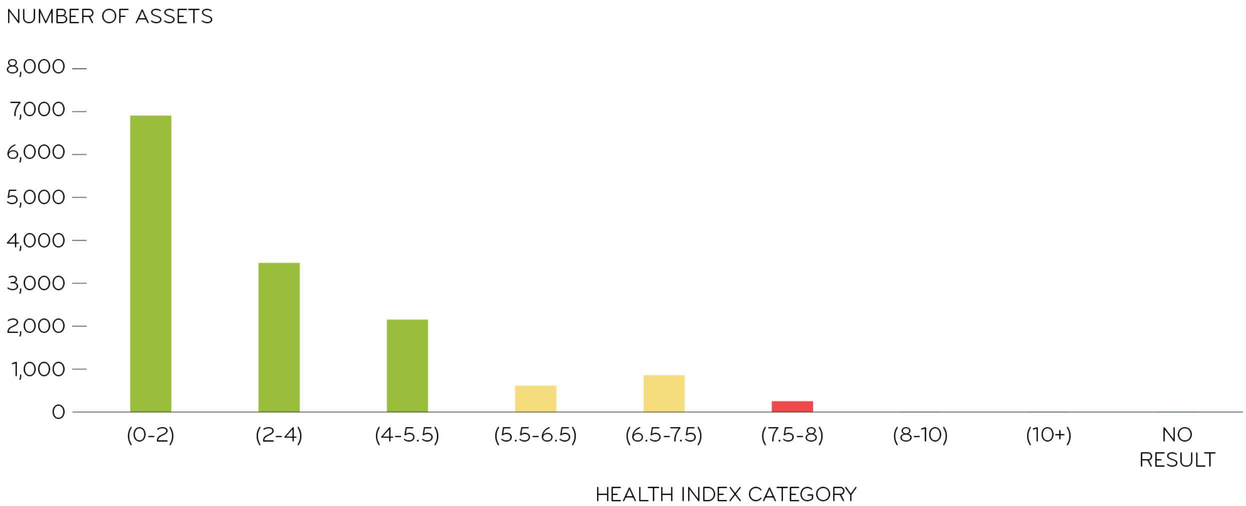

Figure 5-6 Asset health at year 10 with Intervention – Distribution Ground Mounted Transformers

By undertaking this proactive 10-year replacement programme of works we will maintain distribution transformers with a health score of 7.5 or above to limited and manageable numbers.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED FOR POLE MOUNTED AND GROUND MOUNTED TRANSFORMERS

Options to address the need identified above have been assessed and are summarised in the following tables.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	There is a high risk that a bathtub curve scenario could eventuate where a sudden increase in deterioration / asset failures are likely and may encompass a greater number of assets that can be attended to under the budgeted corrective maintenance programme. This will have a negative impact on SAIDI and Asset Safety Incident rate service level. A 'Do nothing' approach is not recommended.		Rejected
Option 2: Undertake a staged and scheduled programme of works to replace pole mounted and ground mounted transformers prioritised by condition and criticality	The programme of works will see the replacement of ~ 1,556 pole mounted transformers that are forecast to have a health index of 7.5 at the end of the 10-year AMP period. This replacement number represents ~ 20% of the installed asset base. The program of works will also see the replacement of ~ 1,680 ground mounted transformers with a health index in excess of 7.5 within the 10-year AMP period, which represents ~ 10% of the installed asset base. This programme of works will improve SAIDI and will reduce the H&S risk to the public and operational staff.	$35.50M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland distribution transformer replacement	0.50	0.50	0.70	1.00	1.20	1.50	1.70	2.00	2.00	2.30	13.40
Northern distribution transformer replacement	1.00	1.00	1.30	1.50	1.80	2.00	2.80	3.50	3.50	3.70	22.10
Total CAPEX	**1.50**	**1.50**	**2.00**	**2.50**	**3.00**	**3.50**	**4.50**	**5.50**	**5.50**	**6.00**	**35.50**

5.2.5 SECONDARY SYSTEMS AND OTHER NETWORK ASSETS

The following sections set out the project proposals for Vector's secondary systems and other network assets.

AUCKLAND AND NORTHERN DC SYSTEMS REPLACEMENT

NEEDS STATEMENT

It is essential that zone substations have a secure DC supply because it is paramount for the safe and reliable operation of protection, control and interlocking. The need for a reliable DC supply becomes even more important during disturbances and faults in the distribution network or zone substation primary equipment. The 110 V DC system is continuously charged as a back-up power supply in the event of an AC outage on site and proper functioning of protection systems and reinstatement of electricity in zone substations post a fault are reliant on able and trustworthy 110 V DC systems.

An incident in 2016 during which a DC charger failure occurred at Keeling Road zone substation – during the incident the system failed to alert the SCADA master station and locked out the substation protection and control system. This reiterated the importance of the DC systems and correct alarming. DC systems in a number of zone substations, especially some of the older systems, are showing increasing signs of poor health and high probability of failure and a programme of replacement and refurbishment is now needed. Following the incident, a comprehensive assessment was completed on DC systems at all zone substations in Vector's Northern region. This programme of works will include a comprehensive assessment of DC systems at all zone substations in the Auckland region. The corrective actions identified during the assessments will culminate into a master actions list and scope of works for repair, refurbishment and replacement as the case may require. The objective is to ensure that after completion of this programme of works, DC systems for both the Northern and Auckland regions, will provide the associated alarms to the SCADA master station and meet the functional requirements as per the latest Vector standards for redundancy and the successful operation of protection and other equipment that are reliant on DC systems in zone substations.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓		✓	

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Failure to assess and subsequently correct potential issues with DC systems and associated SCADA alarms, may result in extended unplanned outage events. Customers will be at risk of extended unplanned events and zone substations will be at risk of serious damage such a fire if DC systems are not brought to the correct level of reliability.		Rejected
Option 2: Undertake a scheduled programme of works to complete DC system assessments in the Auckland region and complete all corrective actions in both Auckland and Northern regions	Undertaking this programme of works will significantly improve DC Systems' asset reliability and security of supply to customers and the avoidance of consequent SAIDI risk. A reliable DC system will ensure tripping of circuits as and when required during faults and disturbance and will reduce the risk of serious damage to zone substations. Proper and effective alarming will notify the EOC of any pending issues	$3.25M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland DC systems replacement	0.25	0.25	0.25	0.12	0.13	0.12	0.13	0.13	0.12	0.13	1.63
Northern DC systems replacement	0.25	0.25	0.25	0.12	0.13	0.13	0.12	0.13	0.13	0.12	1.63
Total CAPEX	**0.50**	**0.50**	**0.50**	**0.24**	**0.26**	**0.25**	**0.25**	**0.26**	**0.25**	**0.25**	**3.26**

REPLACE AUCKLAND LOAD MANAGEMENT PC85 LOAD CONTROLLERS

NEEDS STATEMENT

Vector regularly offers into the New Zealand Electricity Market tranches of up to approximately 80 MW of a total available 100 MW controllable hot water load within the Auckland electricity network. This assists with peak power shifting and allows for deferral of CAPEX projects.

The 1980's Plessey/GPT PC85 load controller provides the local and remote SCADA control interface at the 13 Auckland zone substations that have this load management function. A Landis+Gyr power line carrier ripple plant then adds a 475 Hertz signal onto the substation 22 kV and 33 kV subtransmission circuits to signal customers hot water cylinders and

Auckland Transport's street lights on and off. This system has a minimum 15-year projected life before a new technology solution would be completely rolled out across the network.

All PC85 controllers require replacement, with the first completed in FY18. They are at the end of their life, are an unsupported product, with no spares available from the supplier. Units have been failing over the last three years, only three of the original 12 units are fully functioning and further failures will result in permanent loss of load control. Replacement will also allow decommissioning of the similarly end of life and unsupported Nokia-based communication system.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓		✓	

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Reliance on the existing controllers hold unacceptable risks to performance for the Auckland network customers and Auckland Transport for whom we still control a sizeable portion of streetlights. Non-control of street lighting is a risk to Public safety and reputation for Auckland Transport and Vector. Loss of ability to offer controllable load into the Energy Market risks loss of reputation and revenue. Selecting a 'Do-nothing' approach could result in no recovery options during unpredictable failures.		Rejected
Option 2: Replace the PC85 controllers with a modern equivalent configured for the Auckland ripple control systems in the Auckland zone substations	This programme will remove the risk of single mode failure of the load control system in the Auckland network. It will reduce the risks associated with the 'Do-nothing' approach	$0.39M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Ripple Plant PC85 controller replacement	0.39										0.39
Total CAPEX	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.39

PENROSE - HOBSON TUNNEL SYSTEMS UPGRADE PROGRAMME

NEEDS STATEMENT

The Penrose to Hobson Tunnel contains Vector's 110 kV, 33 kV and 22 kV subtransmission cables from Transpower GXPs and between Vector's CBD bulk supply zone substations. The tunnel also contains Transpower's 220 kV North Auckland and Northern cable from Penrose GXP to Vector's Hobson Street zone substation. 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 are now progressively starting to fail having reached end of life. To also ensure maintenance and emergency access these systems cannot be run to failure. This includes the service train within the tunnel, that 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 these specified auxiliary systems to be operational 24/7.

For an auxiliary system failure there is a health and safety risk, which could result in the Asset Safety Incident Rate being increased (see Section 2.3.2). 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.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓	✓	✓	

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Not undertaking replacement or refurbishment works will result in continued and escalating maintenance costs and the risk that plant will be operated to failure. This runs the risk that that the tunnel cannot be safely operated and entered for regular maintenance or emergencies. Failure of auxiliary systems poses a risk to the continued operation of Vector and Transpower primary plant required for supply to Auckland CBD, North Auckland and Northern customers. Do nothing implies a Health and Safety risk to personnel and contravention of the New Zealand Transport Authority statutory Rail Act and risk of loss of reputation with Transpower, Electricity Commission, New Zealand Government and Auckland City Council.		Rejected
Option 2: Undertake a staged and scheduled programme of works to replace and refurbish auxiliary systems in the tunnel	Selecting this option will remove the risks associated with the 'Do nothing' option. Undertaking a staged and scheduled programme of works will ensure continued operation and maintenance of the primary plant in the tunnel. It will also correctly manage the Health and Safety risks to personnel that work in the tunnel	\$3.56M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Tunnel - Nokia radio system replace	0.01										0.01
Tunnel - Rail Track and Anchor Replace	0.05	0.05	0.04	0.05	0.05	0.04	0.05	0.05	0.04	0.05	0.47
Tunnel - Atmospheric Sensors Replace	0.15										0.15
Tunnel - Penrose portal replacement of cable supports		0.40									0.40
Tunnel - Newmarket Lift replacement	0.05	0.60									0.65
Tunnel - Train, Generator, Rolling Stock Replace			0.20								0.20
Tunnel - Airlock Security New	0.17									0.16	0.33
Tunnel - Ventilation Motor Replace								0.45			0.45
Tunnel - UPS Replace			0.09								0.09
Tunnel - Fire Main Valve Replace					0.14						0.14
Tunnel - Newmarket Plant Room LV Reinforce				0.20							0.20
Tunnel - PLC Replace	0.07										0.07
Tunnel - SCADA EOC HMI Replace	0.05										0.05
Tunnel - Sump pump replacement									0.10		0.10
Tunnel - Ventilation VSD Replace									0.20		0.20
Tunnel - Newmarket Plant Room Exterior Replace									0.05		0.05
Total CAPEX	**0.12**	**1.00**	**0.09**	**0.20**	**0.14**	**0.05**	**0.05**	**0.45**	**0.35**	**0.17**	**3.56**

AUCKLAND AND NORTHERN PQM METERS

NEEDS STATEMENT

For the decentralised electricity distribution network of the future asset lifecycle information will become ever more important. The new generation load equipment with microprocessor based controls and power electronic devices is more sensitive to power quality variations than equipment used in the past. Power quality disturbances are caused by a combination of utility, customer and outside actions but the vast majority of customers experience relatively little inconvenience or cost as a result of electric outages or power quality problems but there are customers who experience significant economic losses when power is interrupted or when power quality problems occur – the quality of power can have a direct economic impact on some industrial customers. The NZ Electricity Governance Rules 2003 Part C common quality, NZECP36 and AS/NZS 61000.3 state power quality requirements.

Power quality meters at zone substations allow us to record power system disturbances to a high level of detail and accuracy and give Vector the ability to analyse faults and disturbances and report thereon. Power quality monitoring is a mixture of data gathering and measurement of power quality items such as frequency distortions, supply interruptions, voltage dips, sags and swells, supply voltage variations, flicker and transients. PQM meters are also used as check meters for energy flows and peak demands for revenue meters to zone substations. Our main measuring points are at zone substation nodes.

The PQM metering population median age is approaching 17 years and the older generation PQM meters cannot be upgraded with the latest PQM reporting software. Some older PQM meters have failed and the software versions in older meters are unsupported. To ensure continued visibility of the quality of the power supply at zone substation busbars a programme of replacement forms part of the capital investment plan. There are also a number of zone substations where PQM meters do not exist and new meters will be rolled out to enable analysis of power quality.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓		✓	

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	A 'Do-nothing' approach means that Vector will continue to use existing first generation PQM meters for which software is not supported anymore. This will lead to the risk of Vector not being able to measure and analyse the quality of power and peak demand at the source of supplies to the distribution network		Rejected
Option 2: Undertake a staged and scheduled programme of works to refurbish and replace PQM meters as the case may be	Improves visibility of the network peak demand, provides a check of energy flow through revenue meters, allows post incident network parameter analysis and allows reporting on power quality. A reliable, technically sound and software supported fleet of PQM meters at zone substation will allow Vector to monitor its compliance with power quality standards	$3.4M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Northern PQM replacements	0.07	0.07	0.07	0.07	0.07	0.12	0.13	0.13	0.12	0.13	0.98
Auckland PQM replacements	0.07	0.07	0.07	0.07	0.07	0.12	0.13	0.13	0.12	0.13	0.98
PQM new sites rollout	0.10	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.45
Total CAPEX	**0.24**	**0.29**	**0.29**	**0.29**	**0.29**	**0.39**	**0.41**	**0.41**	**0.39**	**0.41**	**3.41**

ROUTERS, RTU, COMMUNICATIONS CABLES AND COMMUNICATIONS DEVICES UPGRADES

NEEDS STATEMENT

Vector's zone substations are interfaced to the WAN and the SCADA master station in the EOC via routers in SCADA panels at zone substations. The majority of routers are Cisco model 2811 routers for which software support will end within the next year and replacement spares are becoming an issue to source and software security updates cannot be implemented to an appropriate level to ensure breach of SCADA is a low risk. There is a need to replace first generation network routers and network switches with devices that are technically supported.

Notwithstanding the rollout of a fibre optic communications network that has been going for a number of years there are still communications channels, for SCADA and unit differential protection communications, between a number of zone substations and from zone substations to wide area network primary nodes that consist of copper cables. These copper communications and differential protection cables have been in service for circa 50 to 60 years and are failing and heavily committed, i.e. little or no spare channels. A major risk to Vector is loss of communications and visibility due to deterioration of the insulation of individual cores to a point where they come in contact with other cores. Cable joints are also a source of failure where moisture ingress causes low resistance between cores and then result in failures of joints. Going into the future there is a need to replace copper cables with fibre optic networks not only for the sake of replacement of the ageing copper based assets but to make the network ready for future communications bandwidth requirements.

There are 295 11 kV network switches with SCADA remote control ability on Vector's 11 kV overhead network. Of these units 56 use Very High Frequency (VHF) radio for communications and the remainder use 2G cellular communications. The EOC can remotely control pole mounted 11 kV switches to isolate faulted sections of the network and restore healthy sections of the network. The ability to operate 11 kV network switching devices decreases outage times because it negates the requirement for operating personnel to drive from switch to switch. Data and communications between the EOC and the communications modules on 11 kV network switches are via the Conitel protocol and VHF analogue radio. The VHF radio system has reached its end of life and the Conitel protocol is obsolete and firmware and software cannot be updated. Intermediate protocol convertors are required and this has resulted in loss of information and loss of SCADA visibility in the EOC of the status of 11 kV switches. Furthermore, the 2G cellular network does not provide sufficient coverage and there is a need to upgrade the 2G network. Generally, there is a need to replace the communications system and controllers to existing 11 kV pole mounted network switches in Vector's 11 kV overhead distribution network.

The WAN for SCADA in the northernmost region of Vector's supply area consists of digital microwave radio communications links. The system provides voice over IP and data communications. The existing digital microwave radio WAN consists of a star configured network with very limited redundancy and if the digital mobile radio link between the Albany Heights repeater station in the northern suburbs and the Kraacks Hill repeater station further north in the rural precincts should fail, the northernmost region will be without SCADA visibility and reliant on field staff to switch the network. It must be noted that the upper reaches of our network is also the area in which we recently completed two large BESS', at Warkworth South and in Snells Beach, that requires reliable communications with sufficient bandwidth. This places even more importance on the requirement to have robust and redundant SCADA connectivity and communications in place to optimize the use of the battery storage systems in the network. There is a need to address the limitations of the northern WAN to ensure reliable network visibility, robust communications channels and control from the SCADA master station. There are implications to SAIDI and health and safety if this is not addressed as the non-visibility of the network leads to longer restoration times, with switching needing to be undertaken by field staff rather than remote control.

The RTU located at our zone substations provide an essential part of the SCADA system to collect status information from site and allow remote control of plant at site. The maximum anticipated life of an RTU is 20 years. As an RTU approaches 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 site is lost, so EOC is unable to receive updates of events from the site or remotely control equipment. Hence, the controller is unable to effectively respond to any emerging contingency. Coincidental failure of RTUs across a number of sites will exacerbate the situation.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓		✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	A do-nothing approach means that SCADA and line differential protection will be reliant on a failing population of 60s vintage copper pilot cables with insufficient bandwidth for the requirements of the future. Ultimately failures of these secondary devices will convert to failures of the primary network and loss of supply to customers. This in turn will result in poor SAIFI and SAIDI indices. There are implications to the H&S of field crews as well without remote visibility of zone substations and switches in the field. This will lead to longer restoration times because of manual switching undertaken by field staff rather than remote control.		Rejected
Option 2: Undertake staged and scheduled programmes of work to replace WAN	Selecting this option will remove the risks associated with the 'Do nothing' option. It will ensure a communications	$11.47M	Selected

routers, LAN switches, communications devices, RTUs and ageing copper pilot cables	network with sufficient reliability for the big data requirements of the future.

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland WAN Routers and Comms Cables Upgrade	0.50	0.40	0.30	0.20	0.10	0.10	0.10	0.10	0.10	0.10	2.00
Northern WAN Routers and Comms Cables Upgrade	0.50	0.40	0.30	0.20	0.10	0.10	0.10	0.10	0.10	0.10	2.00
Auckland Upgrade SCADA Coms to 11kV pole mounted switches	0.08	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	1.65
Northern Upgrade SCADA Coms to 11kV pole mounted switches	0.20	0.22	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	2.52
Northern microwave comms link alternative link	0.15	0.30									0.45
Northern RTU Replacement	0.10	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.55
Auckland RTU Replacement	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	2.00
Liverpool 110kV RTU replacement			0.15	0.15							0.30
Total CAPEX	**1.73**	**1.75**	**1.44**	**1.24**	**0.89**	**0.89**	**0.89**	**0.89**	**0.89**	**0.89**	**11.47**

AUCKLAND AND NORTHERN SUBTRANSMISSION AND ZONE SUBSTATION PROTECTION

NEEDS STATEMENT

The subtransmission protection schemes in Vector's network consist of subtransmission circuits that are generally radial feeds (duplicated or triplicated) to zone substations and historically used copper pilot wire protection in the Auckland network. In the Northern network ,the subtransmission is a reconfigurable meshed network that historically used distance protection at GXPs and directional protection at individual zone substations.

The Auckland subtransmission protection network still has a number of electromechanical pilot wire protection schemes, which are reliant on aged copper pilots that are increasingly failing and is approaching or past anticipated end of life (40 years). Electromechanical pilot wire protection does not have supervision facilities, so asset observations can only be found through routine maintenance. As the pilot wires degrade and the relays age, there is an increasing risk that the protection relays may not operate when required to do so or may operate for out-of-zone faults. This gives an increased risk of wider-spread disturbance to the power system and potential to lose supply to entire zone substations.

The Northern network currently uses distance/directional protection schemes. The Northern network has large sections of overhead lines where two subtransmission circuits share the same pole, often with underbuilt distribution circuits. This results in potential mal-operation of protection caused by mutual coupling between the circuits, or the fault spreading from one circuit to the other adjacent circuits, resulting in genuine operation of the protection. There have been a number of high SAIDI outages caused by these scenarios in recent years as there is potential to lose supply to multiple zone substations due to the meshed nature of the Northern network. Also, most of the existing distance protection relays are approaching end of life (20 years) and a number of failures have been experienced recently. There is no vendor support for electromechanical relays and it is becoming harder to find technical staff to maintain electro-mechanical line differential protection schemes that consist of multiple discreet relays.

A large number of zone substations still has electromechanical and static protection systems that are all past or near end of anticipated maximum life of 40 and 20 years respectively. These systems do not have any self-monitoring, reporting or data storing capability to undertake post fault analysis and have limited alarming capability. First generation numerical relays are also approaching end of anticipated maximum life of 20 years and increased failure rate is being witnessed. These systems are more complicated to replace as they have increased (often bespoke) functionality to consider. As for subtransmission protection schemes the electromechanical protection in zone substations are no longer supported by suppliers and spares are difficult to get hold of. Furthermore, electromechanical relays have moving parts that can lose their calibration and thus protection sensitivity over time.

Quay Street 22 kV substation is a critical node within Auckland's CBD and supplies amongst others electricity to the Ports of Auckland and Parnell. It is not able to have suitable protection settings applied to the bus section CB to allow grading with adjacent protections. This means that if an outgoing feeder CB fails to clear a fault, all 22 kV incomers will trip to clear the fault, resulting in the loss of Quay Street 22 kV, Quay Street 11 kV and Parnell 22 kV. This would result in widespread critical failure for a vital region for Auckland (and New Zealand's) economy with the potential to compromise national productivity with the loss of supply to the country's largest CBD. The current standard for new substations is to install circuit breaker fail (CBF) protection. However, Quay Street 22 kV predates CBF being applied as standard and does not have it installed.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓			

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	A do-nothing approach means that the subtransmission protection schemes will continue to rely on ageing and failing copper pilot cables. The existing electromechanical fleet of protection relays for which there is no product support or spares will continue to age. Getting qualified technical staff to maintain the ~60 year old protection schemes is becoming a bigger and bigger challenge as time goes one. Selecting this option will increase the chances of spurious and undue tripping or protection with reduced sensitivity that could result in backup protection trips for faults and thus larger outages and increased SAIFI and SAIDI. This option is not viable and is not recommended.		Rejected
Option 2: Undertake a staged and scheduled programme of works to replace subtransmission and zone substation protection schemes	A staged and scheduled programme of works is necessary to establish a protection fleet for the future that provides the reporting and analysing functionality to quickly and accurately analyse faults to plan remedial actions. Retaining a fleet of electromechanical relays some of which are 60 years plus old with no vendor support, unsupervised for failure and for which recruitment of field staff with the necessary experience to maintain this is becoming more of a challenge is simply not viable. The subtransmission protection replacements will go hand in hand with a replacement programme of the ageing copper pilot cable fleet (described in a separate Needs Statement).	$30.86M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Northern Subtrans Protection Upgrade	0.50	0.40	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	3.30
Auckland Subtrans Protection Upgrade	1.00	0.91	0.35								2.26
Northern Zone Sub Protection Upgrade		0.40	0.75	1.00	1.20	1.40	1.60	1.60	1.60	1.60	11.15
Auckland Zone Sub Protection Upgrade		0.50	1.00	1.20	1.50	1.70	2.00	2.00	2.00	2.00	13.90
Quay Zone Sub 22 kV CB fail installation	0.25										0.25
Total CAPEX	1.75	2.21	2.40	2.50	3.00	3.40	3.90	3.90	3.90	3.90	30.86

AUCKLAND AND NORTHERN TRANSFORMER MANAGEMENT SYSTEMS

NEEDS STATEMENT

Transformer management systems (TMS) provide monitoring, control and communications functions for our power transformers fleet. The TMS in zone substations provide the essential function to automatically maintain substation busbar voltages within predetermined limits and this allows us to meet statutory requirements for voltage levels at customers' premises and also protects equipment from overvoltage.

Over time TMS have migrated from various discrete electro-mechanical relays performing specialised functions such as voltage regulation and thermal protection to electronic and PLC type controllers. There are three types of legacy TMS in the network: Electromechanical; Static (electronic components) and PLC. All three legacy systems are proving increasingly unreliable, technically unsupported by equipment vendors and obtaining spares is becoming a challenge. The PLC type in particular lacks technical support and there is little knowledge within Vector with regard to the PLC logic software functionality. When a TMS fails, the ability to automatically regulate busbar voltage is lost that then requires the EOC to manually tap transformers to maintain busbar voltages or place transformers in fixed tap. This increases the risk of violating statutory voltage limits or causing damage to equipment, especially if there is a system event causing rapid change in voltage. In recent years, we have embarked on a programme to install modern microprocessor based TMS's that are fully configurable with an array of software functions and approximately 50% of the TMS fleet now consist of microprocessor based transformer management.

The older TMS's are unsupervised and have no disturbance or event recording facilities and cannot be employed to provide input parameters for dynamic ratings in the longer term future. The capital investment and programme of work to replace technically unsupported electro-mechanical and PLC based TMS systems need to continue in this AMP period to ensure reliable control and monitoring of zone substation power transformers well into the future. A TMS costs in the order of 3-5% of the cost of a new transformer but this cost will add improved reliability and facilitate safe loading at higher loads.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓	✓		✓	

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	'Do-nothing' means that Vector will be exposed to the risk of failure of ageing electro-mechanical TMS systems and PLC based systems that are not technically supported anymore. Loss of TMS systems will result in loss of automatic voltage control that in turn will result in the risk of violation of statutory voltage levels and could even lead to damage to transformers and tap change equipment		Rejected
Option 2: Undertake a staged and scheduled programme of work to replace electro-mechanical and PLC based TMS systems	Modern fully software configurable TMS systems will ensure reliable and vastly extended monitoring of the costly power transformers in zone substations. This option will allow on-going automatic control of busbar voltage levels. The risk of failure is reduced and the risk of violation of statutory voltage levels as well as the risk of damage to primary plant is reduced	$8.00M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland TMS replacement		0.25	0.25	0.50	0.50	0.50	0.50	0.50	0.50	0.50	4.00
Northern TMS replacement		0.25	0.25	0.50	0.50	0.50	0.50	0.50	0.50	0.50	4.00
Total CAPEX	0.00	0.50	0.50	1.00	1.00	1.00	1.00	1.00	1.00	1.00	8.00

AUCKLAND AND NORTHERN EXTENDED RESERVE

NEEDS STATEMENT

The provision of Extended Reserve is a statutory requirement in the Electricity Industry Participation Code. The Electricity Authority is replacing the current Automatic Under Frequency Load Shedding (AUFLS) scheme with the new Extended Reserve scheme, which is intended to be a low-cost and more efficient scheme consisting of four demand blocks of load. If load is not shed during frequency excursions, there is a risk of major loss of supply.

The Extended Reserve scheme uses a methodology which centrally selects demand units from the entire North Island and prioritises the disconnection of customers with the lowest cost of interruption. The new scheme may require up to 60% of Vector's demand to be armed for load shedding.

The transition to the Extended Reserve scheme requires the phased decommissioning of the existing AUFLS scheme. It requires the re-programming of existing numerical protection and control relays, and installation of some new protection relays dedicated to Extended Reserve. In October 2017, the Electricity Authority decided to put the implementation of the Extended Reserve scheme on hold due to a number of technical and design issues. The Authority subsequently advised in April 2018 of its decision to obtain the findings of the System Operator's scheduled technical requirements review, which will inform the resolution of the design issues, prior to any further implementation of the Extended Reserve scheme.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
		✓		✓	

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Do nothing	Selecting the 'Do-nothing' option will result in non-compliance of the Code		Rejected
Option 2: Implement the Extended Reserves scheme	Allows compliance with the Code. This option means that load will be shed during frequency excursions and this will reduce the risk of loss of supply	$0.60M	Selected

PREFERRED OPTION

Comply with the Electricity Industry Participation Code and provide an Extended Reserve scheme

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Auckland extended reserves under frequency relays install	0.20										0.20
Northern extended reserves under frequency relays install	0.40										0.40
Total CAPEX	**0.60**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.60**

5.3 NON-NETWORK ASSETS

5.3.1 INFORMATION SYSTEMS, PROCESSES AND DATA

Electricity lines businesses like Vector are facing significant new challenges with customers adopting new technology to improve energy efficiency and support the decarbonisation of the economy. This disruption will continue and accelerate as the price points of the new technologies keep coming down at an increasing rate. Vector is faced with increasing uncertainty in how this will play out in the period of the 2019 AMP. A key disruptor is the take up of electric vehicles (EVs), and the way customers will charge their EVs.

However, at the same time, new and cost effective asset management technologies and supporting digital and information management technologies are providing Vector with exciting opportunities to improve the way we monitor, control and manage our assets.

These new technology options also provide secure and cost effective options for the way Vector engages with its customers, as well as how we enable customer to connect their distributed energy resources (DERs) and other new home automation technologies, seamlessly and effortlessly to the Vector network. As discussed under the Symphony scenario, we are developing the network in such a way that all customers can benefit from the connection and integration of various, on-premise DERs to the network, while developing incentives, signals and pricing structures to manage the assets in the long term interest of customers while ensuring affordability, fairness and equity.

The proposed investment during the 2019 AMP period in enabling non-network digital systems, processes and information management will ensure Vector has the capability and tools required to manage the uncertainty we are facing in such a way that we do not burden future generations with legacy assets but create a network that is more responsive, flexible, integrated, modular and affordable.

To this end, we have developed a plan with a higher degree of certainty for the first five years of the 2019 AMP and less certainty thereafter. Given the rate of change in technology, we continuously look for the optimal solution, whether this is through the use of new and emerging digital technologies or optimising existing solutions. This section is structure to reflect this, and comprised of three parts:

1. Significant projects & program investments
2. Enabling projects
3. Information systems, processes and data investments

a. Data Management & Utilisation
b. End User Computing
c. Cyber Security
d. Application lifecycle management
e. Infrastructure lifecycle management

For all the projects described below we looked for the optimal solution before deciding on the investment choice (and will continue to do so). Whether this is through the use of new and emerging digital technologies or existing solutions, in all cases, we identify the solution that will deliver the best outcome for our customers.

5.3.2 SIGNIFICANT PROGRAMMES OF WORK

ONGOING CUSTOMER ENGAGEMENT TRANSFORMATION

NEEDS STATEMENT

Vector has been progressively changing its predominately phone based contact centre to align with customer preferences for engaging with us through a communication channels of their choice, whether it is social media, emails, text messaging, etc. At the same time, events like the 2018 April storm have highlighted to business need to rapidly scale up for significant events.

We have also been observing a trend towards a 'self-service' first expectation for those customers that do not wish to engage with a person directly when they can get accurate and efficient service from other channels. The focus of this programme is to move Vector towards a majority self-service model, for example, exploring the options and associated benefits where the customer's first point of interaction is through digitally enabled options such as webchat, guided email and voice recognition through an IVR.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓			✓	✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Continue with current 100% outsourced, phone based contact centre. This option will not address the increasing demand from our customers for alternative channels to contact Vector, and does not scale in significant weather events, significantly impacting our ability to deliver our operational and field service outcomes. This option also reduces our ability to deliver innovative services that our customers now expect, and reduces the flexibility we must meet changing customer and stakeholder needs.		Rejected
Option 2: Invest in a Contact Centre transformation with Self-Service and Digital First principles	Investing now in proven technologies that enable self-service for customers through both digital and traditional phone based channels will provide Vector with the capability to deliver to changing customer expectations. This investment also directly enables Vector to increase its scalability and capability to serve customers in significant events, and provide a seamless service experience through the channel of the customer's choice.	$2.64M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Ongoing customer engagement transformation			0.44	1.32	0.88						2.64
Total CAPEX	0.00	0.00	0.44	1.32	0.88	0.00	0.00	0.00	0.00	0.00	2.64

CLOUD MIGRATION

NEEDS STATEMENT

Our information systems, processes and data have been developed over time with the aim of providing stable, consistent and valuable customer, business and operational services. These services have traditionally been provided through on premise servers and datacentre infrastructure. With the rapid evolution of cloud services, and the inherent advantages of automated scaling, reduced operational cost and significantly improved resilience and recovery, there is an urgent need to move towards cloud based infrastructure.

This emergence of cloud technologies directly supports the objectives of asset management through improved capability (e.g. for data storage and backup), enable enhanced data analytics and simplify the digital technology infrastructure at a more efficient cost.

More importantly, the migration of applications and infrastructure to cloud first technologies also provides enhanced capabilities to capture and consume the increasing amount of data that is being generated and used across the network, and then better utilise this data in near real time to make accurate, relevant and timely decisions. Increasing penetration of DERs, investments in technology at the grid edge, increasing scale of microgrid deployments, distributed control of network assets all require significant connectivity with an associated demand on computing power – cloud first technologies provide this computing power at scale at a significantly lower cost per unit than on-premise and datacentre infrastructure.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
				✓	

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Continue with management and maintenance of core technology infrastructure in existing physical server and data-centre capabilities, with continued investment in on premise infrastructure to support increasing volume of data, processing and backup required due to rapidly changing connectivity across network assets		Rejected
Option 2: Undertake migration towards cloud services	Build readiness for cloud migration through standardising existing cloud environments, simplifying account and hierarchy structures and identifying those server workloads which have the lowest complexity. From there begin moving these workloads to cloud services and continue to optimise cloud investments towards high value transactions, providing greater elasticity, self-service provisioning, redundancy and a flexible 'pay-per-use' model	$3.28M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Cloud migration	0.57	0.57	1.07	1.07							3.28
Total CAPEX	0.57	0.57	1.07	1.07	0.00	0.00	0.00	0.00	0.00	0.00	3.28

VECTOR GROUP IT NETWORK MODERNISATION

NEEDS STATEMENT

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. The current IT network has grown organically over many years and is now in an unfit state, presenting multiple functional issues and security risks. The move to cloud is putting further pressure on the need to remediate. This is a critical and urgent piece of work as the IT network is foundational to all system technologies.

The IT Network includes both corporate and SCADA Internet Protocol (IP) and Ethernet computer networks. The functional role of these networks is to provide secure and reliable access to the internet, and effectively limit access to some areas of the network to provide redundancy and disaster recovery capability, alongside enabling 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.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
					✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Continue with existing ad-hoc IT system network, and maintain this through ongoing incremental investment in patching and recovery to mitigate risk of significant failure		Rejected
Option 2: Complete IT network modernisation	Conduct end to end review of existing IT network and identify path to resolve and replace core components. Develop new network architecture with security and accessibility for multiple user groups defined and agreed during the design phase. Implement enhancements towards achieving the target state defined and modernise the network environment to enable secure, scalable and resilient connectivity to all core assets and infrastructure where connectivity is a critical component to achieving business outcomes.	$2.2M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
IT network modernisation	0.71	0.57	0.57	0.36							2.21
Total CAPEX	0.71	0.57	0.57	0.36	0.00	0.00	0.00	0.00	0.00	0.00	2.21

DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM (DERMS)

NEEDS STATEMENT

The rapid growth of Distributed Energy Resources across our network is posing a risk to the electricity network, but at the same time these DERs also create great opportunities for Vector and our customers when managed correctly. To manage these DERs, the key needs are full visibility of available DERs on the network, better understanding on their behaviour and potential impact on the network. Together with real time load and flexibility forecast, the Vector DERMS Platform can be used to achieve the following outcomes:

- Reduction in the need for capital upgrades for replacement of traditional network assets, specifically power transformers at GXP and Zone Substations; and HV cables which is a long term multi-year benefit.
- Ability to manage loading on critical network assets, particularly when the assets are under stress and during network outage events. This provides ability to maintain reliability and reduce the possibility of cascade failures.
- Ability to use DERs and DR in support of restoration efforts, reducing loading on remaining assets in service to reduce the need for field switching to effect restoration to customers. Ability to accurately predict and quantify loading relief commitments to Transpower. Enables Vector to be more accurate with its committed load shedding levels.

DERMS is a long-term investment asset that will also need continuing investment to be able to adapt to the changing environment, include new DER types and provide better customer outcomes utilising DERs. The idea is to integrate customers who want to play an active role and make the most use of their DERs.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓		✓	✓	✓	

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Utilise existing DERMS capability and manage existing DER's to reduce traditional investment in assets and manage peak demand. This option would not bring full benefits to Vector and its customers the number of new DER's is increasing monthly, meaning existing DER types are increasing on numbers as well as brand new DER types are emerging. With these new DER Types new opportunities are being created to create value to Vector and its customers.		Rejected
Option 2: Continue investment in DERMS	This option is selected, to ensure ongoing development of DERMS and ensuring that opportunities are not being missed out or being used too late. DERMS is a key system for Vector to be able to create a new energy future.	$4.0M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
DERMS	1.00	0.50		1.00	0.50			0.50	0.50		4.00
Total CAPEX	1.00	0.50	0.00	1.00	0.50	0.00	0.00	0.50	0.50	0.00	4.00

SCADA UPGRADE, ENHANCED OUTAGE MANAGEMENT AND DISTRIBUTION MANAGEMENT SYSTEM CAPABILITIES

NEEDS STATEMENT

The need to invest in SCADA systems has multiple factors:

- Our current SCADA system is a sunset product which poses a substantial risk in not being able to manage utilising new technologies on the network in the medium term
- Customers' demands for faster and more granular information about outages also drives the need to invest in better outage management capabilities
- Current systems are not well integrated and the current SCADA system has no provision for standardised interfaces given its age
- Health & Safety – to ensure all switching and work activities on the network are being executed without incident, permits and competencies can be managed within the system and every switching plan can be checked against the real network status before being executed
- With the increasing amount of DERs on the electricity network, the LV network increases in importance. Real time visibility as well as remote operation of the LV network will be of essence to manage changing customer and stakeholder expectations of the network and the new SCADA system must be able to digest and display the information to Vector's Control Room
- DERMS needs to be fully integrated with the new system(s) to achieve the optimal outcome for our customers

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.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓	✓	✓	✓	✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – Keep existing SCADA	Not investing in a new SCADA system will keep manual processes as relevant systems can't be fully integrated. This leads to data silos and manual work to synchronize data. In addition, the requirements to manage an electricity network today have changed and the current system does not provide this functionality. Especially as it is a sunset product, no further development is being expected.		Rejected
Option 2: Invest in new SCADA/OMS/DMS	Modern SCADA system combined with Outage Management and DMS functionality that provides standard interfaces and fits into Vector's Digital Platform ecosystem. These systems will provide capabilities to manage the electricity network and its current requirements.	$18.0M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
SCADA upgrade /OMS/DMS	2.00	7.00	6.00	3.00							18.00
Total CAPEX	2.00	7.00	6.00	3.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00

FIELD SERVICE OPERATIONS DATA INTEGRATION AND PLATFORM ENABLEMENT

NEEDS STATEMENT

Maintenance standards and practises, alongside the record of maintenance completed in the field by field service providers is currently stored and maintained in a variety of legacy systems, dependent on the type of maintenance and the field service provider. This project is tasked with providing a standard method of field service providers accessing maintenance standards and informing Vector of work completed.

The ongoing proposed investment in this project is to ensure that simple, consistent integration is achieved, and all applicable standards and practises are known and understood by the FSP teams, including changes and updates to the standard maintenance methods.

Development of fit for purpose integration and standardised data management for these functions is critical to ensuring a consistent level of maintenance, and standardised behaviour across all field operations. In parallel there are significant efficiencies to be gained by consolidating and simplifying the way in which Vector and our field service providers manage and maintain asset data.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
			✓	✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Continued management and maintenance of multiple legacy systems across field providers and Vector will contribute towards increased ongoing maintenance and management costs of these systems, and the reduced visibility will result in continued issues with classification and management of the asset maintenance schedule		Rejected
Option 2: Continue SAP-PM program	Investment in the development of integration interfaces to ensure a standardised data model and standardised method of serving and consuming maintenance related data. This will enable increased efficiency in the maintenance of Vector assets, through an improved and enhanced asset maintenance process	$1.8M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Full integration with FSPs	1.75										1.75
Total CAPEX	1.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.75

CORE BILLING AND CUSTOMER RECORD MANAGEMENT INTEGRATION AND ENABLEMENT

NEEDS STATEMENT

As part of the digital platform strategy, we are moving towards a micro-service led architecture, where individual components are functional on their own, and all integration is completed via API gateway and management platforms, to increase flexibility and significantly reduce complexity of core systems. The development of microservices and fit for purpose core business enablement platforms will reduce complexity and risk on legacy platforms. The existing monolithic legacy enterprise platforms will result in significant cost and risk to migrate when they start to reach end of life and the integration in this way will provide Vector the ability to complete lifecycle migration activity and improve our capability to meet changing customer and technology demands.

In this context, microservices along with enhanced and simplified integration of core capabilities through API's provide a lightweight, highly scalable, and cost effective digital platform capable of meeting the rapidly changing demands for service providers. The integration of our core billing (Gentrack and SAP) and customer record management (Siebel) capabilities through this new microservices method, will increase the resilience of these core systems, reduce complexity of lifecycle migration activity and significantly enhance the ability to drive value from our monolithic legacy systems as they move towards end of life.

Transition and migration of these platforms towards fit for purpose and microservices focussed solutions is required to reduce the cost of legacy platform migration as these reach end of life.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓			✓	✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Large, monolithic legacy platforms are maintained with point to point connectivity, significantly reducing our ability to enhance core capabilities without significant investment in like for like upgrades and enhancements on technology that is no longer fit for purpose		Rejected
Option 2: Core billing and customer record management integration and enablement	Invest in development of a microservices and API led model, where core capabilities are developed to enable multi-party, seamless integration and significantly reduced dependency on individual core systems. This will ensure the continued scalability and reliability of services, increasing resilience and significantly improving our ability to deliver services to customers	$9.98M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Core billing and customer record management integration		0.71	1.43	2.14	2.85	2.14	0.71				9.98
Total CAPEX	0.00	0.71	1.43	2.14	2.85	2.14	0.71	0.00	0.00	0.00	9.98

5.3.3 NETWORK CENTRIC CAPABILITY INVESTMENTS

The Network centric capability investments are defined based on the IEC 61968 architecture reference model, which defines the core domains responsible for the orchestration and execution of distribution management, alongside those functions which are external to distribution management but contribute to business or customer operations. We have utilised this reference model as the basis through which to develop its own domain reference architecture and capabilities.

In a broad sense, the IEC reference model provides a standard framework for digital capabilities and domains to be associated with network capabilities, and a standard definition of these capabilities to ensure clear, consistent and accurate representation of capability across multiple domains. The network centric capability needs statements are broken into these asset categories based on this model:

ASSET CATEGORY	TYPE (ASSET CLASS)
Network Operations (NOPE-BEP)	Network Operation (NO) Asset Management (AM Maintenance and Construction (MC) Network Extension Planning
Business Operations	Customer Account Management (ACT) Financial (FIN) Premises (PRM) Human Resources (HR)
Customer Operations	Customer Support (CS) Customer Channels and Engagement Employee Channels and Engagement Partner Channels and Engagement

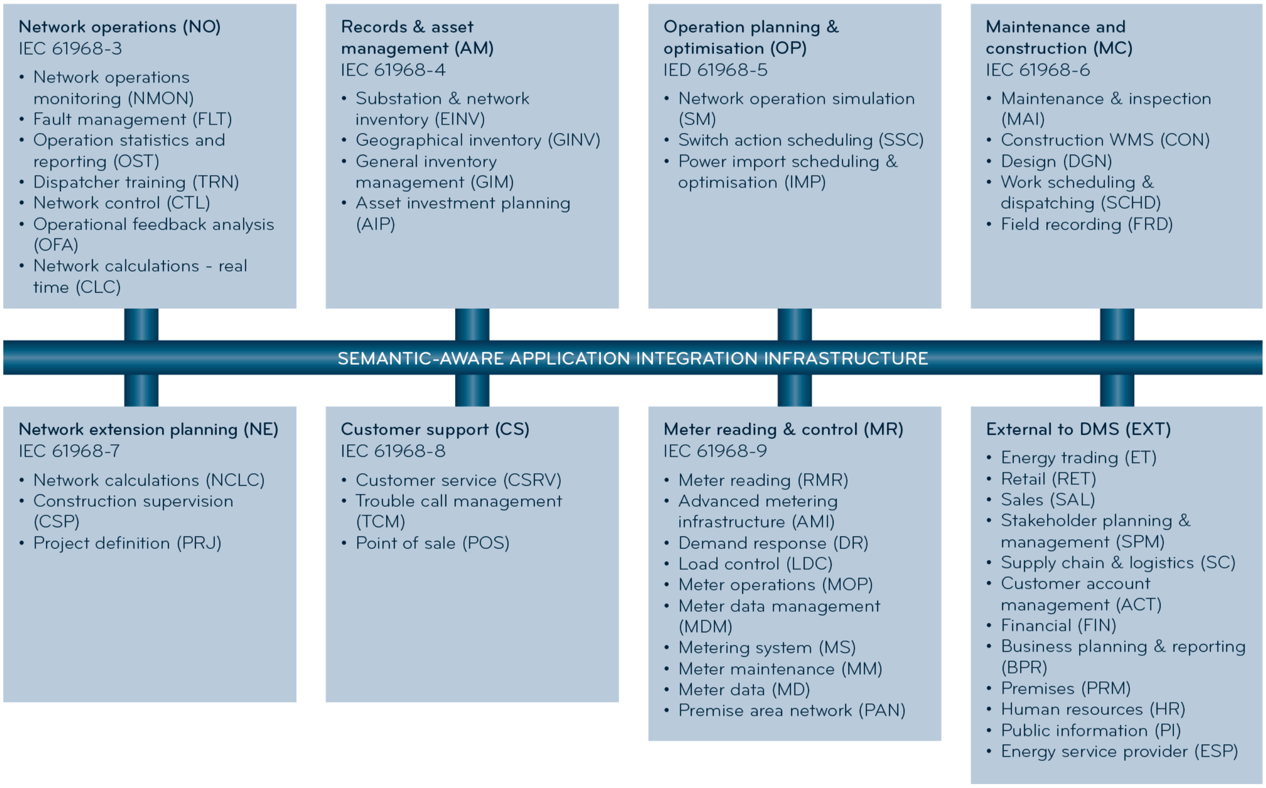

Figure 5-7 IEC61968 reference architecture – utilised as the basis for Vector reference architecture

NETWORK OPERATIONS

NEEDS STATEMENT

Network operations investment is targeted at ensuring consistent, reliable and resilient supply across the network, and the digital capabilities required to support achievement of this. The network operations domain includes multiple categories and functions which are required to support the execution and management of a distribution network in the future.

These are summarised with their core functions below:

- Network operations – Electricity control room, switching, scheduling and outage management
- Maintenance and construction – in field work completion
- Network extension planning – expansion and growth of the network
- Asset Management – assessment and maintenance of master data associated with assets

The focus of this investment category in the early years of the period is on development of fit for purpose capability to enable enhanced control room functions, with increasing capability in operational management of outage events across their lifecycle, including significant events. In parallel, there is capability growth associated with meeting the changing customer expectations for electricity, including increased EV and smart device penetration. Examples of specific initiatives categorised here include: fault location detection, weather monitoring, SCADA simulations, power flow computation and thermal rating assessments.

We have identified that increasing our inhouse capability to deliver effective and efficient field services is critical to improving capability to meet customer needs, and in line with this there are specific projects and initiatives associated with permit management, scheduling and notification of planned works, field crew loading analysis and work order scheduling. Alongside this, there is investment identified to enable enhanced field crew visibility, and optimisation of routes and patterns for work completion.

A core component of the Network Operations capability is our ability to accurately identify and manage asset records, and there are specific projects identified in this category to enable improved visibility of asset failure history, reliability centred analysis, budget allocation and supporting the delivery of asset financial performance measures through data and analytics capabilities.

The Network Operations digital investment category targets both specific projects and expected investment in required capabilities to enable enhanced network performance, and ensures that we deliver effective, resilient and reliable services.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓	✓	✓	✓	✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Vector will react to changing demands for Network Operations enablement capabilities on an as needed basis, and will respond only when break fix or critical business functions are impacted. Our ability to meet changing customer and stakeholder expectations of service will be hampered and likely lead to reduced effectiveness.		Rejected
Option 2: Network Operations enablement	Vector invests in developing capabilities to support achievement of the network of the future, including advanced planning and optimisation of network management, fault and field crew response and targeted, specific analysis of assets to enable improved investment decisions. In parallel, we will be equipped to meet the rapidly changing needs of our customers and stakeholders, as these continue to evolve into the future.	$19.1M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Network Operations	1.90	1.25	1.95	0.60	1.97	1.25	2.40	2.70	2.40	2.72	19.14
Total CAPEX	**1.90**	**1.25**	**1.95**	**0.60**	**1.97**	**1.25**	**2.40**	**2.70**	**2.40**	**2.72**	**19.14**

BUSINESS OPERATIONS

NEEDS STATEMENT

The successful functioning of any business requires capabilities to support successful execution of business operations. This investment category reflects the ongoing investment in financial capabilities, customer account management, human resources and premises (including physical security and monitoring (e.g.: camera recording and backup). Optimising and automating core business functions in the Finance domain will lead directly to improved customer and business outcomes, through improved processing time and more consistent and concise processes. We are heavily reliant on our customer data, and investing in improving the way we store, manage and maintain that customer data for both communication and engagement purposes.

Specific investments in this area include enhancing our existing finance domain to enable automated reconciliation, developing new employee engagement and communication capabilities and providing more accurate and relevant information to customers about the status of their account and connection across the customer lifecycle.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
				✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	No targeted investment in HR, Finance, premises and customer account management leads to significantly reduced efficiencies in internal processes, and increased cost to serve for customers. This will also directly contribute to a reduction in the availability of Vector team members to engage with value creating customer activities.		Rejected
Option 2: Business Operations	Reflecting the need to develop capabilities that enable both employees and customers to achieve their objectives will improve Vector's ability to provide quality services at an optimised price point. Further to this, investment in this area will enable Vector to improve its ability to communicate with customers through more effective management of customer accounts.	$16.2M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Business Operations	0.18	0.99	1.77	1.71	2.07	2.19	1.59	1.57	1.90	2.28	16.25
Total CAPEX	**0.18**	**0.99**	**1.77**	**1.71**	**2.07**	**2.19**	**1.59**	**1.57**	**1.90**	**2.28**	**16.25**

CUSTOMER OPERATIONS

NEEDS STATEMENT

Investment in the customer operations domain is focused on treating the experience we provide as a product; enabling the management, optimisation, and innovation of features to deliver exceptional customer experiences through improved transparency, customer choices and options to engage across the customer's journey – for example enhancing new connection processing, managing and communicating about outages and providing both reactive and proactive customer support.

We are using digital technology and platforms to improve the customer's experience by providing them with frictionless multi-channel, bi-directional and secure platforms for engagement with Vector and distribution of accurate, timely and relevant information surrounding network events, leading to a significantly reduced cost to serve and improved customer experiences.

Customer's expectations are rapidly changing and we are no longer being compared only to other Energy providers. Customers expect a similar level of personalised interaction and engagement with all service providers. In this new world, customer experience is the currency through which organisations will be successful, and therefore we must ensure we develop fit for purpose and best in class digital customer engagement services to meet demand.

Specific projects included in this investment category include extensions to our standard pricing agreements to simplify and improve connection times, enabling improved self-service for connections, disconnections and alterations and providing new channels for customers to engage for support, for example via webchat and pro-active SMS notifications. Alongside this, the expected investment in capability required over time is reflected in the outer years, where there is recognition that customers' expectations are changing and Vector's service mix must also change to meet them, and this will be enabled through enhanced customer support and self-service channels. There are also specific investments in initiatives aimed at changing customer behaviour and providing incentives to engage, such as Peak Time Rewards, a digital channel to enable Vector to undertake demand response type activity with direct customer engagement.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓			✓	✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Vector chooses to only respond reactively via existing channels. There is no ongoing investment in customer operations, and customer choice for service is limited to the call centre and basic online functionality. Customer expectations are not met or managed during significant storm or other network events, and Vector is unable to provide accurate, timely or relevant information to its customers.		Rejected
Option 2: Customer Operations	Through identifying high priority customer journeys, and developing multi-channel engagement capabilities Vector meets and manages customer expectations of service. During significant network events, Vector can provide relevant, timely and accurate updates to its customers and stakeholders. Customers can engage with Vector through self-service and digital channels, and be supported 24/7 across all interactions due to increasing digitisation and automation. This will also reduce the cost to serve and improve Vector's ability to respond.	$8.6M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Customer Operations	1.10	1.00	1.66	0.72	0.38	0.75	0.65	0.62	0.85	0.89	8.62
Total CAPEX	1.10	1.00	1.66	0.72	0.38	0.75	0.65	0.62	0.85	0.89	8.62

5.4 OTHER INFORMATION SYSTEM, PROCESS AND DATA INVESTMENTS

DATA MANAGEMENT & UTILISATION

NEEDS STATEMENT

The increasing volume of data that is being generated and captured across the entire network requires a significant re-think of how we capture, where we store, how we ensure data security and privacy, and how we best utilise and generate insights from this information. Today, there is a collection of legacy data storage and analytics platforms, with varied levels of maturity, development and maintenance across these platforms. This results in significant amounts of time required to compile and consolidate data from multiple different source systems, while also reducing the consistency and efficacy of the data that we have available. A further complication is the fact that the master data kept in these source systems is maintained and controlled in different functional business areas, for example employee master data in HR, financial records in Finance, Health and Safety in HSE etc, and as such have different levels of access, management and oversight.

The investment in data management is targeted at resolving this, through the implementation of a big data and analytics platform known as the 'Data Lake'. This platform will provide a single source of data to be served into any channel, and will significantly improve our ability to combine data from multiple different sources and present accurate and relevant insights from the data. For example, utilising asset performance data and weather data, we can create enhanced predictive models of where assets may fail and how we can better target our investments to increase resilience across the network. Machine Learning and advanced algorithms will enable us to improve our forecasting and modelling capability, and provide for improved transparency and prediction of the impact of changes to the network. This will further enable real time integration of customer facing channels and enablement of predictive and pro-active notifications of events, improving the customer experience for all Aucklanders.

The investment in data utilisation through development of dashboards and business intelligence, where relevant and timely information and analytics can be served to end users to improve decision making will increase our ability to meet changing Network demands and customer expectations. Today, the utilisation of insights is heavily dependent on specialist tools and techniques to gather and analyse the data, to enable Vector to better react to this changing environment, insight needs to be available to end user's through self-service access to relevant data, enabling improved decision making and reducing the time and friction required for business stakeholder's and customers to access the information they require.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
✓	✓	✓	✓	✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual – no additional investment	Vector will continue to utilise data and analytics in a structured fashion, however will not have capacity to develop advanced, predictive and pro-active analytics capabilities, or enhance self-service for end users of insights. This will directly impact our ability to optimise response in significant and BAU events, reduce the capability the organisation must make data driven		Rejected

	decisions and continue to place a heavy reliance on data specialists for insight generation		
Option 2: Data Management & Utilisation program	Invest in advanced, predictive and pro-active analytics tools, alongside development of advanced algorithms and methods. This will enable Vector to optimise response, provide insights to support decision making, proactively identify potential areas of weakness and continue to deliver services to Vector's customers.	$5.1M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Data Management and Utilisation	0.73	0.40	0.42	0.44	0.46	0.48	0.51	0.53	0.54	0.59	5.10
Total CAPEX	0.73	0.40	0.42	0.44	0.46	0.48	0.51	0.53	0.54	0.59	5.10

END USER COMPUTE & COLLABORATION

NEEDS STATEMENT

All businesses are now heavily reliant on end user computing and collaboration between parties. The ability to access the internet, send and receive emails, utilise word processing, data capture and note taking mechanisms on multiple devices is an expectation of all employees and stakeholders. Further, there is an increasing expectation on the ability of employees to collaborate, engage and share documents, content and collateral in a simple and easy to use fashion.

Today, we provide employees with laptop, desktop and some mobile devices, alongside supporting 'bring your own device (BYOD) using corporate identity management and security platforms. End user computing investment is focussed on ensuring the lifecycle of employee devices is actively managed, employees are equipped with devices that are fit for purpose, and all employees have access to the tools, systems and capabilities they need to complete their jobs.

The collaboration between employees is supported by Microsoft enterprise platforms, including SharePoint, and a significant amount of investment in collaboration will be made in this period to further enhance these capabilities, improve the security of devices and provide access to authenticated third parties for relevant information.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
				✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual	Run all end user devices through end of life and only replace essential items when they are failing. No investment in collaboration or access management will lead to sensitive information being improperly stored, transferred and distributed		Rejected
Option 2: End User compute & collaboration program	Continue to keep employee devices up to date across lifecycle. Provide secure, stable and easy to use collaboration capabilities. Increase penetration of BYOD devices alongside the increased security capabilities, providing employees with choices as to what they use and how, and reducing the overall demand on device management for the core IT functions.	$23.2M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
End user compute and collaboration	2.96	3.60	1.82	1.96	1.96	1.96	2.32	2.32	1.96	2.32	23.18
Total CAPEX	**2.96**	**3.60**	**1.82**	**1.96**	**1.96**	**1.96**	**2.32**	**2.32**	**1.96**	**2.32**	**23.18**

CYBER SECURITY

NEEDS STATEMENT

The increasing prevalence of connected devices, connected networks and consumer engagement is also rapidly increasing the threat profile for cyber security. Vector is heavily invested in a program of work focussed on improving our cyber security posture, and reflects security by design in everything we do. This investment category is primarily focussed on providing increased mobile device threat detection, and refreshing and upgrading all core cyber security capabilities to deliver against this increased threat profile.

The nature of connected networks means Vector must continue to focus investment in cyber security over time, and implement regular updates, upgrades and ongoing optimisation of the security capabilities of the organisation to ensure we continue to deliver safe, secure and reliable connected services. We have partnered with leading cyber-security and threat response researchers and are proud to take a leading position in implementing security and delivering highly secure services to its customers. Alongside this, we are developing and implementing new privacy by design measures in all customer facing tools, systems and capabilities, and these further improve our ability to deliver safe and reliable services.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
					✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: Business as usual	Investment in cyber security is reactive and based on point solutions. Applications are run through end of life and minimum-security standards are met. Minimum security and privacy obligations are met, however there is no ongoing investment in capability to ensure all services are always delivered securely and safely to customers		Rejected
Option 2: Cyber Security	Continuous upgrade cycle of core assets associated with cyber security, including replacement of firewalls, replacement and optimisation of mobile device tracking and ongoing investment in security review, audit and penetration testing. Privacy and Security by design principles are embedded in all work completed.	$7.6M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Cyber Security	1.53	1.03	0.96	0.54	0.54	0.68	0.54	0.54	0.68	0.54	7.58
Total CAPEX	**1.53**	**1.03**	**0.96**	**0.54**	**0.54**	**0.68**	**0.54**	**0.54**	**0.68**	**0.54**	**7.58**

APPLICATION LIFECYCLE MANAGEMENT

NEEDS STATEMENT

Vector has multiple core technology applications, all of which require ongoing upgrade, minor works and refreshment over their lifecycle. This investment category is associated with the ongoing lifecycle management of our core digital assets, throughout the 'Buy, Build, Run, Maintain, End of Life' lifecycle. In order to deliver effective and efficient services to our customers, we must maintain a baseline level of investment in running our digital applications, and other minor system upgrades and enhancements. These investments ensure the digital applications are up to date and maintained, minor enhancement to meet business needs can be made, and ongoing upgrade and lifecycle management can be completed.

There are significant upgrades required to core application such as Siebel and SAP, to bring them in line with the latest versions, ensure ongoing maintainability and vendor support, and improve business functions and capabilities.

Further examples include upgrading our risk and incident management software to the latest version, enhancing our ability to manage records and contracts, while improving the traceability and auditability of commercial and operational agreements relating to the management of our assets and network. The management of the lifecycle of digital assets is critical to ensuring the ongoing effectiveness and security of Vector's core applications, their ability to meet customer needs and continue to deliver to our internal stakeholders.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
	✓			✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: No application lifecycle management – only respond to end of life	Applications will be managed until they reach end of life, they will then be decommissioned and replaced with like for lie capabilities. This will result in significantly increased capital cost over time, and a reduced ability for Vector to meet changing business and customer needs, enhance existing applications and actively manage the application lifecycle.		Rejected
Option 2: Application Lifecycle management in place	All assets are managed through the application lifecycle. Upgrades and enhancements are made to simplify and extend asset life, optimise ongoing investment and improve security posture. Minor enhancements and major upgrades can be made to core applications to improve their effectiveness, enable new capabilities and meet changing business and customer needs.	$30.8M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Application lifecycle management	3.37	3.04	3.32	2.16	2.91	3.90	3.37	3.11	2.77	2.86	30.81
Total CAPEX	**3.37**	**3.04**	**3.32**	**2.16**	**2.91**	**3.90**	**3.37**	**3.11**	**2.77**	**2.86**	**30.81**

INFRASTRUCTURE LIFECYCLE MANAGEMENT

NEEDS STATEMENT

The multiple enabling capabilities utilised to deliver digital services are all supported by underlying digital infrastructure, including that for automated testing, server and data-centre, monitoring, deployment pipelines and network switching, routing and management infrastructure. All of this infrastructure requires ongoing optimisation, attention and management throughout its lifecycle, to ensure the original investment is optimised, the infrastructure remains fit for purpose, supportable and secure.

TARGETED OUTCOMES

CUSTOMER EXPERIENCE	SAFETY	RELIABILITY	RESILIENCE	OPERATIONAL EFFICIENCY	CYBER SECURITY AND PRIVACY
				✓	✓

OPTIONS CONSIDERED

Options to address the need identified above have been assessed and are summarised in the following table.

DESCRIPTION	DISCUSSION OF OPTION	ESTIMATED COST (NPV IF APPLICABLE)	STATUS
Option 1: No infrastructure lifecycle management	Core supporting digital infrastructure is maintained on a 'break fix' basis, where only broken components are fixed and maintained as necessary. This leads to significant downtime and regular failure of core applications supported by this infrastructure		Rejected
Option 2: Infrastructure lifecycle management	A program of regular lifecycle refresh, upgrade and enhancement is maintained on all core infrastructure. Patching, standards and definitions are maintained and kept up to date, and all core technology is supported on a pro-active and monitored basis	$16.1M	Selected

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Infrastructure lifecycle management	0.54	0.64	0.71	1.18	1.71	3.21	1.93	2.07	2.07	2.07	16.13
Total CAPEX	0.54	0.64	0.71	1.18	1.71	3.21	1.93	2.07	2.07	2.07	16.13

5.5 NON-NETWORK OPEX

Non-network OPEX provides the support services required to ensure the network business can operate as an effective, well-governed business. The networks business benefits from economies of scale with Vector providing shared support services across its group of regulated and non-regulated businesses. Support services include health and safety, finance, legal, human resources, digital and risk management.

PROPOSED INVESTMENT SUMMARY ($MILLION NOMINAL)

DESCRIPTION	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
System operations and network support	40.82	40.42	41.10	41.59	42.27	42.69	42.72	42.73	42.74	42.61	419.69
Business Support	36.26	36.27	36.26	36.27	36.26	36.27	36.26	36.276	36.26	36.26	362.65
Total CAPEX	77.08	76.69	77.36	77.86	78.53	78.96	78.98	79.01	79.00	78.87	782.34

DELIVERING OUR PLAN

SECTION 06.

SECTION 6. DELIVERING OUR PLAN

This section of the AMP outlines how we develop an optimal portfolio of works so as to improve service levels and deliver on our strategic outcomes. These works are based on the plans set out in Section 5. We summarise our approach to project prioritisation and optimisation of investment and resourcing. The forecasted capital and operational expenditure (CAPEX and OPEX) needed to deliver on our asset management plans for our electricity network, for the 2020-2029 period, is included.

6.1 PRIORITISING OUR WORKS PORTFOLIO

The key objectives that guide how we manage our assets relate to safety, reliability, resilience, cyber security and privacy, customer service and operational efficiency – see our asset management policy in Section 4. How we perform against these objectives is captured by our service-level metrics (see Section 2). These objectives also align with Vector's vision and its mission to create a new energy future (see Section 1).

The process of prioritising our portfolio of works aims to ensure the investment needed to meet both our key network objectives and service levels targets is efficient and results in the greatest long-term benefit to our customers. This is also an important step in achieving best industry practice in asset management, as prescribed by the standard, ISO 55000:2014 Asset management - Overview, principles and terminology.

The process for deciding on our investment proposals is summarised below:

1. Project proposals: Once a project need has been identified, project proposals are created. These describe the project need, show the options considered and detail the preferred option. Project proposals are prepared by Vector's subject matter experts, and these also consider the business value of each project.

   For network infrastructure projects, the value (both from a business and customer perspective) is usually expressed in terms of improvements to service-level metrics or risk mitigation – for example, how the project prevents a possible negative impact affecting our asset management objectives. A network-specific risk assessment matrix that is aligned with our enterprise risk management framework is used to assign a risk score against each project. This score signals the relative business value of proposed new projects.

2. Preliminary investment plans: Once the business value of a project proposal has been assessed, these are then peer-reviewed, to ensure consistency, before being incorporated into preliminary infrastructure and digital investment plans. As part of developing these initial plans, our projects are staggered, so a realistic volume of work can be undertaken in each year. This is based on resource availability and specialist capability requirements. Any synergies and interdependencies between projects are also highlighted and incorporated into the plans.

3. Portfolio prioritisation: A ranking approach is used for our early-stage investment plans to consolidate and prioritise them for delivery. The ranking considers key business objectives, including safety, network performance and customer experience. It also acknowledges the non-discretionary nature of certain projects (see below).

   Under this prioritisation model, a project's contribution to achieving each of the following outcomes (listed in no particular order) is assessed and rated:

   - Net financial benefit
   - Customer experience
   - Safety
   - Reliability
   - Resilience
   - Operational efficiency
   - Cyber security and privacy

Ratings don't represent the total value of each project to the network. Instead, they are based on the relative benefit and merit of each project compared with all other projects.

The ratings assigned for each target outcome for an individual project are then aggregated, with the relative importance of each outcome being set using a scalar multiplier/weighting. The resulting score allows each project to be ranked and prioritised.

A further overlay is applied during the project-ranking process that considers key business drivers. This allows for the identification and appropriate prioritisation of projects that are:

1. Non-discretionary – projects that help us meet legal, regulatory or safety requirements (key driver)
2. Enablers – foundation projects needed before other projects can be implemented (key driver)
3. Strategic – projects that help Vector realise its long-term strategy (secondary driver)
4. R&D – projects that fall under a trial or are part of our research and development programme (secondary driver)

The ranking process is done on an unconstrained basis, assuming no spending or resource constraints, but provides guidance to the relative importance of different projects. Subject-matter experts participate throughout the project prioritisation process, to ensure the resulting evaluation is credible and tested, and aligns with industry knowledge and experience, which may not be captured by the qualitative inputs included in the modelling process.

4. Draft investment plan: Once projects have been through the portfolio prioritisation process, the draft investment plan is formed, with financial and capacity constraints applied. Different scenarios based on the level of constraint is considered to balance the multiple business objectives. This plan is then reviewed and approved by the executive management team. The risk associated with projects that have not formed part of the draft investment plan following prioritisation is highlighted and acknowledged.

5. Final Investment Plan: Following consideration and approval by the executive management team, the final investment plan is reviewed and approved by the Board.

6.2 OUR RESOURCE REQUIREMENTS AND CONSTRAINTS

To address the challenge of meeting the power infrastructure requirements of a growing Auckland, we have a panel of Specialist Contractors who compete for the opportunity to deliver the programmes of work. The addition of new specialist contractors gives Vector access to additional skilled resources and supports delivery of the programme of works. To assist with the management of the panel's resources, we have monthly meetings where we guide our contractors and present our forthcoming programme of work. Our contractors know what work is coming up for the next 18 months, and we expect them to manage their resources to meet our delivery requirements. The size of our contractor panel grows and shrinks to meet anticipated workloads and to accommodate contractors' resource constraints.

We use a modified version of the NZ3910 building and engineering standard contract when we engage a specialist electrical contractor from the panel to be a head contractor. However, depending on the value and complexity of the civil engineering part of a job, we may engage a civil contractor or other specialist contractor using the standard NZ3910 contract.

We also engage consultants to help with managing internal workloads, specialist design or other services. This allows us to maintain our schedules without the cost of directly employing extra resources, so we can meet peak workloads or access specialist resources to meet specific project requirements.

We are currently reviewing our field services delivery models. As part of this review, we are evaluating a performance framework to enhance Vector's ability to respond to challenges such as the impact of Auckland Growth and the implementation of our New Health and Safety Policies on fault restoration times, the resource challenges we are facing given the high demand for electrically qualifies workers across NZ and the cost of living in Auckland and the changing expectations of our customers.

The Vector Digital Group manages technology infrastructure and operational resource requirements to enable the asset management strategy, using a multi-speed delivery model when it comes to development and technology delivery.

The stated platform-centric approach enables standardisation, scalability and synergy of our technical architecture. It also makes the best use of the skills needed to both develop and support technology in several areas, including customer engagement, business enablement, network integration and systems of intelligence. It allows us to in-source strategic core capability, through simpler resourcing, and makes outsourcing more manageable – we can outsource non-core system and software development to our vendor panel using standardised tools and processes.

6.3 DELIVERING OUR PROJECTS

A Project Delivery Framework (PDF) based on industry best practice is used throughout our projects and programmes of work – this includes the Project Management Institute's Project Management Body of Knowledge (PMBoK).

The PDF lays out the standard procedures and processes project managers must comply with – for example, safety in design and standard contract templates. It focuses on core corporate obligations associated with health and safety, the environment, and time, cost and quality. This is done through close alignment with our corporate policies.

The PDF has seven distinct phases, and these are associated with the project delivery lifecycle – this includes pipeline, concept, procurement, development, construction, test and commission, and project closure. In addition, the PDF provides our project managers with the templates, guidelines and tools relevant to each of these phases.

Inception of a project usually follows three distinct stages:

a. Initially, a project is defined in the Asset Management Plan
b. The project is then planned and a CAPEX justification (business case) is develop which includes a budget estimate. It is then submitted for approval
c. Following approval, a 'project scope' is created where the project is then handed over to a Vector project manager for development and delivery

The 2019 AMP summarises the high-level plan for technology solutions in support of the asset management objectives and related operations.

Our digital delivery framework enables a scalable, multi-speed delivery approach structured to deliver varying programmes of work and is based on industry best practice. The framework provides standard processes, procedures and tools designed to ensure the stated benefits and objectives of the asset management process are realised. Security, privacy, user experience, architecture, quality, operations and support are all taken into account. This ensures 'diligence' and alignment with Vector's strategic objectives from inception through to planning and delivery – and that benefits to both the business and technology operations are realised. It also acknowledges – and compensates for, the uncertainty inherent in complex system development by selecting the appropriate delivery methodology (this depends on the outcome planned) and there is a strong focus on delivering small increments of value frequently. This is done in close collaboration with our subject matter experts.

6.4 INVESTMENT PLAN

Through the adoption of the Symphony model (described in Section 1), we are taking an active view to network planning to ensure we appropriately respond to system growth and the changing demands of our customers, while meeting our targeted outcomes. Our investment plans consider and provide flexibility to accommodate future network needs, taking account of new types of generation, new technology capabilities and the ever-changing preferences of customers. However, this means that existing spend trends no longer serve as an effective indicator of future expenditure, with historic investment levels not reflective of the changing operating environment and the increasing pace of change which the network needs to respond to.

This section describes the CAPEX and OPEX forecasts for the electricity distribution network assets for the next 10-year planning period based on the capital investment proposals outlined in Section 5. It provides a comparison with the 10-year forecast included the 2018 AMP (disclosed in March 2018), highlighting how our investment plan has evolved over the last year to both grow and improve the network to meet Auckland's needs

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 2020 dollars (note: Section 5 figures are in 2019 dollars). The regulatory disclosure forecast, shown in Appendix 6 and Appendix 7, are presented in regulatory year (RY) 1 April to 31 March, in both constant and nominal dollars, as per the Information Disclosure requirements.

CAPEX FORECAST

The forecast CAPEX during the next 10-year planning period, broken down into the asset categories defined in the Commerce Commission's Electricity Distribution Information Disclosure Amendments Determination 2012 is shown in Table 6-1.

FINANCIAL YEAR ($000)

AMP19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Customer connection	73,201	72,656	61,623	59,169	55,776	54,008	54,008	52,156	49,129	49,129	580,855
System growth	51,167	42,660	31,149	36,325	34,556	28,882	39,654	34,563	37,247	33,427	369,630
Asset replacement and renewal	104,588	99,464	101,474	99,230	94,162	89,396	90,656	97,111	92,200	94,321	962,602
Asset relocations	33,228	43,406	51,765	44,880	41,871	28,560	23,460	23,460	23,460	23,460	337,550
Reliability, safety and environment:	24,847	25,153	29,121	33,813	32,732	33,507	37,077	36,567	36,567	39,285	328,669
Quality of supply	0	0	0	0	0	0	0	0	0	0	0
Legislative and regulatory	0	0	0	0	0	0	0	0	0	0	0
Other reliability, safety and environment	24,847	25,153	29,121	33,813	32,732	33,507	37,077	36,567	36,567	39,285	328,669
Non network asset	30,913	27,231	24,313	19,785	17,275	18,135	33,007	15,471	14,687	15,262	216,079
Total CAPEX	317,945	310,571	299,444	293,202	276,372	252,487	277,862	259,328	253,290	254,885	2,795,386

Table 6-1 2019 Forecast CAPEX

A limited re-categorisation of projects has occurred where some projects previously categorised System growth or Asset replacement and renewal have been moved to the Other reliability, safety and environment category. These projects have been identified as directly addressing network reliability and the new categorisation is considered their key driver. This re-categorisation has a twofold impact on the 2019 AMP as follows:

- reallocating $161m of projects that were in the 2018 AMP categorised as System growth ($38m) and Asset replacement and renewal ($123m); and
- allocating new projects (totalling $109m) to the Other reliability, safety and environment category that in previous years, would have been allocated to System growth or Asset replacement and renewal.

Figure 6-1 shows the difference between the 2018 and 2019 AMP expenditure forecasts year on year, with Table 6-2 breaking down the variance by expenditure categories. It highlights the projected uplift in expenditure per asset category, in particular in asset relocation, reliability, safety and environment and non-network, relative to the 2018 forecast (based on the 9-year period that the two forecasts overlap). This additional spend stems principally from significant new projects whose network implications have become clearer over the last year (particularly Auckland Light Rail), digital enablement to support targeted outcomes, and proactive management and replacement of assets to improve network reliability and address quality standards

Note for comparative purposes, the CAPEX forecast disclosed in the 2018 AMP has been escalated to 2020 prices using an inflator of 2.0%.

AMP MOVEMENT 2019 V 2018

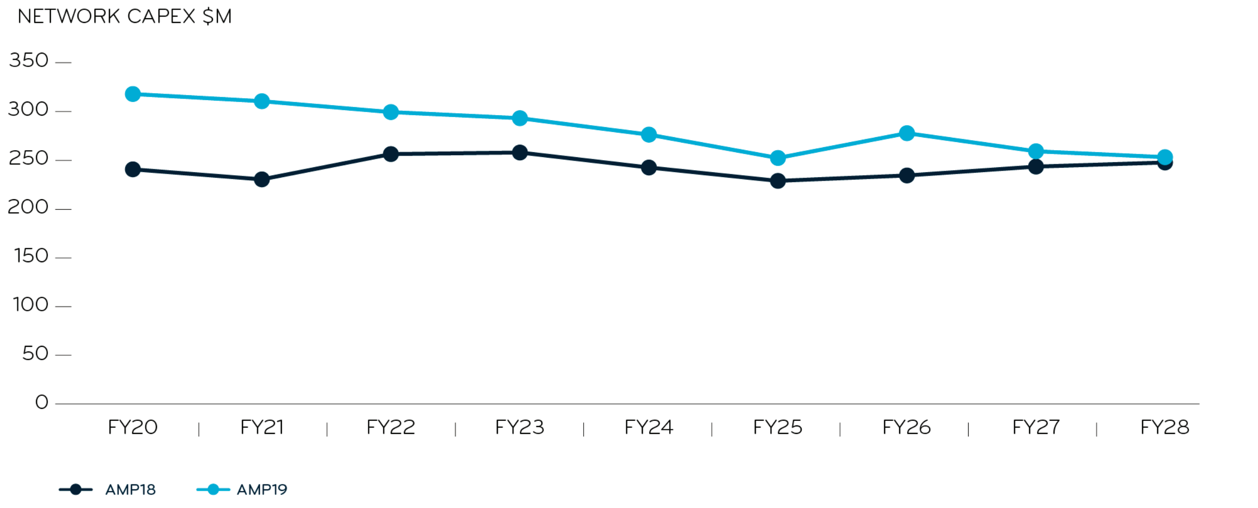

Figure 6-1 CAPEX AMP movement 2018 v 2019 by year

FINANCIAL YEAR ($000)

AMP19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	TOTAL
Customer connection	6,127	8,622	(1,342)	(87)	(2,459)	(4,227)	(569)	(2,379)	(5,405)	(1,719)
System growth	9,118	9,434	(14,945)	(17,718)	(4,023)	(7,507)	(7,762)	(20,784)	(23,711)	(77,898)
Asset replacement and renewal	5,812	4,085	(7,330)	(6,237)	(14,016)	(11,793)	(9,758)	(5,920)	(9,631)	(54,788)
Asset relocations	15,250	25,243	33,682	26,969	24,113	10,710	5,610	5,610	5,610	152,797
Reliability, safety and environment:	22,348	23,062	27,030	31,518	31,422	32,436	36,006	35,496	35,496	274,814
Quality of supply	0	0	0	0	0	0	0	0	0	0
Legislative and regulatory	0	0	0	0	0	0	0	0	0	0
Other reliability, safety and environment	22,348	23,062	27,030	31,518	31,422	32,436	36,006	35,496	35,496	274,814
Non network asset	18,454	9,552	5,892	687	(1,390)	3,836	19,757	3,666	3,080	63,535
Total CAPEX	**77,109**	**79,998**	**42,987**	**35,133**	**33,647**	**23,455**	**43,285**	**15,689**	**5,439**	**356,741**

Table 6-2 2018/2019 CAPEX variance

EXPLANATION OF MAJOR CAPEX VARIANCES

Key changes in **Network** CAPEX over the 9-year period for which the 2018 AMP and 2019 AMP overlap are as follows:

- A reduction of $78m in system growth expenditure forecast is partially due to the slower demand growth under the Symphony scenario. This has deferred the construction of a number of greenfield substations and distribution network feeder reinforcement that were identified under last year's forecast. This is, in part, achieved through investment in demand control devices (Telensa HWLC, EV charging control) to enable time-based load-shifting rather than investment in primary assets. Alignment of reliability and resilience initiatives including distribution feeders meshing and battery-powered micro-grid solutions to Reliability, Safety and Environment (see below) category also contributes to the reduction in this expenditure forecast;

- A decrease of $55m in asset replacement and renewal expenditure resulted from re-categorisation of the proactive overhead conductor replacement programme and protection upgrades programme to Reliability, Safety and Environment (see below), that is partly offset by the provision for the Right of Way poles replacement programme and new proactive 11kV cable replacement programme. Adjusting for the re-categorisation impact, expenditure in this category would have increased $68m relative to the 2018 AMP. A reduction in replacement capex expected from the removal of Albany-Wairau 110kV line ($6m), contingent on Transpower's decision on the HEN-ALB 110kV removal, is also incorporated in the forecast;
- A $153m increase in relocation forecast results from the provision for the Auckland Light Rail Project ($85m), the SH16 Safe Road project ($20m) and an increase in undergrounding of overhead lines;
- The increase in reliability ($109m post re-categorisation) stems from initiatives to improve network reliability including:
  - Proactive replacement programmes of 11kV overhead conductors and distribution transformers to improve the increasing trend of faults associated with this aging asset population;
  - Upgrading of copper pilot wire subtransmission protection and zone substation electromechanical/static protection systems to provide supervision and analytic functionality on faults and enable timely response and remedial actions;
  - Increase in 11kV feeder isolation points to reduce the number of customers impacted in a fault, and installation of isolation remote controls to enable faster restoration of supply during an outage;
  - Meshing of distribution feeders and battery-powered micro-grid solutions where appropriate to the remote part of the network to improve reliability and resilience of supply; and
  - A consolidated area fault reduction programme that undertakes the reactive repair and maintenance in a cohesive approach to targeted areas where there has been a high number outages experienced by the customers;

Key changes in **Non-network** CAPEX over the 9-year period for which the current and prior year AMP overlap stem from:

- The rapid evolution of new network technology and the changing demands of both our stakeholders and customers which is reflected in an uplift in technology-related CAPEX of $30m. This is due to an increased focus on both:
  - Digital enablement of networks outcomes. Specific examples include further investment in Vegetation Management and Outage Prediction; DERMS; LV network visibility for optimised network operation and maintenance and construction; customer operation enhancements; full integration of Field Service Providers; enhancement of operational capability through OMS/DMS; and enhanced ability to manage connected network devices, such as controllable EV Chargers
  - Cyber security, data analytics, IT network modernisation, and lifecycle management of core applications and infrastructure in the later years. Examples of this work include upgrades to core enabling systems (e.g.: Siebel); integration of core technology (e.g. Gentrack/Siebel); and cyber security (e.g.: Web firewall protection)
- An increase in property capex ($33m) related to refurbishment costs and improvements and accounting treatments from the IFRS 16 lease treatment change

OPEX FORECAST

The OPEX forecast for the electricity distribution network assets for the next 10-year planning period, broken down into the asset categories defined in the Electricity Distribution Information Disclosure Amendments Determination 2012, is shown in Table 6-3.

FINANCIAL YEAR ($000)

AMP19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	TOTAL
Service interruptions and emergencies	14,298	13,923	14,051	14,181	14,313	14,444	14,577	14,705	14,843	14,972	144,307
Vegetation management	7,791	8,396	8,498	8,602	8,707	8,814	7,307	7,396	7,487	7,578	80,576
Routine and corrective maintenance and inspection	16,956	17,770	17,992	19,118	23,388	23,579	18,591	18,544	18,633	18,770	193,341
Asset replacement and renewal	13,010	13,812	13,952	14,094	14,237	14,193	14,031	14,174	14,318	14,463	140,284
System operations and network support	42,001	41,590	42,291	42,798	43,496	43,923	43,956	43,967	43,975	43,837	431,834
Business support	37,315	37,315	37,315	37,315	37,315	37,315	37,315	37,315	37,315	37,315	373,150
Total OPEX	**131,371**	**132,806**	**134,099**	**136,108**	**141,456**	**142,268**	**135,777**	**136,101**	**136,571**	**136,935**	**1,363,492**

Table 6-3 2019 forecast OPEX

Figure 6-2 shows the difference between the 2018 and 2019 AMP expenditure forecasts year on year, with Table 6-4 breaking down the variance by expenditure categories.

Note for comparative purposes, the OPEX forecast disclosed in the 2018 AMP has been escalated to 2020 prices using an inflation factor of 2.89%.

AMP MOVEMENT 2018 V 2019

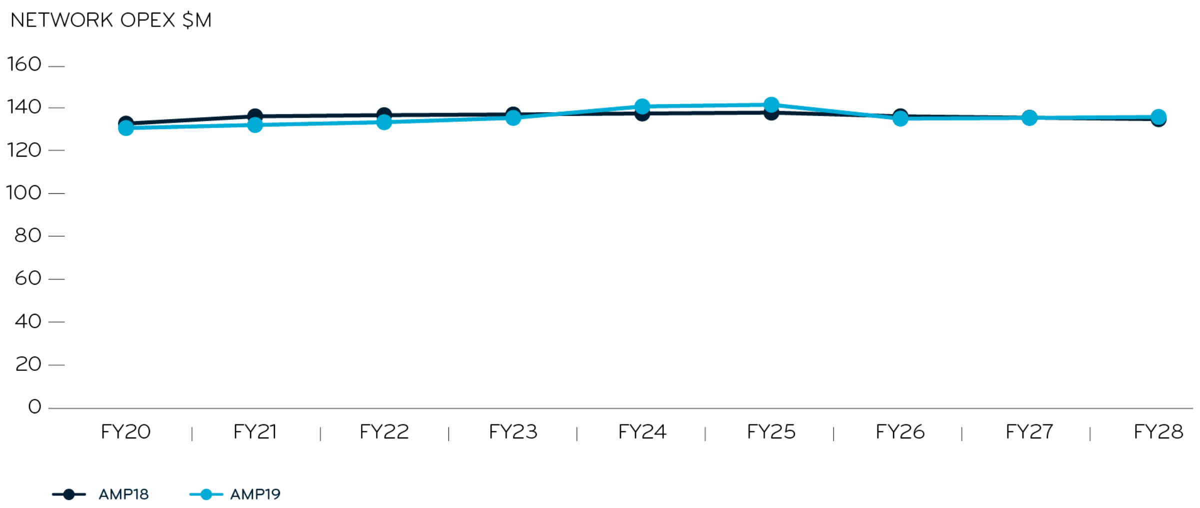

Figure 6-2 OPEX AMP movement 2018 v 2019 by year

FINANCIAL YEAR ($000)

AMP19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	TOTAL
Service interruptions and emergencies	971	77	111	146	183	218	254	284	324	2,568
Vegetation management	1,079	2,537	2,639	2,743	2,848	2,955	1,448	1,537	1,628	19,414
Routine and corrective maintenance and inspection	736	1,189	1,262	2,237	6,357	6,397	1,258	1,059	987	21,482
Asset replacement and renewal	(2,796)	(6,530)	(6,476)	(6,421)	(6,365)	(6,497)	(4,616)	(3,485)	(2,347)	(45,533)
System operations and network support	3,062	3,814	4,285	4,791	5,390	5,738	5,692	5,623	5,572	43,967
Business support	(5,119)	(5,119)	(5,119)	(5,119)	(5,119)	(5,119)	(5,119)	(5,119)	(5,119)	(46,071)
Total OPEX	**(2,067)**	**(4,032)**	**(3,298)**	**(1,623)**	**3,294**	**3,692**	**(1,083)**	**(101)**	**1,045**	**(4,173)**

Table 6-4 2018/2019 OPEX variance

EXPLANATION OF MAJOR OPEX VARIANCES

Variances in **Network** OPEX over the 9-year period for which the 2018 AMP and 2019 AMP overlap, reflect the following key changes:

- An increase of $3m in Service Interruption and Emergencies expenditure is largely attributed to an increase in contractor exceptional remedial expenditure to allow for more frequent severe weather events and additional resource forecast to target reduction in response time to faults. This is partially offset by a higher percentage of capitalisation of Service Interruptions and Emergencies expenditure assumed
- An increase of $19m in Vegetation Management to address the increasing trend of fault rates relating to vegetation. The expenditure would be prioritised incorporating the results from LiDAR survey and target areas to improve network performance and customer interruptions caused by vegetation faults. The increase in cost also reflects our strategy of removing trees that pose a high risk to Vector's overhead network, as opposed to trimming them, for a longer term benefit and cost efficiency. Increases in compliance costs such as traffic management exhibited in the past few years also contributes to a higher expected average cost per job
- An increase of $21m in Routine and Corrective Maintenance is driven by provision for expenditure associated with the removal of Albany-Wairau 110kV line, improvement in the inspection programme on submarine cables, power transformer testing and omniruptor servicing, addition of a new planned maintenance programme developed for ROW poles and electric vehicle chargers, and a reallocation of expenditure from Asset Replacement and Renewal to Routine and Corrective Maintenance to align with the categorisation of network quality improvement initiatives
- An overall reduction of $45m in Asset Replacement and Renewal as a result of the reallocation of resources to Routine and Corrective Maintenance to align with the categorisation of network quality improvement initiatives, as well as a higher number of Asset Replacement and Renewal works that are accounted for under CAPEX rather than OPEX

Variances in **Non-network** OPEX over the 9-year period for which the current and prior year AMP overlap, reflect the following key changes:

- A forecast increase in systems operations and network support expenditure of $44m higher as a result of:
  - New expenditure to purchase customer meter data ($34m) to assist with outage management through LV visibility. Data will also be used to assist in network planning
  - New expenditure to establish an outage management team to handle work that will be transferred from the Field Service Providers (FSP) to Vector and additional resources in the data analytics team to do the analytics of the purchased data
  - New communication costs related to electric vehicle chargers. This expenditure is part of our strategy to manage the demand growth related to EV chargers as per the Symphony scenario.

The above increases are partially offset by the reduction in property lease cost due to the new accounting treatment of leases under IFRS 16.

- A forecast decrease in Business Support expenditure of $46m, mainly due to:
  - A change to the shared cost allocator reducing the allocated corporate cost by circa $52m (the allocator changed from Property, Plant and Equipment used in the prior year AMP to the allocator calculated for the Gas Information Disclosure); and
  - A reduction in property lease cost due to the new accounting treatment of leases under IFRS 16.

  The above reductions were partially offset by increases in expenditure related to cyber security, sustainability and people safety and risk initiatives.

APPENDICES

SECTION 07.

Appendix 1 Glossary of Terms

A	Ampere
AAC	All aluminium conductor
AAAC	All aluminium alloy conductor
ABC	Aerial bundled cable
AC	Alternating current
ACSR	Aluminium conductor steel reinforced
AMMAT	Asset management maturity assessment tool
AMP	Asset management plan
API	Application programming interfaces
ARM	Active risk manager
AUFLS	Automatic under frequency load shedding
AV	Autonomous vehicle
BEP	Business engagement platform
BESS	Battery energy storage system
CaaS	Car-as-a-service
CAIDI	Customer average interruption duration index
CAPEX	Capital expenditure
CB	Circuit breaker
CBD	Central business district
CBF	Circuit breaker fail
CBARM	Condition based asset risk management
CDEM	Civil Defence and Emergency Management
CEP	Customer engagement platform
CNO	Chief networks officer
CRM	Customer relationship management
DAF	Delegated authorities framework
DC	Direct current
DER	Distributed energy resource
DERMS	Distributed energy resource management system
DFA	Delegated financial authority policy
DG	Distributed generation
DPP	Electricity distribution services default price-quality price path determination 2015
EMF	Electromagnetic field
ENA	Electricity Network Association
EOC	Electricity operations centre
ERP	Enterprise resource planning
EV	Electric vehicle
FMEA	Failure mode and effects analysis
FSM	Field service management
FSP	Field service provider
FY	Vector financial year (year ending 30th June)
GCE	Group chief executive

GXP	Grid exit point: A facility owned by Transpower that directly connects the Vector network to the national grid. A GXP may contain more than one supply bus (of same or different voltages).
GWh	Gigawatt hours
HSWA	Health and safety at work act
HILP	High impact low probability
HV	High voltage: a nominal AC voltage of 1000 volts and more
ICP	Installation control point
IEC	International electrotechnical commission
IED	Intelligent electronic data and/or devices
IP	Internet protocol
IoT	Internet of things
ISO55001	International standard for asset management
IT	Information technology
km	Kilometre
kV	Kilovolt
kVA	Kilovolt ampere
kW	Kilowatt
kWh	Kilowatt hour
LAN	Local area network
LED	Light-emitting diode
LiDAR	Light Detection and Ranging
LV	Low voltage – a nominal AC voltage of less than 1000 volts
MBIE	Ministry of business, innovation and employment
MUSA	Multi utility service agreement
MVA	Megavolt ampere
MW	Megawatt
NZX	New Zealand stock exchange
OPEX	Operational expenditure
OT	Operational technology platform
PDF	Project delivery framework
PILC	Paper insulated lead cable
PLC	Programmable logic controller
PQM	Power quality monitor
PV	Photovoltaic
PVC	Polyvinyl chloride
RAB	Regulatory asset base
RIMS	Risk and incident management system
RMU	Ring main unit
RTU	Remote terminal unit
RY	Regulatory year (year ending 31st March)
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAP	Enterprise Resource Planning (ERP) System (SAP)
SCADA	Supervisory Control and Data Acquisition system
SF6	Sulphur hexafluoride

SH	State Highway
SoSS	Security of Supply Standard
TMS	Transformer management system
V	Volts
V2G	Vehicle-to-grid
VHF	Very high frequency
WAN	Wide area network
XLPE	Cross-linked polyethylene

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).
Distribution substation	A substation for transforming electricity from distribution voltage (22 kV or 11 kV) to 400V distribution voltage.
Micro grid	Parts of the distribution network that can be isolated and operated in an island state under contingency situations
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.
N-x security	Subtransmission security class rating.
Reliability	The ability of the network to deliver electricity consistently when demanded.
Resilience	The ability of the network to recover quickly and effectively from an event.
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.
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.
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).

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	Not applicable
Technical Specifications	ENS-0099 General technical requirements
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	1XX SUBTRANSMISSION SWITCHGEAR
Strategies	EAA101 Subtransmission 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
Engineering Standards	ESE101 Primary Indoor Switchgear ESE102 Instrument Transformers Indoor ESE103 33 kV Switchyard Renewal and Extension Design Criteria

ASSET CLASS	2XX POWER TRANSFORMERS
Strategies	EAA201 Power Transformers
Technical Specifications	ENS-0124 Specification for 110 kV-22 kV two-winding power transformers ENS-0149 Specification for neutral earthing resistors
Maintenance Standards	ESM201 Maintenance of Transformers 22-110 kV Power Transformers in Zone Substation
Engineering Standards	ESE201 Power Transformers Zone Substations

ASSET CLASS	3XX HV CABLES
Strategies	EAA301 Underground Cables
Technical Specifications	ENS-0032 Specification for SC-triplex 22-33 kV cable ENS-0110 Thermal backfill for underground cables ENS-0191 Specification for single core 110 kV cable
Maintenance Standards	ESM301 HV Cables
Engineering Standards	ESE302 Sub transmission and distribution cables ESE303 Installation requirements for cables and ducts

ASSET CLASS	4XX OVERHEAD LINES
Strategies	EAA401 Overhead Lines EAA402 Vegetation Management
Technical Specifications	ENS-0094 Specification for prestressed concrete utility services poles ENS-0091 Specification for treated timber utility services poles ENS-0100 Specification for hardwood crossarms ENS-0153 Specification for overhead conductors ENS-0159 Specification for galvanised steel fittings for overhead construction ENS-0160 Specification for LV ABC fittings ENS-0163 Specification for overhead line connectors ENS-0109 Specification for helical fittings and accessories ENS-0084 Specification for pole mounted fuse carriers and links ENS-0088 Specification for overhead insulators ENS-0112 Specification for hazard marking for poles
Maintenance Standards	ESM401 Maintenance of Overhead Lines
Engineering Standards	ESE401 Overhead Line Design Requirements ESE402 Overhead Standard Design Applications ESE406 Overhead Standard Application Structures with Streetlights ESE413 Aerial Fibre Cables Installation ENS-0057 Pole Inspection and Replacement

ASSET CLASS	5XX DISTRIBUTION NETWORK
Strategies	EAA501 Distribution Network
Technical Specifications	ENS-0103 Specification for 11 kV and 22 kV distribution switchgear ENS-0154 Specification for LV distribution service pits ENS-0127 Specification for 11 and 22 kV underground distribution cable ENS-0162 Specification for fault passage indicators ENS-0121 Specification for auto-reclosers ENS-0097 Specification for pole mounted SF_6 switches ENS-0098 Specification for sectionalisers and remote switches ENS-0101 Specification for surge arrestors ENS-0079 Specification for ducting of insulating material ENS-0078 Specification for 400V underground cable ENS-0090 Specification for oil filled distribution switchgear ENS-0093 Specification for fluid filled distribution transformers ENS-0102 Specification for polymeric cable protection covers
Maintenance Standards	ESM501 Maintenance of Overhead Switchgear ESM502 Maintenance of Pole Mounted Distribution Transformers ESM503 Maintenance of Ground Mounted Distribution Equipment and Voltage Regulators ESM505 Maintenance of LV Distribution Systems
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 ESE301 Cable Support Systems in Enclosed Basements ENS-0028 Testing of High Voltage Cables and Switchgear

ASSET CLASS	6XX AUXILIARY SYSTEMS
Strategies	EAA601 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 ESM607 Maintenance of Earthing System
Engineering Standards	ESE601 DC Systems ESE602 AC Systems

ASSET CLASS	7XX INFRASTRUCTURE AND FACILITIES
Strategies	EAA701 Infrastructure and Facilities
Technical Specifications	ENS-0206 Specification for crushed rock in switchyards
Maintenance Standards	ESM701 Maintenance of Building, Structures and Facilities ESM708 Maintenance of Minor Tunnels ESM709 Maintenance of Penrose-Hobson Tunnel
Engineering Standards	ESE701 Zone Substation Buildings ESE702 Zone Substation Grounds ESE703 Zone Substation Building Services ESE704 Zone Substation Earthing ESE002 Zone substation signage

ASSET CLASS	8XX PROTECTION AND CONTROL
Strategies	EAA801 Protection Systems GXP and Zone Substations EAA802 Transformer Management Systems EAA803 Power Quality Metering EAA804 Communication Systems EAA805 Automation Systems EAA806 Related IT Systems EAA807 SCADA and SICAM PAS Systems
Technical Specifications	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 Design Zone Substations & Sub Transmission ESE802 Automation and Control Systems ESE803 Protection and Control for Overhead Distribution Feeders ESE805 Secondary Cabling ESE806 Protection standard for distribution substations ESE807 Protection Philosophy Subtransmission Zone Substations ESE810 Testing and Commissioning of Protection Relays ENS-4002 Protection and Control – Protection Settings Management

ASSET CLASS	9XX NEW ENERGY SOLUTIONS
Strategies	EAA901 New Energy Solutions (Being developed – work in progress)
Technical Specifications	Being developed – work in progress
Maintenance Standards	ESM901 Maintenance of Battery Energy Storage Systems. ESM902 Maintenance of EV Charger ESM903 Maintenance of Residential Solar Energy Systems
Engineering Standards	Being developed – work in progress

HEALTH, SAFETY AND ENVIRONMENT KEY REQUIREMENTS
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

ELECTRICITY OPERATING STANDARDS
ESH001 Electricity 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 110 kV EOS018 Tunnel Procedures Rail Maintenance Planning EOS019 Contingency Plans (35 documents) EOS020 Procedures for Management and Operations on the Vector Low Voltage Network EOS026 Managing Asset Rating Changes

NETWORK INFORMATION STANDARDS
ESD001 Electricity Functional Location Data Standard ESD002 Electricity Reactive Maintenance Data Standard ESD003 HV Event Data Standard ECD005 HV Event Quality Assurance Process ESD005 Asset Data and GIS Data Standard ESD006 Planned and Remedial Maintenance Data Standard EDS007 Vegetation Cut or Trim Data Standard

Appendix 3 Typical Load Profiles

Figure 7-1, Figure 7-2 and Figure 7-3 show typical demand profiles for residential, commercial and CBD customer segments.

TYPICAL RESIDENTIAL DAILY DEMAND PROFILE

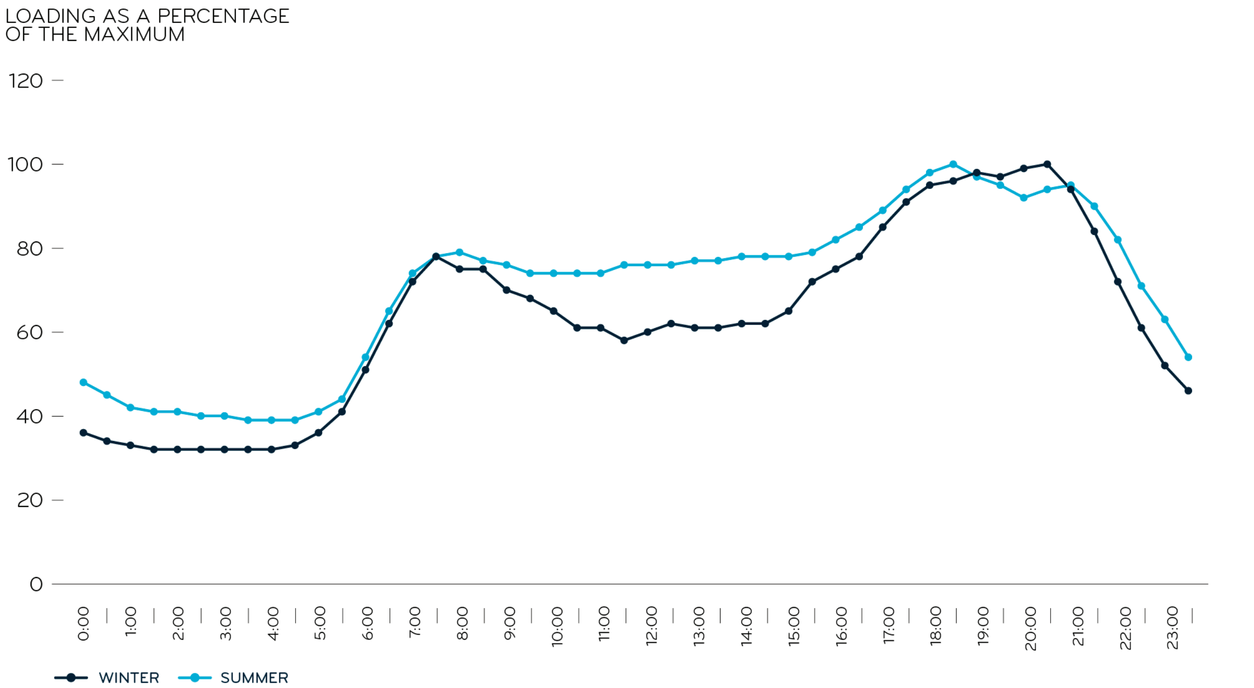

Figure 7-1 Typical residential demand profile

The key characteristics of the residential demand profile are the distinct morning and evening peaks and the significant difference in demand between summer and winter profiles, where in absolute usage terms, the latter is almost double the former. The profiles show the characteristics 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 illustration clearly 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.

TYPICAL COMMERCIAL DAILY DEMAND PROFILE

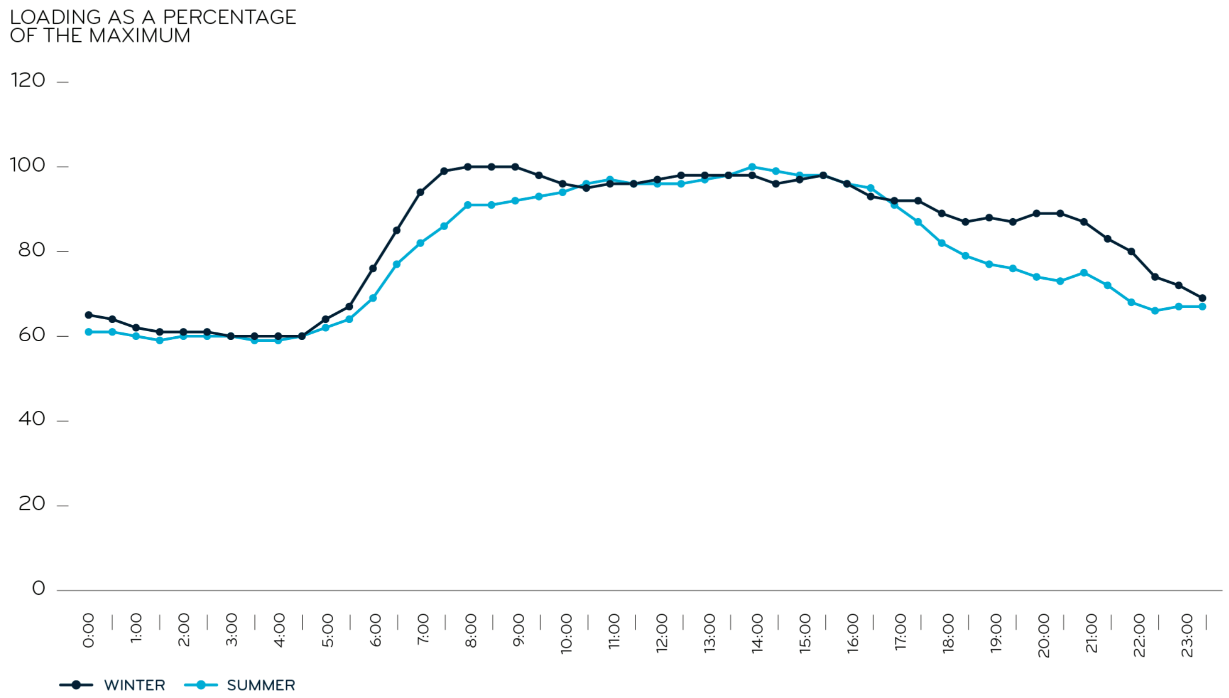

Figure 7-2 Typical commercial demand profile

Commercial demand follows a similar profile and loading for both winter and summer.

TYPICAL CBD DAILY DEMAND PROFILE

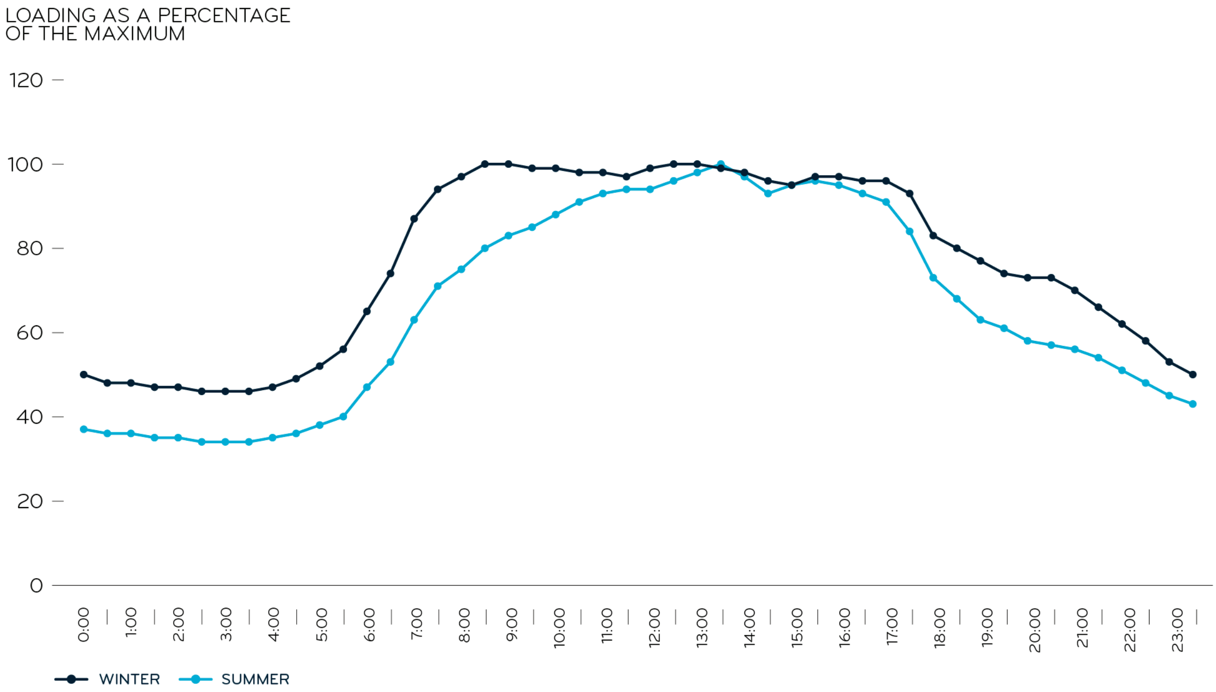

Figure 7-3 Typical CBD demand profile

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 less aggressive uptake after 7:00am and a slower ramp-down in the evenings. The peak load in summer is driven mainly by air-conditioning, adding an extra 10% load above the winter demand profile.

LARGE CUSTOMERS THAT HAVE A SIGNIFICANT IMPACT ON NETWORK

Vector has a number of 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 Waste Water Treatment Plant;
- Bluescope Steel at Mangere
- Pacific Steel at Mangere;
- Auckland Hospital at Newmarket;
- Carter Holt Harvey at Penrose
- Owens Illinois at Penrose

Appendix 4 AMP Information Disclosure Compliance

The following table sets out a mapping of the requirements of the "Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018)" and the contents of the AMP.

INFORMATION DISCLOSURE DETERMINATION REQUIREMENT	AMP SECTION REFERENCE
CONTENTS OF THE AMP	
3. The AMP must include the following-	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant;	Executive Summary
3.2 Details of the background and objectives of the EDB's asset management and planning processes;	Section 1 and Section 3
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;	Section 3
3.3.2 states the corporate mission or vision as it relates to asset management;	Section 1 and Section 3
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	Section 3.4
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	Section 3.4
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans;	Section 3.1
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;	Executive Summary
3.5 The date that it was approved by the directors;	Executive Summary and Appendix 14
3.6 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates-	Section 2.1
3.6.1 how the interests of stakeholders are identified	Section 2.1
3.6.2 what these interests are;	Section 2.1
3.6.3 how these interests are accommodated in asset management practices; and	Section 2.1
3.6.4 how conflicting interests are managed;	Section 2.1
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	Section 3.3

	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;	Section 3.3
	3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured; and	Section 3.3
	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;	Section 3.3
3.8	All significant assumptions-	
	3.8.1 quantified where possible;	Section 1
	3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including-	Section 1
	3.8.3 a description of changes proposed where the information is not based on the EDB's existing business;	N/A
	3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	Section 1 and Section 3
	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;	Appendix 6 and Appendix 7
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;	Section 1
3.10	An overview of asset management strategy and delivery;	Sections 4.1, 4.2, 4.3, 6.1, 6.2, 6.3
3.11	An overview of systems and information management data;	Sections 3.5, 3.6, 3.7
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;	Section 3.7
3.13	A description of the processes used within the EDB for-	
	3.13.1 managing routine asset inspections and network maintenance;	Sections 4.1, 4.1.7, 5, 5.1, 6.1
	3.13.2 planning and implementing network development projects; and	Sections 4.1, 5, 5.1, 6.1
	3.13.3 measuring network performance;	Section 2 and Section 4
3.14	An overview of asset management documentation, controls and review processes.	Sections 3.3, 3.4, 3.5
3.15	An overview of communication and participation processes;	Section 4
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, including-	
4.1	a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	Section 4.1.14
4.1.1	the region(s) covered;	Maps in section 4.1.14 and section 5.1; described in section 5.1
4.1.2	identification of large consumers that have a significant impact on network operations or asset management priorities;	Appendix 3
4.1.3	description of the load characteristics for different parts of the network;	Section 4 and Appendix 3
4.1.4	peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	Section 4.1.15 and Appendix 10
4.2	a description of the network configuration, including-	
4.2.1	identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	Sections 4.1.15, 4.3 and Appendix 10
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;	Sections 4.1.15, 4.2 and Appendix 9
4.2.3	a description of the distribution system, including the extent to which it is underground;	Section 4.4
4.2.4	a brief description of the network's distribution substation arrangements;	Section 4.3 and Appendix 9
4.2.5	a description of the low voltage network including the extent to which it is underground; and	Section 4.5
4.2.6	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	Section 4.7, 4.8, 4.9
4.3	If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	N/A

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;	Sections 4.2-4.9
4.4.2	description and quantity of assets;	Sections 4.2-4.9
4.4.3	age profiles; and	Sections 4.2-4.9
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.	Sections 4.2-4.9
4.5	The asset categories discussed in clause 4.4 should include at least the following-	
4.5.1	the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	Compliant
4.5.2	assets owned by the EDB but installed at bulk electricity supply points owned by others;	N/A

	4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	Section 4
	4.5.4 other generation plant owned by the EDB.	N/A
SERVICE LEVELS		
5.	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition, and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	Sections 2.2-2.6
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.	Section 2.4.1 (SAIFI) Sections 2.5.2 (SAIDI)
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	Sections 2.2, 2.4.2
	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.	Sections 2.3.2, 6.1 and Appendix 9
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.	Section 2
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	Section 2
10.	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	N/A
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;	Section 1 and Section 4
	11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	Section 4.1.3
	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;	Section 4.1
	11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	
	11.4.1 the categories of assets and designs that are standardised; and	Section 3.4
	11.4.2 the approach used to identify standard designs;	Section 3.4

11.5	A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	Sections 3.5, 4.1.5, 6.1
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;	Section 4.1.4
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;	Section 6.1
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;	
11.8.1	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates	Section 3
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;	Section 5 and Appendix 10
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	Section 5
11.8.4	discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	Section 1, Section 4 and Section 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-	
11.9.1	the reasons for choosing a selected option for projects where decisions have been made;	Section 5
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	Section 5
11.9.3	consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	Section 5
11.10	A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	
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;	Section 5
11.10.2	a summary description of the programmes and projects planned for the following four years (where known); and	Section 5
11.10.3	an overview of the material projects being considered for the remainder of the AMP planning period;	Section 5
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	Section 4 and Appendix 2
11.12	A description of the EDB's policies on non-network solutions, including-	
11.12.1	economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	Section 4 and Section 5

11.12.2 the potential for non-network solutions to address network problems or constraints.	Section 4 and Section 5
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;	Section 4.1.7
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-	Sections 4.3-4.9
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;	Sections 4.3-4.9
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	Sections 4.3-4.9
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period;	Section 5 and Section 6.4
12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	
12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	Section 4.1.6
12.3.2 a description of innovations that have deferred asset replacements;	Section 4.1.6
12.3.3 a description of the projects currently underway or planned for the next 12 months;	Section 5
12.3.4 a summary of the projects planned for the following four years (where known); and	Section 5
12.3.5 an overview of other work being considered for the remainder of the AMP planning period; and	Section 5
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	Compliant
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;	Sections 4.1.13, 4.10
13.2 development, maintenance and renewal policies that cover them;	Section 4.10
13.3 a description of material capital expenditure projects (where known) planned for the next five years; and	Section 5.3
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	Section 5.3
RISK MANAGEMENT	
14. AMPs must provide details of risk policies, assessment, and mitigation, including—	

14.1 Methods, details, and conclusions of risk analysis;	Sections 3.6, 4.2-4.9, 5.2
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;	Section 3.6
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	Section 3.4
14.4 Details of emergency response and contingency plans.	Section 3.12
EVALUATION OF PERFORMANCE	
15. AMPs must provide details of performance measurement, evaluation, and improvement, including—	
15.1 A review of progress against plan, both physical and financial;	Section 6.4
15.2 An evaluation and comparison of actual service level performance against targeted performance;	Section 2
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.	Section 3
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.	Section 2 and Section 5
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	Section 1 and Section 6
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Section 3

Appendix 5 Significant Changes from 2018 AMP

2019 AMP SCHEDULE DATE	SUBSTATION	PROJECT AND PROGRAMME DESCRIPTION	2018 AMP SCHEDULE DATE	REASON FOR CHANGE
FY21	Hobson	Hobson - Quay St 110kV SUBT cable	FY19	To coordinate with major road works
	Orewa	Orewa 33kV SWBD ODID	FY23	Change in network configuration
FY25	Quay	Quay 11kV SWBD Replace	FY22	Revised risk assessment
FY23	Quay	Quay St 2nd 22kV SWBD	FY21	To align with customer demand
FY25	St Heliers	St Heliers 11kV vacuum CBs retrofit	FY23	Revised risk assessment
FY24	Te Papapa	Te Papapa 11kV SWBD Replace	FY22	Revised risk assessment
FY22	Wiri	Wiri 11kV vacuum CBs retrofit and upgrade protection	FY20	Revised risk assessment
	Brickworks	Brickworks 2nd 33/11kV TX	FY25	Change in forecast to align with customer demand
FY23	Chevalier	Chevalier SUBT Cable replace	FY21	Revised risk assessment
	Keeling Rd	Keeling Rd 2nd 33kV Supply	FY28	Change in forecast to align with customer demand
FY28	Millwater	Millwater Zone Substation	FY24	Change in demand forecast
FY22	Onehunga	Onehunga SUBT Cable replace	FY24	Review of risk profile
FY29	Red Hills	Redhills Zone Substation	FY23	Change in demand forecast
FY29	Riverhead	Riverhead 33/11kV TX capacity upgrade	FY27	Change in demand forecast
	Takapuna	Second Waitemata Harbour Crossing Tunnel Supply	FY24	Coordinate with major road works
FY20	Mangere GXP	Mangere Transpower 33kV SWBD ODID	FY21	Coordinate with Transpower works
FY25	Warkworth South	Warkworth South Zone Substation	FY27	Change in demand forecast
	Whenuapai	Whenuapai Zone Substation	FY28	Change in demand forecast
	Woodford	Woodford 2nd 33/11kV TX and 33kV cable	FY28	Change in demand forecast
FY23	Hobson	CRL Stations General Relocation Works	FY21	Coordinate with major road works
FY22	Takapuna	Takapuna 2nd 33/11kV TX and Subtrans	FY20	Increase in project scope
	Waimauku	Waimauku 2nd 33kV Supply and 33kV SWBD	FY22	Project split into other individual projects
FY26	Highbury	Highbury 2nd 33/11kV TX and cables	FY20	Change in demand forecast
FY22	Omaha	Omaha Zone Substation	FY20	Allow for delivery capacity
FY21	Warkworth	SH1 Dome Valley future proof ducts	FY23	Coordinate with major road works
FY22	Te Atatu	Te Atatu 33/11kV TX capacity upgrade	FY24	Change in demand forecast
FY26	Sabulite	Sabulite 33/11kV TX capacity upgrade	FY21	Change in demand forecast

	Greenhithe	Greenhithe 2nd 33/11kV TX	FY28	Change in demand forecast
	Mt Albert	Mt Albert SUBT Cable Replace	FY24	Change in network configuration
	Takanini South	Takanini South Zone Substation	FY27	Change in demand forecast
	Warkworth	Wellsford-Warkworth SH1 future proofing ducts	FY28	Replaced by another project
	Glenvar	Glenvar Zone Substation	FY24	Change in demand forecast
	Maraetai	Maraetai Subtrans Reinforcement	FY24	Change in demand forecast
	Henderson valley	Henderson Valley 33/11kV TX capacity upgrade	FY25	Change in demand forecast
	Sunset Road	Sunset Road 33/11kV TX capacity upgrade	FY22	Change in demand forecast
	Belmont	Belmont 33/11kV TX upgrade	FY27	Change in demand forecast
	Forrest Hill	Forrest Hill 33/11kV TX upgrade	FY25	Change in demand forecast
	James St	James St 33/11kV TX upgrade	FY26	Change in demand forecast
	Triangle Rd	Triangle Rd 33/11kV TX upgrade	FY26	Change in demand forecast
	Wairau	Wairau 33/11kV TX upgrade	FY25	Change in demand forecast
	Helensville	South Head micro-grid	FY25	Alternative solution planned
	Helensville	Kaukapakapa micro-grid	FY21	Alternative solution planned
	Gulf Harbour	Gulf Harbour 11kV reinforcement	FY22	Change in demand forecast
	Snells Beach	Tawharanui 11kV reinforcement	FY27	Change in demand forecast
FY24	Mangere East	Mangere East Robertson Road 11KV	FY28	Change in demand forecast
FY23	Waiheke	Waiheke East 11kV feeder new	FY28	Change in demand forecast
FY25	James St	James St 33kV SWBD ODID		New Project
FY26	Hobsonville	Hobsonville 33kV SWBD ODID		New Project
FY27	Henderson valley	Henderson Valley 11kV SWBD replace		New Project
FY28	Manly	Manly 11kV SWBD replace		New Project
FY24	New Lynn	New Lynn 11kV SWBD replace		New Project
FY29	Newton	Newton 11kV SWBD replace		New Project
FY26	Papakura	Papakura 11kV SBWD replace		New Project
FY27	Victoria	Victoria 11kV SWBD replace		New Project
FY21	Warkworth	Warkworth 11kV SWBD replace		New Project
FY27	Sunset Road	Sunset Rd 11kV SWBD replace		New Project
FY27	Woodford	Woodford 11kV SBWD replace		New Project
FY24	Waiheke	Waiheke Subtrans Reinforcement		New Project
FY21	Auckland Airport	Auckland airport third supply		New Project
FY23	Stanley Bay	Stanley Point Zone Substation		New Project
FY23	Various	AMETI EB2		New Project

FY22	Waimauku	SH16 to Waimauku future proof ducts	New Project
FY21	Hobson	Hobson 22kV new CBs and new switchroom	New Project
FY21	Warkworth	Warkworth load control	New Project
FY25	Various	Auckland Light Rail Project	New Project
FY20	Hobson	Auckland Seismic Rebuild Hobson	New Project
FY21	Westgate	SH16 Safe Roads Huapai to Waimauku	New Project

Appendix 6 Forecast Capital Expenditure (Schedule 11a)

Company Name: **Vector Electricity**
AMP Planning Period: **1 April 2019 – 31 March 2029**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		71,090	72,214	73,002	65,859	62,377	60,263	59,109	59,802	59,429	57,468	57,729
11	System growth		38,068	50,140	44,558	34,532	36,261	36,951	32,631	40,600	40,152	41,801	40,079
12	Asset replacement and renewal		88,018	109,368	102,036	104,309	105,154	102,567	99,311	101,021	108,923	108,694	111,299
13	Asset relocations		20,491	30,140	40,970	50,802	48,612	45,351	34,607	27,381	26,489	27,019	27,559
14	Reliability, safety and environment:												
15	Quality of supply		3,055	924	-	-	-	-	-	-	-	-	-
16	Legislative and regulatory		760	398	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		2,656	18,684	25,423	29,088	34,428	35,506	36,557	40,503	41,895	42,585	45,857
18	**Total reliability, safety and environment**		6,471	20,006	25,423	29,088	34,428	35,506	36,557	40,503	41,895	42,585	45,857
19	**Expenditure on network assets**		224,138	281,868	285,989	284,590	286,832	280,638	262,215	269,307	276,888	277,567	282,523
20	Expenditure on non-network assets		33,215	28,003	28,360	25,732	21,922	19,138	19,540	32,577	22,525	17,222	17,845
21	**Expenditure on assets**		257,353	309,871	314,349	310,322	308,754	299,776	281,755	301,884	299,413	294,789	300,368
22													
23	*plus* Cost of financing		3,594	4,264	4,313	4,114	4,051	3,929	3,603	3,890	3,795	3,749	3,766
24	*less* Value of capital contributions		66,673	73,374	76,356	68,525	61,879	56,803	55,218	57,856	58,395	57,002	57,418
25	*plus* Value of vested assets												
26													
27	**Capital expenditure forecast**		194,274	240,761	242,306	245,911	250,926	246,902	230,140	247,918	244,813	241,536	246,716
28													
29	Assets commissioned		217,016	218,673	243,259	246,968	251,835	269,804	228,777	254,803	237,887	249,368	241,230
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
32			**$000 (in constant prices)**										
33	Consumer connection		71,090	70,798	70,167	62,060	57,627	54,582	52,487	52,061	50,722	48,087	47,358
34	System growth		38,068	49,157	42,828	32,540	33,500	33,468	28,975	35,345	34,269	34,977	32,879
35	Asset replacement and renewal		88,018	107,224	98,074	98,293	97,146	92,898	88,185	87,945	92,965	90,950	91,304
36	Asset relocations		20,491	29,549	39,379	47,872	44,910	41,076	30,730	23,837	22,608	22,608	22,608
37	Reliability, safety and environment:												
38	Quality of supply		3,055	906	-	-	-	-	-	-	-	-	-
39	Legislative and regulatory		760	390	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment		2,656	18,318	24,436	27,410	31,806	32,159	32,462	35,260	35,757	35,633	37,619
41	**Total reliability, safety and environment**		6,471	19,614	24,436	27,410	31,806	32,159	32,462	35,260	35,757	35,633	37,619
42	**Expenditure on network assets**		224,138	276,342	274,884	268,175	264,989	254,183	232,839	234,448	236,321	232,255	231,768
43	Expenditure on non-network assets		33,215	27,454	27,259	24,248	20,253	17,334	17,351	28,360	19,225	14,411	14,639
44	**Expenditure on assets**		257,353	303,796	302,143	292,423	285,242	271,517	250,190	262,808	255,546	246,666	246,407
45													
46	**Subcomponents of expenditure on assets (where known)**												
47	Energy efficiency and demand side management, reduction of energy losses												
48	Overhead to underground conversion		7,308	9,808	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321	10,321
49	Research and development		-	-	-	-	-	-	-	-	-	-	-

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
Difference between nominal and constant price forecasts	$000										
Consumer connection	-	1,416	2,835	3,799	4,750	5,681	6,622	7,741	8,707	9,381	10,371
System growth	-	983	1,730	1,992	2,761	3,483	3,656	5,255	5,883	6,824	7,200
Asset replacement and renewal	-	2,144	3,962	6,016	8,008	9,669	11,126	13,076	15,958	17,744	19,995
Asset relocations	-	591	1,591	2,930	3,702	4,275	3,877	3,544	3,881	4,411	4,951
Reliability, safety and environment:											
Quality of supply	-	18	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	8	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	366	987	1,678	2,622	3,347	4,095	5,243	6,138	6,952	8,238
Total reliability, safety and environment	-	392	987	1,678	2,622	3,347	4,095	5,243	6,138	6,952	8,238
Expenditure on network assets	-	5,526	11,105	16,415	21,843	26,455	29,376	34,859	40,567	45,312	50,755
Expenditure on non-network assets	-	549	1,101	1,484	1,669	1,804	2,189	4,217	3,300	2,811	3,206
Expenditure on assets	-	6,075	12,206	17,899	23,512	28,259	31,565	39,076	43,867	48,123	53,961

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
11a(ii): Consumer Connection							
*Consumer types defined by EDB**		$000 (in constant prices)					
Service Connection		13,325	15,545	15,632	15,575	15,563	15,563
Customer Substations		17,875	17,098	17,054	11,627	9,337	8,161
Business Subdivisions		528	1,435	1,440	1,387	1,387	1,223
Residential Subdivisions		29,101	29,649	30,682	28,126	25,995	24,290
Capacity Changes		9,297	5,808	4,475	4,475	4,475	4,475
Street Lighting		958	1,263	884	870	870	870
Relocatons		-	-	-	-	-	-
Easements		6	-	-	-	-	-
**include additional rows if needed*							
Consumer connection expenditure		71,090	70,798	70,167	62,060	57,627	54,582
less Capital contributions funding consumer connection		56,489	56,259	55,738	49,430	45,940	43,573
Consumer connection less capital contributions		14,601	14,539	14,429	12,630	11,687	11,009
11a(iii): System Growth							
Subtransmission		2,453	13,531	13,124	5,011	2,963	3,170
Zone substations		18,924	19,205	15,149	14,858	12,774	10,450
Distribution and LV lines		1,165	1,765	2,314	2,672	2,947	4,421
Distribution and LV cables		8,008	10,323	8,833	7,371	12,261	11,505
Distribution substations and transformers		2,000	10	-	-	-	-
Distribution switchgear		(114)	-	-	-	-	-
Other network assets		5,632	4,323	3,408	2,628	2,555	3,922
System growth expenditure		38,068	49,157	42,828	32,540	33,500	33,468
less Capital contributions funding system growth							
System growth less capital contributions		38,068	49,157	42,828	32,540	33,500	33,468

	for year ended	Current Year CY 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
11a(iv): Asset Replacement and Renewal		**$000 (in constant prices)**					
Subtransmission		1,576	13,509	8,786	5,068	5,481	5,750
Zone substations		18,202	21,881	22,949	26,477	23,617	18,628
Distribution and LV lines		6,836	14,710	12,267	11,060	11,095	11,084
Distribution and LV cables		31,873	30,223	29,509	29,903	30,295	30,369
Distribution substations and transformers		10,757	7,643	5,406	5,420	5,435	5,375
Distribution switchgear		11,038	13,881	14,917	16,565	17,800	18,355
Other network assets		7,736	5,377	4,240	3,800	3,423	3,337
Asset replacement and renewal expenditure		88,018	107,224	98,074	98,293	97,146	92,898
less Capital contributions funding asset replacement and renewal							
Asset replacement and renewal less capital contributions		88,018	107,224	98,074	98,293	97,146	92,898

	for year ended	Current Year CY 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
11a(v): Asset Relocations							
*Project or programme**		**$000 (in constant prices)**					
Overhead to Underground conversions		7,308	9,808	10,321	10,321	10,321	10,321
**include additional rows if needed*							
All other project or programmes - asset relocations		13,183	19,741	29,058	37,551	34,589	30,755
Asset relocations expenditure		20,491	29,549	39,379	47,872	44,910	41,076
less Capital contributions funding asset relocations		10,184	15,676	17,653	15,142	11,227	7,876
Asset relocations less capital contributions		10,307	13,873	21,726	32,730	33,683	33,200

	for year ended	Current Year CY 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
11a(vi): Quality of Supply							
*Project or programme**		**$000 (in constant prices)**					
**include additional rows if needed*							
All other projects or programmes - quality of supply		3,055	906	-	-	-	-
Quality of supply expenditure		3,055	906	-	-	-	-
less Capital contributions funding quality of supply							
Quality of supply less capital contributions		3,055	906	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**

11a(vii): Legislative and Regulatory

*Project or programme**		$000 (in constant prices)					
*include additional rows if needed							
All other projects or programmes - legislative and regulatory		760	390	-	-	-	-
Legislative and regulatory expenditure		760	390	-	-	-	-
less Capital contributions funding legislative and regulatory							
Legislative and regulatory less capital contributions		760	390	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**

11a(viii): Other Reliability, Safety and Environment

*Project or programme**		$000 (in constant prices)					
*include additional rows if needed							
All other projects or programmes - other reliability, safety and environment		2,656	18,318	24,436	27,410	31,806	32,159
Other reliability, safety and environment expenditure		2,656	18,318	24,436	27,410	31,806	32,159
less Capital contributions funding other reliability, safety and environment							
Other reliability, safety and environment less capital contributions		2,656	18,318	24,436	27,410	31,806	32,159

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**

11a(ix): Non-Network Assets

Routine expenditure

*Project or programme**		$000 (in constant prices)					
*include additional rows if needed							
All other projects or programmes - routine expenditure		12,876	6,989	11,246	9,275	8,051	9,029
Routine expenditure		12,876	6,989	11,246	9,275	8,051	9,029

Atypical expenditure

*Project or programme**							
*include additional rows if needed							
All other projects or programmes - atypical expenditure		20,339	20,465	16,013	14,973	12,202	8,305
Atypical expenditure		20,339	20,465	16,013	14,973	12,202	8,305
Expenditure on non-network assets		33,215	27,454	27,259	24,248	20,253	17,334

Appendix 7 Forecast Operational Expenditure (Schedule 11b)

Company Name	**Vector Electricity**
AMP Planning Period	**1 April 2019 – 31 March 2029**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	10,447	12,607	14,370	14,711	15,184	15,670	16,162	16,669	17,187	17,728	18,279
11	Vegetation management	7,017	7,837	8,453	8,891	9,204	9,526	9,854	8,806	8,637	8,935	9,244
12	Routine and corrective maintenance and inspection	15,260	17,772	18,010	18,822	20,215	24,493	26,390	22,738	21,736	22,280	22,923
13	Asset replacement and renewal	14,214	13,227	13,956	14,604	15,087	15,584	15,929	16,128	16,561	17,097	17,651
14	**Network Opex**	46,938	51,443	54,789	57,028	59,690	65,273	68,335	64,341	64,121	66,040	68,097
15	System operations and network support	39,089	42,198	42,745	44,195	45,794	47,539	49,140	50,371	51,498	52,642	53,676
16	Business support	35,810	37,232	38,257	39,157	40,046	40,947	41,848	42,769	43,710	44,671	45,654
17	**Non-network opex**	74,899	79,430	81,002	83,352	85,840	88,486	90,988	93,140	95,208	97,313	99,330
18	**Operational expenditure**	121,837	130,873	135,791	140,380	145,530	153,759	159,323	157,481	159,329	163,353	167,427
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	10,447	12,252	13,622	13,624	13,750	13,878	14,006	14,135	14,260	14,392	14,520
23	Vegetation management	7,017	7,617	8,013	8,234	8,335	8,437	8,540	7,467	7,166	7,254	7,343
24	Routine and corrective maintenance and inspection	15,260	17,272	17,073	17,432	18,306	21,693	22,869	19,280	18,034	18,087	18,209
25	Asset replacement and renewal	14,214	12,855	13,229	13,526	13,663	13,802	13,804	13,676	13,740	13,880	14,021
26	**Network Opex**	46,938	49,996	51,937	52,816	54,054	57,810	59,219	54,558	53,200	53,613	54,093
27	System operations and network support	39,089	41,011	40,520	40,931	41,471	42,103	42,584	42,712	42,727	42,736	42,637
28	Business support	35,810	36,185	36,265	36,265	36,265	36,265	36,265	36,265	36,265	36,265	36,265
29	**Non-network opex**	74,899	77,196	76,785	77,196	77,736	78,368	78,849	78,977	78,992	79,001	78,902
30	**Operational expenditure**	121,837	127,192	128,722	130,012	131,790	136,178	138,068	133,535	132,192	132,614	132,995
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	2,783	2,864	2,936	3,005	3,073	3,142	3,212	3,282	3,354	3,428	3,504

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

38

Appendix 8 Asset Condition (Schedule 12a)

Company Name **Vector Electricity**

AMP Planning Period **1 April 2019 – 31 March 2029**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.02%	0.06%	20.90%	40.22%	38.80%		4	6.33%
11	All	Overhead Line	Wood poles	No.	0.48%	1.46%	80.27%	13.56%	4.22%		4	9.70%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	100.00%		4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	88.62%	3.13%	8.25%		3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	72.35%	-	27.65%		3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	1.66%	5.28%	30.12%	62.95%		2	1.66%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	95.17%	4.83%		2	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	100.00%	-	-	-		2	100.00%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	62.85%	17.64%	16.58%	2.93%		2	83.23%
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	27.96%	72.04%		2	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	93.87%	6.13%		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	-	-	4.95%	95.05%	-		2	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	1.75%	79.82%	18.42%		4	3.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	100.00%	-		4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	7.41%	15.64%	76.95%		3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	21.53%	43.75%	6.94%	27.78%		3	22.22%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	14.05%	50.50%	5.35%	30.10%		3	14.05%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-		3	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	45.00%	55.00%		3	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	100.00%	-	-		3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	13.80%	21.30%	21.46%	43.44%		3	21.46%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	
35												

36					Asset condition at start of planning period (percentage of units by grade)							
37												
38	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.	-	8.80%	44.91%	24.54%	21.76%		4	5.09%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	-	80.41%	13.92%	5.67%		3	2.76%
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	-	0.85%	1.26%	14.42%	83.47%		2	0.84%
44	HV	Distribution Cable	Distribution UG PILC	km	-	1.53%	2.20%	70.13%	26.14%		2	1.53%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	86.11%	13.89%	-		2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.39%	-	8.20%	71.88%	19.53%		4	11.36%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	16.92%	8.85%	74.23%		4	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2.16%	1.99%	47.72%	18.92%	29.21%		4	9.13%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	1.42%	0.59%	76.12%	17.28%	4.60%		3	8.02%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1.56%	1.48%	49.57%	19.07%	28.33%		3	3.93%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.31%	1.26%	49.03%	25.98%	22.42%		3	8.13%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	5.22%	1.55%	33.70%	27.76%	31.77%		3	6.76%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	10.00%	90.00%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.97%	0.68%	76.93%	10.95%	9.47%		4	2.65%
55	LV	LV Line	LV OH Conductor	km	-	-	85.77%	8.83%	5.40%		3	0.23%
56	LV	LV Cable	LV UG Cable	km	0.50%	2.51%	21.77%	39.84%	35.39%		2	3.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km						100.00%	1	0.08%
58	LV	Connections	OH/UG consumer service connections	No.						100.00%	1	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	2.13%	53.78%	28.99%	15.10%		3	2.13%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	5.71%	35.74%	23.42%	35.14%		4	5.71%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	76.92%	16.67%	6.41%		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%	-	91.38%		4	-

Appendix 9 Forecast Capacity (Schedule 12b)

Company Name	**Vector Electricity**
AMP Planning Period	**1 April 2019 – 31 March 2029**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

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

sch ref

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

8	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Atkinson Road	21	21	N-1	21	99%	24	85%	No constraint within +5 years	Meets Vector security criteria
10	Auckland Airport	19	25	N-1	10	75%	25	112%	Other	Meets customers security criteria
11	Avondale	28	24	N-1 switched	26	118%	24	122%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
12	Bairds	27	24	N-1 switched	21	112%	24	113%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
13	Balmain	9	-	N	9	-	-		No constraint within +5 years	Meets Vector security criteria
14	Balmoral	14	24	N-1	15	56%	24	56%	No constraint within +5 years	Meets Vector security criteria
15	Belmont	13	14	N-1	13	96%	14	94%	No constraint within +5 years	Meets Vector security criteria
16	Birkdale	24	24	N-1 switched	24	101%	24	97%	No constraint within +5 years	Meets Vector security criteria
17	Brickworks	11	-	N-1 switched	12	-	18	84%	No constraint within +5 years	Constraint relieved by the installation of the second transformer
18	Browns Bay	18	10	N-1 switched	18	184%	18	99%	No constraint within +5 years	Constraint relieved by transformer capacity upgrade
19	Bush Road	23	24	N-1	23	98%	24	96%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
20	Carbine	17	22	N-1	10	79%	22	77%	No constraint within +5 years	Meets Vector security criteria
21	Chevalier	22	19	N-1 switched	15	115%	24	93%	No constraint within +5 years	Constraint relieved by subtransmission circuit replacement
22	Clendon	22	24	N-1	15	93%	24	93%	No constraint within +5 years	Meets Vector security criteria
23	Clevedon	3	-	N-1 switched	3	-	-		No constraint within +5 years	Meets Vector security criteria
24	Coatesville	11	-	N	11	-	12	91%	No constraint within +5 years	Constraint relieved by the installation of the second transformer
25	Drive	26	24	N-1 switched	25	110%	24	123%	No constraint within +5 years	Constraint relieved by load transfer to Newmarket substation
26	East Coast Road	17	-	N	17	-	-		No constraint within +5 years	Meets Vector security criteria
27	East Tamaki	16	24	N-1	7	68%	24	102%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
28	Flatbush	11	24	N-1	10	47%	24	83%	No constraint within +5 years	Meets Vector security criteria
29	Forrest Hill	16	20	N-1	16	81%	20	78%	No constraint within +5 years	Meets Vector security criteria
30	Freemans Bay	21	22	N-1	17	98%	22	115%	No constraint within +5 years	Constraint relieved by load transfer to the CBD 22kV distribution network
31	Glen Innes	16	13	N-1 switched	34	119%	24	67%	No constraint within +5 years	Constraint relieved by transformer and subtransmission circuit replacements
32	Greenhithe	13	-	N	13	-	-		No constraint within +5 years	Constraint relieved by the Hobsonville Point zone substation
33	Greenmount	40	48	N-1	28	84%	48	90%	No constraint within +5 years	Meets Vector security criteria
34	Gulf Harbour	9	-	N	9	-	-		No constraint within +5 years	Meets Vector security criteria
35	Hans	26	24	N-1 switched	15	107%	24	124%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
36	Hauraki	10	-	N-1 switched	10	-	-		No constraint within +5 years	Meets Vector security criteria
37	Helensville	15	9	N-1 switched	15	169%	18	85%	No constraint within +5 years	Constraint relieved by transformer capacity upgrade
38	Henderson Valley	18	15	N-1 switched	18	118%	15	121%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
39	Highbrook	9	21	N-1	-	44%	21	61%	No constraint within +5 years	Meets Vector security criteria
40	Highbury	16	-	N	16	-	24	66%	No constraint within +5 years	Constraint relieved by the installation of the second transformer
41	Hillcrest	20	24	N-1	20	84%	24	89%	No constraint within +5 years	Meets Vector security criteria
42	Hillsborough	17	24	N-1	17	71%	24	79%	No constraint within +5 years	Meets Vector security criteria
43	Hobson 110/11kV	14	30	N-1	11	46%	30	51%	No constraint within +5 years	Meets Vector security criteria

44	Hobson 22/11kV	18	18	N-1	8	98%	18	109%	No constraint within +5 years	Constraint relieved by load transfer to the CBD 22kV distribution network
45	Hobson 22kV	50	40	N-1 switched	37	125%	80	108%	No constraint within +5 years	Constraint relieved by CBD subtransmission reinforcement
46	Hobsonville	22	15	N-1 switched	22	143%	15	194%	No constraint within +5 years	Constraint relieved by the installation of Hobsonville Point zone substation
47	Howick	41	48	N-1	16	85%	48	84%	No constraint within +5 years	Meets Vector security criteria
48	James Street	20	15	N-1 switched	20	132%	15	128%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
49	Keeling Road	8	-	N-1 switched	17	-	-		No constraint within +5 years	Meets Vector security criteria
50	Kingsland	24	24	N-1	23	98%	24	105%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
51	Laingholm	9	9	N-1	9	94%	9	88%	No constraint within +5 years	Meets Vector security criteria
52	Lichfield	18	20	N-1	-	88%	20	88%	Other	Meets customers security criteria
53	Liverpool	34	48	N-1	22	70%	48	74%	No constraint within +5 years	Meets Vector security criteria
54	Liverpool 22kV	100	140	N-1	57	71%	150	69%	No constraint within +5 years	Meets Vector security criteria
55	Mangere Central	29	24	N-1 switched	16	121%	48	65%	No constraint within +5 years	Constraint relieved by the installation of the third transformer
56	Mangere East	32	24	N-1 switched	23	131%	24	143%	No constraint within +5 years	Constraint relieved by load transfer to Managere Central substation
57	Mangere West	25	30	N-1	3	84%	30	127%	No constraint within +5 years	Constraint relieved by load transfer to Managere Central substation
58	Manly	20	14	N-1 switched	20	145%	14	140%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
59	Manukau	32	48	N-1	27	66%	48	69%	No constraint within +5 years	Meets Vector security criteria
60	Manurewa	51	48	N-1 switched	33	105%	48	103%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
61	Maraetai	9	18	N-1	3	48%	18	51%	No constraint within +5 years	Meets Vector security criteria
62	McKinnon	17	24	N-1	17	72%	24	106%	No constraint within +5 years	Meets Vector security criteria
63	Mcleod Road	11	-	N	11	-	-		No constraint within +5 years	Meets Vector security criteria
64	McNab	42	48	N-1	30	88%	48	87%	No constraint within +5 years	Meets Vector security criteria
65	Milford	8	-	N	8	-	-		No constraint within +5 years	Meets Vector security criteria
66	Mt Albert	7	-	N-1 switched	13	-	-		No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
67	Mt Wellington	20	24	N-1	16	81%	24	84%	No constraint within +5 years	Meets Vector security criteria
68	New Lynn	14	14	N-1	14	99%	14	106%	No constraint within +5 years	Meets Vector security criteria
69	Newmarket	33	48	N-1	32	69%	72	77%	No constraint within +5 years	Constraint relieved by the installation of additional capacity at Newmarket substation
70	Newton	23	19	N-1 switched	20	121%	19	137%	No constraint within +5 years	Constraint relieved by load transfer to the CBD 22kV distribution network
71	Ngataringa Bay	7	-	N	7	-	-		No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
72	Northcote	9	-	N	9	-	-		No constraint within +5 years	Meets Vector security criteria
73	Onehunga	15	15	N-1 switched	14	101%	24	66%	No constraint within +5 years	Constraint relieved by subtransmission circuit replacement
74	Orakei	21	22	N-1	16	99%	22	99%	No constraint within +5 years	Meets Vector security criteria
75	Oratia	6	-	N-1 switched	7	-	-		No constraint within +5 years	Meets Vector security criteria
76	Orewa	18	15	N-1 switched	18	117%	24	95%	No constraint within +5 years	Constraint relieved by 11kV switchgear replacement
77	Otara	28	36	N-1	27	79%	36	81%	No constraint within +5 years	Meets Vector security criteria
78	Pacific Steel	20	44	N-1	-	44%	44	44%	Other	Meets customers security criteria
79	Pakuranga	23	24	N-1	16	98%	24	95%	No constraint within +5 years	Meets Vector security criteria
80	Papakura	28	23	N-1 switched	9	118%	23	124%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
81	Parnell	10	14	N-1	16	71%	18	65%	No constraint within +5 years	Meets Vector security criteria
82	Ponsonby	16	14	N-1 switched	13	109%	18	85%	No constraint within +5 years	Constraint relieved by subtransmission circuit replacement
83	Quay	22	24	N-1	21	92%	24	106%	No constraint within +5 years	Constraint relieved by load within the CBD 22kV distribution network
84	Quay 22kV	43	60	N-1	38	72%	60	88%	No constraint within +5 years	Meets Vector security criteria
85	Ranui	14	-	N	14	-	-		No constraint within +5 years	Meets Vector security criteria
86	Remuera	27	24	N-1 switched	24	113%	24	121%	No constraint within +5 years	Constraint relieved by load transfer to Newmarket substation
87	Riverhead	12	9	N-1 switched	12	131%	9	140%	No constraint within +5 years	Constraint relieved by the Waimauku transformer upgrade and 11kV cable project
88	Rockfield	22	24	N-1	25	90%	24	90%	No constraint within +5 years	Meets Vector security criteria
89	Rosebank	23	22	N-1 switched	11	105%	22	105%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
90	Rosedale	15	-	N	15	-	24	73%	No constraint within +5 years	Constraint relieved by the installation of the second transformer
91	Sabulite Road	22	14	N-1 switched	22	156%	14	154%	No constraint within +5 years	Constraint relieved by transformer capacity upgrade

92	Sandringham	23	24	N-1	21	95%	24	100%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
93	Simpson Road	6	-	N	6	-	-		No constraint within +5 years	Meets Vector security criteria
94	Snells Beach	8	-	N	8	-	-		No constraint within +5 years	Constraint relieved by the installation of a network battery
95	South Howick	30	24	N-1 switched	22	125%	24	122%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
96	Spur Road	13	-	N-1 switched	15	-	24	68%	No constraint within +5 years	Constraint relieved by the installation of the second transformer
97	St Heliers	23	21	N-1 switched	21	111%	21	110%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
98	St Johns	20	24	N-1	34	85%	24	86%	No constraint within +5 years	Meets Vector security criteria
99	Sunset Road	17	14	N-1 switched	17	118%	14	116%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
100	Swanson	12	-	N	12	-	-		No constraint within +5 years	Meets Vector security criteria
101	Sylvia Park	23	24	N-1	11	94%	24	99%	No constraint within +5 years	Meets Vector security criteria
102	Takanini	18	18	N-1 switched	16	102%	18	114%	No constraint within +5 years	Constraint relieved by transformer capacity upgrade
103	Takapuna	9	-	N	9	-	24	47%	No constraint within +5 years	Constraint relieved by the installation of the second transformer
104	Te Atatu	22	14	N-1 switched	22	157%	24	91%	No constraint within +5 years	Constraint relieved by transformer capacity upgrade
105	Te Papapa	21	24	N-1	16	87%	24	86%	No constraint within +5 years	Meets Vector security criteria
106	Torbay	9	-	N	9	-	-		No constraint within +5 years	Meets Vector security criteria
107	Triangle Road	15	12	N-1 switched	15	124%	18	84%	No constraint within +5 years	Meets Vector security criteria
108	Victoria	22	22	N-1 switched	17	102%	22	104%	No constraint within +5 years	Constraint relieved by load transfer to the CBD 22kV distribution network
109	Waiake	9	-	N	9	-	-		No constraint within +5 years	Meets Vector security criteria
110	Waiheke	11	15	N-1	3	76%	15	77%	No constraint within +5 years	Meets Vector security criteria
111	Waikaukau	9	-	N	8	-	-		No constraint within +5 years	Meets Vector security criteria
112	Waimauku	11	-	N	11	-	18	69%	No constraint within +5 years	Constraint relieved by transformer upgrade +11kV cable project
113	Wairau Road	20	16	N-1 switched	20	124%	16	132%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
114	Warkworth	20	18	N-1 switched	20	112%	18	124%	No constraint within +5 years	Constraint relieved by the Omaha substatiob and the BESS at Snells Beach and Warkworth South
115	Wellsford	8	9	N-1	8	93%	9	91%	No constraint within +5 years	Meets Vector security criteria
116	Westfield	25	24	N-1 switched	21	104%	24	108%	No constraint within +5 years	Meets Vector security criteria when combined with 11kV backup
117	Westgate	11	24	N-1	11	45%	24	61%	No constraint within +5 years	Meets Vector security criteria
118	White Swan	30	32	N-1	17	92%	32	94%	No constraint within +5 years	Meets Vector security criteria
119	Wiri	42	43	N-1	21	100%	43	136%	No constraint within +5 years	Constraint relieved by new Wiri West substation
120	Woodford	10	-	N	10	-	-		No constraint within +5 years	Meets Vector security criteria

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

Appendix 10 Forecast Network Demand (Schedule 12c)

Company Name	Vector Electricity
AMP Planning Period	1 April 2019 – 31 March 2029

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

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

sch ref							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
11	*Consumer types defined by EDB**						
12	Residential & Small Medium Enterprise (SME)	12,083	11,904	11,697	11,697	11,697	11,523
13	Industrial & Commercial	176	140	104	104	104	85
14							
15							
16							
17	**Connections total**	12,259	12,044	11,801	11,801	11,801	11,608
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	497	1,000	2,000	6,700	6,700	6,700
21	Capacity of distributed generation installed in year (MVA)	2	3	6	20	20	20
22	**12c(ii) System Demand**						
23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
25	GXP demand	1,809	1,817	1,825	1,834	1,842	1,850
26	*plus* Distributed generation output at HV and above	12	14	14	14	14	14
27	**Maximum coincident system demand**	1,821	1,831	1,839	1,848	1,856	1,864
28	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	1,821	1,831	1,839	1,848	1,856	1,864
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	8,631	8,637	8,636	8,638	8,639	8,645
32	*less* Electricity exports to GXPs						
33	*plus* Electricity supplied from distributed generation	127	127	127	127	127	127
34	*less* Net electricity supplied to (from) other EDBs						
35	**Electricity entering system for supply to ICPs**	8,758	8,764	8,763	8,765	8,766	8,772
36	*less* Total energy delivered to ICPs	8,438	8,444	8,443	8,445	8,446	8,451
37	**Losses**	320	320	320	320	320	321
38							
39	**Load factor**	55%	55%	54%	54%	54%	54%
40	**Loss ratio**	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%

Appendix 11 Forecast Interruptions and Duration (Schedule 12d)

Company Name	Vector Electricity
AMP Planning Period	1 April 2019 – 31 March 2029
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*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	9.6	9.6	9.6	9.6	9.6	9.6
12	Class C (unplanned interruptions on the network)	86.4	86.4	86.4	86.4	86.4	86.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.06	0.06	0.06	0.06	0.06	0.06
15	Class C (unplanned interruptions on the network)	1.23	1.23	1.23	1.23	1.23	1.23

Company Name	Vector Electricity
AMP Planning Period	1 April 2019 – 31 March 2029
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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	2.7	2.7	2.7	2.7	2.7	2.7
12	Class C (unplanned interruptions on the network)	34.9	34.9	34.9	34.9	34.9	34.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.02	0.02	0.02	0.02	0.02	0.02
15	Class C (unplanned interruptions on the network)	0.51	0.51	0.51	0.51	0.51	0.51

Company Name	Vector Electricity
AMP Planning Period	1 April 2019 – 31 March 2029
Network / Sub-network Name	Northern

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	6.9	6.9	6.9	6.9	6.9	6.9
12	Class C (unplanned interruptions on the network)	51.5	51.5	51.5	51.5	51.5	51.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.04	0.04	0.04	0.04	0.04	0.04
15	Class C (unplanned interruptions on the network)	0.73	0.73	0.73	0.73	0.73	0.73

Appendix 12 Asset Management Maturity (Schedule 13)

Company Name	Vector Electricity
AMP Planning Period	1 April 2019 – 31 March 2029
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 Guidance	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 Asset Management Policy (latest version published August 2017) has been authorised by our Chief Network Officer. The document has been circulated to key stakeholders and is readily available for staff to access. The document is part of the controlled document management system and reviewed periodically.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	Good asset management is practiced implicitly based on the policies and strategies which are approved by Vector's Board. The Board also approves the asset management plans and associated budget.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	Specific and more detailed asset management strategies are being developed for all assets. Lifecycle cost and service implications are adequately considered in maintenance and replacement decisions. This is an ongoing program of work with the opportunity to improve and integrate the results of Vector's Condition Based Asset Risk Management (CBARM) 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?	2	High level strategies and plans are contained in the Asset Management Plan (AMP). Life cycle activities are documented in the form of standards covering planning, design, equipment selection, operation, maintenance, inspection, testing and decommissioning. Asset condition data, the collection process and specific asset strategies are being improved.		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 Electricity
AMP Planning Period	1 April 2019 – 31 March 2029
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	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	The AMP is communicated to all stakeholders including employees and Field Service Providers (FSPs). The organisation, end to end process, Vector's Delegated Financial Authorities (DFA) and works programmes are all set up to deliver the works effectively. The AMP is also published on Vector's web site.		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 the delivery for the AMP. Vector's delegated authorities framework and policy, and position descriptions for each role define the roles and authorities further.		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	Vector's delivery model is continuously reviewed to identify opportunities to improve efficiencies. Options are also being reviewed to develop and approve longer term work plans, which provide more certainty to Vector FSP's to allow them to resource appropriately and deliver good customer experience, network performance and cost efficiencies.		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	Contingency plans are in place for business continuity, supply restoration, response to natural disasters, health, safety and environmental events. Supplies to critical areas are duplicated and temporary generation is available for emergency supplies. Regular reviews of business continuity and emergency plans are completed to ensure they remain current. Reviews are also completed following major events to identify and make improvements (eg following the April 2018 Auckland storm). Incident management processes and Corporate HSE policies ensure that incident and emergency situations are appropriately managed and reported both internally and to external regulators if required.		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 Electricity
AMP Planning Period	1 April 2019 – 31 March 2029
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	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	As defined in Section 3 of the AMP, the Chief Networks Officer has overall responsibility for Vector's Network Asset Management. Within the asset management context, the CNO is supported by the Chief Financial Officer, Chief Risk Officer, Group Manager Customer and the Chief Digital Officer in ensuring that appropriate systems, policies and procedures are in place that support and enable asset management, as well as implementation of the management and governance practices required by the Board of Directors and Group Chief Executive. The CNO role is responsible for compliance with the requirements of Vector's risk management framework, delegated financial authorities, and in conjunction with the Chief Digital Officer, for ensuring that Vector's Digital Strategy meets the needs of our asset management practice and enables our network vision The Heads of Asset Management, Engineering, Customer Excellence, Networks Programme Delivery, Regulatory and Pricing, Group Manager Information and Insights and Manager, and Business Performance all report to the CNO and are tasked with delivering various parts of the asset management policy and plan. External Field Services Providers have a good understanding of their roles in the delivery of asset management strategy, 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 eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	Vector utilises external contractors and consultants to supplement internal resources to deliver on its AMP. The successful delivery of the current year development and integrity works programme, and the compilation of new sets of standards demonstrates good management of available resources. Vector has developed Talent identification and retention strategies. The primary goal is to reduce the number of top tier employees lost as a result of being under challenged, under-compensated, and under-trained. With the strong growth in Auckland and potential resource constraints, Vector will continue to focus on resource management initiatives. Vector's contracting operating model is being reviewed in the context of Auckland growth with Auckland regional resourcing constraints being managed with the FSP's now recruiting more technical staff overseas.		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.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	Maintenance, design and planning standards have been developed which together, with the controls established in the commercial contracts with the service providers, ensure that the KPI's established are being monitored and deficiencies addressed. Some maintenance information is collected and stored in SAP-PM and other FSP Systems. The requirements and performance expectations are communicated through well-established communications mechanisms. In addition, delivery and performance of some elements are verified by third parties.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Company Name	Vector Electricity
AMP Planning Period	1 April 2019 – 31 March 2029
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	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	An HR strategy is in place to align competencies and human resources with Vector's AMP and strategy, but there is still opportunity to improve. HR Plans for monitoring development and availability of resources by encouraging on-the-job learning, through financial support for formal learning and the investment of time and energy into the career development framework for our employees, thus solidifying the bond between employee and the organisation. This is supported by in-house guest speaker series focused on information sharing and learning, workshops to assist with the development and career planning process, strong mentoring structures and relationships, targeted training programmes for new managers and emerging 'women leaders' and challenging work assignments/projects, ensure retention of our top talent and enhance our pipeline of internal candidates for succession and promotion.		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?	2	The competency requirements and associated training requirements (e.g. Worker Type Competency (WTC) are well established for safety critical activities across Vector and Vector's FSP's. Individuals, when recruited, have their competency assessed against the job skill requirements. Training needs are identified and agreed. Training achieved is recorded in Vector's learning management system.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the 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	The competency requirements and associated training requirements are well established for safety critical activities across both FSP's and Vector. These are assessed regularly and the currency monitored.		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	Score	Evidence—Summary	User Guidance	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	Readily accessible two-way communication channels are in place for staff and other stakeholders in the form of dashboards, reporting, standards, meetings and additional information on Vector's web site. In addition, the FSPs have direct access to a suite of controlled technical standards and pertinent systems, such as GIS and SAP. The effectiveness of these are reviewed and monitored and ongoing improvements to functionality, accessibility and collaboration toolsets are being developed.		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?	3	The AMP is approved by the Board and widely communicated to internal and external stakeholders, including FSPs. In addition, a comprehensive set of design, maintenance and operating standards have been established. Enhancements to Vector's asset management framework and system is underway. A reference enterprise architecture and data model has been developed. The CIM model has been adopted and is being used as the basis for Information Management planning. An enterprise data catalogue is being developed to catalogue systems and data across the Networks business.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	Asset Management Systems have been developed but are evolving further. A data analytics team has been established to deliver consistent and relevant information needed for improved decision-making. Vector has implemented an Information Lifecycle approach to data. The maintenance standards, and design and construction standards have been used as the basis for all data capture. These engineering standards have been translated into a set of Data Standards, which in turn have been used as the input requirements to the Asset Management system, that is SAP PM. Further upgrades to the SAP PM System are planned which will accommodate our new data standards requirements. All maintenance standards are being reviewed with our FSP's, which will ensure end-to-end alignment between the network engineering standards, systems of record and data capture requirements. The implementation of the SAP PM project will further enhance asset life lifecycle capability and support improvements in asset data analytics, data accuracy and capability to improve decision making.		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?	2	Controls have been developed to manage Asset Master Data (Physical asset data) across all systems. These controls are being revised and aligned with the design and construction standards. In addition, data QA and QC processes are being implemented for all maintenance data, across the PM lifecycle. SAP-PM is being further developed for integration interfaces to ensure a standardised data model and standardised method of serving and consuming maintenance related data. Automated tools for data quality checking and alerting are being considered.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	Business requirements such as condition data and updated maintenance standards have driven the need for a wide range of new asset data. Vector's objective is to align the Asset Management system of record with the Maintenance and Construction standards through formal Data Standards. Asset information systems technical roadmaps have been developed to support asset management needs. These roadmaps will be implemented to enable the plan. The implementation of the SAP PM project will also support this together with the improvements in Customer Information Data to support the new energy future strategy.		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	Risk management processes are documented and managed proactively with the aid of supporting systems such as Active Risk Manager (ARM), Risk and Incident Management System (RIMS), Failure Mode and Effects Analysis (FMEA), HSE Management Systems and Bowtie Analysis. Both the FMEA and Safety Management Systems specifically work to identify risks through the asset lifecycle. These activities and systems are aligned through an established framework. Improvements in the identification of risk controls and assurance activities are ongoing.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	Risk assessments are used to support asset management decisions associated with asset management strategies and plans, and the prioritisation and allocation of resources, budget and activities. The influence of risk management is well documented in Vector's asset strategy documentation. Further improvements are being developed around CBARM and the optimisation process to improve the robustness of the risk management process.		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	Vector's Regulatory and pricing team advises the business of its obligations. The business manages it's legal obligations using "Comply With" software. This includes HSE requirements. Regulatory changes are assessed and corresponding changes are made to business operating procedures and practices. In addition, Vector's asset management is also subject to external audit.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	A suite of technical standards form the basis of Vector's control and management of its network assets. These are supported by the AMP, a maintenance plan and good project and operations management. The effective management of associated projects, budgets and high level work plans are monitored against the expectations established in the AMP.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
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?	2	New maintenance standards are being deployed with more specific data requirements and defined data standards. Further improvements are being developed in the form of audits and better continuous improvement processes. Implementing of the proposed improvements in SAP PM will significantly improve visibility of the AM deliverables expected. This will ensure that activities are completed when required, results recorded consistently and improve the ability to effectively audit, report on and monitor over the lifecycle of the asset. These proposed improvements will support alignment with ISO 55000 and industry best practice.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	Service levels, asset condition and performance information is gathered and reviewed. Vector has also adopted a condition based risk management approach to its asset management together with dashboard KPI's and performance reporting. Ongoing improvements to the collection of asset condition data are underway to support our CBARM models. The updating of the maintenance standards and the associated SAP PM project are also intended to support this.		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	Vector has an investigation process in place and clear responsibilities defined. This is managed in line with Vector's safety management system and is supported by our Risk and Incident Management and Active Risk Manager systems. There are ongoing improvements and upgrades to these systems to provide more functionality, improve visibility and better define links between incidents and risks. Incidents are reported as defined by Vector's Incident Management Process. Major events are investigated systemically, risk assessed and appropriate mitigation plans are developed. Ownership of the actions are defined and followed up and reported on.		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	Score	Evidence—Summary	User Guidance	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	Vector has an established audit procedure. External and internal audits, and reviews on asset management practices are carried out on a regular basis. Field work carried out by contractors is sample audited. However, further improvements in the internal audit process and end-to-end capture of audit actions is underway. Proposed improvements include the development of Asset Management Systems and associated audit requirements; auditing of maintenance standards to ensure they are being followed effectively by the FSP's; closer monitoring of "as built" information to improve data accuracy and the implementation of new standards and supporting information management system changes.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Actions arising from audits, investigations, risks and legal compliance are captured in various registers. Formal corrective and preventative actions are recorded and completed as required with appropriate accountabilities and responsibilities assigned. Work is underway to improve the administration of corrective / preventative work through the consolidation of actions into one system.		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?	2	Continuous improvement processes exist for the ongoing improvements to Vector's technical standards. Internal action registers are also in place to capture improvements, associated risks, audits and asset performance reviews, and lessons learnt. Optimisation improvements across risk, cost and performance will improve with improved data and SAP reporting, currently underway. In addition, further embedded risk thinking and assurance processes will drive continuous improvement in budgeting, strategic thinking and project optimisation. Improvements to enable more condition based data to support this are under development. eg. SAP PM project and new maintenance standards. These improvements together with the development of CBARM models for the major asset classes will further support the continual improvement and optimisation of the performance of assets across their asset lifecycle.		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	Vector participates in a number of national and international working groups to identify new asset management technologies and practices. A dedicated team is in place to review new technologies e.g. Lidar, grid batteries, solar, hot water load control and mPrest etc.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Appendix 13 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 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 a capital expenditure inflator based on the model used by the Commerce Commission in its DPP price reset on 1 April 2015. We have used an inflator which is a mix of Capital Goods Price Index (CGPI) and Labour Cost Index (LCI). The weighting between CGPI (50%) and LCI (50%) is based on the Vector 2017/18 year cost structure, i.e. the capital goods component and labour cost component in our CAPEX.

The CGPI forecast is 2%, which is based on a 10-year average to June 2018. The LCI forecast is 2%, which is based on a 10-year New Zealand average to June 2018.

The constant price capital expenditure forecast is inflated by the above-mentioned index to convert to a nominal price capital expenditure forecast.

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

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

BOX 2: COMMENTARY ON DIFFERENCE BETWEEN NOMINAL AND CONSTANT PRICE OPERATIONAL EXPENDITURE FORECASTS

Vector has used an operational expenditure inflator based on the model used by the Commerce Commission in its DPP price reset on 1 April 2015. We have used an inflator which is a mix of Producer Price Index (PPI) and Labour Cost Index (LCI). The weighting between PPI (40%) and LCI (60%) as per the Commission's model.

Vector has used the NZIER (New Zealand Institute of Economic Research) December 2018 PPI (Producer Price Index-outputs) forecast up to March 2023. Thereafter, we have assumed a long-term inflation rate of 2.50%.

The LCI forecast is 2%, which is based on a 10 year New Zealand average to June 2018.

The constant price operational expenditure forecast is inflated by the above-mentioned index to convert to a nominal price operational expenditure forecast.

Appendix 14 Certificate for Year Beginning Disclosures

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Bob Thomson, and Mike Buczkowski, 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 measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 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

29 March 2019

Date