Electricity
Asset Management Plan
2012 – 2022

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Executive Summary

[Disclosure AMP]

Summary of the Asset Management Plan

Vector aims to be:

“New Zealand’s first choice for integrated infrastructure solutions that build a better, brighter future”




This Asset Management Plan supports achieving our vision.

Purpose of the Plan

The purpose of this Asset Management Plan (AMP) is to comply with requirement 7 of the Commerce Commission’s Electricity Distribution (Information Disclosure) Requirements 2008. It covers a ten year planning period from 1st April 2012 to 30th June 2022.

The AMP accurately represents asset management practices at Vector as well as the forecasted ten year capital and maintenance expenditure on the Vector electricity network[1]. The objectives of the AMP are to:

- Inform stakeholders about how Vector intends to manage its electricity distribution network based on information available at preparation;
- Demonstrate alignment between electricity network asset management and Vector’s vision and goals;
- Provide visibility of effective asset management at Vector;
- Provide visibility of forecast electricity network investment programmes[2] and forecast medium-term construction activities to external users of the AMP;
- Demonstrate innovation and efficiency improvements;
- Discuss the impact of regulatory settings on future investment decisions;

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[1] After allowing for the difference between Vector’s financial year (Jul-Jun) and the regulatory financial year (Apr – Mar).

[2] Vector acknowledges that the Commission’s AMP Requirements 4.5.5e, 4.5.5f and 4.5.5g (analysis of options considered) suggests that a full options analysis should be provided for all material growth projects over the whole AMP planning period. However, given the size of the Vector network, the annual growth expenditure and the number of projects such an analysis would have to include, we do not have sufficient planning resources available to fully meet this requirement and do not believe that it is economically efficient to expand our team for this purpose. Vector has therefore (for economic reasons) decided to only focus its option analysis for AMP purposes on nearer term, large projects. A full option analysis is carried out on all projects as part of our business case planning and approval process.

- Discuss expected technology and consumer developments and the asset investment strategies to deal with a changing environment; and
- Meet Vector's regulatory obligations under the aforementioned information disclosure requirements.

From an asset manager perspective the AMP:

- Supports continued efficient improvement in Vector's performance;
- Is essential to our goal to be effective asset managers; and
- Will help the Vector Group achieve its overarching vision.

BUSINESS OPERATING ENVIRONMENT

Qualification

This AMP represents Vector's current and best view of the ongoing investment, maintenance and operational requirements of its electricity network, in the current operating environment. However, as discussed below, the business faces significant ongoing uncertainty, especially in relation to the current investment landscape and the still-developing regulatory environment. This has a direct impact on Vector's ability to make investment decisions and attract investment capital.

Vector follows an annual budget process and the implementation of the works programmes may be modified to reflect any changing operational and economic conditions as they exist or are foreseen at the time of finalising the budget, or to accommodate changes in regulatory or customer requirements that may occur from time to time. Any expenditure must be approved through normal internal governance procedures. This AMP does therefore not commit Vector to any of the individual projects or initiatives or the defined timelines described in the plan.

Economic Factors

Economic cycles impact on business activities and hence electricity demand particularly on business sectors. GDP figures published by Statistics NZ over the past three years ending March 2011 show two recent years of very low growth (1.4% and 1.8% for the years ending March 2011 and 2010) following a year of negative growth (-3.5% for the year ending March 2009). Other economic indicators such as consumer and business confidence, unemployment rate and housing construction are also pointing towards a cautious recovery. During the same period, electricity delivered through the Vector network recorded growth rates of 4.4%, 0.8% and 0.5% respectively. Overseas, various economies are facing uncertainties caused by state debt burden, the fading effect of economic stimulus packages and low consumer confidence leading to low rates of job creation and economy activities. The impact of this on New Zealand's export earnings and therefore the state of its economy is still uncertain.

For the purposes of this AMP, Vector has assumed that economic growth will resume at relatively modest levels in the short to medium term and that new connection and consumption growth patterns will continue at historical rates.

Regulatory Factors

As a supplier of electricity distribution services, Vector's electricity distribution business is subject to price and quality regulation. This regulation is undertaken by the Commerce Commission under Part 4 of the Commerce Act 1986. Part 4 was amended in 2008 with objectives including the promotion of regulatory certainty and incentives for regulated businesses to invest.

The Commerce Commission, with input from stakeholders including Vector, is currently in the process of implementing Part 4. Vector does not believe that the current Input Methodologies for Electricity Distribution Services, determined in December 2010, provide an adequate level of certainty or investment incentives. In particular, the cost of capital input methodology would not permit commercially realistic returns on investment and the asset valuation input methodology does not allow for a robust asset valuation to be developed at the start of the new regulatory regime. The Commission's decisions on the input methodologies and the regulatory process have been subject to a series of legal challenges, including from Vector.

Greater certainty and improved incentives to invest should emerge once the legal challenges are complete. However, these may not be settled until 2013 and final prices may not be determined until 2014. As the next regulatory price reset is scheduled for 2015, it is likely that considerable regulatory uncertainty will remain a feature of the investment environment until 1 April 2015 and possibly beyond.

It is also not clear whether the regulatory regime and/or customer expectations will support investment in reliability improvements or energy efficiency. The quality requirements for electricity distribution businesses focus only on maintaining the current level of quality of supply, not on improving it. The Commerce Act (Section 54Q) requires the Commission to promote investment by electricity distribution businesses in energy efficiency. However, the Commission has yet to implement this requirement. In the absence of quality or efficiency incentives, investment may only maintain, not improve, energy efficiency or quality of supply on regulated networks such as Vector's.

Technical Factors

Vector anticipates that Auckland will experience continued population increase and associated growth in business activities and electricity demand for the foreseeable future.

This will inevitably involve strengthening the existing electricity distribution network through conventional means, but will also employ emerging technology and alternative energy sources to enhance utilisation of existing network assets and defer investments where feasible to do so. Underlying all of this, Vector will continue to ensure a safe and reliable electricity supply, meeting our customers' electricity demand requirements.

Improvements in the AMP and Asset Management at Vector

Vector noted the results of the Commerce Commission reviews of the 2009 and 2011 AMPs. Vector's 2011 AMP has already been thoroughly revised to reflect the Commission's feedback. This (2012) AMP builds on the 2011 document and incorporates further developments in Vector's approach to and thinking on asset management as well as comments from the 2012 AMP review.

Vector has, over an extended period, engaged external expert technical advisers on an annual basis to review its asset management practices. While these reviews have been very positive in their feedback – confirming asset management at Vector conforms to industry best-practice – we have taken note of the feedback and recommendations received, and where practical and beneficial, reflected this in our asset management practices.

Important further changes recorded in this AMP include:

- The investment plan for network development has been expanded, based on changing electricity demand patterns, updated customer requirements and reflecting the impact of Vector's ongoing capex efficiency improvements. It also reflects in more detail the project options considered;

- The renewal investment plan reflect increased availability of historical performance information, continuing improvement in our understanding of asset performance, commencing the application of an enhanced condition based risk management approach to asset replacement decisions and more detailed justification of investments;
- The AMP includes an updated reflection of Vector's ongoing research into the impact and opportunities of changing network and customer technology and deployment strategies;
- Load forecasting and security of supply methodologies have been further developed and are described in more detail, including treatment of embedded generation and effect of demand management on demand projection, reflecting these developments; and
- The description of the explicit link between asset investment and achieving Vector's overarching strategy and goals is further developed.

Vector's Network

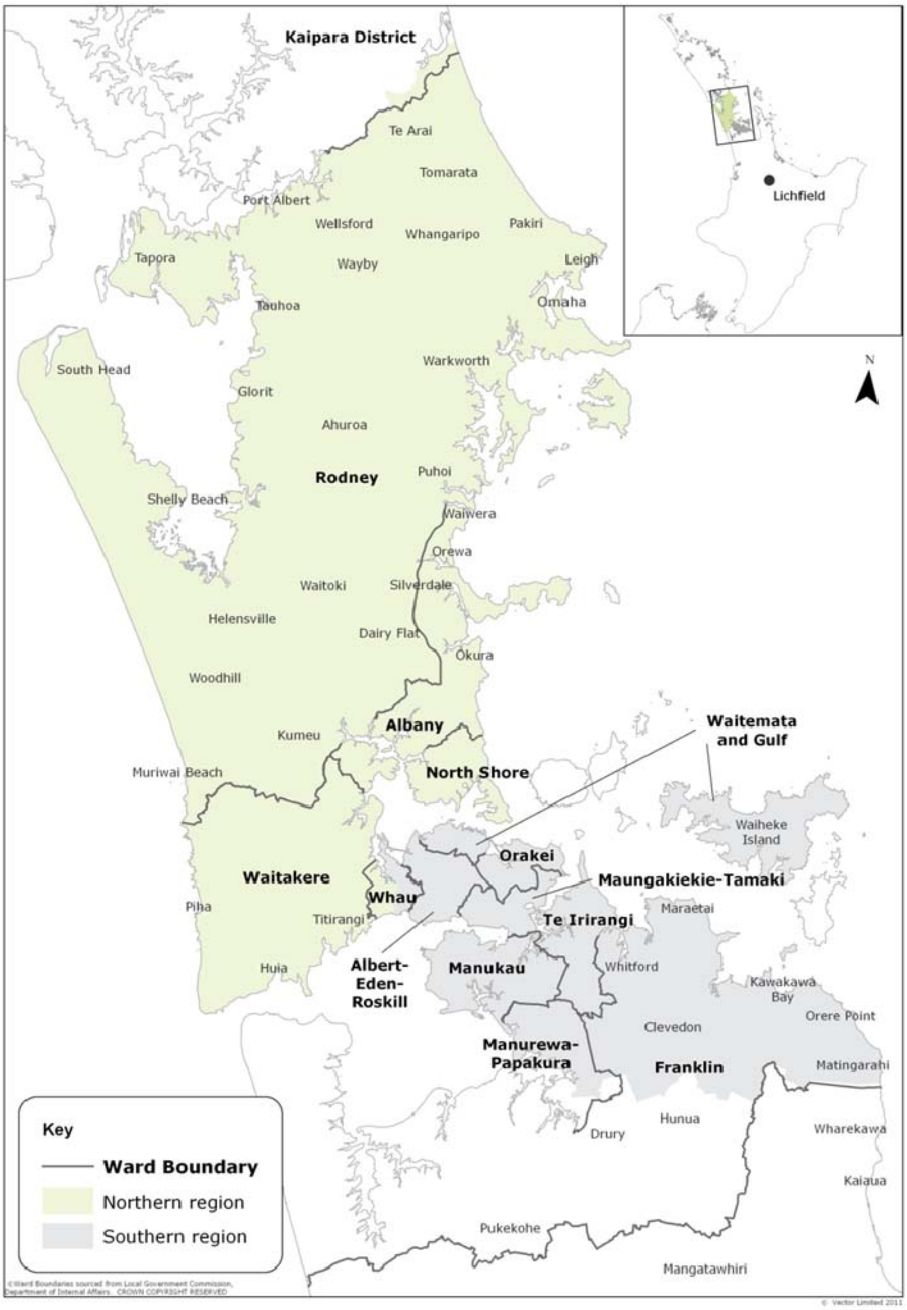
Vector's supply area covers most of the area administered by the recently formed Auckland Council as shown in the map below. Vector operates an electrically contiguous network[3] from Papakura in the south to Rodney in the north. While Vector operates this as a single network, for legacy reasons, it is convenient to describe a Southern region and a Northern region to reflect the different characteristics of the networks.

The Northern region covers those areas administered by the previous North Shore City Council, the Waitakere City Council and the Rodney District Council, and consists of residential and commercial areas in the southern urban areas, light industrial and commercial developments around the Albany Basin, and residential and farming communities in the northern rural areas.

The Southern region covers areas administered by the previous Auckland City Council, the Manukau City Council and the Papakura District Council, and consists of residential and commercial developments around the urban areas on the isthmus, concentrated commercial developments in the Auckland central business district (CBD), industrial developments around Rosebank, Penrose and Wiri areas, and rural residential and farming communities in the eastern rural areas.

In addition, Vector supplies a large customer at Lichfield which is a stand-alone supply.

[3] In addition to the electricity network in Auckland, Vector also owns an 11kV network to supply the Fonterra cheese factory at Lichfield.



Network Summary (Year ending 31st March 2011)

Description	Quantity
Consumer connections	531,185
Network maximum demand (MW)*	1,722
Energy injected (GWh)*	8,679
Lines and cables (km)**	17,720
Zone substations***	104
Distribution transformers	20,962

* Includes embedded generation exports

** Energised circuit length

*** Figure includes Lichfield but excludes Auckland Hospital and Highbrook

Demand Forecasts

Demand growth remains a key investment driver for the electricity distribution network. As noted before, Vector is observing short-term fluctuations in annual peak demand. However, the underlying factors supporting long-term growth remain in place and in the longer term a continued increase in maximum electricity demand is anticipated.

Vector has been monitoring developments of various technologies that could impact on the demand and demand characteristics on the network and this has been incorporated in our demand forecasts (with various scenarios analysed).

As in previous years, the demand forecast takes into account any existing and known new distributed generation, reactive compensation development and demand management policies.

The winter and summer demand forecasts are detailed at zone substation level in Section 5.3. The maximum network demand and energy consumption for the 2010/11 (regulatory year) is given below.

	Peak Demand* (MW)	Total Energy Injected (GWh)
From grid exit points	1,710	8,589
From embedded generation**	12	90
Total	1,722	8,679

* Coincident demand

** Embedded generation excludes Southdown

Network Development

Planning Criteria

Vector's approach to network development planning is driven by:

- Ensuring the safety of the public, our staff and our service providers;
- Meeting network capacity and security requirements in an economically efficient manner;
- Customer needs, which vary by customer segment and are reflected by service level standards and associated pricing;
- Striving for least life-cycle cost solutions (optimum asset utilisation) and optimum timing for capex;
- Maximising capex efficiency in a sustainable manner;
- Outcomes that improve asset utilisation take into account the increased risk trade-off;
- Incorporating enhanced risk management strategies and processes into our planning philosophy;
- Continuously striving for innovation and optimisation in network design, and trialling new technology such as remote switching technology, smart meters at distribution substations, LV/MV monitoring and control technologies to improve network performance;

- Encouraging non network and demand-side solutions where economic and practicable;
- Reference to targets set by industry best practice where economic and practical;
- Ensuring assets are operated within their design (cyclical) rating;
- Meeting statutory requirements such as voltage, power quality (PQ); and
- Providing different levels of service to different customer segments, reflecting as far as practicable their desired price/quality trade-off.

Vector's planning criteria are detailed in Section 5 of this AMP.

Network Development Plan

Vector's ten-year network development plan is described in Section 5 of the AMP.

This plan details the anticipated electricity demand in the various parts of the Auckland region for the next ten years. Based on these demand forecasts and our network planning criteria, various projects are planned (and alternatives considered) to ensure that supply capacity and security will be maintained at economic levels. Planning is especially detailed for the first five years of the plan.

Service Commitment

Vector operates two forms of supply contracts with its customers. In the Southern region, Vector contracts directly with the end users for line services. In the Northern region Vector contracts with energy retailers for line services, while end users contract with energy retailers for both energy and line services (interpose arrangement).

In the Southern region, Vector promotes its service commitment through the "Vector promise" under which Vector provides its customers a prescribed supply quality and service standard, or a level of compensation where this is not achieved. The level of service delivered to customers depends on the location of the customer. Homes in the city or urban areas generally have better reliability than those in rural areas. This is mainly due to the extensive use of overhead networks in rural areas, and the associated length and exposure to the environment of these. While urban networks are not immune, rural networks are more prone to interference from factors that are largely outside Vector's control, such as severe weather conditions, bird strikes, car versus pole accidents and other environmental factors. (Note that incidents arising as a result of bulk supply failures – generation or transmission – or of extreme events are excluded from this scheme).

A similar "Charter payment" arrangement operates in the Northern region under which Vector provides the end users a prescribed supply quality through the retailers, with a level of compensation (channelled through the retailer) where this is not achieved.

During 2009 Vector concluded outage management agreements with most retailers, to improve customer experience in reporting problems and improve response times. Vector's customers are now put in direct contact with Vector's own response staff should an outage be the result of a distribution network problem.

Vector's supply quality and service standards are explained in detail in Section 4 of this AMP.

Asset Management Planning

Maintenance Planning Policies and Criteria

Vector's overall philosophy on maintaining network assets is based on four key factors:

- Ensuring the safety of consumers, the public and the network field staff;
- Ensuring reliable and sustainable network operation, in a cost-efficient manner;
- Achieving the optimal trade off between maintenance and replacement costs. That is, replacing assets only when it becomes more expensive to keep them in service. Vector has adopted, where practicable, condition-based assessments rather than age based replacement programmes; and
- Integration (alignment) of asset management practices given we are a multi utility asset manager.

Vector has developed maintenance standards for each major class of asset it owns. These detail the required inspection, condition monitoring and maintenance tasks, and the frequency at which these are required. The goal of these standards is to ensure that assets can operate safely and efficiently to their rated capacity for at least their full normal lives. Data and information needs for maintenance purposes are also specified.

Based on these maintenance standards, to ensure that all assets are appropriately inspected and maintained, Vector's maintenance contractors develop an annual maintenance schedule for each class of asset they are responsible for. The asset maintenance schedules are aggregated to form the overall annual maintenance plan which is implemented once it has been signed off by Vector. Progress against the plan is monitored monthly.

Defects identified during the inspections are recorded in the contractor's defect database with a copy being kept by Vector. Contractors prioritise the defects for remedial work based on risk and safety criteria. Work necessary in less than three months is undertaken immediately as corrective maintenance. Work that can be carried out over a three to twelve month period is included in the corrective maintenance or asset replacement programme. Work not required within 12 months is generally held over for the future.

Root cause analysis is normally undertaken as a result of faulted equipment. This is also supplemented by fault trend analysis. If performance issues with a particular type of asset are identified, and if the risk exposure warrants it, a project will be developed to carry out the appropriate remedial actions. The asset and maintenance standards are also adapted based on learning from such root cause analysis.

The following summarises the different types of maintenance programmes for the electricity network assets:

- Preventative maintenance:
    - Asset inspections as per asset management standards;
    - Condition testing as specified in asset management standards; and
    - Inspection and test intervals based on industry best practice and Vector experience.
- Corrective maintenance:
    - Correction of defects identified through preventative maintenance.
- Reactive maintenance:

- Correction of asset defects caused by external influences, or asset failure.

- Value added maintenance:
  - Asset protection (e.g. cable location and marking, stand-overs).
- Vegetation maintenance:
  - Preventing interference or damage to assets (e.g. tree-trimming).
- Non-core maintenance:
  - Non-standard assets (e.g. tunnels) and maintaining spares.

Asset Renewal Planning

Vector's asset renewal plans are discussed in Section 6. The overall asset-condition of various asset categories is discussed in detail, highlighting areas where upgrades or renewal is required (as well as the process and factors to support these decisions). This forms the basis of the ten-year asset renewal programme.

In general Vector replaces assets on a condition-assessment rather than age-basis. We strive to achieve the optimal replacement point where the risk associated with asset failure and the likelihood of this occurring becomes unacceptably high, and it is more economically efficient to replace an asset than to continue to maintain it.

Vector is continually monitoring local and international developments in asset maintenance. Based on our surveys and advice from experts, we have identified the substantial benefits that leading utilities are achieving though adopting a formal condition-based risk management (CBRM) framework for the renewal and maintenance of their electricity network assets. As part of its ongoing improvement programme, Vector is therefore in the process of adopting this approach for the future prioritisation of its renewal and maintenance activities.

Risk Management

Risk Management Policies

Managing risk is one of Vector's highest priorities. Risk management is practiced at all levels of the organisation and is overseen by the Board Risk and Assurance Committee and the Executive Risk and Assurance Committee.

Vector's risk management policy is designed to ensure that material risks to the business are identified, understood, and reported and that controls to avoid or mitigate the effects of these risks are in place. Detailed contingency plans are also in place to assist Vector in managing high impact events.

The consequences and likelihood of failure or non performance, current controls to manage these, and required actions to reduce risks, are all documented, understood and evaluated as part of the asset management function. Risks associated with the assets or operations of the network are evaluated, prioritised and dealt with as part of the network development, asset maintenance, refurbishment and replacement programmes, and work practices.

Asset-related risks are managed by a combination of:

- Reducing the probability of failure through the capital and maintenance work programme and enhanced work practices, including design standards, equipment specification and selection, quality monitoring, heightened contractor and public awareness of the proximity of or potential impact of interfering with assets; and

- Reducing the impact of failure through the application of appropriate network security standards and network architecture, selected use of automation, robust contingency planning and performance management of field responses.

The capital and maintenance asset risk management strategies are outlined in the Asset Maintenance and Network Development sections (Section 6 and Section 5). Vector's contingency and emergency planning is based around procedures for restoring power in the event of a fault on the network, and is detailed in Section 5 of this AMP.

Vector also recognises that information technology (IT) systems are a very important part of its business and asset management framework. Vector operates advanced real-time network control and protection systems, deeply integrated with the IT systems of the rest of the business. Potential compromise of the (cyber) security of our IT systems, including our real-time control systems, is recognised as a major (and increasing) business and network risk. Over the past two years Vector has implemented several enhancements to its cyber-security systems to manage this risk and create a more robust operating environment. Further security enhancements will be implemented on an ongoing basis.

Health and Safety

At Vector, safety is a fundamental value, not merely a priority. We are committed to a goal of zero harm to people, assets and the environment. Vector's Health and Safety Policies can be found in Section 8 of this AMP. In summary, the policies are developed to ensure safety and wellbeing of its staff, contractors and the public at its work sites and around its assets.

To achieve this Vector aims to comply with all relevant health and safety legislation, standards and codes of practices; establish procedures to ensure its safety policies are followed; encourage its staff and service providers to participate in activities that will improve their health, safety and wellbeing; and take all practical steps to ensure its field services providers (FSPs) adhere to Vector's health and safety policies and procedures. Vector's health and safety practice can be found in Section 8 of this AMP.

The passing of the Electricity Amendment Act 2006 required companies in New Zealand engaged in the distribution of electricity to develop, implement and maintain a Safety Management System that will ensure their distribution networks do not pose a significant risk of serious harm to members of the public or of significant damage to public property. Vector is well positioned to meet the requirements of the new regulations and intends to review and update its current policies and practices in preparation for an external audit that is to be completed in 2012.

Environment

Vector's environmental policy is contained in Section 8 of this AMP. In summary, the policy is developed to monitor and improve Vector's environmental performance and to take preventive action to avoid adverse environmental effects of our operation.

To achieve this Vector will:

- Plan to avoid, remedy or mitigate adverse environment effects of our operations; and
- Focus on responsible energy management and energy efficiency for all our premises, plant and equipment where it is cost effective to do so.

Vector's long term operational objectives with regard to environmental factors are to:

- Utilise fuel as efficiently as practicable;

- Mitigate, where economically feasible, fugitive emissions and in particular greenhouse gas emissions;
- Wherever practicable use ambient and renewable energy; and
- Work with consumers to maximise energy efficiency.

Approval of the AMP and Reporting on Progress

Approval of the disclosure AMP is sought once a year, at the March Vector board meeting. This timing is aligned with the regulatory requirement to publish a disclosure AMP at the end of March each year. No update of the AMP is made between publication dates.

Progress in implementing Vector's asset management plan is regularly monitored, and progress against its investment plans and asset performance measured through several metrics, including:

- Monthly reporting on progress and expenditure on major projects/programmes;
- Reliability performance – SAIDI, SAIFI, CAIDI (network wide, as well as on a per feeder or zone substation basis);
- Performance and utilisation of key assets such as sub-transmission cables, distribution feeders, power transformers, etc.;
- Progress with risk register actions;
- Health, safety and environmental issues; and
- Security of supply.

Financial Forecasts

The following table summarises the capital and operations & maintenance expenditure forecast covering the AMP planning period.

Budget and Expenditure Forecast	Actual	2011 AMP budget	Forecast									
	RY11	RY12	RY13	RY14	RY15	RY16	RY17	RY18	RY19	RY20	RY21	RY22
Customer connection	$25.7 m	$21.6 m	$25.0 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m
System growth	$31.1 m	$55.5 m	$56.1 m	$47.5 m	$40.3 m	$46.9 m	$37.2 m	$35.8 m	$27.0 m	$30.0 m	$34.9 m	$42.8 m
Asset replacement and renewal	$56.1 m	$55.9 m	$65.9 m	$69.6 m	$63.2 m	$63.7 m	$59.0 m	$60.0 m	$59.2 m	$59.5 m	$57.2 m	$56.4 m
Reliability, safety & environmental	$2.6 m	$3.4 m	$6.9 m	$6.6 m	$5.1 m	$4.4 m	$4.4 m	$4.4 m	$4.1 m	$3.4 m	$2.5 m	$2.3 m
Asset relocation (including undergrounding)	$17.1 m	$25.8 m	$25.2 m	$22.3 m	$19.2 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m
Capital Expenditure Subtotal	**$132.6 m**	**$162.2 m**	**$179.1 m**	**$170.6 m**	**$152.4 m**	**$158.0 m**	**$143.5 m**	**$143.1 m**	**$133.2 m**	**$135.8 m**	**$137.5 m**	**$144.4 m**
Routine & preventive maintenance	$15.2 m	$19.6 m	$19.6 m	$19.8 m	$19.7 m	$19.9 m	$19.9 m	$20.0 m	$20.0 m	$20.1 m	$20.2 m	$20.3 m
Refurbishment & renewal	$10.3 m	$11.6 m	$11.6 m	$12.0 m	$11.9 m	$11.9 m	$11.0 m	$10.7 m	$10.7 m	$10.8 m	$10.7 m	$10.7 m
Fault and emergency	$13.1 m	$13.0 m	$13.0 m	$13.1 m	$13.1 m	$13.2 m	$13.3 m	$13.3 m	$13.4 m	$13.5 m	$13.6 m	$13.6 m
O & M Subtotal	**$38.6 m**	**$44.2 m**	**$44.2 m**	**$44.8 m**	**$44.8 m**	**$44.9 m**	**$44.1 m**	**$44.0 m**	**$44.2 m**	**$44.4 m**	**$44.5 m**	**$44.7 m**
Total Direct Expenditure	**$171.2 m**	**$206.4 m**	**$223.2 m**	**$215.3 m**	**$197.1 m**	**$202.9 m**	**$187.6 m**	**$187.1 m**	**$177.4 m**	**$180.2 m**	**$182.0 m**	**$189.1 m**
Overhead to underground	$7.7 m	$17.3 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m

* Figures are in January 2012 dollars (million);

** The year reference indicates the end date of the financial year

Glossary of Terms

A	Ampere
AAC	All aluminium conductor
AAAC	All aluminium alloy conductor
ABS	Air break switch
ac	Alternating current
ACSR	Aluminium conductor steel reinforced
ADMD	After diversity maximum demand
AELG	Auckland Engineering Lifelines Group
ALIS	Asset Lifecycle Information System
AMP	Asset management plan
AUFLS	Automatic under frequency load shedding
AI	Asset Investment, a functional unit at Vector
BRAC	Board risk and assurance committee
Capex	Capital expenditure
CATI	Computer assisted telephone interviewing
CAU	Census Area Unit
CB	Circuit breaker
CBD	Central business district
CBRM	Condition based risk management
CDEM	Civil Defence Emergency Management
CIM	Common information model, as defined by IEC 61970-301
CMS	Customer Management System
CPI	Consumer price index
CPP	Customised Price-Quality Price Path
Cu	Copper
dc	Direct current
DFA	Delegated financial authority
DGA	Dissolved gas analysis
DP	Degree of polymerisation
DPP	Default Price-Quality Price Path
EGCC	Electricity and Gas Complaints Commission
ERAC	Executive risk and assurance committee
EV	Electric Vehicle
FAR	Fixed asset register
FF cables	Fluid filled cables
FSP	Field service provider
FY	Vector financial year (year ending 30th June)
GIS	Geospatial Information System
GXP	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).
HV	High voltage – ac rated voltages above 52kV (IEC62271)
HVABC	High voltage aerial bundle cable
IEC	International Electrotechnical Commission
IED	Intelligent electronic data and/or devices
IP	Internet protocol
km	Kilometre
KPI	Key performance indicators
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere reactive

kW	Kilowatt
LV	Low voltage – ac rated voltages below 1kV
LVABC	Low voltage aerial bundle cable
LTOS	Live tank oil sampling
MCR	Maximum continuous rating
MGCU	Mobile generator connection unit
Micro grid	Parts of the distribution network that can be isolated and operated in an island state under contingency situations
MIS	Maintenance Information System
MUSA	Multi utility service agreement
MV	Medium voltage – ac rated voltages above 1kV up to and including 52kV
MVA	Mega volt ampere
MVAr	Mega volt ampere reactive
MW	Megawatt
NER	Neutral Earthing Resistor
OCB	Oil type circuit breakers
ODV	Optimised deprival value/valuation
Opex	Operational expenditure
PD	Partial discharge test
PI	Plant information system
PIAS	Paper insulated aluminium sheath
PILC	Paper insulated lead cable
PQ	Power quality
PQM	Power quality monitor
PV	Photo-voltaic
RAB	Regulatory asset base
RTU	Remote terminal unit
RY	Regulatory year (year ending 31st March)
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAP	Systems Applications and Processes (Vector's corporate enterprise resource planning system)
SAP-BW	SAP Business Warehouse
SAP-FI	SAP Financial Information
SAP-GIS	SAP Geospatial Information System
SAP-MM	SAP Materials Management
SAP-PM	SAP Plant Maintenance module
SCADA	Supervisory Control and Data Acquisition system
SD	Service Delivery, a functional unit at Vector
SF_6	Sulphur hexafluoride
SF_6GIS	HV switchgear using Sulphur hexafluoride as the insulation and breaking medium
SLA	Service level agreement
SWA	Steel wire armour
TAM	Technical asset master
TASA	Tap changer activity signature analysis
TC	Technical Council
TCA	Transformer condition assessment
THD	Total harmonic distortion
TUDS	Total Underground Distribution System
V	Volt
VCB	Vacuum circuit breaker
VRLA	Valve regulated lead acid

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 sub-transmission voltage (110kV, 33kV or 22kV) to distribution voltage (22kV or 11kV).
Distribution voltage	A substation for transforming electricity from distribution voltage (22kV or 11kV) to 400V distribution voltage.
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).
National grid (or grid)	The 110kV and/or 220kV 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.

Electricity
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2012 – 2022

Background and Objectives – Section 1

[Disclosure AMP]

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1. Background and Objectives

1.1 Context for Asset Management at Vector

Asset management is critical for ensuring Vector's electricity distribution business provides safe and reliable services which meet the needs and expectations of consumers, help to achieve the business' commercial and strategic objectives and satisfies its regulatory obligations. Effective planning helps ensure Vector maintains and invests appropriately in its network. Vector's ongoing goal is to ensure good industry practice asset management, given its critical nature to the business and consumers, while reflecting the regulatory and economic environment within which it finds itself.

Vector also recognises that providing a network that is safe to customers, the public and operators alike is a top priority. This is reflected in our work processes and standards, as well as the safety management system that is currently being enhanced from the present well developed systems.

The asset management framework adopted for Vector's electricity distribution business is illustrated in Figure 1-1.

This is a generic asset management model widely adopted by many types of infrastructure businesses. The framework is superimposed on the environment within which Vector operates.

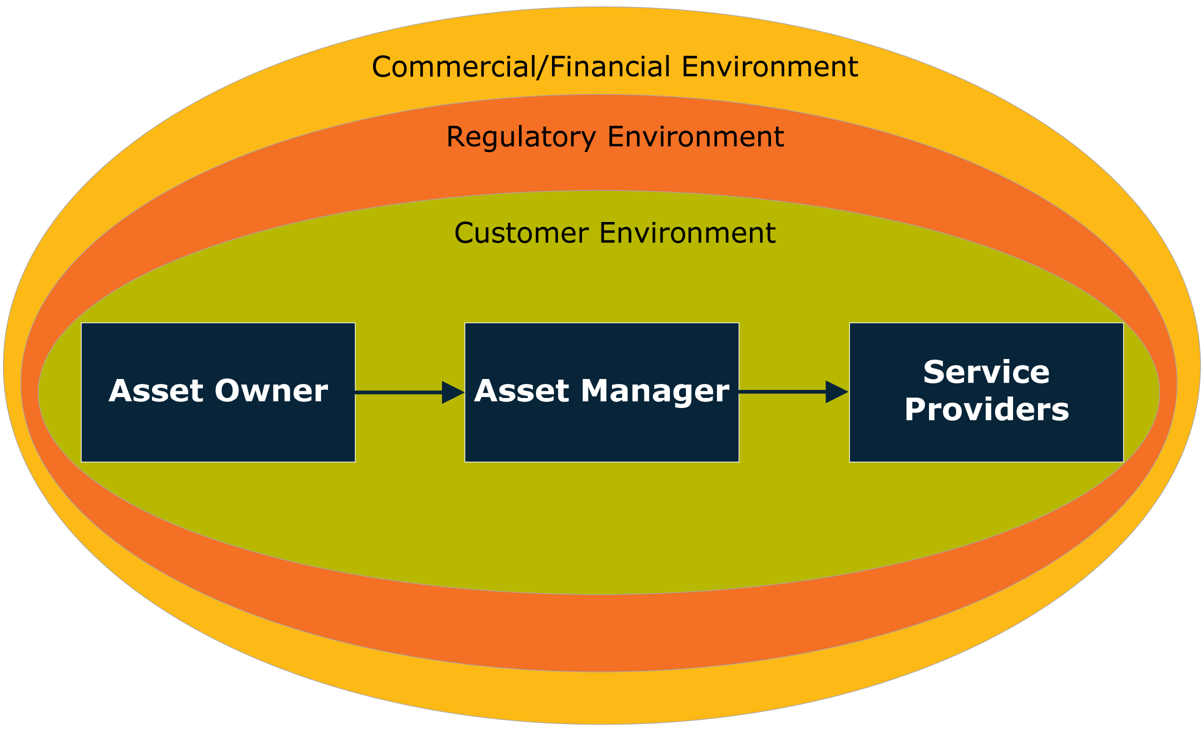

Figure 1-1 : Vector's asset management framework

In this model, the Asset Owner is the highest level of management within the organisation that owns the assets. In Vector's case this is the Vector executive, with oversight from the Vector Board. The Asset Owner determines the operating context for the Asset Manager, focusing on corporate governance and goals, and the relationship with regulators and other stakeholders.

The Asset Manager develops the asset management strategy, directs asset risk management, asset investment and asset maintenance planning, and decides where and how asset investment is made in accordance with directions set by the Asset Owner. The Asset Manager sets policies, standards and procedures for the service providers to implement. In Vector the Asset Manager function is, broadly, the responsibility of the Asset Investment (AI) group.

The Service Providers are responsible for delivering asset investment programmes, to maintain and operate the assets based on the guidelines set by the Asset Manager.

Vector's service providers are a combination of the Service Delivery (SD) group -capital programmes, network operations and service operations - and the external contractors and consultants supporting them (see Section 1.7 for a discussion).

Asset management is strongly influenced by safety and customer needs as well as commercial, financial and regulatory requirements:

- Safety is one of Vector's key priorities. The Health and Safety Policy sets out the directives of Vector's health and safety framework to ensure health and safety considerations are part of all business decisions.
- Customer needs and expectations, along with safety and technical regulations, are the key determinants of network design. Network layout and capacity is designed to ensure contracted or reasonably anticipated customer demand can be met during all normal operating circumstances. Quality of supply levels, which relate to the level of redundancy built into a network to avoid or minimise outages under abnormal operating conditions have been translated into the Vector electricity network security standards[1]. These standards balance customer requirements and the value they place on reliability of supply with the level of service Vector can economically and safely provide.[2]

  Most direct interaction with customers occurs through the Commercial group. Asset management involves close interaction with the Commercial group to assist with understanding and addressing customer technical requirements, consumption forecasts and upcoming developments.
- There are technical and commercial regulations around how networks are allowed to be built and operated, how network services are provided and sold, and the limits on commercial returns on investments. These regulations directly influence investment decisions. There are also a number of regulatory compliance rules that have an impact on network configuration and operations.

  Regulatory certainty and a suitable rate of return on investments are critical to the investment framework, given the long-term nature of the assets and the need for electricity distribution businesses to have confidence that they can expect to recover their cost of capital (i.e. earn a sustainable commercial return) from efficient and prudent investment. Importantly, Vector also has to attract capital both locally and from offshore.[3]

[1] These are discussed in section 5 of the AMP (asset management plan).

[2] Customers who require a higher standard of supply than that provided under the normal Vector security standards, can contract for that.

[3] In Vector's experience, the New Zealand regulatory regime is often cited by capital markets and rating agencies as being uncertain.

Direct contact with the regulators is generally maintained through the Regulation and Pricing group, which in turn works with the Asset Manager to provide guidance on regulatory issues and requirements. Setting and executing regulatory strategy is also closely intertwined with asset investment activities.

- Vector operates in a commercial environment where shareholders expect a commercially appropriate return on their investments reflecting the risk of the investment. To maintain commercially sustainable returns, Vector has to ensure it is able to make optimal investment and maintenance in the network, including replacement, upgrades and new assets while always keeping safety as a priority. This requires demonstration that investment decisions are not only economically efficient, but that realistic alternative options have been investigated to ensure the most beneficial solution – technically and commercially – is applied. This may involve taking a view on likely future technical changes in the energy sector.

  In addition, financial governance has a direct and significant bearing on asset management. Capital allocation and expenditure approvals are carefully managed in accordance with Vector's governance policies. Short and long-term budgeting processes take into account the balance between network needs, construction resources and available funding – requiring careful project prioritisation.

  Asset management, in particular where expenditure is involved, therefore requires close interaction with the Finance and Service Delivery groups.

In the context described above, a Vector asset management plan (AMP) was developed to define Vector's asset management policies, responsibilities, targets, investment plans and strategies to deal with the future of the electricity network. It describes Vector's asset management policies, responsibilities, targets, investment plans and strategies to provide confidence to its Board and regulators that it has considered all options to ensure the electricity distribution network is maintained and enhanced to deliver a commercially sustainable return to shareholders and meets the needs of consumers, while ensuring safe and efficient electricity network operations. It also reflects feedback obtained from customers on their requirements for the quality and cost of their electricity supplies, and the manner in which they interact with Vector. The plan sets out the forward path for Vector's electricity network capital investment and maintenance needs and how we intend to address these.

While this asset management plan's emphasis is on electricity network asset management, it is a document used Vector-wide. It supports the achievement of the vision and goals of the wider company through maximising the efficiency of asset management activities. Rather than being prepared in isolation by and for the electricity business only, the plan is guided by Vector's overall goals, relies extensively on inputs from all areas within Vector, and one of its key functions is to provide visibility on the asset investment strategies and forecasts to the entire company.

This plan is also publicly disclosed to satisfy Vector's regulatory obligation. To satisfy the Information Disclosure requirements, the contents of this AMP are presented in accordance with the regulatory requirements and Information Disclosure Handbook guidelines.

1.1.1 Relationship between Asset Management and Vector's Strategies and Goals

As indicated above, the Asset Owner determines the operating context for the Asset Manager, focusing on corporate governance, strategies and goals, and the relationship between regulatory issues and other stakeholder requirements. The Asset Manager interprets these strategies and goals and translates the strategic intentions into an asset investment strategy which is supported by a series of asset management policies. Technical standards, work practices and equipment specifications support the asset management policies, guiding the capital and operational works programmes.

Performance of the network is monitored against a set of performance indicators that are based on realising customer expectations, meeting regulatory requirements, meeting safety obligations and achieving best-practice network operation.

The diagram in Figure 1-2 illustrates the relationship between Vector's corporate strategies and goals with its asset management policy framework.

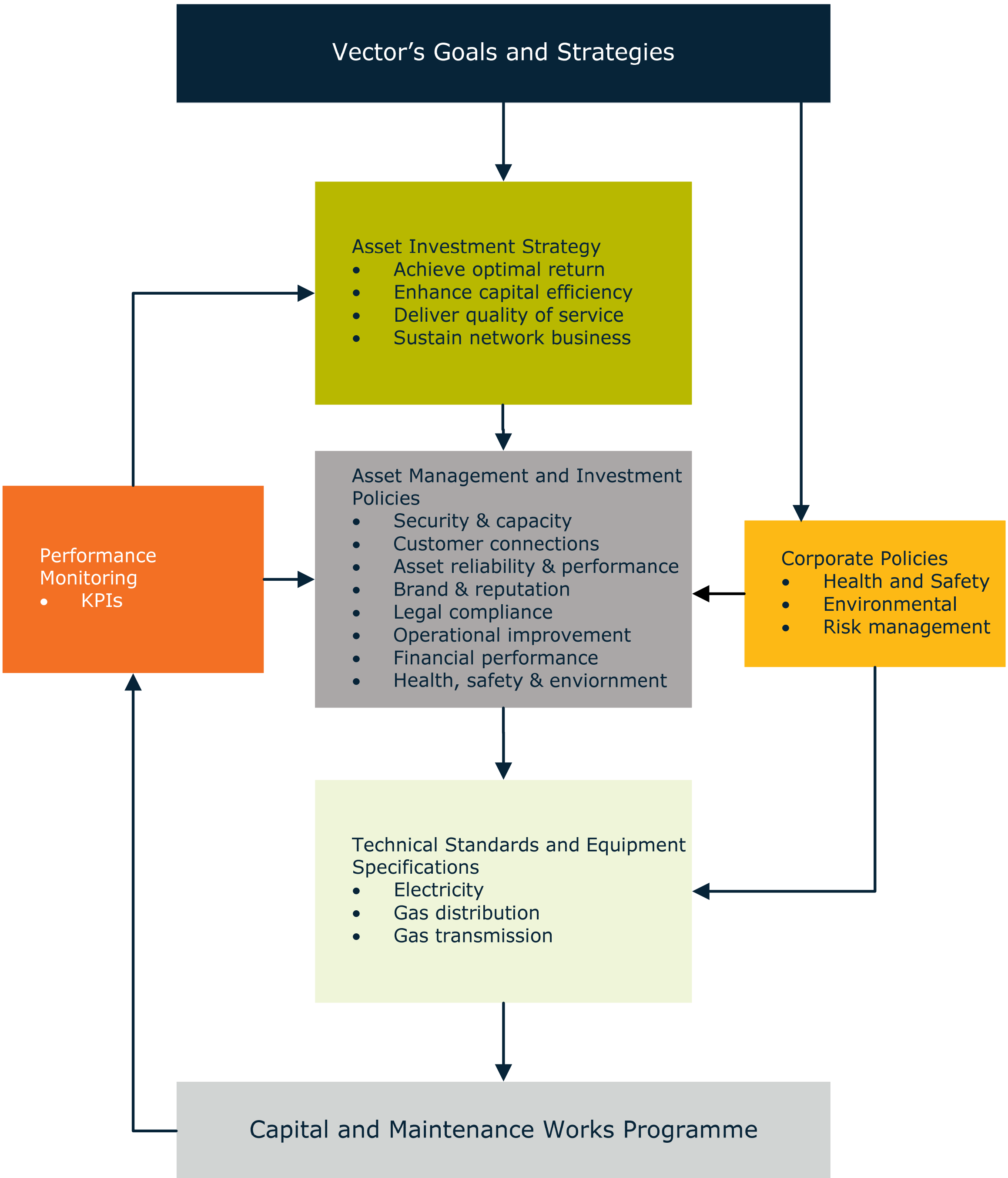

Figure 1-2 : How Vector's asset management strategies and policies relate to the strategic goals

Vector's electricity network asset management objective is to efficiently and effectively deliver safe and reliable electricity network services to customers at a quality commensurate with their technical and economic preferences.

1.2 Planning Period and Approval Date

This AMP covers a ten year planning period, from 1st April 2012 through to 30th June 2022[4] and was approved by the board of directors on 13 March 2012.

The first five years of the plan is based on detailed analysis of customer, network and asset information and hence provides a relatively high degree of accuracy (to the extent reasonably possible) in the descriptions and forecasts. The capital and maintenance budgets set out in the plan, particularly for the first year, are important inputs into Vector's annual budgeting cycle.

The latter period of the plan is based on progressively less certain information and an accordingly less accurate and detailed level of analysis. From year five on, the AMP is only suitable for provisional planning purposes. In addition to the normal variability around asset performance and customer growth patterns, the accelerating rate of development in technologies such as photovoltaic panels, electric vehicles, smart network and home appliances, batteries and fuel cells is introducing even more uncertainty in the medium to long-term future of network development.

1.3 Purpose of the Plan

This regulatory AMP has been developed as part of requirement 7 of the Commerce Commission's Electricity Distribution Disclosure Requirements 2008 and covers ten years starting on 1st April 2012. The purposes of this AMP are to:

- Inform stakeholders how Vector intends to manage and expand its electricity distribution network based on information available at preparation;
- Demonstrate the impact of regulatory settings on future investment decisions;
- Demonstrate alignment between electricity network asset management and Vector's goals and values;
- Demonstrate innovation and efficiency improvements;
- Provide visibility of effective asset management at Vector;
- Provide guidance of asset management activities to its staff and field service providers;
- Provide visibility of forecasted electricity network investment programmes and upcoming medium-term construction programmes to external users of the AMP;
- Discuss Vector's views on expected technology and consumer developments and the asset investment strategies to deal with a changing environment; and
- Meet Vector's regulatory obligation under the aforementioned requirement.
- Demonstrate that safe management processes are in place.

This AMP does not commit Vector to any of the individual projects or initiatives or the defined timelines described in the plan. Vector follows an annual budget process and the implementation of the works programmes may be modified to reflect any changing

[4] Vector operates to a June financial year. All asset management and financial reporting is carried out based on its financial calendar. Works programmes and the corresponding expenditures presented in this document align with its financial reporting timeframes. To comply with the Commerce Commission's Electricity Information Disclosure Requirements 2008, the budgets and expenditure forecasts in Section 9 are converted into regulatory years (ending on 31st March). This plan therefore covers the ten financial years from July 2012 to June 2022 as well as the three months prior to the start of the 2012 financial year.

operational and economic conditions as they exist or are foreseen at the time of finalising the budget, or to accommodate changes in regulatory or customer requirements that may occur from time to time. Any expenditure must be approved through normal internal governance procedures.

1.3.1 Asset Management in Support of Vector's Vision

Vector's strategic vision is to be:

"New Zealand's first choice for integrated infrastructure solutions that build a better, brighter future"

To support Vector in achieving this vision a number of group goals have been defined. The group goals are supported by the strategies of the various Vector business units. Asset management, as captured in this AMP, is a key part of the wider AI business plan and consequently plays an important part in achieving the overall Vector vision. The manner in which the AMP supports Vector's vision is demonstrated in Figure 1-3.

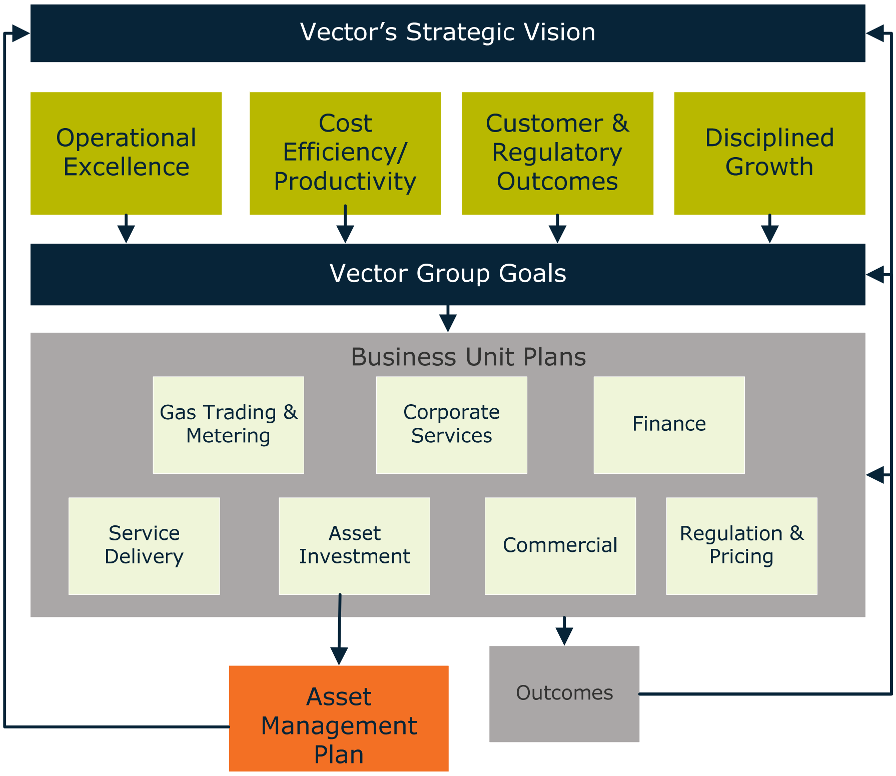

Figure 1-3 : The AMP in support of the overall Vector strategic vision

Table 1-1 below demonstrates how asset management supports Vector to achieve its strategic objectives[5].

Group Goal	**Asset Management in support of**
Disciplined Growth	• Investigate new technologies and associated opportunities • Optimise capital contributions • Support commercially attractive investments • Innovation and optimal investment efficiency • Economies of scale from long-term view
Customer and Regulatory Outcomes	• Providing safe and reliable services • Fit-for-purpose network designs • Understanding and reflecting customer needs in designs • Security and reliability levels adapted to customer needs • Meeting regulatory requirements • Maintaining appropriate price/quality trade-off • Detailed five-year expenditure budgets • Strategic scenario planning •
Operational Excellence, Cost Efficiency & Productivity	• Safety is a top priority • Full compliance with health, safety and environmental regulations • Needs clearly defined • Understanding risks • Technical excellence • Reliable asset information source • High quality network planning • Effective maintenance planning • Fit-for-purpose network designs • Providing reliable service • Security and reliability levels adapted to customer needs • Easy-to-maintain and operate networks • Investigate new technologies and opportunities offered • Clear prioritisation standards • Clear roles and responsibilities for asset management • Strong, well-documented asset management processes • Support sustainability of partners • Clear communication of network standards and designs
People Engagement	• Health and safety, environmental and risk management principles implemented at an asset investment level • Asset management and performance expectations clearly set • Clear roles and responsibilities

Table 1-1 : How asset management supports Vector's group goals

1.3.2 Vector's Vision Driving Asset Management

The previous section indicated how asset management at Vector supports the group's overall vision and goals. Conversely, and very importantly for this AMP, the Vector vision and goals also sets the framework and fundamental parameters for asset management[6]. This is illustrated in Table 1-2.

[5] The group goals and initiatives are not in any priority order.

[6] The group goals and initiatives are not in any priority order.

Group Goal driving	Asset Management
Disciplined Growth	• Keep abreast of technology changes • Seek optimal commercial outcomes in investment decisions • Innovation and capital efficiency • Optimised network solutions • Optimised investment timing • New product development and investment where economically viable
Customer & Regulatory Outcomes	• Understanding customer needs and recognising this in decisions • Good project communications • Appropriate price/quality trade-off • Soundly justified investment programme • High quality asset data management • Fit-for-purpose solutions • Security of supply levels appropriate to customer needs • Respond to regulatory quality incentives (when they are introduced) • Keep abreast of technology changes
Operational Excellence, Cost Efficiency & Productivity	• Effective consideration of HS&E in investment and maintenance decisions • Asset decisions reflects safe networks as top priority • Implement high priority projects only • Appropriate to network environment • Maintain appropriate risk levels • Fit-for-purpose solutionsEasy-to-maintain and operate networks • Consistent project prioritisation • Minimising asset environmental impact • Standardisation • Clear roles and responsibilities • Strong, well-documented asset management processes • Clear forward view on upcoming work • Consider partner capacity
People Engagement	• Setting KPIs for company and individual performance • Technical training & development • Leadership development

Table 1-2 : How Vector's group goals drive asset management

1.3.3 Key Assumptions for the AMP

On a practical level, incorporating the Vector values and goals in the asset management strategy determines the fundamental assumptions or premises on which the AMP is based. These assumptions[7], listed in Table 1-3 below, reflect the manner in which AI understands and implements Vector's strategic direction.

Following the earthquakes experienced in Christchurch and the implications this has highlighted for operating utility services, Vector has reviewed its network standards during the course of 2011 and, where necessary, adapted these to reflect our key learnings. Flowing from this, we have embarked on a 10-year program to seismically upgrade potentially vulnerable substation buildings – as reflected in this AMP.

[7] The assumptions are not listed in any priority order.

Key Premises for the AMP	
The present industry structure remains	• The Vector electricity network will continue to operate as a stand-alone, regulated electricity distribution business (not vertically-integrated). Open access of the network will be maintained. • The transmission grid will continue to be owned and operated by a separate entity. Grid development will continue broadly in its current direction and the existing grid will be maintained in accordance with good industry practice, ensuring that sufficient electricity capacity, at appropriate reliability levels, will be retained to meet the needs of Vector's customers.
Existing Vector electricity business operation model remains	• Field services will continue to be outsourced. Adequate resources with the relevant skills will be available to implement the works programme to deliver the service to the required level. (Alternative approaches for field services provision were investigated three years ago, prior to the current field services contracts being awarded. The commercial model for these contracts is continually tested and refined. Any changes to the provisions of the contract require negotiation with the field services providers.)
Current supply reliability levels remain unchanged	• Under the current regulatory arrangement in New Zealand, there is no clear incentive to improve network reliability from historical levels. However, it is imperative that reliability does not materially deteriorate. Under current price quality regulation Vector will therefore ensure reliability levels are maintained. • Customer survey results indicate Vector's customers in general are satisfied with the quality of service they receive, at the level of price they pay for the service. There is no material evidence to support increased service levels with the associated price increases.
Safety will not be compromised	• Safety of the public, our staff and our contractors is paramount. Asset management must drive this. • Current safety regulations place the accountability for public safety on Vector as the owner of the assets. This is not expected to change.[8] • Vector fully complies with New Zealand safety codes, prescribed network operating practices and regulations.
A deteriorating asset base will be avoided	• In general, assets will be replaced when economic to do so, which is likely to be before they become obsolescent, reach an unacceptable condition, can no longer be maintained or operated, or suffer from poor reliability. (In a number of instances where it is technically and economically optimal and safety is maintained, some assets will be run to failure before being replaced.)
Regulatory requirements will be met	• Regulatory requirements with regards to information disclosure or required operating standards will be met accurately and efficiently.
A sustainable, long-term focused network will be maintained	• Asset investment levels will be appropriate to support the effective, safe and reliable operation of the network. • Expenditure will be incurred at the economically optimum investment stage without unduly compromising supply security, safety and reliability. • New assets will be good quality and full life-cycle costing will be considered rather than short-term factors only. • Networks will be effectively maintained, adhering to international best-practice asset management principles. • Avoid over design or building excess assets. • Investments must provide an appropriate commercially sustainable return reflecting their risks.
Existing efficiency, reliability and supply quality levels will generally be	• This may change, depending on the Commerce Commission's decisions in relation to an s-factor regime to improve quality and the Commission's final interpretation of Section 54Q of the Commerce Act and the regulatory incentives (or disincentives) this brings about.

[8] This does not absolve out service providers from meeting Vector's health & safety obligations, particularly in respect of public safety – Vector requires full compliance to our health and safety policies from all our service providers. Their performance in this regard is audited on a regular basis, with serious penalties in place should breaches be observed.

Key Premises for the AMP	
maintained	• At present there is no regulatory incentive to improve efficiency, reliability of quality of supply.
Under normal operating conditions the full required demand will be met	• Assets will not be unduly stressed or used beyond appropriate short or long-term ratings to avoid damage. This is part of maintaining a long term sustainable electricity distribution network.
Network security standards (for delivery) will be met	• In exceptional cases breaches may be accepted, as long as this is consciously accepted, explicitly acknowledged and contingency plans prepared to cater for asset failure. The security standards are based on the optimal trade-off between providing an economically efficient network and Vector's best understanding of customer requirements and the price/quality trade-offs they would like to make.
Asset-related risks will be managed to appropriate levels	• Network risks will be clearly understood and will be removed or appropriately controlled – and documented as such.
An excessive future "bow-wave" of asset replacement will be avoided	• Although asset replacement is not age-predicated, there is a strong correlation between age and condition. To avoid future replacement capacity constraints or rapid performance deterioration, age-profiles will be monitored and appropriate advance actions taken.
Quality of asset data and information will continue to improve	• Vector's asset management is highly dependent on the quality of asset information. Its information system and data quality improvement programme will continue for the foreseeable future.
More non-network solutions will be adopted	• Vector will continue to investigate non-network solutions as practical alternatives to network reinforcements. This includes demand side options, pricing incentives, embedded generation, reactive compensation, alternative fuel, energy storage, etc. Such alternatives will be implemented where it is economical and practical.
New consumer and network technology will progressively influence how the network is operated and utilised	• The rate at which new consumer technologies are developing is accelerating. Demand and consumption patterns are changing and will increasingly impact on how the network is managed. Vector has always actively pursued innovative solutions to address changing consumption patterns, and is in the process of widening out its application of intelligent network devices, making use of the opportunities that the new technologies offer. Subject to economic justification and sufficient regulatory incentives, Vector will therefore continue to invest in its evolution of the intelligent electricity network.

Table 1-3 : Key premises for the AMP

These key premises have a direct and major impact on the quality of service provided by the network, the condition of the assets, the levels of risk accepted and the asset expenditure programmes.

1.4 Changing External Outlook

1.4.1 Economic Outlook

The Auckland region has yet to experience a strong economic recovery following the recession of 2008/09. Recent events around the world and in particular in Europe where several countries face sovereign debt issues, raised the prospect of slowing down the economy recovery and may even cause a second round of recession. The effect of this on New Zealand's economy, in particular the banking and export sectors are not yet clear, but could potentially have significant adverse impact over the short to medium term. Acceleration in the current slow growth trend for electricity demand in Auckland is therefore not anticipated in the foreseeable future (see Section 5.3 of the AMP for a discussion).

1.4.2 Formation of the Auckland Council

From 1 November 2010, the eight district, city and regional councils of Auckland were amalgamated into a single council structure under the Auckland Council. The Auckland Council comprises a single governance body, seven Council-Controlled Organisations (CCO) and 21 local boards. Key structural changes include the establishment of CCOs to manage the transport and water service needs for the region. The diagram in Figure 1-4 shows the structure of the Auckland Council.

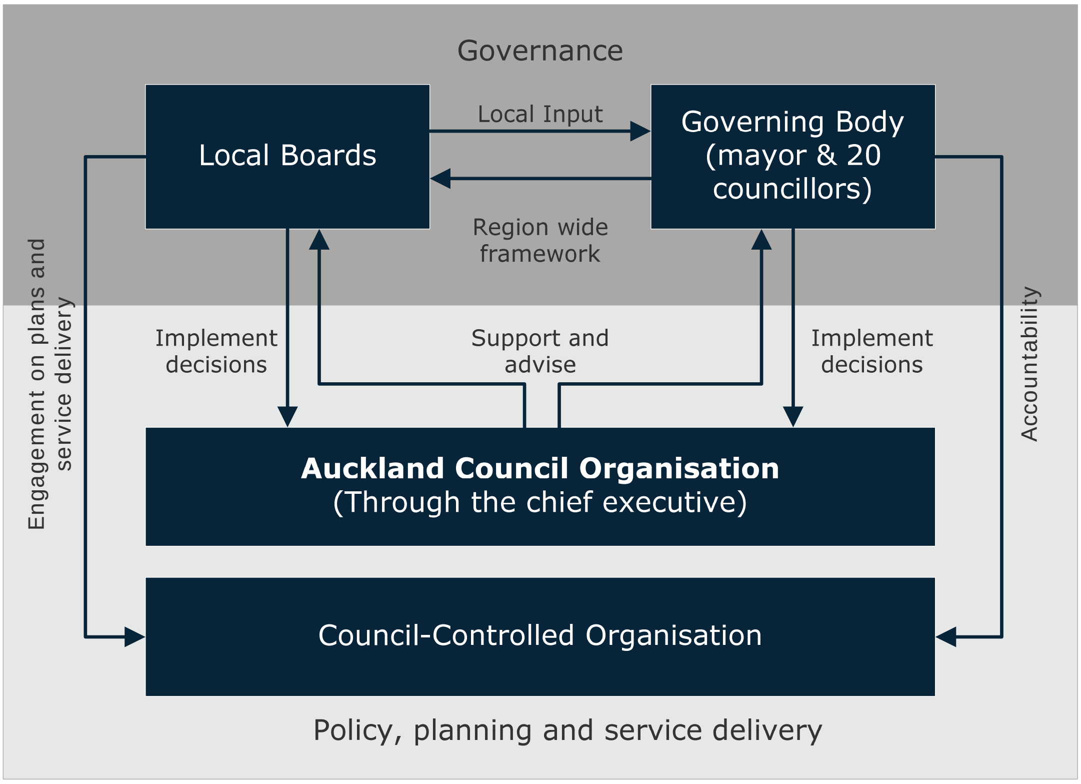

Figure 1-4 : Structure of the Auckland Council

The changes had a significant impact on Vector's activities in the region. A number of key relationships with regional councils have changed as the management of our existing activities across the region was transferred to new entities and new roles. Relationships with the new council are constructively and pro-actively managed.

As required by the legislation establishing the Auckland Council, the Council has to prepare a "spatial plan" to guide Auckland's growth and development strategy 20 to 30 years into the future. In response the Auckland Council has published a draft "Auckland Plan" with the following key features:

- How Auckland may develop in the future, including how growth may be sequenced and how infrastructure may be provided;
- Identification of future location and mix of residential, business, rural production, and industrial activities within Auckland; and critical infrastructure, services, and investment within Auckland (including, services relating to cultural and social infrastructure, transport, open space, water supply, wastewater, and storm-water, and services managed by network utility operators) to support these activities; and

- Identification of policies, priorities, land allocation programmes and investments to implement the strategic direction.

The Auckland Plan is currently being finalised. Once this is in place, Vector's long term network development will take into account the relevant features of this plan.

1.5 Asset Management in the Wider Vector Context – Internal Stakeholders

Asset management at Vector is not practised in isolation. It is heavily reliant on inputs from the various parts of the company, either directly or indirectly. The AMP provides visibility of asset management activities to the rest of the company, for incorporation into the broader business plans and strategies. This two-way support flow is illustrated in Figure 1-5 and Figure 1-6.

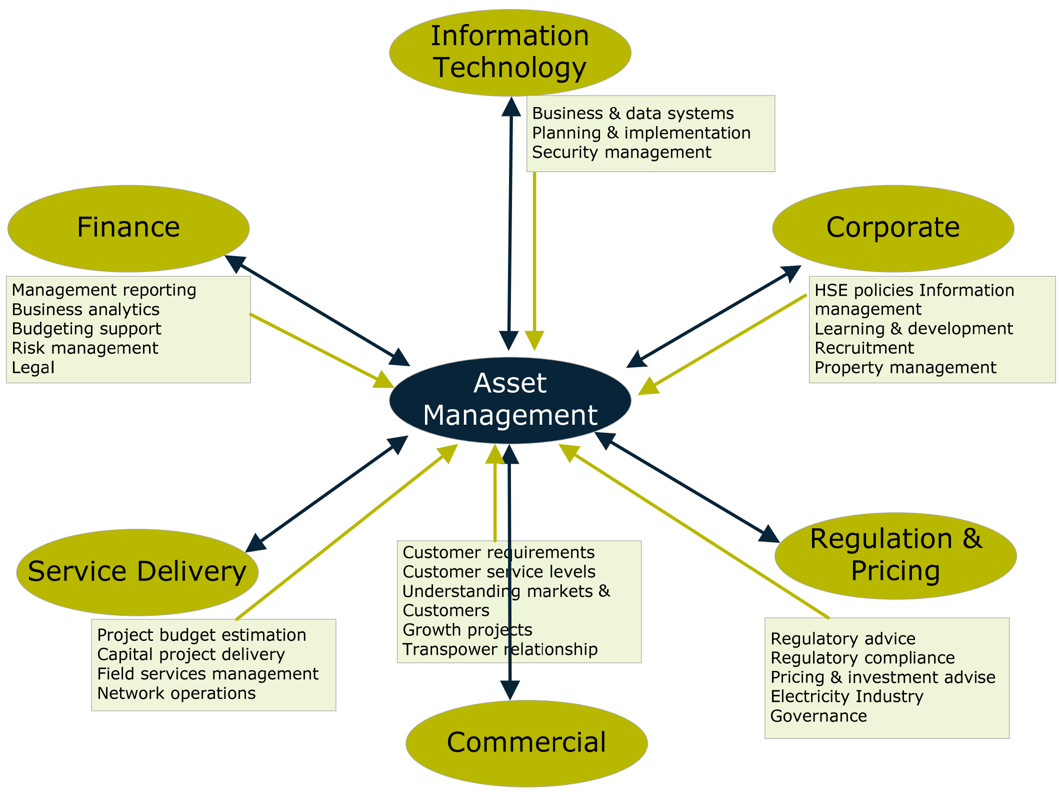

Figure 1-5 : Interaction with the rest of Vector - the flow into asset management

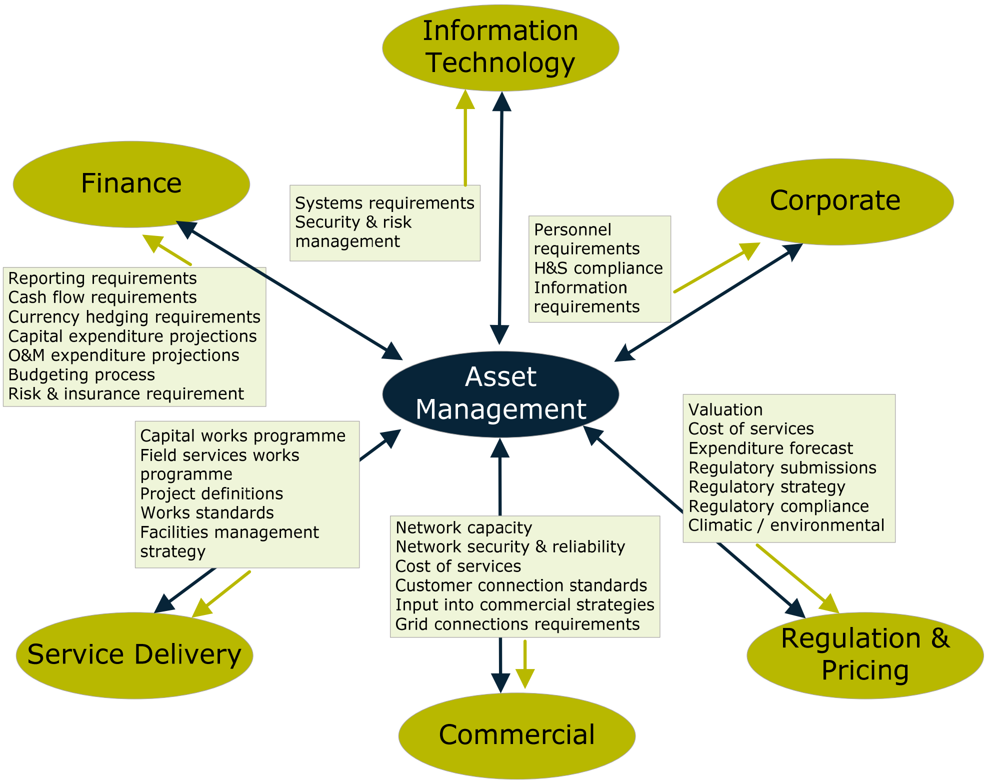

Figure 1-6 : Interaction with the rest of Vector - the flow from asset management

1.6 Asset Management in the Wider Vector Context – External Stakeholders

Vector has a large number of internal and external stakeholders that have an active interest in how the assets of the company are managed. The essential service nature of the service we provide and its importance to the Auckland well-being and economy creates a keen interest in how we conduct our business.

In Figure 1-7, the important external stakeholders to Vector are highlighted. Understanding of how these stakeholders interact with Vector and the requirements or expectations they have of the company has a major bearing on the manner in which we construct and operate the electricity networks.

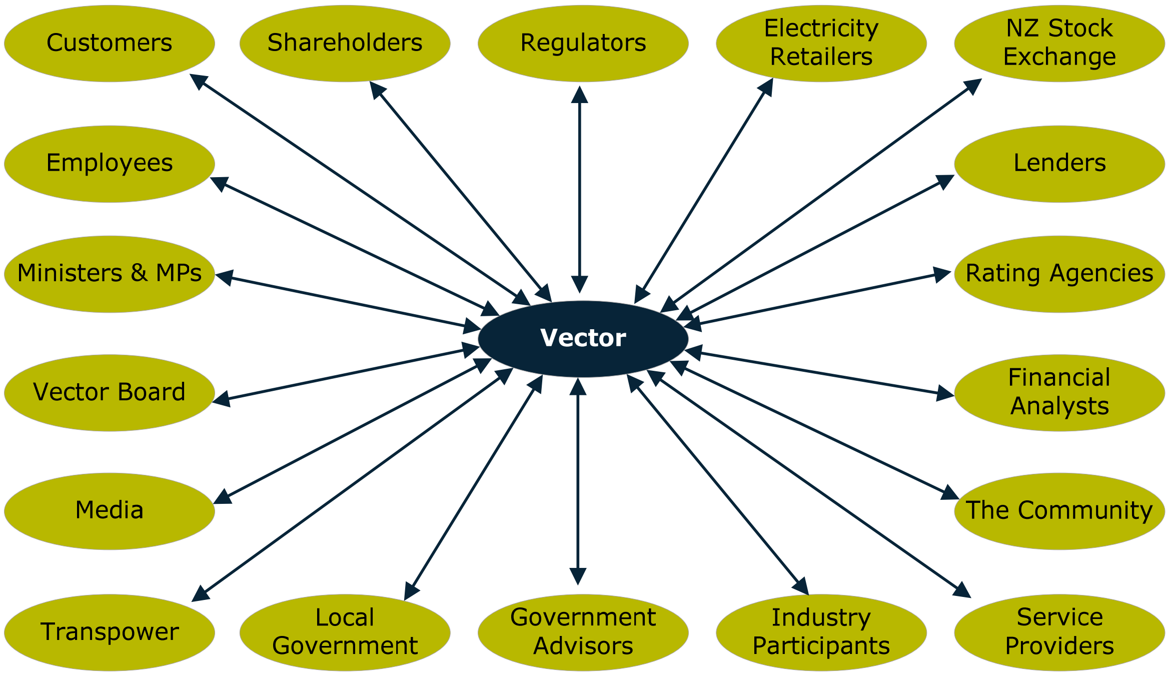

Figure 1-7 : Vector's key external stakeholders

1.6.1 Stakeholder Expectations

Important stakeholder expectations[9] are listed in Table 1-4 below.

Customers (and End-Use Consumers)	
Health and safety Quality of supply Security of supply Efficiency of operations Reasonable price Timely response to outages Innovation, solution-focus	Reliable supply of electricity Planned outages Timely response to complaints and queries Information in fault situations Environment Timely connections
Shareholders	
Health and safety Sustainable growth Sustainable dividend growth Reliability Confidence in board and management Accurate forecasts	Regulatory and legal compliance Prudent risk management Good reputation Good governance Clear strategic direction Return on investment
Retailers	
Reliability of supply Quality of supply Managing any customer issues	Information in fault situations Ease of doing business Good systems and processes

[9] The stakeholders and their expectations are not listed in any order of priority.

Regulators	
Statutory requirements Accurate and timely information	Inputs on specific regulatory issues Input into policy proposals and initiatives Fair and efficient behaviour
Vector Board	
Health, safety and the environment Regulatory and legal compliance Good governance Accurate and timely provision of information Expenditure efficiency	Prudent risk management Security and reliability of supply Return on investment Accurate budgeting
New Zealand Stock Exchange	
Compliance with market rules	Good governance
Financial Analysts/Rating Agencies/Lenders	
Transparency of operations Accurate performance information Clear strategic direction Adhering to New Zealand Stock Exchange rules	Prudent risk management Good governance Accurate forecasts Confidence in board and management
Service Providers	
Safety of the work place Stable work volumes Quality work standards Maintenance standards Clear forward view on workload	Construction standards Innovation Consistent contracts Clearly defined processes Good working relationships
Government Advisors	
Accurate and timely provision of information Vector's views on specific policy issues Efficient and equitable markets	Innovation Infrastructure investment Reduction in emissions
Ministers and MPs	
Security of supply Reliable supply of electricity Efficient and equitable markets Industry leadership	Investment in infrastructure and technologies Environment Good regulatory outcomes Energy and supply outage management
Local Government	
Public safety Environment Coordination between utilities Sustainable business	Support for economic growth in the area Visual and environmental impact Compliance
Community	
Public safety Good corporate citizenship Community sponsorship Electricity safety programme	Engagement on community-related issues Improvement in neighbourhood environment Visual and environmental impact
Energy Industry	

Health and safety Leadership Innovation Participation in industry forums	Policy inputs Influencing regulators and government Sharing experience and learning
Transpower	
Effective relationships Ease of doing business Secured source of supply	Well maintained assets at the networks interface Co-ordinated approach to system planning and operational interfaces Sharing experience and learning
Media	
Effective relationship Access to expertise	Information on company operations

Table 1-4 : Stakeholder expectations

Vector ascertains its stakeholders' expectations by, amongst other things:

- Meetings and discussion forums;
- Consumer engagement surveys;
- Engagement with legislative consultation processes;
- Employee engagement surveys;
- Annual planning sessions;
- Direct liaison with customers;
- Membership on industry working groups;
- Feedback received via complaints and compliments;
- Investor roadshows and annual general meetings;
- Analyst enquiries and presentations;
- Monitor analyst reports;
- Media enquiries and meetings with media representatives; and
- Monitoring publications and media releases.

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 safe and reliable distribution network;
- Quality of supply performance meeting consumers' needs and expectations;
- Optimisation 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;
- Security standards reflecting consumers' needs and expectations;
- Network growth and development plans;
- Provision of accurate and timely information;

- Development of innovative solutions; and
- Comprehensive asset replacement strategies.

1.6.2 Addressing Conflicts with Stakeholder Interests

In the operation of any large organisation with numerous stakeholders with diverse interests, situations will inevitably arise where not all stakeholder interests can be accommodated, or where conflicting interests exist. From a Vector asset management perspective, these are managed as follows:

- Clearly identifying and analysing stakeholder conflicts (existing or potential);
- Having a clear set of fundamental principles drawing on Vector's vision and goals, on which compromises will normally not be considered (see the list in Section 1.3);
- 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; and
- Where Vector fundamentals are not compromised, seeking an acceptable alternative or commercial solution.

Other aspects considered when assessing aspects impacting on stakeholder interests or resolving conflicts include:

- Health and safety;
- Cost/benefit analysis;
- Central and local government interface and policies;
- Commercial and technical regulation;
- Long-term planning strategy and framework;
- Environmental impacts;
- Societal and community impacts;
- Legal implications;
- Sustainability of solutions (technically and economically);
- Works/projects prioritisation process;
- Security and reliability standards;
- Quality of supply;
- Risks; and
- Work and materials standards and specifications.

At a practical level in relation to asset management, 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. At an investment decision level, a project prioritisation matrix (Table 9.1) has been developed to provide guidance on the selection of projects for implementation.

1.7 Asset Management Structure and Responsibilities

1.7.1 Senior Level Organisation Structure

The Vector senior level organisation structure is provided in Figure 1-8 below. The Vector group is split into several functional areas, each with a responsible general manager.

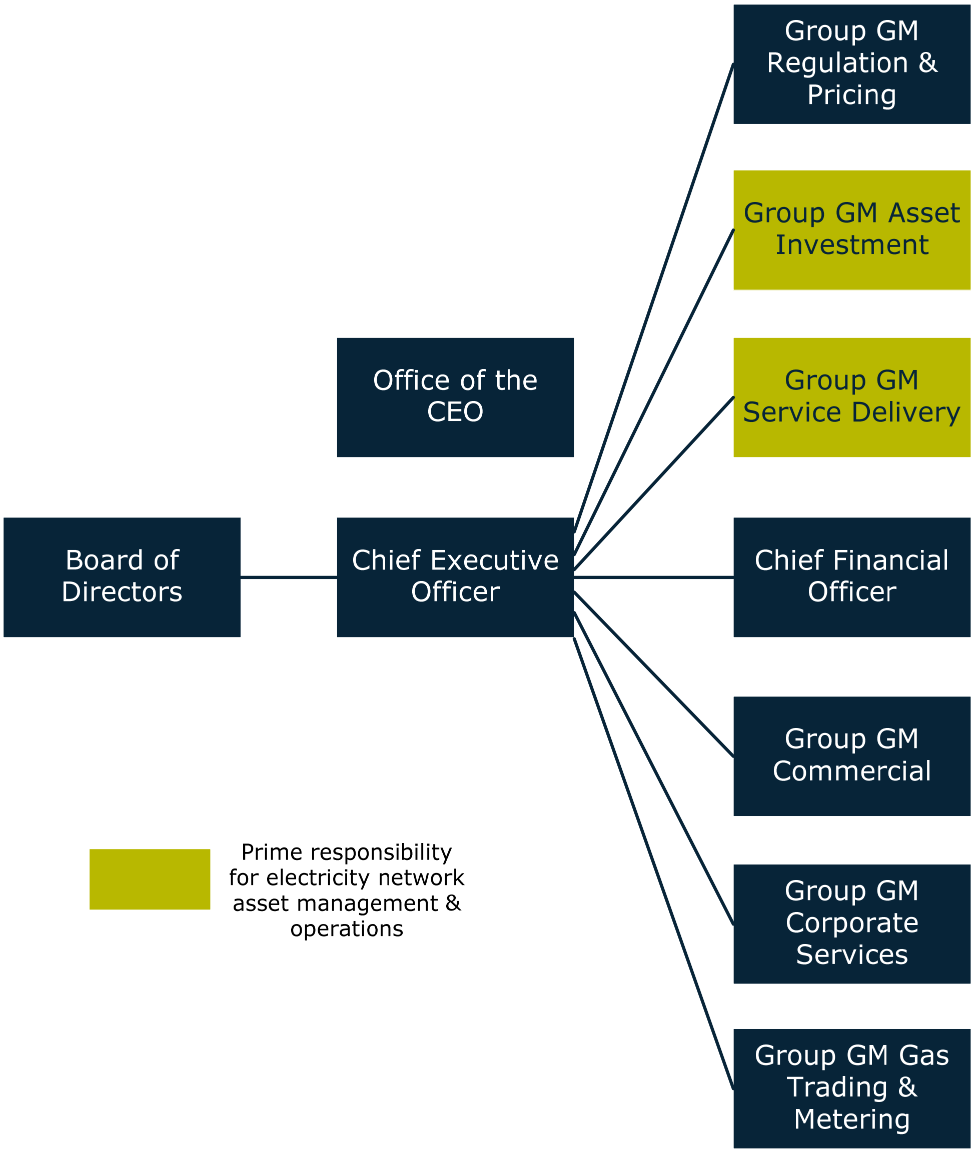

Figure 1-8 : The Vector senior management structure

The primary responsibility for the asset management of the electricity distribution network lies with the Group General Manager Asset Investment. The service provider function for the electricity network is primarily fulfilled by the SD group, under the Group General Manager Service Delivery. The role these two sections play in asset management is further discussed in Section 1.7.2 and Section 1.7.3.

In summary, the responsibilities of the other groups are as follows:

- Office of the CEO

  Public affairs; company secretary; economic advisor and corporate growth initiatives.

- Regulation and Pricing

  Responsible for interaction with the industry regulators, monitoring regulatory compliance, developing regulatory strategies, making regulatory submissions, setting electricity pricing, developing pricing strategy and asset valuation.

- Finance

  Financial accounting and reporting, budgeting, treasury, management accounting, group legal services, corporate risk management, investor relations, business analytics and insurance.

- Commercial

  Key customer relationships, mass market customer relationships, customer connections, commercial strategies, Vector's fibre and Communications business and energy consumption projections.

- Corporate Services

  Human resource management, training and development, recruitment, health, safety and environmental policies, personnel performance management, property services, business and data systems, IT support, computer hardware and software support and maintenance, cyber-security and communication networks.

- Gas Trading and Metering

  Wholesale gas business, liquid petroleum gas (LPG) business and metering services.

1.7.2 The Asset Investment Group

As the Asset Manager, the primary responsibility for the management of the electricity network and preparation of the AMP lies with the AI group. In broad terms, this group is responsible for:

- Setting electricity network security standards;
- Supporting Vector's development and implementation of a Safety Management System;
- Ensuring asset investment is efficient and provides an appropriate commercially sustainable return to the company's shareholders;
- Ensuring the configuration of the electricity network is technically and economically efficient, meets customer requirements, and is safe, reliable and practical to operate;
- Planning network developments to cater for increasing electricity demand and customer requirements;
- Ensuring the integrity of the existing asset base, through effective renewal, refurbishment and maintenance programmes;
- Keeping abreast of technological and consumption trends, assessing the potential impact thereof and devising strategies to effectively deal with this in the long-term network planning;
- Maintaining current and accurate information about the extent and performance of the network and assets;

- Maintaining good strategic relationships with local government bodies and major infrastructure providers to support the long-term protection of Vector's assets by ensuring that obligations (from all perspectives) are well understood and met, works are co-ordinated and best mutual outcomes are sought; and
- Ensuring that Vector's obligations to the Auckland Electricity Consumer Trust (AECT) with regard to undergrounding networks in the Southern region are met.

The AMP is the prime document that captures how the above functions are discharged.

In Figure 1-9 the structure of the AI group is expanded, emphasising the electricity network asset management responsibilities.

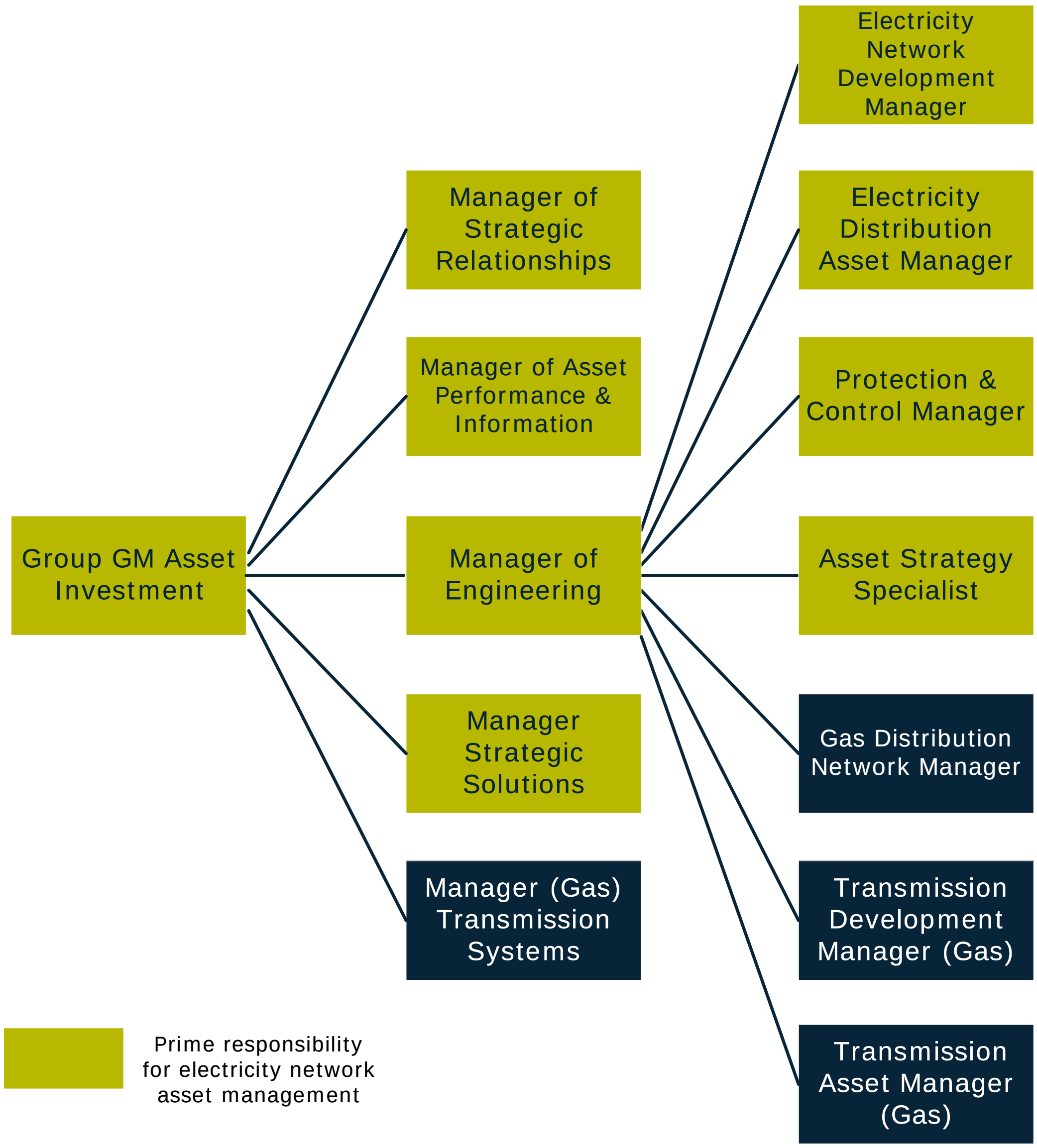

Figure 1-9 : The Asset Investment management structure supporting the AMP

1.7.3 The Service Delivery Group

In Vector's asset management model, the service provider function is predominantly fulfilled by the SD group. In conceptual terms, the AI team defines what assets are required, when and where, and how these should be operated and maintained, while the SD group delivers on providing, operating and maintaining the assets.

The SD group has a wide brief but the key functions as far as it relates to asset management, or the provision of the service provider function for the electricity network, are illustrated in Figure 1-10 and further expanded below.

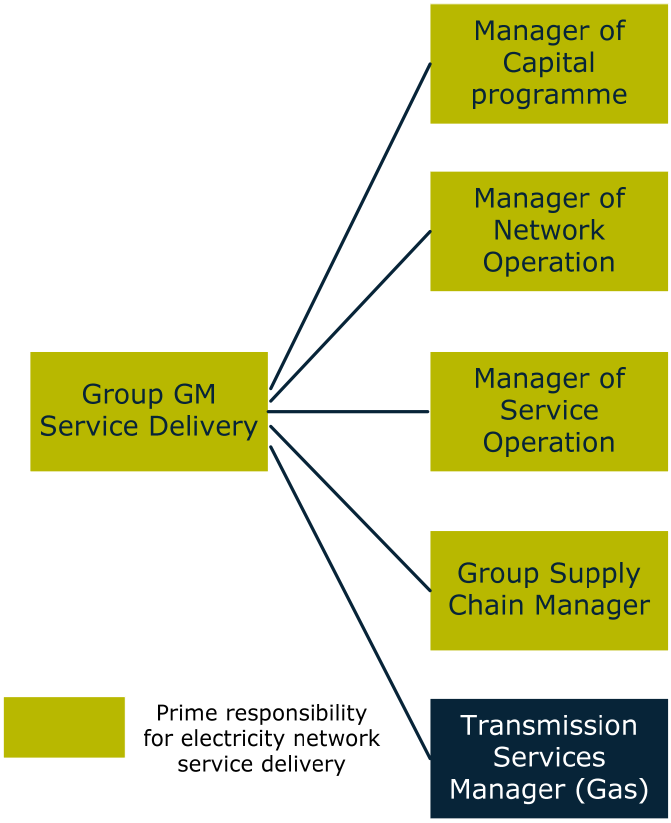

Figure 1-10 : Service Delivery as an Asset Management Service Provider

1.7.3.1 Network Operations

The Network Operations section is responsible for the day-to-day operational management of the network. It includes the control room, from where network operations are monitored and operational instructions are issued. Other functions include managing, reporting and investigating outages; switching on the network to ensure optimal configuration or to maintain supply during asset outages; and network switching during commissioning of new assets.

As the prime "operator" of the network, this team interacts closely with the Asset Manager, particularly on the following:

- Setting safe asset operation levels (short and long-term);
- Planning network configuration;
- Defining user requirements;

- Investigating outages and the root causes – especially if asset-related; and
- Contingency management.

1.7.3.2 Capital Programme

The Capital Programme section is responsible for the delivery of large infrastructure projects and is a key partner to AI in the end-to-end asset creation/replacement processes. It provides detailed project engineering and cost estimates, as well as project and contract management services. Vector does not have an in-house construction section for the electricity network - construction work is predominantly undertaken through external providers through a competitive tender process, or by our contracted service providers Northpower and Electrix (who were also selected through a competitive tender process).[10]

The Capital Delivery team and AI group have numerous touch-points, particularly the following:

- Managing the end-to-end project delivery process;
- Work scopes and project briefs;
- Detailed project engineering, including appointment of design consultants;
- Detailed project cost estimation;
- Reporting on project progress;
- Expenditure tracking and forecasting;
- Construction and commissioning standards; and
- Project close-out and capturing learning.

The AI engineering group manages the overall capital budget and is responsible for setting and controlling this, including obtaining the necessary expenditure approvals through the Vector governance process. After expenditure is approved, Capital Delivery manages the individual projects and associated expenditure.

1.7.3.3 Service Operations

The Service Operations section is responsible for the maintenance of the electricity network. This is done in conjunction with Vector's service provider partners (Northpower and Electrix), who carry out all physical work in the field. This section is also responsible for managing customer service processes and operations relating to outage management, customer complaints (including EGCC), mass market connections and value-adding services.

The Service Operations section interacts with asset management in various areas, including:

- Implementation of asset maintenance and vegetation management policies;
- Providing asset information for AI to set maintenance budgets;
- Managing replacement of mass assets (eg. poles, cross-arms or distribution transformers)[11], including project progress and expenditure reporting;

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[10] Works provided by our contracted service providers are still managed through a competitive bid process, although it may not be put out to open tender on a project by project basis.

[11] These mass-replacement works are not included in the large projects that are managed through the Capital Delivery group.

- Feedback on asset performance and customer issues; and
- Investigating asset failures.

1.7.3.4 Procurement

The Procurement section manages procurement of major assets for Vector. Since the bulk of these assets are procured for capital delivery projects this activity is closely linked to asset management, including:

- Preparation of asset (contract) specifications;
- Selection of equipment suppliers;
- Supply line negotiation;
- Tender awards; and
- Equipment cost-estimation.

1.7.4 Asset Management Activities by Other Groups

While the bulk of electricity network asset management activities are performed by the AI group, supported by the SD group, as noted in Section 1.5 the rest of Vector has many inputs. Most of these inputs are indirectly related to the assets themselves, but there are the following exceptions, where electricity-related assets are directly sourced and incorporated by others.

1.7.4.1 Commercial

The Commercial group is responsible for new customer connections and the revenues derived from these assets. For large connections, which require core network extensions or could have material capacity implications, the installations are generally managed by AI and SD groups as part of the normal core network growth projects[12]. Provision of smaller, non-standard connections is directly managed by the Commercial group – through the Vector service providers. Routine connections are managed by the SD group (through the Vector service providers), under the guidance of the Commercial section.

The Commercial group is also responsible for setting and measuring the service experience that customers on our networks should receive for connections and faults.

Lastly, the Commercial group manages Vector's relationship with retailers, large customers and Transpower (which is a key service provider).

1.7.4.2 Information Technology (part of Corporate Services)

There is increasing overlap in the real-time operation of electricity network assets and corporate-wide information technology services. Not only does asset management require increasingly sophisticated information systems, but the traditional SCADA networks are, over time, becoming less of a stand-alone electricity network application with unique requirements and protocols, and more of an integrated IT network application. Increased cyber-security of both SCADA and Communications has to be provided for.

Procurement and implementation of asset management and IT support systems, and the core SCADA equipment, is managed by the Information Technology group.

[12] The Commercial group remains responsible for the contractual and commercial arrangements.

1.7.4.3 Vector Communications (part of Commercial)

Vector Communications manages Vector's fibre optic network, for internal and external clients. They provide a major part of the SCADA network – the communication link between field devices and the central control stations.[13] Provision of this service is on a strict commercial basis, with the AI group treated similar to external clients and charged on the same basis.

1.7.5 Field Service Model

Vector's business model for operating and maintaining its electricity network assets is to outsource this work to Field Services Providers (FSPs).

After an extensive investigation in 2008/09 it was decided to retain the outsourcing model. Through a competitive process, Vector selected two FSPs, viz., Electrix Ltd as the maintenance contractor for the Northern region and Northpower Ltd as the maintenance contractor for the Southern region. These two FSPs are responsible for the preventative, corrective and reactive maintenance works of the electricity network.

Other outcomes of the review included establishing new key performance indicators (KPIs) and a new framework with guiding principles to manage the working relationships between Vector and the FSPs. The objective of the new business model is to improve the efficiency and quality of the delivered services to Vector and its customers.

1.8 AMP Approval Process

Approval of the disclosure AMP is sought at the March Board meeting.

The AMP is subject to a rigorous internal review process, initially within the AI group (the developer of the plan), and then by the Regulatory, Commercial, Financial and SD groups as well as external experts. Finally, the AMP is reviewed and certified by the Board, in accordance with the Information Disclosure[14] requirements.

1.8.1 Alignment with the Vector Budgeting Process

Vector operates under a July to June financial year. The asset management planning processes and documents form a key input into the budgeting process. These contain detailed, prioritised breakdowns of the electricity network expenditure requirements identified by AI for the next five years, with supporting evaluation for the individual projects or programmes. This is intended to assist the executive with the budget process, clarifying the electricity network priorities and also prioritising these along with other business investment needs.[15] The regulatory regime and economic conditions directly impact on the return Vector is able to make on its assets, which in turn determines the revenue which Vector is able to earn and the extent it is able to invest in its networks.

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[13] Not all of the SCADA communication is provided over fibre optic communications. There is still a substantial pilot wire system in place and radio links are also used.

[14] Requirement 7(1) of the Commerce Commission's Electricity Distribution (Information Disclosure) Requirements 2008.

[15] As with all companies, Vector does not have unlimited cash resources, and competing investment needs and commercial opportunities have to be balanced.

The Information Disclosure Requirements require the disclosure AMP to be prepared for a regulatory timeframe that differs from Vector's financial year. The asset management activities in this AMP are prepared on the basis of the Vector financial year (July to June year) to ensure they are consistent with all the financial and management reporting information. To satisfy the regulatory requirements, the summary financial information is converted and presented on the basis of the regulatory year (April to March year). This plan therefore covers the period between 1st April 2012 and 30th June 2022 to meet both Vector's internal and regulatory requirements.

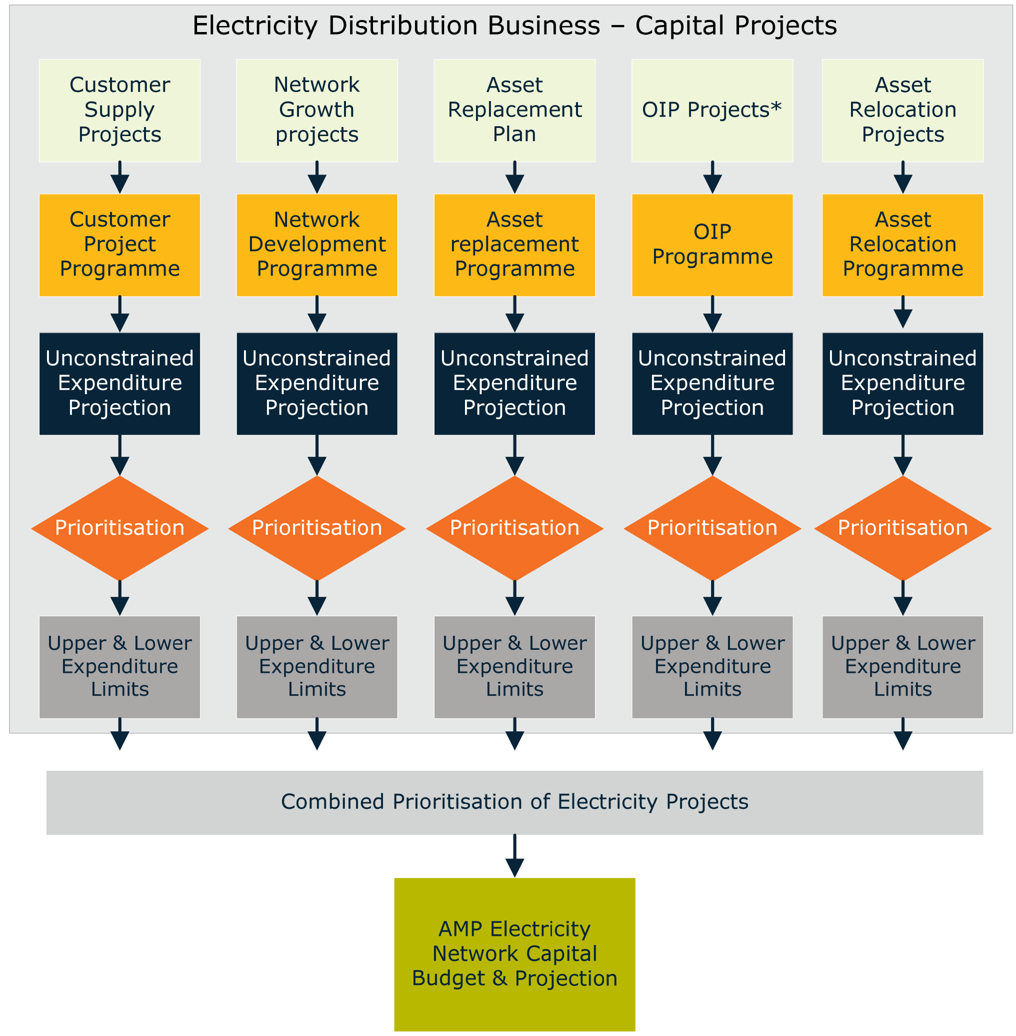
1.8.2 The Expenditure Forecasting Process

In Figure 1-11 the forecast process for capex projects in the AMP is illustrated. This process follows the following steps:

- The overall capital works programme is divided into different work categories. A plan covering the next five-year period is first developed for each work category (based on the asset management criteria for that work);
- A works programme is then drawn up and the corresponding capex to implement the works programme is developed. This is an unconstrained estimate;
- The prioritisation process described in Section 9 is then applied to the projects and programmes within the work category. This identifies projects that could be left out from the programmes without undue negative consequences. Through this, it is possible to set an upper and lower boundary for the expenditure levels; and
- An overall prioritisation process is then applied to the combined suite of network projects, to develop the final AMP forecast for combined capex.

As noted before, the accuracy of forecasts further out in the planning period diminishes. The capital forecasts for years six to ten are based on a combination of projects foreseen at this stage and trend analysis for other types of projects. Project prioritisation for this period is indicative only.

A similar process is adopted for the operation and maintenance expenditure forecasts, which are prepared in conjunction with Service Delivery.



*OIP refers to Overhead Improvement Programme

Figure 1-11 : Capex forecasting process adopted for the AMP

1.9 Asset Management Decisions and Project Expenditure Approval

Implementation of the AMP requires decisions to be made by management and staff at all levels, reflecting their functional responsibilities and level of delegated financial authorities (DFAs), as set in accordance with the Vector governance rules. Functional responsibilities define the role of each staff in the organisation. The DFAs specify the level of financial commitment that individuals can make on behalf of the company.

Investment decisions are budget-based, with the Board approving yearly budgets before any commitment can be made. Preliminary project approval is normally given through the annual (one-year) budgeting process, but projects are not individually assessed in detail at this stage. Project-specific capex approval therefore still has to be granted for all projects prior to committing capital, despite these having been included in the approved annual budget. The detailed project approval process has been developed in accordance with the Vector DFA system.

Critical unbudgeted investments will be taken to the Board for consideration at any stage of the financial year, if supported by a robust business case or arising from an urgent safety, reliability or compliance issue.

Applications for expenditure approval must be supported by formal business cases. Each business case contains information on the expenditure objective, constraints and assumptions, strategic fit, options investigated, project time line, resources required and available, project deliverability, cost benefit analysis, return on investment and risk assessment. This assists Vector management to assess and approve investment applications.

Under current price regulation (default price-quality path regulation, or DPP), Vector is allowed to earn a regulated return on its initial regulated asset base, including an allowance made by the Commerce Commission for likely capital expenditure required during the remaining part of the current regulatory period (2010 to 2015). The capex allowance is based on the Commission's interpretation of Vector's (previous) AMP. For the DPP, individual projects are not assessed, and as such, no specific allowance is made for any particular expenditure item in Vector's allowed price path, whether it was identified in the AMP or not. It is possible that an unforeseen network need, not previously identified in the AMP, may arise for which the allowance under the DPP is insufficient to allow Vector to recover the cost of the required investment, or to earn any return prior to the start of the next regulatory period.

No mechanism exists under the DPP to recover the losses associated with such an unforeseen investment. In addition, it is not clear in advance, that investments will automatically be included in the future regulatory asset base to match future price paths. While Vector does have the option to apply for a customised price-quality path (CPP) to address this issue, such an application is a complex, resource-intensive and costly process. The threshold to justify such an application is therefore very high. At this stage it is not clear how costs associated with investments that do not meet the justification threshold for a CPP application, can be recovered.[16]

1.10 Progress Reporting

Performance against the annual budgets is closely monitored, with formalised change management procedures in place. Regular reports are sent to the Vector Board regarding:

- Health, safety and environmental issues;
- Monthly report on overall expenditure against budget;
- Progress of key capital projects against project programme and budget;
- Reliability performance – SAIDI, SAIFI, CAIDI;
- Performance and utilisation of key assets such as sub-transmission cables, distribution feeders, power transformers, etc;
- Progress with risk register actions (the board has a risk committee with a specific focus on risks to the business); and
- Network reliability.

[16] In addition, the Commission has indicated that it will only consider a limited number of CPP applications in any year. There is a risk that any CPP application made by Vector may be delayed, impacting on investment.

1.11 Asset Management Processes

The diagram in Figure 1-12 shows the high level asset investment process within Vector. This highlights the relationship between the different asset creation and evaluation processes within Vector.

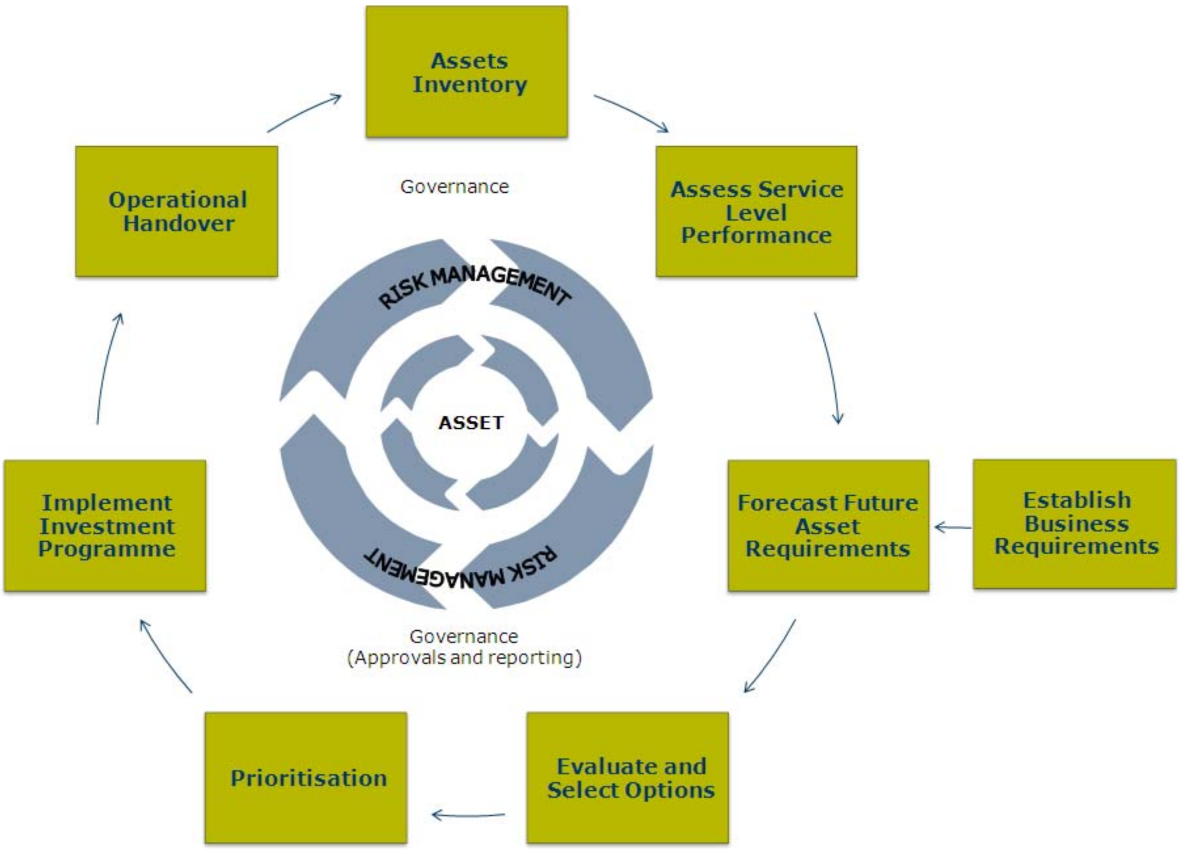


Figure 1-12 : High-level overview of the Vector asset investment process

Assets Inventory

Information on the quantity, age and capability of existing assets is essential to understand and effectively manage the asset base. Information on the existing assets and network configuration is set out in Section 2 and Section 6 of this AMP.

The asset register, geographical information system (GIS) and associated databases store cost information and technical characteristics for all assets, including their location, history and performance. The way in which information systems support asset management processes is described in Section 7.

Assess Service Level Performance

Information on the performance, utilisation and condition of existing assets and the different parts of the network is needed to forecast future investment, renewal or upgrading requirements and improve service level. This requires ongoing monitoring of asset condition and network performance, the consumption of resources associated with maintaining the assets, and the efficiency and effectiveness with which assets are utilised (including network configuration). Information on the condition and performance of existing assets and on the network configuration is set out in Section 4, Section 5 and Section 6.

Establish Business Requirements

The levels of service required from the electricity network are guided by the wider business requirements. These requirements in turn are determined by Vector's operating environment and reflect corporate, community, environmental, financial, legislative, institutional and regulatory factors together with stakeholder expectations.

Section 1 sets out the background and business requirements that drive the AMP. Service levels are described in Section 4 and Section 5.

Forecast Future Asset Requirements

The combination of asset condition and performance drivers, load demand and the business requirement driver form the basis for assessing future asset needs and the resulting network development plans. Section 4, Section 5 and Section 6 discuss this information.

Vector operates an electricity network in a changing environment, and future requirements are likely to differ materially from the situation faced today. Such changes have to be anticipated in current development plans. Section 3 discusses the anticipated impact of future technology on the network, and Vector's development strategies to position for this.

Evaluate and Select Options

Once the future network or asset requirements are established, options for addressing these needs have to be evaluated and potential solutions have to be identified. Decision tools and systems used to support the evaluation of options include loadflow analysis, effective capital budgeting techniques, optimised renewal modelling, life-cycle costing, risk assessments and geographic information. At the same time, the feasibility of non-network or unconventional solutions to address network requirements is also considered.

Vector broadly categorises asset investment planning in two main streams:

- Network development planning is undertaken to ensure service target levels are met in an environment of increasing load (demand) growth, or increased customer quality expectations. It is based on systematic analysis of maximum demand trends, consumer requests and demographic estimates. Vector's approach to network development planning is set out in Section 5; and
- Asset maintenance and replacement planning is undertaken to ensure assets remain fully functional for their reasonably expected lifespan when operating within expected design ratings. It also includes activities to prolong asset lives or to enhance asset performance. Maintenance planning addresses both capital investments on renewal or refurbishment, or long, medium and short-term asset maintenance. Vector's approach to maintenance planning is set out in Section 6.

Prioritisation

Prioritisation is a process that ranks all projects identified during the network development and maintenance planning processes. This process ensures only projects that meet Vector's investment thresholds – which encompass commercial, safety and technical considerations - are included in the project programme.

Projects also undergo a second prioritisation process, to compare investment needs across the company. This is to ensure the best use of available resources on a company-wide basis.

The way Vector prioritises electricity capital investment projects is discussed in Sections 5, 6 and 9.

Implement Investment Programme

Budgets are prepared on a cash-flow basis mirroring expected expenditure based on works programmes. The Board approves the overall expenditure on an annual cycle and project expenditure on the larger projects in accordance with DFA governance rules. While most projects are delivered in the financial year, the delivery of larger projects, such as new zone substations (a substation containing equipment at sub-transmission voltage, sub-transmission voltage includes 110kV, 33kV and 22kV), may straddle financial years. Budgetary provision is made in the year expenditure will be incurred.

The implementation of solutions identified as part of the asset replacement (Section 6) or planning process (Section 5) are managed by the SD and Commercial (for customer connections) groups. For larger projects, the Capital Programme team, as part of the SD group, develops the conceptual solution into a detailed design suitable for implementation. Contracts are let to approved service providers (following a competitive tender process) for the execution of these projects.

Service Operations (a team within the SD group) manages the bulk replacement and maintenance programmes, liaising directly with the service providers while the Customer Solutions team in the Commercial Group manages the customer connections with the service providers.

Operational Handover

Once construction and installation is completed, a formal handover process takes place. The process is designed to check the quality of work and equipment meets Vector's standards and the assets are constructed to allow maintenance in accordance with Vector's Operation and Maintenance Manuals. It also includes a walkover between the project manager and AI group asset specialists who take assets over and arrange the maintenance regime. The GIS record is updated with the new assets as well as the technical asset master (TAM) database.

Governance (Approvals and Reporting)

Formal approval (budgets and expenditures) and reporting (progress and risks) processes are in place to satisfy Vector's Corporate Governance requirements.

Risk Management

Risk management which underpins all asset management business processes and forms an important part in defining project requirements is discussed in Section 8.

1.12 Works Coordination

1.12.1 Internal Coordination

Over the last few years, Vector has put extensive effort into continuously improving the coordination of the various activities associated with the delivery of the capital works programme with the objectives of better utilisation of resources, enhancing capital efficiency and delivering improved customer outcomes. Improvement initiatives have included:

- Deployment of the "Project Server" to capture project and resource information and to track project progress against schedule from the conception stage through to commissioning and hand-over to operations;
- Establishing and refining the project "end-to-end" process to improve visibility of the delivery performance on capital projects;

- Development of enhanced “project solution studies” to ensure optimal project outcomes; and
- Improved processes and communication between project initiators, network planners, asset specialists, designers and contract managers.

In addition to its electricity networks, Vector operates gas distribution networks, a gas transmission system and a fibre optic telecommunication network. To maximise the synergy benefits that can be achieved from cooperation, and to deliver projects in the most effective, least disruptive manner, effective coordination of capital works between these business units is essential. Significant improvement in delivery has been achieved over the last couple of years through the implementation of these initiatives.

1.12.2 External Coordination

As well as internal coordination, new processes have also been put in place to improve coordination between Vector and other utilities, roading authorities, local councils and their service providers. These works coordination processes are focused on maintaining effective communication channels with external agencies, identifying cost effective future proofing opportunities, minimising disturbance to the public as a result of infrastructure works, streamlining works processes and meeting Vector’s regulatory obligations.

It is important for Vector to be cooperative and supportive in its relationships with other agencies. In the past this has resulted in a number of win-win outcomes, with Vector for example obtaining access to motorway corridors for laying cables.

1.13 Other Asset Management Documents and Policies

Vector has a number of other documents used to capture asset management polices and particulars. Including all of these in one document would produce an unwieldy, impractical plan. In addition, there are a number of company-wide policies that have a direct bearing on asset management.

1.13.1 Other Asset Management Documents

The AMP is supported by a collection of detailed asset management documents and policies. These include (not in any order of priority):

- Asset Management and Investment Policy
- Network security standards and policies;
- Detailed asset maintenance standards;
- Network design policies;
- Network architecture;
- Risk management policies;
- Ownership policy;
- Contracts management policy;
- Procurement policy;
- Health and safety policy;
- Environmental policy;
- Asset rehabilitation policy;
- Load management plans;
- Asset settlement manual;

- Network contingency plans;
- Network projects quality assurance policy; and
- Drug and alcohol policy.

In addition to the policies, Vector has also developed a suite of work practice standards and guidelines and equipment specifications to guide its service providers in the course of implementing the works programme. These standards, guidelines and specifications can be found on our internal communications website.

1.13.2 Other Company Policies Affecting Asset Management

Vector has a number of business policies[17] designed to help the business to operate efficiently and effectively. Many of these interact with, or impact on, the asset management policies and this AMP.

Business:

- Code of conduct;
- Legal compliance policy;
- Protected disclosure policy;
- Remuneration policy;
- Customer credit policy;
- Foreign exchange policy;
- Expense management policy;
- Network WIP (work-in-progress) Management policy;
- Network Fixed Asset Creation and Disposal policy; and
- Capex policy.

Information Technology:

- Access policies;
- Password and authentication policy;
- Network management policy;
- Internet use policy;
- E-mail policy;
- Access control policy;
- Antivirus policy;
- Communications equipment policy;
- Computer systems and equipment use policy;
- Cyber crime and security incident policy;
- E-commerce policy;
- Firewall policy;

[17] These policies are not listed in any order of priority.

- Hardware management policy;
- Information technology exception policy; and
- Information technology general user policy.

1.14 External Review of Vector's Asset Management Practice

Vector has, over an extended period, engaged external expert technical advisers on an annual basis to review its asset management practices. While these reviews have been very positive in their feedback – confirming asset management at Vector conforms to good industry practice – we have taken note of the feedback and recommendations received, and where practical and beneficial, reflected this in our asset management practices.

1.14.1 2010 Asset Management Practice Review

During 2010 Vector engaged SKM Australia to carry out an independent specialist review of our asset management practices. This resulted in a very positive endorsement, confirming that our practices match the very best in Australasian network management in most areas. Highlight findings included:

- Vector's asset management planning is of high quality and its AMP is the most comprehensive witnessed;
- The general condition and serviceability of the assets were good and assets were well maintained in accordance with sound industry practice;
- Planning and processes for implementing new capital works are sound and security and reliability of the power system will likely be sustained or enhanced over the next 10 years;
- Based on current budgets and demand forecasts security, Vector's capital work programme and budgets appear sufficient to sustain capacity; and
- Vector has adopted appropriate asset management practices to minimise risk of failure on the network.

1.14.2 2010 Asset Management Plan Review

During 2010 we also engaged Utility Consultants, to review our AMP both from a content and regulatory compliance point of view. The review provided very positive endorsement of our electricity network asset management practices and strategic thinking. In particular, the consultant endorsed the approach taken to improve capital efficiency and encourage innovation, and in future-proofing the network against any adverse impact of future technologies.

Suggestions were also made on the presentation of the AMP, particularly on its alignment with regulatory disclosure requirements. These suggestions are accounted for in this current AMP.

1.14.3 2011 Maintenance Strategies Review

During 2011 we engaged an Australian consultant (Chris Brennan and Associates) to review our asset maintenance strategies. This review focused on current maintenance standards, our approach to asset maintenance and asset condition information.

The review concluded that Vector's asset maintenance approach compares well with good industry practice, and in particular with how this is applied by the major electricity distribution businesses in Australia. It also concluded that Vector's maintenance expenditure is at the most efficient end of that of the peer group of Australian electricity distribution businesses considered, comparing well with the most efficient Australian electricity distribution companies.

It was suggested that Vector should consider adopting an enhanced condition-based risk management (CBRM) approach to asset maintenance (and renewal), as well as some small possible further cost and performance improvements that could be made by modifying some of our inspection and maintenance programmes and audits of preventative maintenance work and prioritisation of work identified through inspection programmes.

Vector is investigating these recommendations with the view to adopting them where appropriate. In particular, we have embarked on the development of an enhanced CBRM approach for life-cycle network asset management. This is described in more detail in section 6 of the AMP.

1.15 Cross Reference to the Information Disclosure Requirements

As indicated earlier (Section 1.3), one of the key purposes of this disclosure AMP was to also inform internal stakeholders on how Vector intends to manage its asset management activities. As such the order of presentation of this disclosure AMP is somewhat different from that presented in the Electricity Information Disclosure Handbook (31 March 2004 as amended 31 October 2008).

The following table provides a cross reference between the disclosure requirements and the sub-sections in this AMP. A column "Interpretation" is included in the table to elaborate on the "Handbook Requirements" with the aim of helping the reader to locate the appropriate sections in the AMP against the detailed requirements as specified in the Handbook. The "Interpretation" is based on the description given in the Commerce Commission's Asset Management Plan (2009 – 2019) compliance review.

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
4.4.5	The disclosed AMP must: a) Enable the suitability of asset management practice and assets for current and future service; b) Specifically support the achievement of disclosed service level targets; and c) Provide a sound basis for ongoing risk assessment. *Explanation: Disclosed AMPs must be presented in a manner that meets the needs of external users.*	Does the disclosed AMP meet the needs of external users?	This AMP has been reviewed and edited to ensure ease of use by external users.
4.4.6	Disclosed AMPs must clearly identify limitations in availability or completeness of information, and include: a) Details of the basis for asset management planning, including assessment of the methodologies used; b) The information required by Requirement 7(2); and c) Details of plans for improvement in information quality. *Explanation: The detail and accuracy of information available will vary. Information gaps should be specifically addressed to enhance the transparency of disclosure, place emphasis on identifying deficiencies and promote improvement.*	Are information gaps specifically addressed to enhance the transparency of disclosure, is there an emphasis on identifying deficiencies and promoting improvement?	Sections 7.4 and 7.5
		Does the AMP comment on the completeness or accuracy of the asset data and does it identify any specific areas where the data is incomplete or inaccurate?	Sections 6.3 and 7.5
4.4.6c		If there is a problem with data accuracy or completeness, does the AMP disclose initiatives to improve the quality of the data?	Section 7.4
4.4.3 4.5.1	AMPs must include a summary. *Explanation: The inclusion of a summary aids understanding and readability, and also provides an opportunity for EDBs to emphasise important content.* Summary of the AMP The AMP is to include a summary that provides a brief overview of the contents of the plan and highlights information that the EDB considers significant.	Does the AMP include a summary that provides a brief overview of the AMP contents?	Executive summary
4.4.4 4.5.1	Disclosed AMPs must consist of a single document containing all information necessary to allow the document to be fully understood by a reader with a reasonable understanding of the management of electricity distribution assets. *Explanation: Disclosure of AMPs as a single document will prevent disclosure of disjointed, poorly coordinated material that is difficult to understand. In some cases EDBs may choose to include other documents in their disclosed AMP for example, separate network development plans. This does not necessarily require integration of separate plans into a single framework if the linkages between parts of the plan are made and indexed.*	Does the AMP summary highlight information that the EDB considers significant?	The AMP is presented as a single document containing 9 sections and an Executive summary covering Vector's asset management information as required by the Electricity Information Disclosure Handbook and the Electricity

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Summary of the Asset Management Plan The AMP is to include a summary that provides a brief overview of the contents of the plan and highlights information that the EDB considers significant.		Distribution Information Disclosure Requirements 2008.
4.5.2a	The AMP must include details of the asset management plan background and the objectives of the EDB's asset management and planning processes including: a) The purpose of the plan; *Explanation: For some EDBs the disclosed AMP is also a key internal planning document. Other EDBs base their asset management processes around other planning documents and produce the disclosed AMP purely to meet regulatory requirements. The purpose statement should clearly state the intention of the business in preparing the disclosed document. If the AMP is intended to describe asset management processes documented elsewhere in order to meet information disclosure requirements, this should be stated; otherwise the wider purpose of the document and the manner in which it is used by the EDB should be described. It should be noted that the objective of the AMP disclosure requirement is to encourage the development of best practice asset management processes. Therefore the disclosed AMP must contain sufficient information to allow stakeholders to make an informed judgement as to the extent that an EDB's asset management processes meet best practice criteria.* *The purpose statement should also state the objectives of the EDBs asset management and planning processes. These should be consistent with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest.*	Does the AMP contain a purpose statement?	Section 1.3
4.5.2a		Does the purpose statement make the status of the AMP clear? For some businesses the AMP will be the key document that guides the asset management process? Other businesses will have a different asset management system in place and will write the disclosed AMP purely to meet the disclosure requirements.	Sections 1.1 and 1.3
4.5.2a		Does the purpose statement also include the objectives of the EDB's asset management and planning process? To what extent are these objectives consistent with the EDB's vision and mission statements? Do the objectives show a clear recognition of stakeholder interest?	Sections 1.3, 1.4, 1.5, 1.6, 1.8, 1.9, 1.10 and 1.11.
4.5.2bi	b) A description of the interaction between those objectives and other corporate goals, business planning processes, and plans; *Explanation: Best practice asset management and planning processes are integrated with other business plans and goals. The AMP should describe this relationship. In particular, it should:* *(i) State the high level corporate mission or vision as it relates to asset management;* *(ii) Identify the documented plans produced as outputs of the annual business planning process adopted by the EDB; and* *(iii) Describe how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management.*	Does the AMP state the EDB's high level corporate mission or vision as it relates to asset management?	Section 1.3
4.5.2bii		Does the AMP identify the documented plans produced as outputs of the EDB's annual business planning process?	Section 1.3
4.5.2biii		Does the AMP show how the different documented plans relate to one another with particular reference to any plans specifically dealing with asset management?	Sections 1.1, 1.3, 1.8 and 1.13.
4.5.2b		How well are the objectives of the EDB's asset management and planning processes integrated with its other business plan and goals and how well does the AMP describe this relationship?	Sections 1.3, 1.5, 1.6, 1.8, 1.9, 1.10, 1.11 and 1.12.

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
4.5.2c **7(3)a**[1]	c) The period covered by the plan, and the date the plan was approved by the board of directors of the EDB; *Explanation: The AMP must cover at least a projected ten year asset management planning period. Good asset management practice recognises the greater accuracy of short-to-medium term planning, and will allow for this in the AMP. Hence the asset management plans for the second five years of the asset management planning period need not be presented in the same detail as the near term plans.*	Does the AMP specifically state that the period covered by the plan is ten years or more from the commencement of the financial year?	Section 1.2
4.5.2c **7(1)d**[11]		Does the AMP state the date on which the AMP was approved by the Board of Directors?	Section 1.2
4.5.2.d	d) A description of stakeholder interests (owners, consumers etc); *Explanation: Recognising and accommodating stakeholder interests are key parts of the AMP. AMPs should therefore identify important stakeholders and indicate:* *(i) How the interests of stakeholders are identified;* *(ii) What these interests are;* *(iii) How these interests are accommodated in asset management practices; and* *(iv) How conflicting interests are managed.*	Does the AMP identify the EDB's important stakeholders and indicate:	Sections 1.4, 1.5 and 1.6
4.5.2.di		- how the interests of stakeholders are identified;	Section 1.6
4.5.2.dii		- what these interests are;	Sections 1.5 and 1.6
4.5.2.diii		- how these interests are accommodated in the EDB's asset management practices: and	Sections 1.5 and 1.6
4.5.2.div		- how conflicting interests are managed?	Sections 1.5 and 1.6
4.5.2ei	e) A description of the accountabilities and responsibilities for asset management within the EDB; and *Explanation: An AMP should consider the accountability and responsibility for asset management on at least three levels:* *(i) Governance;* *(ii) Executive; and* *(iii) Field operations.* *At the governance level, the AMP should describe the extent of Board approval required for key asset management plans and decisions and the extent to which asset management outcomes are regularly reported to the Board.* *At the executive level the AMP should provide an indication of how the in-house asset management and planning organisation is structured.* *At the field operations level it should comment on how field operations are managed, the extent to which field work is undertaken in-house and the areas where outsourced contractors are used.*	At the governance level, does the AMP describe the extent of Board approval required for key AMPs and decisions and the extent to which asset management outcomes are regularly reported to the Board?	Sections 1.1, 1.8, 1.9 and 1.10
4.5.2eii		At the executive level, does the AMP provide an indication of how the in-house asset management and planning organisation is structured?	Section 1.7
4.5.2eiii		At the field operations level, does the AMP comment on how field operations are managed, the extent to which field work is undertaken in-house and the areas where outsourced contractors are used?	Sections 1.1 and 1.7
4.5.2f	f) Details of asset management systems and processes, including asset management systems/software and information flows.	Does the AMP identify the key systems used to hold data used in the asset management process? Does it	Sections 7.1, 7.2 and 7.3

[1] Disclosure relating to Asset Management Plans (part 7) of the Electricity Distribution (Information Disclosure) Requirements 2008

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Explanation: The key systems used to hold asset data used in the asset management process should be identified, with the data held in each system and what it is used for. Good asset management practice requires that all assets are identified and the asset type, capacity and condition recorded. The AMP should identify areas where asset data is incomplete or inaccurate, and should disclose any initiatives to improve the quality of this data. *The processes used within the business for:* *(i) Managing routine asset inspections and network maintenance;* *(ii) Planning and implementation of network development projects; and* *(iii) Measuring network performance for disclosure purposes should be described.*	describe the nature of the data held in each system and what this data is used for?	
		Does the AMP describe the processes used within the business for: managing routine asset inspections and network maintenance; planning and implementation of network development processes; and measuring network performance (SAIDI, SAIFI) for disclosure purposes?	Sections 1.11, 4.1, 5.2, 5.3, 6.2 and 6.3.
4.5.3ai	The AMP shall include details of the assets covered including: a) A high-level description of the distribution area; *Explanation: The AMP should describe at a high level the distribution areas covered by the EDB and the degree to which these are interlinked. The description should include:* *(i) The distribution area(s) covered;* *(ii) Identification of large consumers that have a significant impact on network operations or asset management priorities;* *(iii) Description of the load characteristics for different parts of the network; and* *(iv) The peak demand and total electricity delivered in the previous year, broken down by geographically non-contiguous network, if any.*	Does the high level description of the distribution area include: - the distribution areas covered;	Section 2.1
4.5.3aii		- identification of large consumers that have a significant impact on network operations or asset management priorities;	Section 2.1
4.5.3aiii		- description of the load characteristics for different parts of the network; and	Sections 2.1 and 2.2
4.5.3aiv		- the peak demand and total electricity delivered in the previous year, broken down by geographically non-contiguous network, if any?	Section 2.2
4.5.3.bi	b) A description of the network configuration; *Explanation: The AMP should include a description of the network configuration that should include:* *(i) Identification of bulk electricity supply points and any embedded generation with a capacity greater than 1 MW. The existing firm supply capacity and current peak load of each bulk supply point should be stated;* *(ii) A description of the sub-transmission system fed from the bulk supply points, including identification and capacity of zone substations and the voltage of the sub-transmission network. The AMP should identify the extent to which individual zone substations have n-x sub-transmission security;* *(iii) A description of the distribution system, including the extent to which it is underground;* *(iv) A brief description of the network's distribution substation arrangements;*	Does the AMP include a description of the network configuration which includes: - identification of the bulk electricity supply points and any embedded generation with a capacity greater than 1 MW;	Sections 2.2 and 2.3
4.5.3.bi		- the existing firm supply capacity and current peak load at each bulk supply point;	Section 2.3
4.5.3.bii		- a description of the sub-transmission system fed from the bulk supply points,	Sections 2.3 and 5.6

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	(v) A description of the low voltage network including the extent to which it is underground; and *(vi) An overview of secondary assets such as ripple injection systems, SCADA and telecommunications systems.* *If non-contiguous networks exist, these should be noted and treated as separate distribution areas.*	including identification and capacity of zone substations and the voltage of the sub-transmission network;	
4.5.3.bii		- the extent to which individual zone substations have n-x sub-transmission security;	Section 2.3
4.5.3.biii		- a description of the distribution system including the extent to which it is underground;	Section 2.3
4.5.3.biv		- a brief description of the network's distribution substation arrangements;	Section 2.3
4.5.3.bv		- a description of the low voltage network, including the extent to which it is underground; and	Section 2.3
4.5.3.bvi		- an overview of secondary assets such as ripple injection systems, SCADA and Tele communications systems.	Section 2.3
4.5.3c	c) A description of the network assets by category, including age profiles and condition assessment; and *Explanation: Each asset category used in the network should be discussed, providing at least the following information for each category:* *(i) Voltage levels;* *(ii) Description and quantity of assets;* *(iii) Age profiles;* *(iv) Value of the assets in the category (which can be drawn from the ODV disclosure or other record bases kept by an EDB); and* *(v) A discussion of the condition of the assets, further broken down as appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.* *The asset categories discussed should include at least the following:* *(i) Assets owned by the EDB but installed at bulk supply points owned by others;* *(ii) Sub-transmission network including power transformers;* *(iii) Distribution network including distribution transformers;* *(iv) Switchgear;* *(v) Low voltage distribution network; and* *description of supporting or secondary systems including:* *- ripple injection plant;* *- SCADA;* *- communications equipment;*	Does the AMP include a description of the assets that make up the distribution system that includes, for each asset category: voltage levels, description and quantity of assets, age profiles, value of the assets in each category (which can be drawn from the ODV disclosure or other record bases kept by the EDB, and a discussion of the condition of the assets, further broken down as appropriate and including, if necessary, a discussion of systemic issues leading to premature asset replacement?	Section 6.3
4.5.3c		Do the asset categories discussed at least include: 1. assets owned by the EDB but installed at bulk supply points owned by others; 2. sub-transmission network including power transformers;	Sections 2.3 and 6.3.

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	- metering systems; *- power factor correction plant;* *- EDB owned mobile Substations and generators whose function is to increase supply reliability or reduce peak demand; and* *- other generation plant owned by an EDB.* *While asset quantities must be presented in a way that fairly describes the size of the asset base, detailed schedules similar to those presented in an optimised deprival valuation ODV) are not necessary. However, where disclosed quantities or other asset related information is based on estimates, this should be explicitly stated.*	3. distribution network including distribution transformers; 4. switchgear; 5. low voltage distribution network; and 6. description of supporting or secondary systems including: - ripple injection plant; - SCADA; - communications equipment; - metering systems; - power factor correction plant; - EDB owned mobile Substations and generators whose function is to increase supply reliability or reduce peak demand; and - other generation plant owned by an EDB.	
4.5.3d	d) The justification for the assets *Explanation: The basic justification for an EDB's asset base is that it is the minimum required to provide electricity of sufficient capacity and reliability to all consumers, accommodating reasonable growth forecasts. Network standards could differ between different parts of a network.* *The extent that an existing network is over-designed is reflected in the optimisation process completed when undertaking an ODV valuation. An explanation of the network optimisation included in the last ODV report could therefore be provided to satisfy this requirement.* *EDBs may choose to include in this section a discussion on assets that are excluded from the ODV valuation in accordance with clause 2.6 of the ODV Handbook. EDBs may also discuss assets they consider to be justified, even though these assets have been optimised out of the ODV valuation on account of the optimisation requirements.*	How does the EDB justify its asset base? Comment briefly whether the AMP includes any asset justification and the nature and reasonableness of the justification provided.	Section 2.4

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
4.5.4a	Service Levels *Explanation: Best practice requires that any performance indicators should be objectively measurable and be suitable for applying consistently across the network and over time. All indicators used as the basis for performance targets should be clearly defined in the AMP in order for it to be a self contained document. Targets should be consistent with business strategies and asset management objectives, and be provided for each year of the AMP planning period.* The disclosed AMP must include details of the proposed levels of service including: a) Consumer oriented performance targets; *Explanation: As a minimum, the reliability performance measures used for threshold compliance assessment (SAIDI, SAIFI) should be included. It is preferable for consumer orientated performance targets to differentiate between different parts of the network, such as between urban and rural areas.*	What consumer performance targets are included in the AMP? Are the targets objectively measurable, adequately defined and is the EDB proposing to improve the level of service over the period of the plan? To what extent are the targets consistent with the other plans set out in the AMP?	Section 4.1
4.5.4b	b) Other targets relating to asset performance, asset efficiency and effectiveness, and the efficiency of the line business activity; and *Explanation: This section should include technical and financial performance indicators related to the efficiency of asset utilisation and operation.*	Does the AMP disclose other targets relating to asset performance, asset efficiency and effectiveness, and the efficiency of the line business activity?	Sections 4.2 and 4.3.
4.5.4c	c) The justification for target levels of service based on consumer, legislative, regulatory, stakeholder, and other considerations. *Explanation: The basis on which the target level for each performance indicator was determined should be indicated, even if the justification is that the target is indicative of current performance levels.* *Targets should take account of stakeholder requirements and reflect what is practically achievable given current network configuration, condition and planned expenditure levels. It should be demonstrated in the AMP how stakeholder needs were ascertained and, where appropriate, translated into service level targets.*	Does the AMP include the basis on which each performance indicator was determined? Does the justification include consideration of consumer, legislative, regulatory, stakeholder requirements?	Sections 4.1 and 4.2
4.5.5a	Network Development Planning Disclosed AMPs must include a detailed description of network development plans, including: a) A description of the planning criteria and assumptions; *Explanation: Planning criteria for network developments should be described logically and succinctly. Where probabilistic planning techniques are used, this should be indicated and the methodology briefly described.* *The AMP should also describe the criteria used for determining the capacity of new equipment for different types of assets or different parts of the network. These relate to the philosophy of the business in the management of planning risk.*	Does the AMP describe the planning criteria used for network developments?	Section 5.3
4.5.5a		Does the AMP describe the criteria for determining the capacity of new equipment for different asset types or different parts of the network?	Section 2.4
		Does the AMP describe the planning techniques used?	Section 5.3

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
4.5.5c	c) Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast load increases; *Explanation: The load forecasting methodology used should be explained, indicating all the factors used in preparing the estimates.* *Load forecasts should be broken down to at least the Zone Substation level, covering the whole AMP period. The impact of uncertain, but substantial individual projects/developments should be discussed and the AMP should make clear the extent to which these uncertain load requirements are reflected in the load forecast.* *Load forecasting should take into account the impact of any embedded generation or anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives.* *Network or equipment constraints anticipated due to the anticipated load growth during the AMP should be identified.*	Does the AMP describe the process and criteria for prioritising network developments?	Sections 5.4 and 9.2
4.5.5c		Does the AMP describe the load forecasting methodology, including all the factors used in preparing the estimates?	Section 5.3
4.5.5c		Are load forecasts broken down to at least the Zone Substation level and do they cover the whole of the planning period?	Sections 5.3 and 5.4
4.5.5c		Is there any discussion of the impact of uncertain but substantial individual projects or developments? Is the extent to which these uncertain load developments are included in the forecast clear?	Section 5.3
4.5.5c		Does the load forecast take into account the impact of any embedded generation or anticipated levels of distributed generation within the network?	Section 5.3 and 5.5
4.5.5c		Does the AMP identify anticipated network or equipment constraints due to forecast load growth during the planning period?	Section 5 (throughout)
4.5.5d	d) Policies on distributed generation; *Explanation: As increasing number of owners of small generators seek connection to distribution networks, distributed generation is anticipated to have an increasingly important influence on network operation and design. AMPs should describe the policies of an EDB's in relation to the connection of embedded generation. The impact of such generation on network development plans should be stated.*	Does the AMP describe the policies of the EDB in relation to the connection of distributed generation?	Section 5.5
4.5.5d		Does the AMP discuss the impact of distributed generation on the EDB's network development plans?	Section 5.3
4.5.5e	e) Policies on non-network solutions; *Explanation: Economically feasible and practical alternatives to conventional network augmentation should be discussed in this section. These are typically approaches that would reduce network demand and/or improve asset utilisation. This section should also include discussion on the potential for distributed generation or other non-network solutions to address network problems or constraints.*	Does the AMP discuss the manner in which the EDB seeks to identify and pursue economically feasible and practical alternatives to conventional network augmentation in addressing network constraints?	Section 5.5
4.5.5e		Does the AMP discuss the potential for	Section 5.5

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
		distributed generation or other non-network solutions to address identified network problems or constraints?	
4.5.5f	f) Analysis of the network development options available and details of the decisions made to satisfy and meet target levels of service; and	Does the AMP include an analysis of the network development options available and details of the decisions made to satisfy and meet target levels of service?	Section 5 (throughout)
4.5.5g	g) 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. *Explanation: The network development plan should include:* *(i) A detailed description of the projects currently underway or planned to start in the next twelve months;* *(ii) A summary description of the projects planned for the next four years; and* *(iii) A high level description of the projects being considered for the remainder of the AMP planning period.* *For projects where decisions have been made, the reasons for choosing the selected option should be stated. For other projects planned to start in the next five years, alternative options should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations.* *Forecast expenditure and reconciliations shall be provided and prepared in accordance with Appendix A. Capital budgets should be broken down sufficiently to allow an understanding of expenditure on all the main types of development projects. Overhead to underground conversion projects should be separately indicated. Renewal and refurbishment projects should be included in the capital budget, although they are considered maintenance related works. The cost of major development projects should be separately identified in the capital budget.* *Minor capital works, or works related to whole categories of assets that have not been previously identified, may be discussed and budgeted in aggregate.*	Does the AMP include : a detailed description of the projects currently underway or planned to start in the next twelve months;	Sections 5.6, 5.7, 5.8 and 5.10
4.5.5g		a summary description of the projects planned for the next four years; and	Sections 5.6and 5.10
4.5.5g		a high level description of the projects being considered for the remainder of the planning period?	Sections 5.6 and 5.10
4.5.5g		Does the AMP discuss the reasons for choosing the selected option for those major network development projects for which decisions have been made?	Sections 5.6
4.5.5g		For other projects that are planned to start in the next five years, does the AMP discuss alternative options, including the potential for non-network alternatives to be more cost effective than network augmentations?	Section 5.6
4.5.5g		Does the AMP include a capex forecast, broken down sufficiently to allow an understanding of expenditure on all main types of development projects?	Section 5.11 and 5.12
4.5.6a	Disclosed AMPs must include a detailed description of lifecycle asset management plans, including: a) A description of maintenance planning criteria and assumptions; *Explanation: The key drivers for maintenance planning should be described.*	Does the AMP include a description of the EDB's maintenance planning criteria and assumptions?	Sections 6.1 and 6.2
4.5.6b	b) A description and identification of routine and preventative inspection and maintenance policies, programmes, and actions to be taken for each asset category, including associated expenditure projections;	Does the AMP provide a description and identification of routine and preventive inspection and maintenance policies, programmes, and actions to	Sections 6.2 and 6.3

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Explanation: The approach to inspecting and maintaining all asset management categories should be described, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done. *Systemic problems identified with any particular asset type should be highlighted and the actions to address these should be discussed.* *Budgets for maintenance activities broken down by asset category should be provided for the whole AMP period.*	be taken for each asset category, including associated expenditure projections?	
4.5.6b		Does the AMP describe the process by which defects identified by its inspection and condition monitoring programme are rectified?	Sections 6.2 and 6.3
4.5.6b		Does the AMP highlight systemic problems for particular asset types and the actions being taken to address these?	Section 6.3
4.5.6b		Does the AMP provide forecasts for routine maintenance activities, broken down by asset category, for the whole planning period?	Sections 6.2 and 6.3
4.5.6c	c) A description of asset renewal and refurbishment policies;	Does the AMP provide a description of the EDB's asset renewal and refurbishment policies, including the basis on which refurbishment or renewal decisions are made?	Sections 6.1 and 6.3
4.5.6d	d) A description and identification of renewal or refurbishment programmes or actions to be taken for each asset category, including associated expenditure projections; and	Does the AMP discuss the planned asset renewal and refurbishment programmes for each asset category including:	Section 6.3
4.5.6di	*Explanation: Asset renewal and refurbishment should be separately discussed, - although these are capex items they are not network development related and are therefore classed under maintenance. The process for deciding when and whether asset should be replaced or refurbished should be explained, as well as the factors on which these decisions are based.* *The discussion of renewal and refurbishment projects should include:* *(i) A detailed description of the projects currently underway or planned for the next twelve months;* *(ii) A summary description of the projects planned for the next four years; and* *(iii) A high level description of other work being considered for the remainder of the AMP planning period.* *The budget for renewal or refurbishment should be included as part of the capital budget.* *Forecast expenditure and reconciliations shall be provided and prepared in accordance with Appendix A.*	- a detailed description of the projects currently underway and planned for the next twelve months;	Section 6.3
4.5.6dii		- a summary description of the projects planned for the next four years; and	Section 6.3
4.5.6diii		- a high level description of the other work being considered for the remainder of the planning period?	Section 6.3
4.5.6e 7(2)a11	e) Asset replacement and renewal expenditure (which must be separately identified in the capital budget).	Does the AMP include a forecast for renewal and refurbishments, broken	Sections 6.6

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Forecast expenditure and reconciliations shall be provided and prepared in accordance with Appendix A.	down by major asset category, and covering the whole of the planning period?	
		Does the AMP include details of the EDB's risks policies and assessment and mitigation practices including:	
4.5.7a	Disclosed AMPs must include details of risk policies, assessment, and mitigation, including: a) Methods, details, and conclusions of risk analysis; and b) Details of emergency response and contingency plans. *Explanation: Asset risk management forms a component of an EDB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset related risks and describe the main risks thus identified. The focus should be on credible low-probability, high-impact risks and how they will be managed.* *Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.*	- methods, details and conclusions of risk analysis;	Sections 8.1, 8.2 and 8.3
4.5.7		- the main risks identified;	Section 8.3
4.5.7b		- details of emergency response and contingency plans?	Sections 8.4 and 8.5
4.5.7		Does the AMP identify specific development projects or maintenance programmes with the objective of managing risk? Are these projects discussed and linked back to the development plan or maintenance programmes?	Section 8.3
4.5.8	Disclosed AMPs must include details of performance measurement, evaluation, and improvement, including: *Explanation: A key outcome of an AMP is the identification of significant asset performance gaps that need to be addressed, or to adjust service level and asset performance targets to more appropriate levels.* a) A review of progress against plan, both physical and financial; *Explanation: Actual capex should be compared against that planned in the previous AMP and any significant differences discussed. The progress of development projects against plan should be assessed and reasons for substantial variances highlighted, along with any significant construction or other problems experienced.* *Actual maintenance expenditure should be compared against that planned in the previous AMP and reasons for significant differences discussed. Progress against maintenance initiatives and programmes should be assessed and discussed and the effectiveness of these programmes noted.* b) An evaluation and comparison of actual performance against targeted performance objectives; and	Is the actual capex for the previous year compared with that presented in the previous AMP and are significant differences discussed?	Section 9.4
4.5.8		Is the progress of development projects against plan (as presented in the previous AMP) assessed and are the reasons for substantial variances highlighted? Is any construction or other problems experienced discussed?	Section 5.10
4.5.8		Is the actual maintenance expenditure compared with that planned in the previous AMP and the reasons for significant differences discussed?	Section 9.4
4.5.8		Is progress against maintenance initiatives and programmes assessed and discussed and is the effectiveness of these programmes noted?	Section 6
4.5.8		Is the measured service level and	Sections 4.1 and 4.2

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Explanation: Service level and asset performance measurement should be carried out for all the targets discussed under the Service Levels section of the AMP. A comparison of actual against target performance for the year preceding the AMP should be provided, with an explanation for any significant variances.	asset performance for the previous year presented for all the targets discussed under the Service Levels section of the AMP?	
4.5.8		Is there a comparison between actual and target performance for the preceding year with an explanation for any significant variances?	Sections 4.1 and 4.2
4.5.8c	c) A gap analysis and identification of improvement initiatives. *Explanation: Where significant gaps between targeted and actual performance exist, the action to be taken to address the situation (if not caused by one-off factors) should be described.* *It is good practice to also review the overall quality of asset management and planning processes and the AMP itself, and to discuss any initiatives for improvement.*	Does the AMP identify significant gaps between targeted and actual performance. If so, does it describe the action to be taken to address the situation (if not caused by one-off factors)?	Sections 4.1 and 4.2
4.5.8c		Does the AMP review the overall quality of asset management and planning within the EDB and discuss any initiatives for improvement?	Section 1.14
4.5.9a	Disclosed AMPs must include: a) Forecasts of capital and operating expenditure for the minimum ten year asset management planning period; and b) Reconciliations of actual expenditure against forecasts for the most recent financial year for which data is available. *Explanation: Expenditure forecasts and reconciliations shall be prepared in accordance with Appendix A. For the avoidance of doubt, these include forecast expenditure required under subclauses 4.5.5(g), 4.5.6(d) and 4.5.6(e). Sections A and B of the Appendix A report for the Financial year ending 31 March 2008 or 31 March 2009 need include only:* a) The "Actual for Current Financial Year" for the line items "Subtotal – Capex on Asset Management", "Subtotal – Opex on Asset Management" and "Total Direct Expenditure on the Distribution Network"; and b) In the case of the Appendix A report for the Financial year ending 31 March 2009, all information (including all line items) for all of the forecast years specified in part A of Appendix A. It should be noted that asset management expenditure forecasts, *for the first 5 years of the plan,* derived from the most recent AMP, are required to be disclosed with other financial statements (i.e. Report AM1, Schedule 12 of the Distribution Disclosure Requirements). This report is required to be audited, in accordance with Distribution Disclosure Requirement 10, which refers to Distribution Disclosure Requirement 7(5).	Does the AMP include: a) forecasts of capital and operating expenditure for the minimum ten year asset management planning period	Section 9.4
4.5.9b		b) reconciliations of actual expenditure against forecasts for the most recent financial year for which data is available.	Section 9.4

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
7.2	In any case where prospective information is required by subclause (1) to be Publicly disclosed the Distribution business must also Publicly disclose the following (as at the date of the asset management plan): (a) All significant assumptions, clearly identified in a manner that makes their significance understandable to electricity consumers, and quantified where possible; (b) A description of changes proposed where the information is not based on the Distribution business's existing business; (c) The basis on which significant assumptions have been prepared, including the principal sources of information from which they have been derived; (d) The factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures; and (e) The assumptions made in relation to these sources of uncertainty and the potential effect of the uncertainty on the prospective information.	Does the AMP identify all significant assumptions that are considered to have a material impact on forecast expenditure (capital or operating) for the planning period?	Section 1.3, 3.2, 3.3, 5.3, 5.4, 6.3, 9.1 and 9.3
7.2		Are the significant assumptions presented and discussed in a manner that makes their source(s) and impact(s) understandable to electricity consumers?	Section 1.3, 3.2, 3.3, 5.3, 5.4, 6.3, 9.1 and 9.3
7.2		Does the AMP identify assumptions that have been made in relation to the sources of uncertainty?	Section 1.3, 3.2, 3.3, 5.3, 5.4, 6.3, 9.1 and 9.3

Electricity
Asset Management Plan
2012 – 2022

Assets Covered by This Plan – Section 2

[Disclosure AMP]

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2. Assets Covered by This Plan

2.1 Distribution Area

The Vector network is centred on the Auckland isthmus and supplies north to Mangawhai Heads (Northern region) and south to Franklin (Southern region). The map in Figure 2-1 shows the network boundaries, with Northpower in the north and Counties Power in the south. It also shows the boundary of the new wards administered by the Auckland Council. In addition, Vector supplies a large customer at Lichfield which is a stand-alone supply.

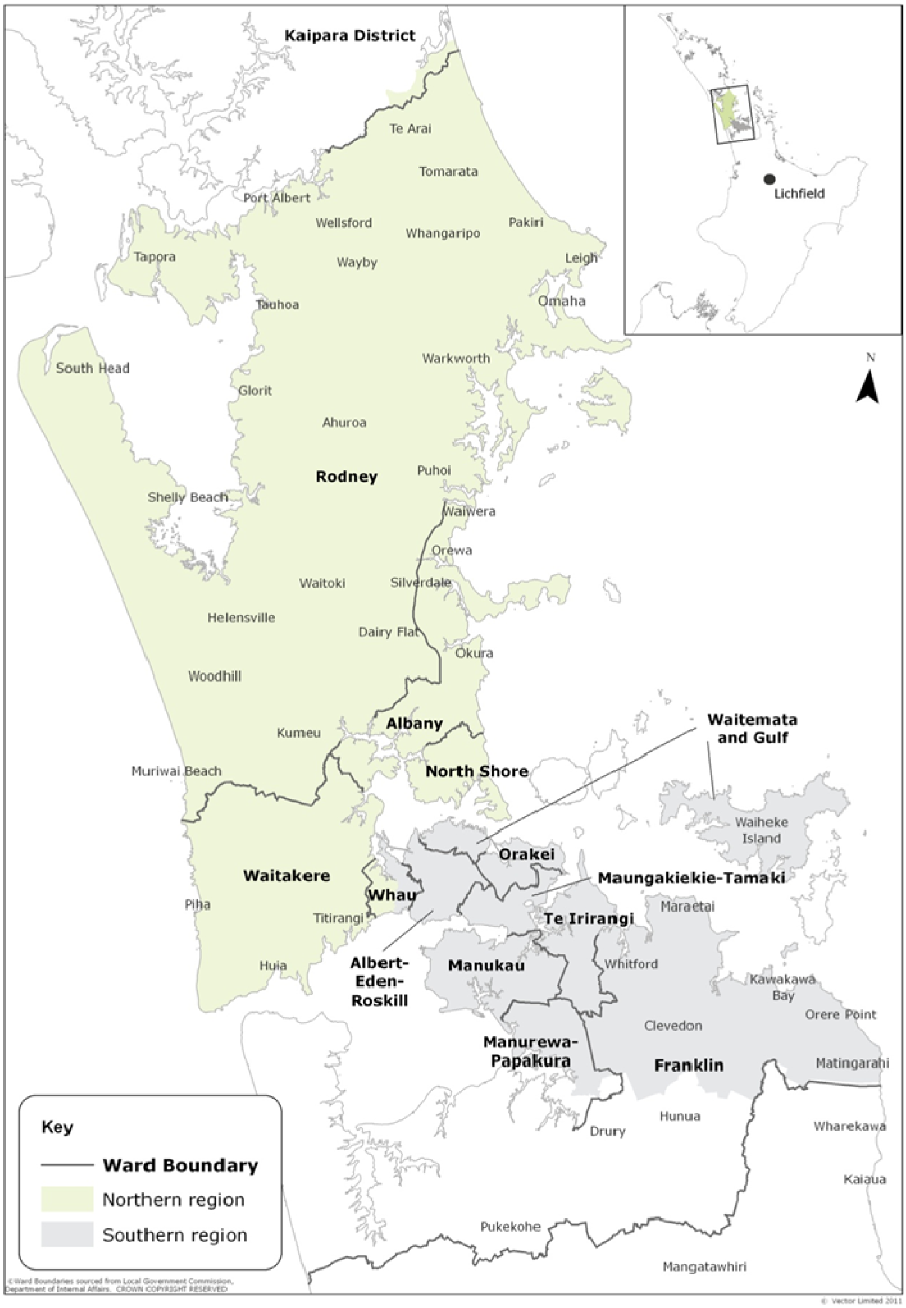

Figure 2-1 : Vector electricity supply area

While Vector operates its network in Auckland as a single unit, there are some legacy differences associated with previous ownership structures and it is convenient to separately describe the Southern and Northern regions.

2.1.1 Northern Region

The Northern region covers those areas administered by the previous North Shore City Council, Waitakere City Council and Rodney District Council. The Northern region consists of residential, commercial and industrial developments in the urban areas, and residential and farming communities in the rural areas.

Most commercial and industrial developments are in Takapuna, the Albany basin, Glenfield, Henderson and Te Atatu. New regional commercial centres are being developed as part of the development in growth areas such as Westgate, Orewa/Silverdale and Whenuapai. There are few high density, high rise developments typical of major central business districts (CBDs) but the trend is evolving.

Areas north of the Whangaparaoa Peninsula and west of Henderson and Te Atatu are predominantly rural apart from scattered small townships. Zoning in these areas is largely for farming or conservation use.

The eastern and south-eastern parts of Waitakere City and the southern parts of North Shore City consist of medium density urban dwellings that are part of metropolitan Auckland.

The historical development of the electrical network has centred around coastal townships that have in time expanded with population growth. With New Zealand Transport Agency's expansion of the motorway network north of the Albany basin, it is expected that urban development will continue to move northwards.

2.1.2 Southern Region

The Southern region covers areas administered by the previous Auckland City Council, Manukau City Council and Papakura District Council. The Southern region consists of residential, commercial and industrial developments in the urban areas, and residential and farming communities in the rural areas.

Most commercial and industrial developments are in Penrose, Newmarket, St Lukes, Mt Wellington, East Tamaki, Mangere, Takanini and Onehunga. Auckland also has the largest CBD area in New Zealand which accommodates the main commercial centre of the country.

There is also a significant amount of in-fill commercial and residential developments scattered throughout the region. Development density in the Auckland tends to be higher than in other parts of the country. This includes high rise residential apartments in the CBD, high density town house developments in suburban areas, industrial parks etc.

2.1.3 Major Customer Sites on the Vector Network

Vector has a number of large customer sites at various locations in its network. The following are those customer sites with individual demand[1] above 5MVA, which are considered to have a significant impact on network operations and asset management:

- Fonterra cheese factory at Lichfield;
- Auckland International Airport;

[1] Some sites have installed capacities higher than 5MVA but demand less than 5MVA. These sites have not been included.

- Mangere Waste Water Treatment Plant;
- Owens Illinois;
- Fisher & Paykel appliance factory at East Tamaki;
- Pacific Steel;
- Ports of Auckland;
- Sylvia Park;
- Sky City;
- Devonport Naval Base;
- Carter Holt Harvey, Penrose; and
- Masport Limited.

2.2 Load Characteristics

Traditionally, residential load has a winter evening peaking characteristic. This is ideal from an asset rating perspective, as the cool temperature and (usually) moist ground condition increase equipment ratings. However, we anticipate a strong trend towards installing new residential appliances such as heat pumps, with indications that some winter peaking residential feeders and substations will move towards summer daytime peaking. The Auckland CBD and other air conditioned office blocks already exhibit summer peaking characteristics. Presently the winter residential peak load is about twice the summer peak load but it is expected this gap will close over the next ten years. The typical daily load profiles for residential and commercial loads for summer and winter are illustrated in Figure 2-2 to Figure 2-5 below. The demands are expressed as a percentage of the peak demand. It can be seen that the residential load has peaks in the mornings and evenings whereas the commercial load is consistent throughout the day. During weekends, the commercial load, due to office blocks not being occupied, is much lower, apart from large shopping centres that operate seven days a week.

Figure 2-2 : Typical summer load profile for residential customers

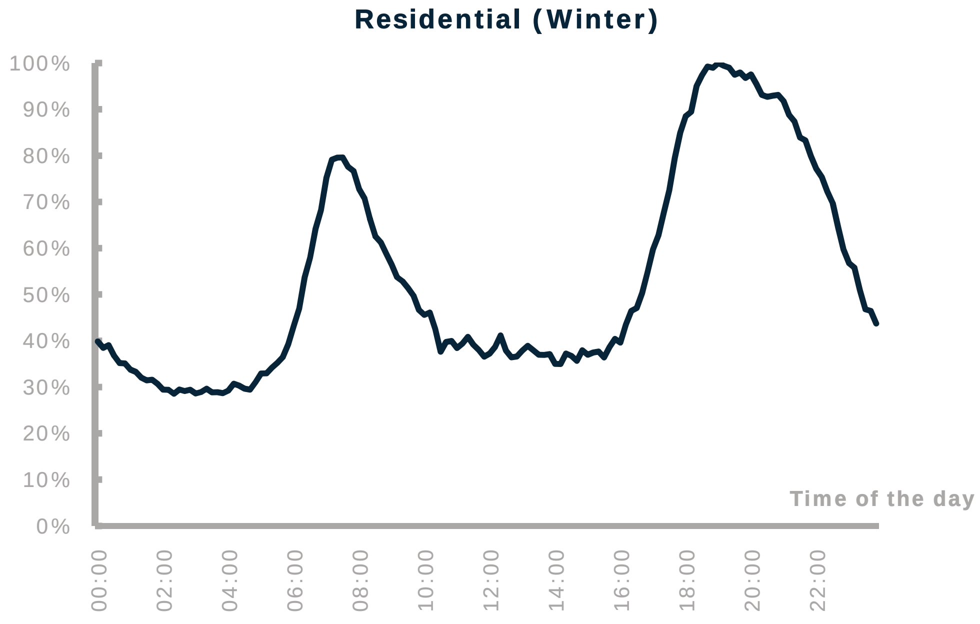

Figure 2-3 : Typical winter load profile for residential customers

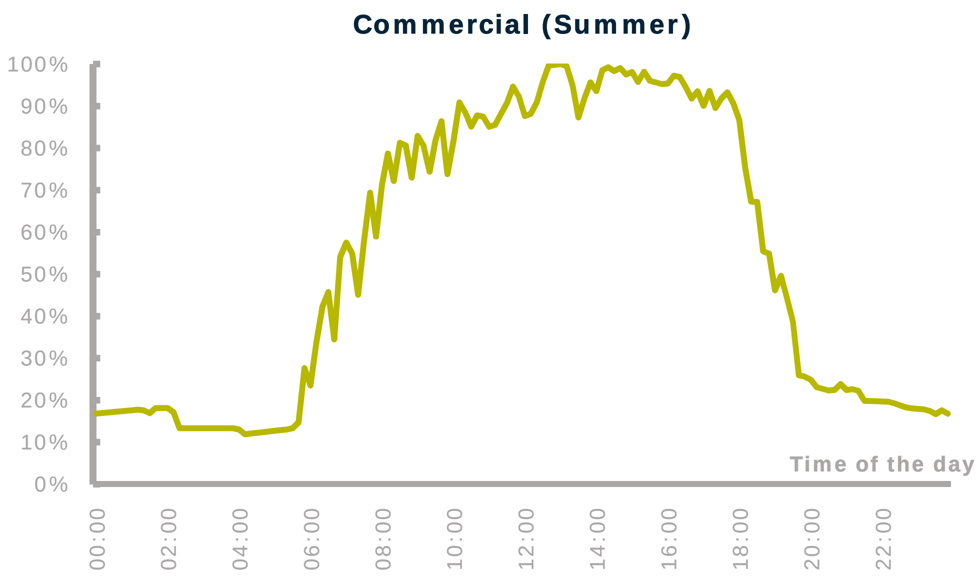

Figure 2-4 : Typical summer load profile for commercial customers

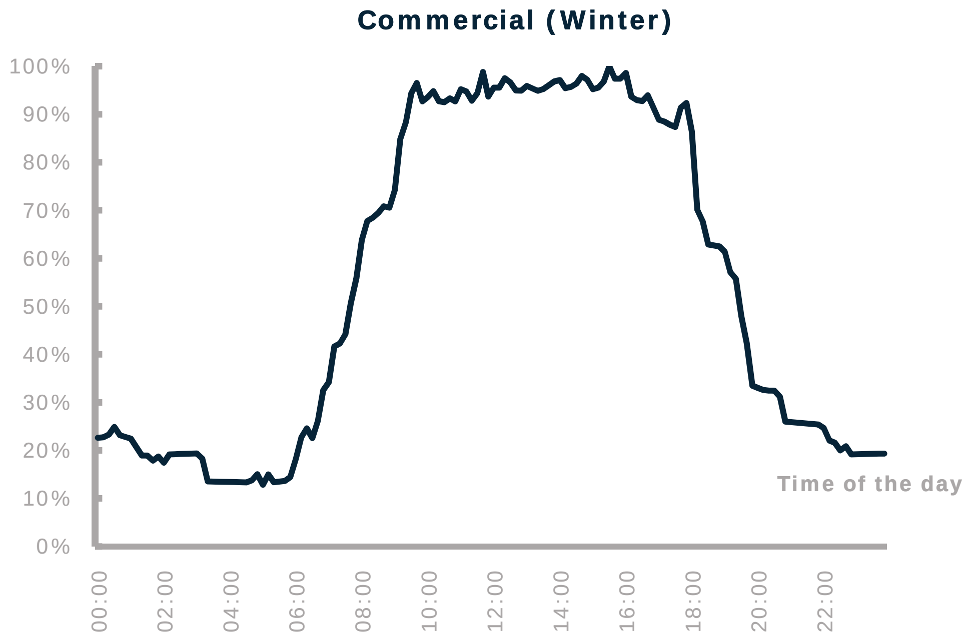

Figure 2-5 : Typical winter load profile for commercial customers

A measure of load diversity is achieved with residential customers providing peaks in the morning and early evening, with the commercial load filling in the trough between these peaks. Clearly the mix of customer types on a feeder influences the size and duration of the peaks.

Demand curves for industrial customers are far more variable – conforming closely to the nature of the customer's business. A typical industrial load curve is, therefore, not a meaningful concept.

The half-hour peak demand on the regional networks and the energy delivered for the past three years are listed in Table 2-1. (The individual demand forecasts for zone substations on Vector's network are detailed in Section 5.4.)

Regulatory Year	Northern Regional Peak Demand (MW)	Southern Regional Peak Demand (MW)	Vector Peak Demand (MW)	Northern Energy Delivered (GWh)	Southern Energy Delivered (GWh)
2008/09	603	1110	1711	2556	5688
2009/10	613	1162	1775	2598	5713
2010/11	594	1128	1722	2710	5969

Table 2-1 : Half-hour peak demand and energy delivered on the regional networks

The peak demand reported above are the coincidental peak demands of all Grid Exit Points (GXPs) delivering supply to Vector, as well as major embedded generation with net export into the Vector distribution network. It can be seen that during peak demand times, there is very little diversity between the regions and the total Vector demand.

In accordance with the Commerce Commission's Electricity Information Disclosure Requirements 2004, Lichfield is included in the Northern region in the above table.

Embedded Generation

The major embedded generators[2] on the network (capacity > 1MW) are at Greenmount, Whitford, Redvale and Rosedale landfill sites, Mangere Waste Treatment Plant, and at Auckland Hospital, but excludes Southdown which is a notionally embedded generator (connected at 220kV to the Transpower Otahuhu to Henderson line, with no direct physical connection to the Vector network). Generation at the Auckland Hospital and Mangere Waste Treatment Plant is used to offset the local demand and does not export into the Vector distribution network. Over time, when gas production at landfill sites becomes depleted, the gas generators will be relocated and feeder reinforcement will have to be considered to maintain security of supply in the local areas. The generation capacities of embedded generators will be closely monitored to ensure sufficient forewarning of reinforcements.

2.3 Network Configuration

The overall architecture of the Vector network is shown in Figure 2-6.

Vector receives electricity supply from the national grid at thirteen Grid Exit Points (GXPs), owned by Transpower. The Vector network is made up of three main component networks: sub-transmission (110kV, 33kV and 22kV), medium voltage distribution (22kV and 11kV) and low voltage distribution (400/230V).

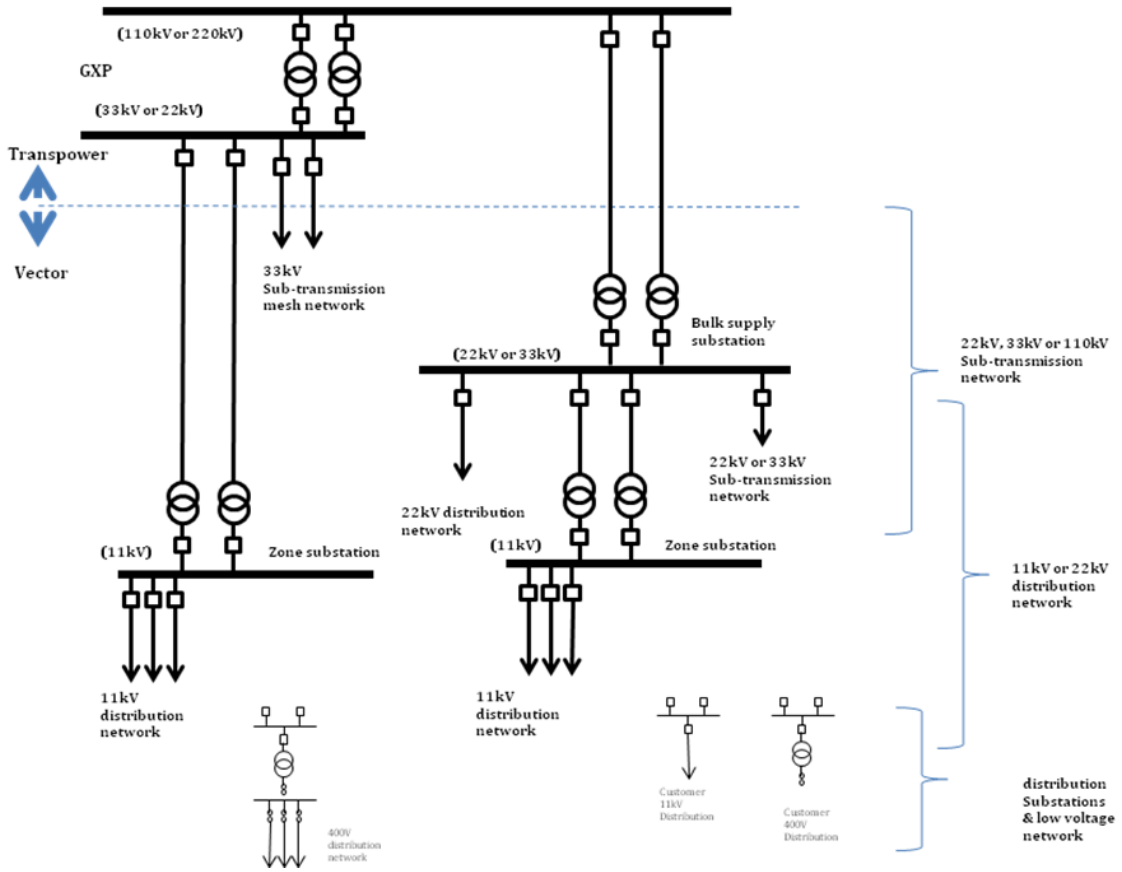

Figure 2-6 : Schematic of Vector's network

[2] This includes only those generators connected to the Vector network at 11kV or above, with a positive injection of energy into the Vector network and metered with half-hourly meters.

2.3.1 The Transmission Grid around Auckland

The electricity supply into Auckland from generation in the central North Island and the South Island is provided by six 220kV circuits and two 110kV circuits. All eight circuits terminate onto the 220kV busbar and 110kV busbar at Otahuhu GXP. From Otahuhu GXP, two 220kV circuits and four 110kV circuits have been installed to supply the demand north of the Auckland Isthmus. Another two 220kV circuits and four 110kV circuits have been installed to supply the Auckland Isthmus.

Vector takes supply from the national transmission grid at 12 GXPs to supply its sub-transmission network in Auckland. A thirteenth GXP (Lichfield GXP) is dedicated to the supply of the Fonterra Cheese Factory at Lichfield in Tokoroa. Sub-transmission supply is taken at 110kV, 33kV and 22kV. Vector has also established five internal bulk supply substations to supply its sub-transmission networks in Auckland, to supply load centres that are at a distance from the grid.

Table 2-2 to Table 2-5 show the winter and summer peak demands at GXPs and bulk supply substations. The tables also show the installed capacity and firm capacity at each of these supply points. For completeness, the tables also show the GXP at Lichfield in Tokoroa where Vector takes supply from Transpower to supply the Fonterra cheese factory.

Grid Exit Point	Supply Voltage	Installed Transformer Capacity (MVA)	Firm Capacity[3] (MVA)	2011 Winter Peak Demand (MVA)
Albany	110kV			140
Albany	33kV	3x120	234	162
Henderson	33kV	2x120	135	127
Hepburn	33kV	1x85 + 2x120	245	140
Lichfield	110kV			9
Mangere	110kV			56
Mangere	33kV	2x120	118	107
Otahuhu	22Kv	2x50	59	64
Pakuranga	33kV	2x120	136	153
Penrose	110kV			198
Penrose	22kV	3x45	90	55
Penrose	33kV	1x169[4] + 2x160 + 1x200	429	343
Roskill	110kV			59
Roskill	22kV	2x70 + 1x50	141	140
Silverdale	33kV	1x120 + 1x100	109	83
Takanini	33kV	2x150	123	117
Wellsford	33kV	2x30	31	31
Wiri	33kV	2x100	107	83

Table 2-2 : Grid Exit points for Auckland and Lichfield winter loads

[3] Firm capacities supplied by Transpower

[4] The 169MVA 220/33kV transformer operates on normally open standby mode

Grid Exit Point	Supply Voltage	Installed Transformer Capacity (MVA)	Firm Capacity (MVA)	2011 Summer Peak Demand (MVA)
Albany	110kV			85
Albany	33kV	3x120	234	107
Henderson	33kV	2x120	135	74
Hepburn	33kV	1x85 + 2x120	239	89
Lichfield	110kV			7
Mangere	110kV			52
Mangere	33kV	2x120	118	87
Otahuhu	22KV	2x50	59	46
Pakuranga	33kV	2x120	136	103
Penrose	110kV			204
Penrose	33kV	1x169 + 2x160 + 1x200	406	273
Penrose	22kV	3x45	90	53
Roskill	110kV			34
Roskill	22kV	2x70 + 1x50	141	73
Silverdale	33kV	1x120 + 1x100	109	46
Takanini	33kV	2x150	123	86
Wellsford	33kV	2x30	31	21
Wiri	33kV	2x100	107	70

Table 2-3 : Grid Exit points for Auckland and Lichfield summer loads

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	Firm Capacity (MVA)	2011 Winter Peak Demand (MVA)
Hobson[5]	22kV	2x65[6]	80[7]	76.7[8]
	11kV		25	18.6
Kingsland	22kV	2x60	60	60.4
Lichfield	11kV	2x20	24	8.5
Liverpool	22kV	2x75+1x60	114[9]	77.6
Pacific Steel	33kV	70+40	40	55.8

[5] The two 65MVA three winding transformers operate in parallel with the 60MVA transformer (unit T3B) at Quay substation via 22kV interconnector cables.

[6] These are three winding transformers with two secondary windings supplying 40MVA at 22kV and 25MVA at 11kV

[7] Firm capacity includes the capacity of unit T3B (60MVA) at Quay substation.

[8] The load includes Hobson substation 22kV, Liverpool substation 22kV lower bus and Quay substation 22kV lower bus.

[9] Firm capacity reduced due to uneven sharing of transformers.

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	Firm Capacity (MVA)	2011 Winter Peak Demand (MVA)
Quay	22kV	1x60[10]+2x50	48	32.7
Wairau Road	33kV	3x80	160	140.2

Table 2-4 : Bulk Supply Substations for Auckland and Lichfield winter loads

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	Firm Capacity (MVA)	2011 Summer Peak Demand (MVA)
Hobson	22kV	2x65	80	81.0
	11kV		25	22.2
Kingsland	22kV	2x60	60	34.8
Lichfield	11kV	2x20	24	8.7
Liverpool	22kV	2x75+1x60	114	80.9
Pacific Steel	33kV	70+40	40	52.2
Quay	22kV	1x60+2x50	33	29.9
Wairau Road	33kV	3x80	160	85.0

Table 2-5 : Bulk Supply Substations for Auckland and Lichfield summer loads

The following map in Figure 2-7 shows the locations of the GXPs and the main 110kV and 220kV lines supplying into and across Auckland.

[10] This 60MVA transformer (unit T3B) operates in parallel with the two 65MVA three winding transformers at Hobson substation via 22kV interconnector cables and is independent of the two 50MVA transformers at Quay substation.

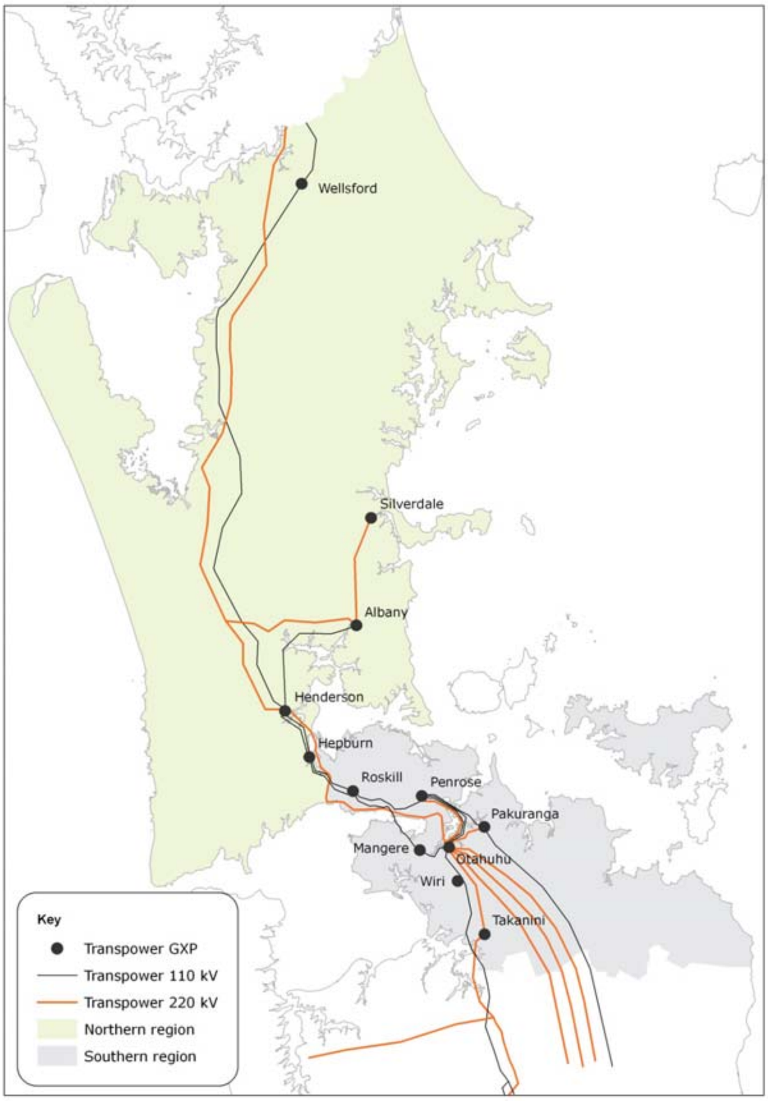

Figure 2-7 : Locations of GXPs and major transmission lines supplying Vector

2.3.2 Sub-Transmission Network

The sub-transmission networks for the Northern and Southern regions have been developed differently. The Northern network has a mixture of interconnected 33kV ring and radial circuits (largely overhead lines) connected to the Transpower GXPs. It is a common practice to have 33kV switches at zone substations. This has allowed some interconnection between GXPs.

The Southern region is largely radial circuits supplying two to three transformer zone substations. These are largely supplied by underground cables. Sub-transmission voltages range from 110kV in the Auckland CBD and supply to Kingsland, through to 33kV and 22kV elsewhere in the Southern region.

Capacities of existing zone substations in the Southern region are larger (typically two or three 20MVA transformers at each substation) whereas about half of the Northern region's zone substations are single transformer substations (with transformer size ranging from 5MVA to 20MVA). Since 2005, new transformers purchased for urban zone substations are rated at 20MVA whereas those for rural areas are 10MVA.

Typically zone substations in the Northern region are equipped with a 33kV switchboard (or outdoor busbar), an 11kV switchboard and transformers. Zone substations in the Southern region typically do not have 33kV (or 22kV) switchboards except for those that are established as part of a bulk in-feed substation or switching station.

A description of the development plan for the sub-transmission network and the zone substations is given in Section 5 of this plan.

Table 2-6 lists Vector's zone substations as at the beginning of 2012 together with their installed capacities, n-1 firm capacities (if applicable), the 2011 winter peak demand, the substation security level and distribution backstop capacities.

Zone Substation	Supply Voltage	Installed Capacity[11] (MVA)	Substation N-1 Capacity[12] (MVA)	2011 Winter Peak Demand (MVA)	Security (N-X)	Feeder Backstop Capacity[13] (MVA)
Atkinson Road	33kV	2x20	24.0	21.1	N-1	20.1
Auckland Airport	33kV	2x25	25.0	15.3	N-1	10.0
Avondale	22kV	2x20	24.0	32.1	N	23.3
Bairds	22kV	2x20	24.0	25.3	N	25.6
Balmain	33kV	1x12.5	0.0	9.9	N	9.8
Balmoral	22kV	2x12	14.4	18.4	N	15.2
Belmont	33kV	2x12.5	14.0	14.8	N	6.1
Birkdale	33kV	2x12.5	15.2	24.7	N	17.1
Brickworks	33kV	1x12.5	0.0	10.9	N	10.4
Browns Bay	33kV	2x12.5	14.0	15.6	N	17.0
Bush Road	33kV	2x24	23.8	23.5	N-1	13.2
Carbine	33kV	2x20	22.5	16.8	N-1	8.4
Chevalier	22kV	2x20	17.1	17.4	N	14.9
Clendon	33kV	2x20	24.0	21.0	N-1	19.5
Clevedon	33kV	1x5	0.0	3.1	N	3.6
Coatesville	33kV	1x12.5	0.0	10.5	N	10.0
Drive	33kV	2x20	24.0	30.4	N	27.1
East Coast Road	33kV	1x24	0.0	18.0	N	13.3
East Tamaki	33kV	2x20	24.0	16.4	N-1	8.5
Forrest Hill	33kV	1x12.5 +1x20	16.0	19.6	N	15.1
Freemans Bay	22kV	1x18 + 1x20	21.6	20.6	N-1	16.4
Glen Innes	22kV	2x12	12.2	12.3	N	14.4

[11] Transformer nameplate ratings apply.

[12] Substation cyclic capacity (at sub-transmission level) after losing the component with the largest capacity.

[13] Total backstop capacity available from the 11kV network for 11kV zone substations, and 22kV express feeders for CBD substations 22kV load.

Zone Substation	Supply Voltage	Installed Capacity[11] (MVA)	Substation N-1 Capacity[12] (MVA)	2011 Winter Peak Demand (MVA)	Security (N-X)	Feeder Backstop Capacity[13] (MVA)
Greenhithe	33kV	1x20	0.0	14.3	N	10.0
Greenmount	33kV	3x20	48.0	39.9	N-1	29.7
Gulf Harbour	33kV	1x20	0.0	7.9	N	12.6
Hans	33kV	2x20	24.0	26.1	N	11.0
Hauraki	33kV	1x12.5	0.0	9.2	N	10.1
Helensville	33kV	2x7.5	9.0	14.1	N	9.4
Henderson Valley	33kV	2x12.5	15.2	19.8	N	23.5
Highbrook[14]	22kV	-	23.0	4.9	N-1	0.0
Highbury	33kV	1x12.5	0.0	11.1	N	8.7
Hillcrest	33kV	2x24	23.8	24.3	N	24.1
Hillsborough	22kV	1x20	0.0	19.7	N	22.2
Hobson 110/11kV[15]	110kV	2x25	25.0	18.6	N-1	12.8
Hobson 22/11kV[16]	22kV	2x15	15.0	17.8	N	12.9
Hobson 22kV[17]	110kV	2x40	40.0	5.8	N-1	31.1
Hobsonville	33kV	2x12.5	16.0	21.4	N	10.1
Auckland Hospital	22kV	1x10	0.0	7.2	N	8.7
Howick	33kV	3x20	46.0	44.9	N-1	14.9
James Street	33kV	2x12.5	16.0	21.5	N	16.5
Keeling Road	33kV	1x24	0.0	13.1	N	15.0
Kingsland	22kV	2x20	24.0	24.3	N	17.6
Laingholm	33kV	2x7.5	8.4	10.0	N	5.5
Liverpool	22kV	3x20	48.0	41.2	N-1	28.3
Liverpool 22kV	110kV	2x75+1x50	125.0	80.9	N-1	69.8
Mangere Central	33kV	2x20	24.0	28.1	N	13.2
Mangere East	33kV	2x20	24.0	28.7	N	25.5
Mangere West	33kV	2x30	36.0	17.4	N-1	3.9
Manly	33kV	2x12.5	14.0	16.8	N	14.9

[14] Highbrook is a 22kV switching station supplying the 22kV network for Highbrook Industrial Park.

[15] The Hobson 11kV busbar is supplied by 2x22/11kV 15MVA transformers and 2x110/22/11kV (25MVA) transformers.

[16] The Hobson 11kV busbar is supplied by 2x22/11kV 15MVA transformers and 2x110/22/11kV (25MVA) transformers.

[17] The Hobson 22kV busbar is supplied by 2x110/22/11kV (40MVA) transformers.

Zone Substation	Supply Voltage	Installed Capacity[11] (MVA)	Substation N-1 Capacity[12] (MVA)	2011 Winter Peak Demand (MVA)	Security (N-X)	Feeder Backstop Capacity[13] (MVA)
Manukau	33kV	3x20	48.0	30.7	N-1	26.9
Manurewa	33kV	3x20	46.9	52.0	N	28.2
Maraetai	33kV	2x15	15.2	7.4	N-1	3.6
McKinnon	33kV	1x24 +1x20	23.8	21.8	N-1	15.3
Mcleod Road	33kV	1x12.5	0.0	14.8	N	12.9
McNab	33kV	3x20	48.0	47.2	N-1	28.0
Milford	33kV	1x12.5	0.0	8.6	N	8.7
Mt Albert	22kV	1x12	-	11.4	N-1	12.4
Mt Wellington	33kV	2x20	24.0	21.0	N-1	21.5
New Lynn	33kV	2x12.5	14.0	14.2	N	14.2
Newmarket	33kV	3x20	48.0	36.7	N-1	38.2
Newton	22kV	2x16	19.2	19.8	N	21.3
Ngataringa Bay	33kV	1x12.5	0.0	9.2	N	9.5
Northcote	33kV	1x16	0.0	9.3	N	4.1
Onehunga	22kV	2x15	14.8	14.9	N	13.5
Orakei	33kV	2x18	21.6	24.8	N	16.1
Oratia	33kV	1x10	0.0	5.8	N	6.9
Orewa	33kV	2x20	15.2	15.6	N	7.6
Otara	22kV	2x15+20	30.8	33.5	N	25.0
Pacific Steel	110kV	1x70 + 1x40	40.0	55.8	N	18.2
Pakuranga	33kV	2x20	24.0	26.2	N	9.7
Papakura	33kV	2x20	24.0	27.1	N	10.8
Parnell	22kV	1x15+1x12	14.6	11.5	N-1	16.4
Ponsonby	22kV	2x12	14.4	18.0	N	8.9
Quay	22kV	2x20	24.0	23.4	N-1	25.0
Quay 22kV	110kV	2x50 + 1x60	66.0	7.3	N-1	34.4
Ranui	33kV	1x20	0.0	9.7	N	9.9
Red Beach	33kV	1x20	0.0	15.0	N	14.2
Remuera	33kV	2x20	24.0	30.0	N	20.8
Riverhead	33kV	2x7.5	9.0	10.9	N	11.1
Rockfield	33kV	2x20	24.0	19.2	N-1	23.2
Rosebank	33kV	2x21.5	25.8	23.4	N-1	12.8

Zone Substation	Supply Voltage	Installed Capacity[11] (MVA)	Substation N-1 Capacity[12] (MVA)	2011 Winter Peak Demand (MVA)	Security (N-X)	Feeder Backstop Capacity[13] (MVA)
Sabulite Road	33kV	2x12.5	14.0	21.4	N	17.5
Sandringham	22kV	2x20	24.0	24.0	N	44.9
Simpson Road	33kV	1x7.5	0.0	5.6	N	5.7
Snells Beach	33kV	1x7.5	0.0	6.3	N	4.0
South Howick	33kV	2x20	24.0	33.8	N	16.9
Spur Road	33kV	1x12.5	0.0	12.8	N	16.6
St Heliers	33kV	2x17.5	21.0	25.0	N	18.6
St Johns	33kV	2x20	24.0	17.4	N-1	23.2
Sunset Road	33kV	2x12.5	14.0	18.8	N	16.4
Swanson	33kV	1x12.5	0.0	13.4	N	11.1
Sylvia Park	33kV	2x20	24.0	16.2	N-1	44.9
Takanini	33kV	2x15	18.0	16.6	N-1	12.4
Takapuna	33kV	1x24	0.0	9.0	N	10.6
Te Atatu	33kV	2x12.5	14.0	22.7	N	11.2
Te Papapa	33kV	2x20	24.0	24.6	N	11.1
Torbay	33kV	1x12.5	0.0	10.5	N	7.1
Triangle Road	33kV	2X10	12.0	18.2	N	18.9
Victoria	22kV	2x20	24.0	23.1	N-1	25.2
Waiake	33kV	1x12.5	0.0	10.4	N	8.9
Waiheke	33kV	2x12.5	15.0	10.8	N-1	3.5
Waikaukau	33kV	1x7.5	0.0	7.7	N	8.2
Waimauku	33kV	1x7.5	0.0	6.9	N	4.0
Wairau	33kV	2x12.5	16.0	17.1	N	17.8
Warkworth	33kV	3x7.5	18.0	17.7	N-1	18.7
Wellsford	33kV	2x7.5	9.0	8.9	N-1	5.0
Westfield	22kV	2x20	24.0	29.4	N	16.3
White Swan	22kV	3x15	34.7	30.4	N-1	18.2
Wiri	33kV	3x20	48.0	38.6	N-1	21.4
Woodford	33kV	1x12.5	0.0	9.4	N	12.1

Table 2-6 : Vector's zone substation loading and security

2.3.2.1 Outdoor Versus Indoor Substations

All new zone substations have switchgear installed indoors.

Some older substations still have outdoor equipment. The condition of these outdoor 33kV switchyards is monitored and where economically or technically justifiable they are being replaced with indoor switchgear.

2.3.2.2 Undergrounding

The Northern region has a large percentage of overhead lines, particularly in the rural areas. The sub-transmission system in this region is largely constructed overhead. This makes the network much more vulnerable during strong winds and storms. On the other hand, the Southern region sub-transmission network is all underground except for the supply to Maraetai. This makes the sub-transmission network very secure from winds and storms, but vulnerable to dig-ins and ground movement.

Since the ownership of the Northern network changed to Vector in 2003, all new sub-transmission circuits have been installed underground except for the rural areas which will remain overhead. As at the end of March 2011, 90% of the sub-transmission network is underground in the Southern region and 27% in the Northern region. Overall, 59% of Vector's sub-transmission network is underground.

2.3.2.3 Vector Grouping[18]

Due to historical development, the power transformers supplying different parts of Vector's sub-transmission network are configured to different vector groups.[19] Using the grid (220kV and 110kV) as reference, the phase angles of the sub-transmission network in the different parts of the Vector network are shown in the vector diagrams in Figure 2-8 to Figure 2-10.

[18] To avoid confusion, in this context the vector grouping refers to the internal winding configuration of a transformer and has nothing to do with Vector as a company or group.

[19] Ibid.

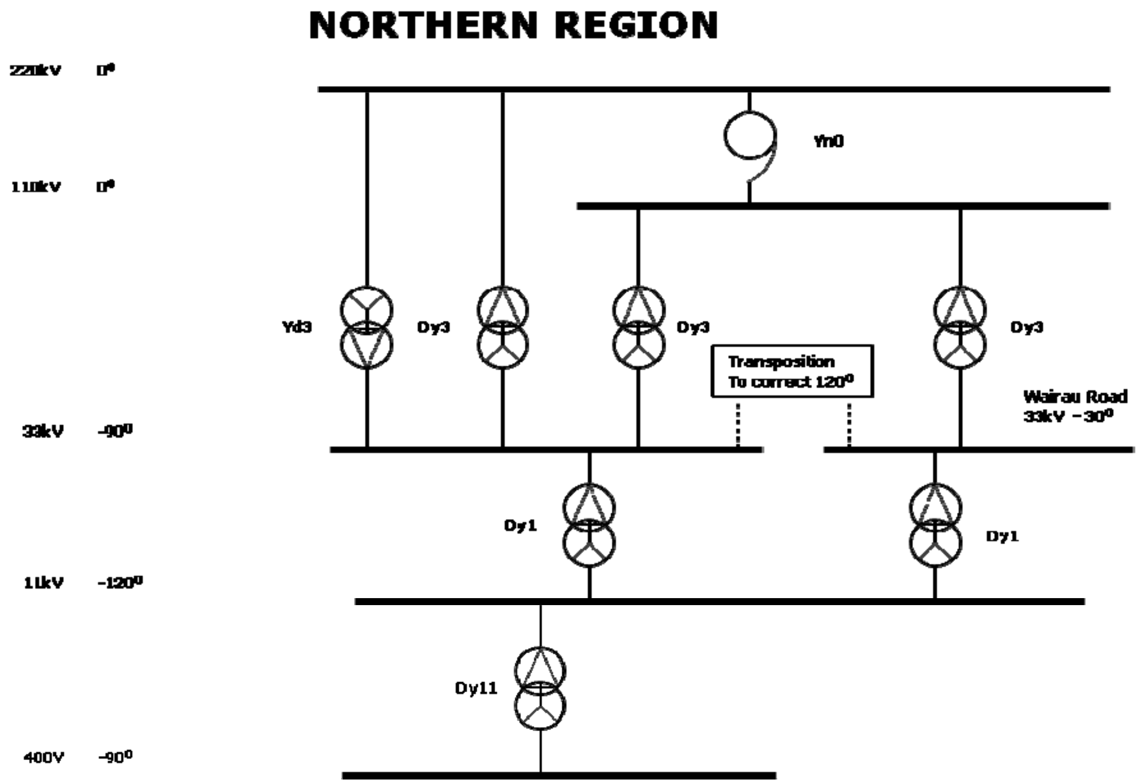

Figure 2-8 : Vector groups of transformers supplying the Northern region

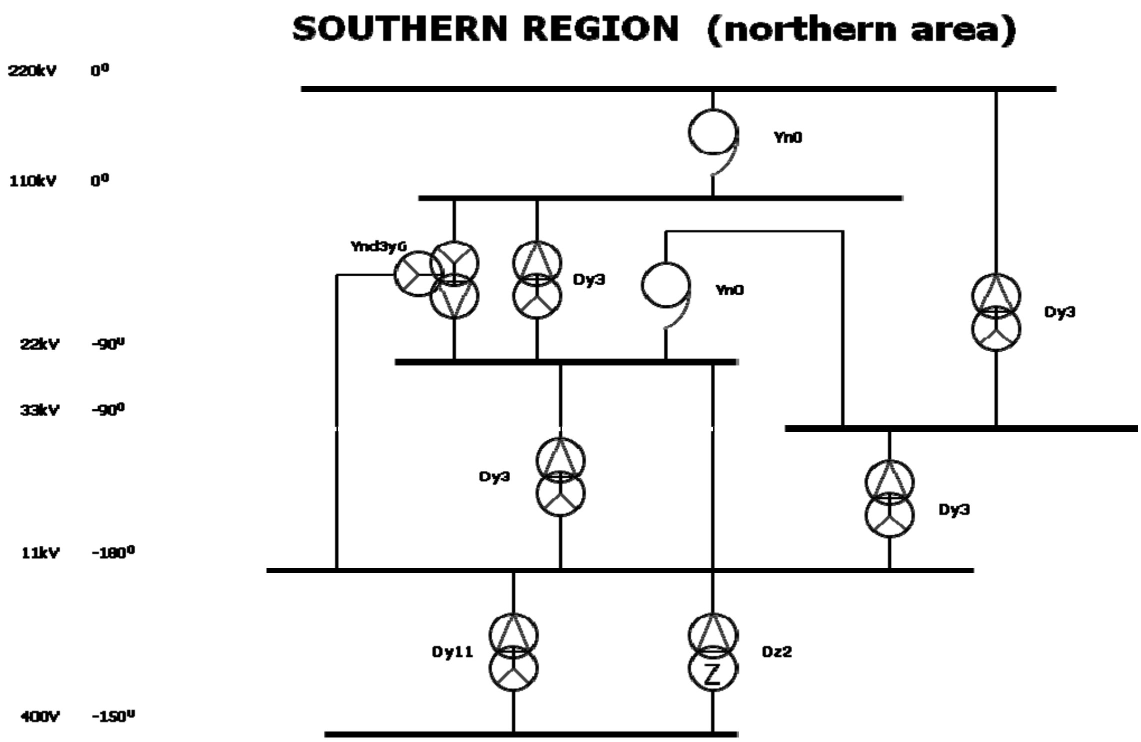

Figure 2-9 : Vector groups of transformers supplying the Southern region (northern area)

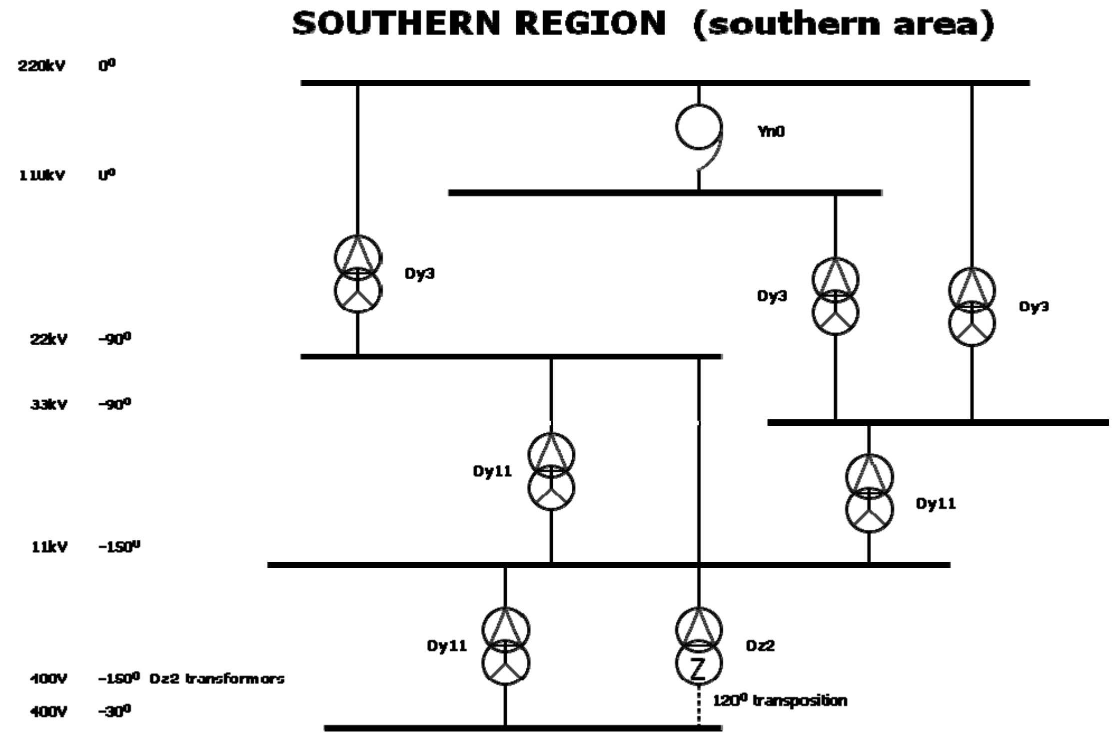

Figure 2-10 : Vector groups of transformers supplying the Southern region (southern area)

From the vector diagrams, it can be seen that the sub-transmission network in all regions is all in phase except at Wairau Road substation where the 110/33kV transformers are Dy11. Rotation of the 33kV feeders supplied by the Dy11 transformers by 120^o before connecting to the network fed from other substations enable them to operate in parallel with the rest of the sub-transmission network. This rotation will be corrected when a new 220/33kV transformer and a new 33kV switchboard is commissioned (scheduled for 2013).

The 11kV network between the northern area and southern area of the Southern region is 120^o out of phase. A rotation of 120^o has already been made at the 11kV network supplied by the two areas to allow them to operate in parallel. The same rotation applies to the 400V network. The phase angle between the 11kV network in the Northern region and Southern region is 60^o. Phase correction between the two regions can only be made via a phase correction transformer. The 22kV/400V transformers in the Auckland CBD are Dz2 units to enable them to run in parallel with the existing LV network supplied from the 11kV network. The 22kV/400V transformers used at Highbrook development are Dz2 units. The 400V network is, therefore, 120^o out of phase with the LV network supplied from neighbouring 11kV network and has to be rotated by 120^o before parallel operation is feasible.

2.3.2.4 Prospective Fault Currents

Prospective fault currents at the various zone substation busbars were calculated using DigSilent Power Factory version 14.0 with the network configuration as at January 2011. The source fault levels were obtained by connecting the Vector model onto Transpower's 2011 NIPS model. Known significant embedded generation were included in the model.

The DigSilent Complete Methodology was used in the fault current calculation. This is a superposition method where load flows are performed to determine the pre-fault condition of the network such as the busbar voltage and tap changer positions. The winter demand forecasts in section 5.4 of this plan have been used for the load flow study.

Vector's 11kV circuit breakers have historically been specified to break fault currents of 13.1kA, although some individual circuit breakers purchased from certain manufacturers recently may have higher capabilities. It is essential to recognise the prospective fault currents when designing the fault ratings of equipment.

Table 2-7 summarises the prospective fault currents (expressed in kA) at the various zone substations with the 11kV bus sections at multi transformer substations closed.

Zone Substation	Fault Current (kA)								
	2012			2017			2022		
	3P	P-P	P-E	3P	P-P	P-E	3P	P-P	P-E
Atkinson Road	9.2	8.0	10.3	9.2	8.0	10.3	9.2	7.9	10.2
Auckland Airport	11.1	9.6	1.9	11.3	9.8	1.9	11.4	9.9	1.9
Avondale	7.7	6.6	8.3	7.7	6.7	8.3	7.8	6.7	8.4
Bairds	8.8	7.6	9.3	8.8	7.6	9.3	8.7	7.6	9.2
Balmain	6.1	5.3	6.8	6.1	5.3	6.8	6.1	5.3	6.8
Balmoral	8.7	7.5	9.5	8.7	7.5	9.5	8.7	7.5	9.5
Belmont	10.4	9.0	12.0	10.5	9.1	12.0	10.4	9.0	12.0
Birkdale	10.5	9.1	12.1	10.6	9.1	12.2	10.5	9.1	12.1
Brickworks	6.7	5.8	7.3	6.8	5.9	7.3	6.8	5.9	7.3
Browns Bay	7.6	6.6	8.0	7.6	6.6	8.0	7.6	6.5	8.0
Bush Road	12.0	10.4	12.9	12.0	10.4	12.9	12.0	10.4	12.9
Carbine	8.4	7.3	8.8	8.4	7.3	8.8	8.4	7.2	8.8
Chevalier	5.5	4.7	5.9	5.5	4.7	5.9	5.5	4.8	6.0
Clendon	9.5	8.2	10.6	9.5	8.2	10.6	9.6	8.3	10.7
Clevedon	3.8	3.3	4.2	3.8	3.3	4.2	3.8	3.3	4.2
Coatesville	6.5	5.5	6.9	6.5	5.5	6.9	6.5	5.5	6.9
Drive	8.6	7.5	9.0	8.6	7.5	9.0	8.6	7.5	9.0
East Coast Road	6.5	5.6	6.9	6.5	5.7	7.0	6.6	5.7	7.0
East Tamaki	10.7	9.3	1.0	11.4	9.9	1.0	11.4	9.9	1.0
Forrest Hill	10.5	9.1	11.7	10.5	9.1	11.7	10.5	9.1	11.7
Freemans Bay	10.1	8.7	11.1	10.1	8.7	11.1	10.1	8.7	11.1
Glen Innes	7.7	6.7	8.7	7.7	6.7	8.7	7.7	6.7	8.7
Greenhithe	4.9	4.3	5.5	4.9	4.3	5.5	4.9	4.2	5.5
Greenmount	11.8	10.2	12.8	12.8	11.1	**13.6**	12.7	11.0	**13.5**
Gulf Harbour	5.3	4.6	5.8	5.3	4.6	5.9	5.3	4.6	5.8

Zone Substation	Fault Current (kA)								
	2012			2017			2022		
	3P	P-P	P-E	3P	P-P	P-E	3P	P-P	P-E
Hans	8.2	7.1	8.8	8.2	7.1	8.8	8.3	7.2	8.8
Hauraki	6.3	5.4	6.8	6.2	5.4	6.7	6.2	5.4	6.7
Helensville	4.9	4.3	6.0	4.9	4.3	6.0	5.0	4.3	6.0
Henderson Valley	7.2	6.2	7.6	7.2	6.2	7.6	7.2	6.2	7.6
Highbrook	19.4	16.8	20.2	19.4	16.8	20.2	19.1	16.6	19.9
Highbury	6.0	5.2	6.7	6.0	5.2	6.7	5.9	5.2	6.6
Hillcrest	10.8	9.4	12.1	10.9	9.5	12.2	10.9	9.4	12.1
Hillsborough	4.6	4.0	4.8	4.6	4.0	4.8	4.6	4.0	4.8
Hobson 110/11kV	12.7	11.0	1.1	12.7	11.0	1.1	12.5	10.9	1.0
Hobson 22/11kV	7.8	6.8	8.3	7.9	6.8	8.3	7.9	6.8	8.3
Hobson 22kV distribution	19.2	16.6	1.3	19.2	16.7	1.3	19.2	16.6	1.3
Hobsonville	11.6	10.0	12.8	11.6	10.1	12.8	11.6	10.0	12.8
Hospital	5.3	4.6	5.5	5.3	4.6	5.5	5.3	4.6	5.5
Howick	11.7	10.1	12.7	12.6	11.0	**13.5**	12.6	10.9	**13.5**
James Street	9.9	8.6	11.6	9.9	8.6	11.6	9.9	8.6	11.6
Keeling Road	6.3	5.4	7.5	6.3	5.5	7.6	6.3	5.5	7.7
Kingsland	7.9	6.8	8.7	7.9	6.8	8.8	7.8	6.8	8.7
Kingsland 22kV	12.4	10.8	12.9	12.5	10.8	12.9	12.4	10.8	12.9
Laingholm	7.6	6.6	8.6	7.6	6.6	8.6	7.6	6.6	8.6
Liverpool 11kV	10.8	9.3	11.8	10.8	9.3	11.8	10.9	9.4	11.9
Liverpool 22kV Dst Lower Bus	19.7	17.1	1.5	19.7	17.0	1.5	19.8	17.1	1.5
Liverpool 22kV Dst Upper Bus	19.7	17.1	1.5	19.7	17.0	1.5	19.8	17.1	1.5
Liverpool 110kV	20.9	18.1	23.0	19.7	17.1	22.0	19.7	17.1	21.9
Mangere Central	8.0	6.9	8.6	8.1	7.0	8.6	8.1	7.0	8.7
Mangere East	8.0	7.0	8.6	8.1	7.0	8.6	8.2	7.1	8.7
Mangere West	10.3	8.9	1.0	10.3	9.0	1.0	10.4	9.0	1.0
Manly	9.6	8.3	11.1	9.6	8.3	11.1	9.6	8.3	11.1
Manukau	12.2	10.5	13.1	12.2	10.5	13.1	12.1	10.5	13.0
Manurewa	11.1	9.6	12.3	11.2	9.7	12.3	11.2	9.7	12.3
Maraetai	6.0	5.2	7.4	6.0	5.2	7.5	6.0	5.2	7.4
McKinnon	11.9	10.3	12.8	12.0	10.4	12.9	12.0	10.4	12.9

Zone Substation	Fault Current (kA)								
	2012			2017			2022		
	3P	P-P	P-E	3P	P-P	P-E	3P	P-P	P-E
Mcleod Road	7.1	6.1	7.5	7.1	6.1	7.5	7.1	6.1	7.5
McNab	12.6	10.9	1.5	12.7	11.0	1.5	12.8	11.0	1.5
Milford	6.6	5.7	7.3	6.7	5.8	7.3	6.6	5.7	7.3
Mt Albert	4.8	4.2	5.2	4.8	4.2	5.2	4.9	4.2	5.2
Mt Wellington	11.9	10.3	12.6	11.9	10.3	12.7	12.0	10.4	12.8
New Lynn	11.3	9.8	12.6	11.4	9.9	12.7	11.3	9.8	12.6
Newmarket	12.4	10.8	**13.4**	12.6	10.9	**13.6**	12.8	11.1	**13.7**
Newton	8.2	7.1	8.8	8.2	7.1	8.8	8.2	7.1	8.8
Ngataringa Bay	6.3	5.4	6.9	6.3	5.5	6.9	6.3	5.4	6.9
Northcote	6.1	5.3	6.7	6.1	5.3	6.7	6.1	5.3	6.7
Onehunga	7.9	6.9	8.8	8.0	6.9	8.9	7.9	6.9	8.8
Orakei	9.0	7.8	9.4	9.1	7.8	9.5	9.1	7.8	9.5
Oratia	5.2	4.5	5.5	5.1	4.4	5.5	5.1	4.5	5.5
Orewa	9.2	7.9	10.5	9.2	7.9	10.5	9.2	8.0	10.5
Otara	9.5	8.2	10.1	9.5	8.2	10.1	9.5	8.2	10.1
Pacific Steel furnace 33kV	7.9	6.8	8.2	8.0	6.9	8.3	8.0	6.9	8.3
Pacific Steel 33kV	4.2	3.6	4.3	4.2	3.6	4.3	4.2	3.6	4.3
Pakuranga	8.1	7.0	8.6	8.6	7.4	9.0	8.6	7.5	9.0
Papakura	8.1	7.0	8.6	8.2	7.1	8.7	8.1	7.0	8.7
Parnell	11.5	9.9	12.9	10.9	9.5	12.5	11.0	9.5	12.5
Ponsonby	6.8	5.9	7.5	6.8	5.9	7.5	6.8	5.9	7.5
Quay	8.3	7.2	8.9	8.1	7.0	8.8	8.1	7.0	8.8
Quay 22kV	19.0	16.4	1.3	16.4	14.2	1.0	16.4	14.2	1.0
Quay 22kV distribution	19.0	16.4	1.3	16.4	14.2	1.0	16.4	14.2	1.0
Ranui	5.5	4.7	5.9	5.5	4.8	5.9	5.5	4.7	5.9
Red Beach	6.2	5.4	6.5	6.3	5.4	6.6	6.2	5.4	6.5
Remuera	8.6	7.5	9.1	8.7	7.6	9.2	8.7	7.6	9.2
Riverhead	5.1	4.4	6.1	5.1	4.4	6.2	5.1	4.4	6.2
Rockfield	8.7	7.6	9.1	8.8	7.6	9.1	8.8	7.7	9.2
Rosebank	9.0	7.8	9.6	9.1	7.9	9.6	9.0	7.8	9.6
Sabulite Road	10.4	9.0	11.0	10.4	9.0	11.0	10.4	9.0	11.0

Zone Substation	Fault Current (kA)								
	2012			2017			2022		
	3P	P-P	P-E	3P	P-P	P-E	3P	P-P	P-E
Sandringham	8.6	7.5	9.3	8.6	7.5	9.3	8.7	7.5	9.3
Sandringham 22kV	18.7	16.2	18.2	18.8	16.3	18.3	19.0	16.4	18.4
Simpson Road	4.1	3.5	4.3	4.1	3.5	4.3	4.1	3.5	4.3
Snells Beach	2.6	2.3	3.2	2.6	2.3	3.2	2.6	2.2	3.1
South Howick	8.4	7.3	9.0	9.0	7.8	9.4	8.9	7.7	9.3
Spur Road	6.7	5.7	7.2	6.7	5.8	7.2	6.7	5.8	7.2
St Heliers	8.8	7.6	9.3	8.9	7.7	9.4	8.9	7.7	9.3
St Johns	10.7	9.3	11.6	10.7	9.3	11.6	10.7	9.3	11.6
St Johns 33kV	20.3	17.6	20.8	20.5	17.7	20.9	20.6	17.8	20.9
Sunset Road	7.1	6.2	7.5	7.1	6.1	7.4	7.1	6.1	7.4
Swanson	6.9	6.0	7.4	7.0	6.1	7.5	7.0	6.0	7.4
Sylvia Park	8.8	7.6	9.2	8.9	7.7	9.2	8.9	7.8	9.3
Takanini	9.2	7.9	9.9	9.3	8.0	10.0	9.2	8.0	9.9
Takapuna	6.1	5.2	6.5	6.1	5.3	6.5	6.1	5.2	6.5
Te Atatu	11.5	9.9	13.0	11.6	10.0	13.0	11.5	9.9	12.9
Te Papapa	8.6	7.4	9.0	8.5	7.4	8.9	8.6	7.4	9.0
Torbay	6.1	5.3	6.8	6.1	5.3	6.7	6.1	5.3	6.7
Triangle Road	11.4	9.9	12.3	11.5	9.9	12.3	11.4	9.9	12.3
Victoria	8.1	7.0	8.7	8.1	7.0	8.7	8.1	7.1	8.8
Waiake	6.5	5.6	7.0	6.5	5.6	6.9	6.5	5.6	6.9
Waiheke	5.6	4.8	7.0	5.6	4.8	7.1	5.6	4.8	7.0
Waikaukau	4.5	3.9	4.6	4.6	4.0	4.7	4.6	4.0	4.7
Waimauku	3.1	2.7	3.6	3.0	2.6	3.6	3.1	2.6	3.6
Wairau	11.4	9.8	12.7	11.4	9.9	12.7	11.3	9.8	12.6
Wairau 33KV	11.6	10.1	12.9	11.8	10.3	13.0	11.8	10.2	13.0
Warkworth	5.4	4.6	7.0	5.3	4.6	6.9	5.3	4.6	6.9
Wellsford	5.5	4.7	6.5	5.5	4.7	6.5	5.5	4.7	6.5
Westfield	8.8	7.7	9.9	8.9	7.7	9.9	8.9	7.7	9.9
White Swan	12.1	10.5	**13.4**	12.1	10.5	**13.4**	12.2	10.5	**13.5**
Wiri	12.1	10.5	13.0	12.1	10.5	13.0	12.1	10.5	13.0
Woodford	6.4	5.6	6.9	6.5	5.6	7.0	6.4	5.6	6.9

Table 2-7 : Fault levels at Vector zone substations

The zone substations where the calculated prospective fault currents are in excess of the 13.1kA standard (for 11kV) equipment rating (Howick, Greenmount, Newmarket and White Swan) are highlighted in bold. Some 11kV busbars with existing prospective fault currents in excess of 13.1kA (Browns Bay, Henderson Valley and Sunset Road substations) are operated in split mode to contain the fault levels to within the rating of the circuit breakers.

2.3.3 Distribution Network

The function of the distribution network is to deliver electricity from zone substations to customers. It includes a system of cables and overhead lines, operating at 11kV or 22kV, which distribute electricity from the zone substations to smaller distribution substations. Typically up to 2,000 customers are supplied by a medium voltage (MV) distribution feeder, the number being determined by the load density and level of security.

At distribution substations the electricity is stepped down to 400/230V and delivered to customers either directly or through a reticulation network of low voltage (LV) overhead lines and cables. Approximately 30 to 150 customers are supplied from each distribution substation. A typical distribution substation contains an MV (22kV or 11kV) / LV transformer, LV board and MV switchgear.

The 11kV distribution network was originally constructed as an overhead network with interconnected radial feeders. However, since the mid-1960s most new subdivisions have been constructed with underground cables and any new 11kV feeder cables in urban areas are installed underground. The same applies to the 400V distribution network. The 22kV distribution network (around Highbrook industrial development and the Auckland CBD) is newly established and is underground.

There are a number of large customers in the Southern region connected to the network at higher voltage levels. The ownership of the substations serving these customers varies from site to site but generally Vector owns the incoming switchgear and any protection equipment associated with it. The customer owns the transformer(s), any outgoing switchgear and associated protection, and the building.

A more detailed description of the distribution network is given in Sections 5 and 6 of this AMP.

2.3.3.1 Undergrounding

Vector has an obligation to its majority shareholder, the Auckland Electricity Consumer Trust[20], to conduct an undergrounding programme for the Southern region and the percentage of overhead network is gradually reducing. All new subdivisions have been reticulated underground (distribution and LV networks) for the past 40 years. This is required by the local authorities.

As at the end of March 2011, 69% of the distribution (11kV and 22kV) network was underground in the Southern region and 30% in the Northern region. Overall, 46% of Vector's distribution network is underground.

2.3.4 Low Voltage Network

While substantial parts of the existing Vector distribution network are still overhead, all new subdivisions are reticulated underground. Vector has an ongoing undergrounding programme in the Southern region.

[20] Vector is listed on the New Zealand Stock Exchange. The Auckland Energy Consumer Trust (AECT) is the majority shareholder with voting rights of 75.4%.

Distribution transformers are designed to supply a predetermined number of customers based on an expected after diversity maximum demand (ADMD) and can withstand some cyclic overloading, based on industry standards. The LV cables are configured in a radial formation with limited interconnection capacity to other distribution transformers (LV cables are not sized to supply adjacent substations). In the event that a transformer fails, a mobile generator will be deployed to restore supply while the transformer is replaced. Alternatively, a temporary cable can be installed provided capacity is available from neighbouring substations.

As at the end of March 2011, 62% of the LV distribution network was underground in the Southern region and 47% in the Northern region. Overall, 56% of Vector's LV distribution network is underground.

2.3.5 Protection, Automation, Communication and Control Systems

2.3.5.1 Power System Protection

The main role of protection relays is to detect network faults and initiate power circuit isolation upon detection of abnormal conditions. All new and refurbished substations are equipped with multifunctional intelligent electronic devices (IEDs). Each IED combines protection, control, metering monitoring, and automation functions within a single hardware platform. It also communicates with the substation computer or directly to SCADA central computers over the IP based communication network using industry standard communication protocols.

2.3.5.2 Substation DC Auxiliary System

A substation's DC auxiliary system is the most vital component of each substation - it provides power supply to the substation protection, control, and communication systems, including circuit breaker (CB) control and tripping. The substation's DC auxiliary system provides power supply to the substation protection, automation, communication, control and metering systems, including power supply to the primary equipment motor drive mechanisms.

Vector's standard DC auxiliary systems consist of a dual string of batteries, battery charger, a number of DC/DC converters and a battery monitoring system. The major substations are equipped with a redundant DC auxiliary system.

Vector uses Valve-Regulated Lead-Acid (VRLA) batteries which are safer for personnel, more cost effective and require less routine maintenance. The VRLA batteries are charged with a temperature compensated charger.

To increase system reliability, reduce maintenance costs and increase maintenance personnel safety, a battery monitoring system is fitted to all new installations.

2.3.5.3 Substation Automation (SA)

Substation automation (SA) describes the collection of infrastructure within a substation enabling the coordination of protection, automation, monitoring, metering and control functions, and utilising substation internal communications network infrastructure. Vector's substation automation system is based on resilient optical Ethernet local area network running IEC 61850 compliant IEDs.

2.3.5.4 Feeder Automation (FA)

Feeder automation (FA) can be defined as schemes of equipment (automated switches, auto-reclosers etc) that are capable of acting without human intervention in order to minimise outages, restore supply or carry out other network/asset automation functions e.g. substation off-loading.

The feeder automation schemes are frequently interfaced to the network control centre for remote indication, control and data acquisition (SCADA functions).

The feeder automation in its present implementation state enables SCADA functionalities, auto-reclosing, auto-sectionalising, feeder reconfiguration, fault detection and voltage control.

2.3.5.5 Supervisory Control and Data Acquisition - SCADA

A typical SCADA system is hierarchically architected and consists of:

- Master Station – centralised computer systems with SCADA application software, workstation and HMI (Human Machine Interface);
- Communication protocols;
- Communication systems; and
- Field Installed Intelligent Electronic Devices (Remote Terminal Units, IEDs).

A SCADA system enables remote control (telecontrol) of power system equipment (e.g. switchgear, power transformers) and remote measurements (telemetry) of power system current and voltages.

Currently two SCADA master stations are being used for the electricity SCADA:

- Siemens Spectrum Power TG; and
- LN2068 with Foxboro Workstations.

A Siemens Spectrum Power TG master station has been deployed for monitoring and control of the Southern region electricity network, while LN2068 is used for the Northern region. Vector's modern SA system and other field IEDs installed in recent years have been, and continue to be, interfaced to both SCADA master stations, enabling migration of Northern SCADA information into PowerTG. Once migration is completed, LN2068 will be retired.

2.3.5.6 Remote Terminal Units (RTU)

An RTU is a microprocessor controlled electronic device which interfaces objects in the physical world (e.g. switchgear, power transformers) to a distributed control system or SCADA system by transmitting telemetry data to the system and/or altering the state of connected objects based on control messages received from the system. An RTU can act as a substation.

For remote control, the traditional RTU solution has been to install an RTU device as an interface between the network control SCADA master station and the substation primary equipment (switchgears, power transformers). This functionality is in modern SA systems being distributed to IEDs installed within substations.

Over time a number of different RTUs have been installed in Vector's network, many of which are nearing the end of their technical life or are obsolete. Vector has embarked on a replacement programme enabling a standard RTU to be deployed across the network. RTUs installed in the Northern region are interfaced to both SCADA master station systems.

2.3.5.7 Communication Protocols

A variety of SCADA communication protocols are presently used to communicate between the various SCADA systems and different types of IEDs installed on the network. Vector's current standard for internal and external communication systems is IEC 61850 standard. DNP3 is also used as an interim solution.

2.3.5.8 Communication System

Vector's communications network 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 (Cu) wire telephone-type pilot cables and third party radio communication systems.

The communications network is used for protection signalling, SCADA communications, operational telephony, access security, metering, remote equipment monitoring and automation.

Vector is committed to an open communications architecture based on industry standards. This has resulted in the adoption and deployment of ethernet and internet protocol (IP) based communication technology.

2.3.5.9 Energy and Power Quality Metering

Vector's energy and power quality (PQ) metering system consists of a number of intelligent web-enabled revenue class energy and PQ meters installed at GXPs and zone substations. The meters communicate to the metering central software over an ethernet-based IP routed communication network.

The metering system provides Vector with essential information about the quantity, quality and reliability of the power delivered to Vector's customers, and is currently used to:

- Improve asset utilisation by managing network peak demands;
- Provide PQ and load data for network management and planning purposes;
- Provide information to assist in the resolution of customer-related PQ issues; and
- Contribute to the power system stability by initiating instantaneous load shedding during under-frequency events.

2.3.5.10 Load Control Systems

Vector's load control systems consist of audio frequency ripple, pilot wire and cyclo control types. The load control systems offer the ability to:

- Control residential hot water cylinders;
- Control street lighting;
- Meter switch for tariff control;
- Time shift load to improve network asset utilisation;
- Time shift load to defer reinforcement of network assets; and
- Manage GXP demand charges from Transpower.

Load control equipment utilises older technology, much of which is approaching the end of its life. As newer customer metering ("smart meters" or associated intelligent home hubs) and communications technologies are rolled out, alternative means of load control will become possible. It is, therefore, anticipated that the existing load control systems will be phased out. Strategies for the transition are being developed. (See Section 3 for a discussion.)

2.3.6 Lichfield

Lichfield substation was established with two 20MVA 110/11kV transformers, from a tee off the Transpower 110kV lines. Vector owns the transformers and the 11kV cabling and switchgear on the Lichfield site. The two transformers are Y-y vector group (the only Y-y units within the Vector network). The map in Figure 2-11 shows the location of Lichfield GXP.

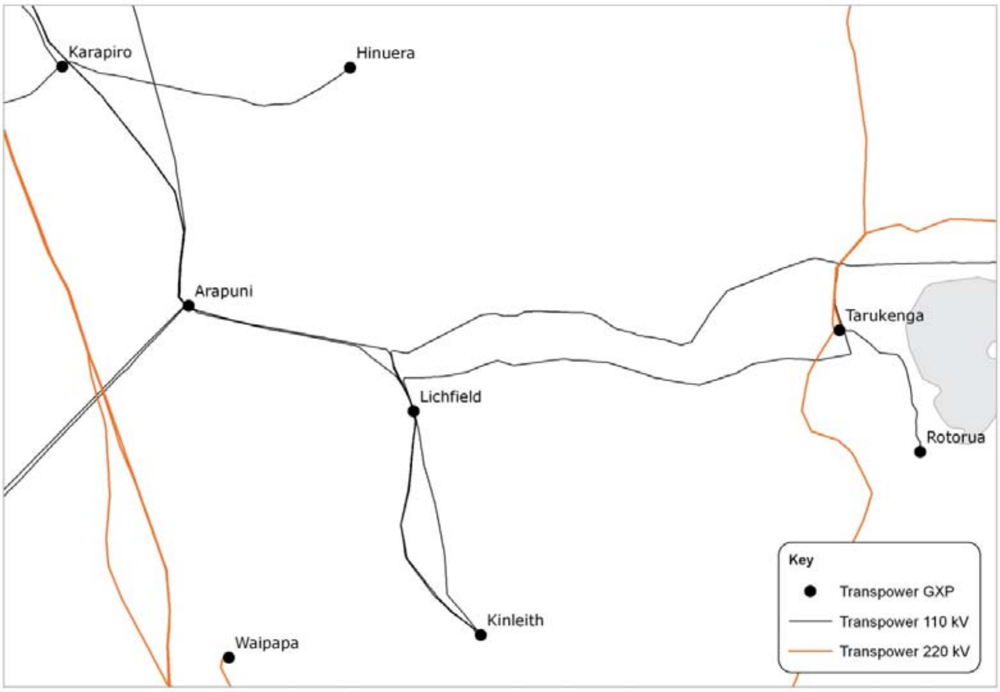

Figure 2-11 : Location of Lichfield GXP

2.3.7 Vector Assets Installed at Transpower GXPs

For practical reasons Vector has installed some of its equipment at Transpower GXPs, with agreement from Transpower. These assets are described below.

2.3.7.1 Power Equipment

Vector owns the 33kV feeder circuit breakers at Wellsford GXP, Albany GXP, Hepburn Road GXP (except for the two Rosebank feeders) and Henderson GXP. These circuit breakers were purchased from Transpower. Vector has responsibility for their maintenance and operations.

Vector owns all 22kV, 33kV and 110kV sub-transmission cables and overhead lines terminating onto Transpower's 22kV and 33kV switchboards at all GXPs feeding its network, irrespective of whether the 22kV and 33kV circuit breakers are owned by Vector or Transpower.

The Penrose end of the CBD tunnel (owned by Vector for connecting Penrose GXP to the Auckland CBD) is constructed within the Penrose GXP site boundary. This tunnel accommodates Vector's 33kV and 110kV cables.

2.3.7.2 Protection and Communications Equipment

Vector uses unit protection schemes as primary protection for its sub-transmission network. As part of the unit protection schemes, protection relays are installed at GXPs where the sub-transmission circuits are connected. Other parts of the protection schemes include control wiring, batteries and chargers. Communications equipment including RTUs, pilot wires, etc are also installed as part of Vector's SCADA and control system.

Vector has installed power quality meters and check meters at GXPs to monitor power quality and energy injected into Vector's distribution network.

2.3.7.3 Load Control Equipment

Vector's ripple injection plants in the Southern region are connected to its sub-transmission network. For zone substations supplied from the sub-transmission network connected to a Transpower GXP, the ripple injection plants are located at the respective GXP. For zone substations supplied from the sub-transmission network connected to a Vector bulk supply substation, the ripple injection plants are located at the respective bulk supply substation. Ripple injection plants in the Northern region are 11kV rated and are located within the zone substations.

2.4 Justification of Assets

Network assets are created for a number of reasons. While asset investment is often the most effective and convenient means of addressing network issues, Vector also considers other solutions to network issues and applies these where practical and economic. Such alternatives may include network reconfiguration, asset refurbishment, adopting non-network solutions (such as distributed generation) or entering into load management arrangements with customers.

The key factors (not listed in any order of priority) leading to asset investment at Vector are:

- Health and safety: where health and safety concerns indicate the need for asset investment, this takes priority;
- Legal and regulatory compliance: ensuring Vector is not in breach of statutory obligations of electricity service providers or regulatory requirements such as satisfying the voltage limits;
- Capacity: maintaining sufficient network capacity to supply the needs of consumers is a key driver for asset investment;
- New developments: where new building or urban developments occur, or existing developments are extended, this usually requires investment in network assets;
- Security of supply standards: Vector is committed to meeting its security of supply standards, and potential breaches of these often indicate a need for asset investment. Network assets are constructed to provide both capacity and security;
- Reliability: Vector's customers expect a certain level of reliability of supply. Decisions in the optimal expenditure to achieve the target reliability often involve optimising the capex/opex mix. On occasions, more assets are required to reduce opex with the overall result of reducing costs in the long term;
- Customer requirements: assets are often installed at the request of customers (who then contribute to the investment cost) such as requiring higher security;
- Renewal: assets are usually replaced when they have deteriorated to the extent that they pose a safety or reliability risk, or have reached the end of their useful

lives (where maintenance or refurbishment start to be more expensive than replacing an asset);

- Refurbishment: investing to prolong the useful lives of assets when it is economic and safe to do so; and
- Technology improvements: when technology becomes obsolete and assets can no longer fulfil the basic requirements of a modern, effective network, this may give rise to replacement expenditure.

Vector's network investment has always been prudent, meeting only realistic network requirements. This is also illustrated by the most recent optimised deprival valuation (ODV) of the electricity network carried out in 2004. For this ODV, Vector recorded $51.6 million of optimisation for its Auckland (excluding Wellington) assets, being assets deemed unnecessary for current requirements due to stranding, over-capacity for current demand or other similar factors. This figure equates to 3.4% of the corresponding ODV, a very small margin.[21] Of the assets affected, all were optimised down to a lower capacity and not optimised out. With the demand growth in the past seven years, should network optimisation be reinstituted, a significant portion of these optimised assets would be reinstated.

In submitting business cases for project approvals, planners are required to develop credible and viable options (including network and non-network options) for evaluation. Evaluation criteria included in the business case include economic efficiency, financial viability, technical suitability, strategic fit and a risk assessment. This further ensures prudent investment decisions.

Several factors influence how assets are selected and the manner in which they are implemented.

- **Network design standards**

  Vector has developed a detailed network security standard, which sets out the basic requirements for network planning for the distribution and sub-transmission networks (refer to Section 5 of this AMP for details). These standards define largely the stage at which network reinforcement (i.e. new assets) becomes essential, and the capacity to which new installations should be built.

  We have adopted a probabilistic security standard (although the standard is expressed in deterministic language to allow easier understanding by the reader) rather than the more conventional deterministic standards used by most distribution utilities. Our security standard is comparable with, but more cost-effective than, that of most other distribution utilities in New Zealand and Australia.

  In practice, the security standard allows Vector to operate its sub-transmission network to a level marginally below N-1 for a small number of peak-demand hours during a year (except in the Auckland CBD, where higher standards apply).

  To manage supply risk, Vector has put in place a system of operational contingency plans (which are regularly updated). In addition, assets are used to their cyclical rating capacity – generally allowing short-term loading to exceed the normal long-term equipment rating. This approach allows Vector to maximise asset utilisation.

  Capacity and security are not the only criteria for the design of the distribution network. In Section 5 other planning criteria are also described.

- **Optimising installations**

  When a potential network issue or constraint is identified, project options will be developed and the optimal (usually least life cycle cost) solution will be adopted.

[21] Even this figure gives an over-estimate of "stranded assets" given the unrealistic asset planning horizons (from an engineering/economic perspective) provided for in the ODV Handbook.

The optimal solution may not have the lowest initial capital cost or be the lowest capacity solution.

- **Very long term network development plan**

  Vector has developed a very long term (50+ years) plan to guide the development of the electricity network. This plan is based on the growth strategy for the region prepared by the (previous) councils of the region which identifies the location and extent of growth in the various parts of the region and allows a spatial load distribution plan to be developed covering Vector's supply area. From this spatial load distribution plan, a very long term network configuration is developed to ensure there is optimal capacity and security to supply the region and to avoid piece meal development of the network.

- **Equipment standardisation**

  To minimise cost in the long-term and to ensure optimally rated equipment is installed to meet a range of possible situations, Vector has a policy of using standardised equipment on its network. For example, Vector has standardised on 20MVA and 10MVA for power transformers. 20MVA transformers are used in higher load density urban areas whereas 10MVA transformers are used in lower load density rural areas.

  Standardisation helps to reduce design and procurement costs during the establishment phase, increase operational flexibility and makes equipment maintenance more effective. It also allows more effective strategic spares management.

- **Customer-specific assets**

  From time to time, Vector builds dedicated assets to supply customers to meet their anticipated demand growth at their requests based on agreed commercial terms. Examples are Lichfield and Auckland International Airport (AIAL).

- **Life-cycle considerations**

  Vector adopts a life cycle cost approach to choosing network solutions and assets. This means the lowest cost short-term solution may not always be adopted. For example, Vector builds indoor substations within concrete buildings to accommodate switchgear and auxiliary equipment, although outdoor equipment is initially cheaper to install. Over time the initial additional costs are offset by lower maintenance costs, more secure and reliable operations, and longer life-spans.

- **Historical considerations**

  Load growth, load density and historical network architecture and equipment standards can result in varying types of assets, states of security and asset condition throughout the network. While historical network architectures and equipment standards converge over time, replacing well-functioning assets to achieve such alignment in the short term can generally not be economically justified. However, as failing assets are replaced or new assets added to the network, these are generally designed to comply with the present specifications.

- **Equipment utilisation**

  The utilisation (the ratio between the peak demand on an equipment over its capacity) of Vector's feeders and zone substations are generally high. The utilisation graphs shown in section 4.2 indicate that the majority of zone substations are utilised well above traditional n-1 security levels. Vector is able to achieve this higher utilisation by making effective use of the higher short-term ratings of equipment and through the high degree of interconnection of its zone substations. The utilisation graphs also show a significant increase in substation and feeder utilisation over the past ten years.

The network architecture of the networks in the two regions inherently causes a higher utilisation in the Northern region. This higher utilisation also reflects the largely residential characteristics of the region (compared to the high concentration of industrial and commercial load in the Southern region).

2.4.1 Determination of Capacity of New Equipment

As stated earlier, Vector has a policy of using standard equipment on its network to minimise long-term cost. For example, standard power transformers are 20MVA and 10MVA units. 20MVA transformers are used in high load density urban areas whereas 10MVA transformers are used in lower load density rural areas.

The key factor in deciding the standard capacities (20MVA and 10MVA) of power transformers is the load density of the area being supplied. While economy of scale suggests the use of large capacity transformers, higher capacity zone substations will result in a larger supply catchment area (for the same load density) and longer distribution feeders. Larger supply catchment areas will also result in zone substations further away from GXPs, thus requiring longer sub-transmission feeders. Deciding the optimal economic capacity of standard urban transformers requires optimisation between cable and transformer costs to achieve the lowest overall cost per MVA of network capacity. Scenario analysis (of different transformer capacities and feeder lengths), considering a range of equipment costs and load densities, supported a decision on standardising urban transformer capacity at 20MVA. Other factors considered included the impact of transformer capacity on fault level, transformer impedance, reactive power and tap changer / voltage control.

For power transformers used in rural zone substations, voltage performance of the distribution network is another important factor in addition to those stated above. The result of the analysis for these areas indicates that here 10MVA is the optimal transformer capacity.

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Electricity
Asset Management Plan
2012 – 2022

Future Vision and Strategy – Section 3

[Disclosure AMP]

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3. Future Vision and Strategy

3.1 Overview

The environment within which electricity distribution businesses operate is undergoing considerable change:

- From a technological perspective, developing trends in consumer appliances, technology convergence, renewable generation and an increasing ability to build distributed intelligence into networks have major potential for improving the customer experience and network efficiency and reliability. However, it also holds a very real risk of forcing major network augmentations[1] and/or causing stranded assets[2]; and
- Societal changes are also having a marked impact on network operations and asset management decisions due to changing customer expectations and increased awareness of energy-related matters.

Making investment decisions on major, long-life assets in a changing environment poses challenges. Vector has developed a future vision to help guide asset management strategy to ensure its networks can cope with the anticipated changes and it is well-positioned to make best use of the opportunities offered. This vision will be regularly reviewed to take into account ongoing changes to the environment Vector operates in.

Through its ownership of Advanced Metering Services (AMS), a leading provider of smart meters for the industry, and by virtue of its long-term involvement in installing fibre optic networks in the Auckland region, Vector is ideally placed to maximise the benefits from developing technology for its distribution network. This also supports the Vector asset management strategy for an all encompassing continual efficiency improvement drive to providing a reliable, safe and affordable electricity supply while achieving commercially sustainable returns on investments.

3.1.1 Focus on Investment Efficiency

Vector seeks to continually improve the efficiency of its investment decisions. To help drive this, specific business-wide targets have been established to improve capital efficiency. The targets will be achieved through a combination of continual improvement and innovation:

- Keeping an open mind (“how we can” not “why we can’t”);
- Broadening thinking around potential asset solutions, including multiple utility and non-network solutions;
- Leveraging previous smart solutions into new areas of application;
- Keeping abreast of solutions others are applying and relating these to Vector’s challenges;
- Taking advantage of new technologies that enable solutions not previously possible;
- Making better decisions through better information and analysis;
- Enhanced, robust decision-making processes (a “value engineering” type approach) which seek broad and effective input to potential solutions and includes review steps to support continuous improvement; and

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[1] Through increasing electricity demand peaks.

[2] When equipment becomes obsolete at an early date, or demand shifts lead to redundant capacity.

- Making continuous incremental improvements in our project planning and delivery.

These efficiency factors are reflected at all levels of asset management at Vector – from the asset design phase, through the procurement and construction phase and into the lifecycle operational phase.

Systems and processes have been established to track efficiency progress and to ensure that enhanced efficiency considerations are built into asset decision making processes at all levels.

3.1.2 Clear Understanding of Future Network Demands and Challenges

Recent worldwide development trends in consumer technology and renewable generation make it imperative for Vector to understand the potential impact of these emerging technologies on the network and to develop strategies so that Vector's network is ready to cater for these technologies and meet new consumer demand.

Vector has therefore:

- Considered emerging technologies that are likely to have significant impacts on the electricity and gas networks;
- Developed a view as to how the network may be affected by these technologies in 5-20 years time; and
- Developed strategies to mitigate potential adverse impacts on the network, capture opportunities and to shape the development of the network.

3.1.3 Leverage Technology

Developments in information, communication and automation technology present opportunities to introduce greater levels of intelligence into the distribution network.

To date, cost factors have limited the intelligence in the network to the higher voltage (11kV and above) parts. Technology developments are now making it operationally feasible and economically viable to extend to the lower voltage parts of the network.

The outcomes from this offer the potential to:

- Improve asset utilisation resulting in deferred investment expenditure;
- Increase network reliability and reduce restoration times; and
- Lower operational costs.

A number of trials of potential technologies will progress over the coming months to test performance and integration with Vector's existing systems, which will inform our future strategies in this regard. In areas where specific benefits can be identified, targeted deployment of trialled and proven technologies will be programmed for progressive implementation.

One area of concern that will have to be addressed is the regulatory and pricing implications of investment in emerging technologies. From a consumer perspective there may be clear efficiency gains achievable through adopting the emerging technologies, but it is less clear the regulatory framework and the New Zealand electricity market structure will provide appropriate incentives or rewards for any particular sector of the market, including electricity lines business, to unlock the full available potential. This is because distributors recover a large portion of their revenues through volumetric charges and any reduction in demand due to new technologies would reduce revenues of distribution businesses. If the correct regulatory long-term incentives are not in place the efficiency gains may not be made.

Vector's "intelligent network" strategy is detailed in Section 3.4 below.

3.1.4 Constraints on implementing new solutions

Vector is actively pursuing optimal investment and energy efficiency through embracing innovation, new technology and solutions. However, we note that some aspects of the electricity market structure in New Zealand and the commercial regulation of electricity distribution business constrains our ability to maximise the potential benefit that could be derived not only for our customers, but also for the wider New Zealand economy. These factors are being discussed in other forums, but the main aspects impacting on asset management planning, are summarised below:

- While Section 54Q of the Commerce Act directs the Commerce Commission to encourage energy efficiency, the Commission has yet to implement policies to comply with this section and few incentives exist for electricity distribution business to alter their investment practices in this regard;
- The separation of the retail and distribution functions has led to a distance between electricity distribution businesses and their customers, especially where interposed relationship models exist. Many of the potential efficiency benefits that are likely to arise from technology changes will rely on close interaction between distribution businesses and end-users, including:
  - Interfacing smart home devices with network management tools;
  - Creating pricing structures that incentivise customers to shift consumption to off-peak periods (and providing them the means to effectively do so) and having these signals flow through to customers; and
  - Better understanding of customer consumption patterns, allowing optimal network planning and utilisation.

  To fully embrace the opportunities offered by evolving technology will require a much closer relationship between lines companies and end-users.
- The current regulation of network quality is aimed at maintaining historical performance levels and there is no incentive to improve on this. A key attraction of improving technology is the ability to improve network reliability and fault response time, but absent an incentive to do so, it is not commercially viable to invest in this ability; and
- Under current price-setting arrangements it is only commercially feasible to invest in energy-efficient network solutions where these are cheaper than (on a life-cycle basis) or allow deferment of conventional network investments. These are narrow benefits, accruing to the electricity distribution business (and ultimately to its customers), but many opportunities to realise wider economic benefits are likely to be foregone. Downstream benefits such as allowing deferment of transmission or generation investments are not reflected in the business cases for investments that have to be funded solely by the distribution companies.

3.2 Future Technology Assessment

A broad scan of technologies that could impact on Vector's network has been undertaken. The technologies that are more likely to have significant impact on the electricity network in the short to medium-term are:

- Heat pumps;
- Photo-voltaic (PV) panels;
- Electric vehicles (EV);
- Light emitting diode (LED) lighting;
- Battery storage; and

- Smart home technologies.

It is also noted that fuel cells and V2G (vehicle to grid) application could have significant impacts on how the electricity network operates. Fuel cells have not been included in the current list pending a technological breakthrough to enable practical application and to reduce cost of production. V2G application is dependent on the uptake of electric vehicles and future development of battery and charging technologies. Development of both these technologies will be monitored.

3.2.1 Understanding the Impact of New Technologies

Extensive research has been carried out to analyse the experience of overseas utilities facing similar opportunities and threats from emerging technologies. These have then been reconciled with local situations to ensure the relevant and appropriate experience has been applied.

Technology change could have a significant impact on the load profile of Vector's electricity network over the next 10-15 years. Some technologies are likely to increase peak loads (and/or energy usage), others to reduce it and still others to change the time of day at which energy is used, resulting in significant potential changes in peak demand patterns and overall electricity usage. These changes could have significant flow on effects on Vector's asset investment strategy.

Some of the developments that are most likely to have a material impact in the near to medium-term future are discussed below.

3.2.1.1 Solar PV

Photovoltaic (PV) panels convert sunlight into electricity. Distributed PV refers to the installation of the panels on buildings that are already connected to an electricity distribution grid, with the panels connected to the grid. By drawing power off the PV panels, households and commercial buildings reduce their purchases of electricity from the grid, thus saving money. They can also sell any excess electricity into the grid[3], thus improving the economics of the PV installation.

Technology developments over the past five years have seen the cost of photovoltaic panels reduced from around $15 per watt in 2005 to around $4 per watt in 2011. The cost reduction has been achieved through advances in the chemistry of the panels, manufacturing efficiencies and through overcoming material and manufacturing capacity bottlenecks.

It is widely forecast that the prices of PV will continue to fall and are likely to provide an economically attractive alternative to grid electricity in the next 5-7 years. For some remote locations, even today a PV solution (including backup batteries) provides the most cost-effective solution (compared to the cost of extending the conventional supply network).

Internationally, incentives (subsidies, feed in tariffs, etc) offered by governments such as Germany, Spain, California and Australia have accelerated the uptake of PV. This increase in demand in turn drives down the cost of manufacturing and provides incentives to further develop the technology. Although it is not foreseen that the New Zealand government will offer similar incentives in the near future, the downward trend in price could eventually provide sufficient incentives for PV uptake.

The introduction of PV on the network is expected to reduce average feeder loading (utilisation). PV output is however intermittent, and without further energy storage or other localised forms of generation, is not a reliable energy source. During periods where PV units are inefficient (for example at night, or during heavy cloud conditions)

[3] On the proviso that certain technical and safety requirements are met.

electricity would be drawn from the grid. Should this occur during peak consumption periods, as is likely from time to time, the resulting peak demand may not change from current levels. From a distribution network perspective, assuming existing reliability levels would be maintained, it is, therefore, not foreseen that the delivery capacity can be reduced as PV is introduced (at least until effective energy storage solutions are developed).

Distributed generation from PV may impact on network security, as the effective load reduction would increase the backstop capability at zone substations. This, however, would again be intermittent (unless additional energy storage devices are available) and, therefore, is not a reliable alternative to network capacity.

Network modelling has been undertaken by Vector to understand the impact on the network of PV under various "penetration rates" (capacity of installed PV as a percentage of total network demand) scenarios. Of interest is the amount of PV that would need to be installed beyond which there could be two way power flow (flow back up the network) and associated over-voltage issues. The analysis found very high penetration rates (above 20%) would be required for there to be general network issues. This greatly exceeds the forecast uptake rate of 5% in the next 25 years. It is recognised, however, that there may be localised issues in areas of high concentration of PV e.g. very large PV installations on a number of commercial buildings in one area or large PV installations on a long rural line. Potential technical solutions to such issues are being explored.

3.2.1.2 Electric Vehicles

Most major car manufacturers are planning launches of plug-in electric vehicles in 2012/2013. While energy cost per kilometre travelled are falling, electric vehicles currently require a battery, which adds around $10,000 per vehicle compared to equivalent petrol powered vehicles. This premium is expected to reduce as design and manufacturing improvements to electric vehicles and batteries are made. In addition, increases in oil price due to scarcity and demand are likely to make electric vehicle options more attractive in future.

Based on vehicle sales data, studies by the Ministry of Economic Development (MED) and international EV forecasts, it is expected that there may be in the order of 50,000 electric vehicles in Auckland by 2020 and 150,000 by 2025. There is considerable uncertainty around the likely impact electric vehicle charging may have on the network. The reasons for this are:

a. **Plug in hybrid versus pure electric**: While some vehicles to be introduced will be pure electric (e.g. Nissan Leaf), others will be hybrid vehicles (Toyota and Honda) which have a smaller battery capacity for short trips (30km) and a conventional petrol engine for longer trips.

b. **Charging location and time:** Charging will likely be achieved through a mix of public or work place charging stations and at home charging. Depending on vehicle usage, charging may occur in early evening (if used as a work commute vehicle) or at any time during the day if the owner is home based.

c. **Charging rate:** Vehicle manufacturers may provide both "normal charge" options (10 amps) and rapid charge (60 amps).

We have considered a variety of scenarios and modelled the network impacts for each. For the scenario where 80% of vehicles are plugged-in to charge at peak times (at normal charging rates), additional network investment of $120m over 15 years would be required to manage the additional demand. While pricing signals may provide incentive for customers to charge at off-peak times, the level of incentive able to be provided through distribution tariffs may not be sufficient to change consumer behaviour. The average daily charging cost (based on 40km daily usage) would be around $1.50 at 25c per kWh.

Potential direct control of charging is being considered as part of a wider project to develop a strategy for demand management (see Section 3.5). It is estimated 40% of charging will be conducted using a public charging network. The key issue is the high upfront cost of developing this network, while electric vehicle numbers are slowly growing e.g. charging stations currently cost between $5-10k per unit. A few large cities are building limited trial networks using public funds e.g. London. The developing of such a public charging network will need further careful evaluation to establish its commercial viability.

3.2.1.3 Heat Pumps

Heat pumps are becoming a popular option for space heating and cooling Auckland homes. The Building Research Association of New Zealand (BRANZ) has undertaken comprehensive research of heat pump uptake and is forecasting the trend to accelerate. Currently 10% of Auckland homes have a heat pump installed and this is modelled to increase to 50% by 2025.

The principal impact on the electricity network will be a significant increase in summer load in residential areas on days when heat pumps are used for cooling. The current maximum heat pump demand in summer is around 30MW. This is forecast to increase to 190MW in 15 years (maximum network demand for Vector's network is currently around 1,800MW). During summer, the capacity of underground cables is reduced by around 30% due to temperature effects. At the expected rate of penetration, heat pump cooling loads are likely to introduce summer peaks (higher than winter peak demand) in residential areas (commercial feeders already experience these peaks). The additional investment needed to reinforce the network to meet the forecast increase in summer demand is estimated to be $100m over the next 10 years. Winter peak demand is expected to drop initially as heat pumps are installed to replace existing less efficient resistance heaters. Over time, however, winter peak demand is expected to creep up as consumers start to utilise the heat pumps for longer periods to raise home comfort levels.

3.2.1.4 Advanced Meters and Smart Home Technologies

Technology which supports intelligent management of energy is being deployed globally. The current roll out of advanced meters is a foundational step. In their most basic form, the meters will provide consumers with improved visibility of their energy use and provide a platform to support "time of use" rates for electricity consumption. International experience of smart meter deployments have shown savings of 5% energy consumption and 2% peak demand reduction following installation of smart meters.

Vector (through AMS) is a leading provider of smart meters to the New Zealand market. By virtue of using a highly flexible, advanced meter type for its roll-out, several further benefits can be realised from the meters[4], including:

- Load control applications, using conventional ripple control (Decabit), radio-based, GPRS-based or fibre-optic based means of communication. This can be used on conventional hot-water control systems, or as an interface to other home appliances.
- Interface to Home Area Networks (HAN), supporting customer-based load control or energy-saving applications.
- Signalling electricity costs and usage rates to customers.
- Providing real-time energy flow data to be used in smart network applications.[5]

[4] This may require the meters to be fitted with some additional hardware devices, but the potential to do so is in place.

- Measurement of two-way power-flow – accommodating distributed generation sources.
- Measuring power quality and voltage levels.
- Providing an exact location and record of power outages.

Other potential future developments of smart home technologies include:

a. **In-home displays:** Dedicated displays or internet displays (e.g. Google Powermeter), providing consumers with greater understanding of their energy use. They will typically include analysis tools to identify potential savings through altering times that appliances are used, or savings from investing in more energy efficient options.

b. **Smart plugs/thermostats:** These devices communicate with a suitably equipped smart meter or an energy management hub to turn power on or off to wall sockets or to adjust the thermostat by a programmed amount. For example, adjusting the thermostat of a heat pump from 24 to 22 degrees during winter peak periods.

c. **Smart appliances:** Include communication capability such that they can respond to signals from smart meters or energy management hubs. For example, signal not to run refrigerator's defrost cycle during a certain time period.[6] The appliances will also report their energy consumption.

d. **Energy management "hubs":** Energy management hubs provide central control and communication to a number of appliances or other loads/energy sources at the customer's premises. The hubs allow the consumer and/or power companies to set rules as to how energy is to be managed. Communication with the hub is either through a smart meter, or directly. Several major companies are developing products to provide the above functions. The rules can be set to respond to the customers' needs as well as any pricing incentives from power companies.

While the potential for advanced demand management systems exist, high levels of uncertainty remain regarding communication standards. Until this is resolved investments in such technologies will be risky. Vector will closely follow developments in this area.

3.2.1.5 Battery Storage

Battery technology has been the subject of major development over the past five years. This has been driven both by electric vehicle developments and by recognition of the challenges of incorporating intermittent renewable energy into electricity networks. There are a number of different battery technologies being developed for different applications including sodium sulphide, flow batteries, lithium ion as well as traditional lead acid batteries. Technology improvements as well as manufacturing efficiencies have seen costs falling significantly over the last two years.

Projects to evaluate the potential of battery storage as a network solution have been completed. The projects have provided understanding of the sizing and economics of using batteries at zone substations, distribution substations and customer premises to provide either security of supply or load shifting advantages. Various battery technologies were evaluated.

The investigations concluded solutions involving batteries are at present still higher cost than traditional network solutions. (The cost differences in some scenarios are within 20~30%.) Given that costs of some battery technologies have seen large reductions in

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[5] This requires a fast two-way communication medium.

[6] A switch in the time the defrost cycle occurs will have little or no negative impact on consumers, while it could offer benefits to the operation of the network.

the past 12 months, distributed battery storage could however provide a feasible alternative in the next three to five years. Further analysis will be undertaken, which may lead to the deployment of field trials to improve understanding of the practical application of battery solutions.

3.2.1.6 LED Lighting

Technology developments in light emitting diodes (LED) lighting have led to LED replacements for most standard domestic and commercial applications. LED bulbs use around 10%-15% of the energy of incandescent and halogen bulbs and around 70% of typical commercial fluorescent tubes. As well as being energy efficient LED bulbs last for around 30,000 hours, which reduces replacement costs (because they don't need replacing as often). While providing similar energy savings to compact fluorescents (CFL's), it is anticipated that LED bulbs will prove more popular in the longer-term because of light quality, instant brightness, improved aesthetics and the absence of mercury.

Currently LED bulbs are expensive (around $40 for a standard 60W bulb) which is limiting uptake. Prices are forecast to reduce by 50% over the next 12 months. At current prices, payback in energy savings is only around two to three years and bulb life is expected to be 15 years plus so the economic case for LED lighting is improving.

Lighting accounts for around 20% of peak residential network demand. Currently CFL's only account for around 5% of light bulbs in homes. There is, therefore, scope for a significant reduction in peak demand if there is widespread uptake of LED bulbs in residential areas.

Further evaluation of the potential application of LED bulbs is continuing, with field trials in New Zealand likely in 2012.

3.3 Strategies for Long-term Network Development

3.3.1 Very Long-Term Demand Projection

As part of the process for preparing the very long-term (50+ years) network development plans for the Northern and Southern regions, an exercise was carried out to predict the very long-term load distribution for the whole of Vector's supply area. The very long-term load distribution assumes the area is developed to its full potential based on the existing designated land use zoning by the city and district councils in their district plans and a continuation of the existing consumption behavioural trend. Based on these assumptions, the total loads in the very long-term for the two regions are estimated at:

- Auckland CBD 1000MVA
- Southern region (except the Auckland CBD) 2500MVA
- Northern region 1500MVA

(The above figures represent the upper limit of demand growth in the regions when the land is developed, occupied and utilised to their full potential, if it is ever developed to that extent, based on the existing consumption trend. The demand increase caused by emerging technologies has not been included in this forecast.)

By comparison, the 2011 non-coincident demand for the two regions is about 2000MVA. The potential demand increase in the very long-term is, therefore, about 150% over the existing demand.

3.3.2 Long-Term Demand Position

According to the Regional Growth Strategy (RGS) developed by the (previous) Auckland region's mayoral forum, the region is to be developed to accommodate a population of two million by the year 2050. The plan is to accommodate about a quarter of the population in higher density, multi-unit accommodation while the remainder would live in lower density suburbs and rural areas. The strategy allows a coordinated approach to transport, land use and other resources planning.

Based on the very long-term demand distribution study, the technology roadmap study and the ten year load forecast (2010-2020), an indicative long-term demand projection for the next seventy years is presented in Figure 3-1. The straight line projection (instead of an annual growth percentage) reflects the historic growth pattern (see Section 5.3 for a discussion).

The black line represents the demand based on the present consumer behaviour, whereas the green line includes the demand due to the introduction of new technologies and appliances (such as electric vehicles and heat pumps) that are not widely used today. Detailed, more accurate forecast of the first ten years (from 2010 to 2020) of the projection is given in Section 5.4 of this AMP.

The newly formed Auckland Council has published a draft "Auckland Plan" to guide the development of the city in the next twenty to thirty years to accommodate the anticipated population growth to 2.2 million by 2030. The "Auckland Plan" will supersede the Regional Growth Strategy when it is formalised. A preliminary assessment of the "Auckland Plan" indicated that it is very similar in approach to the RGS with intense developments within the region's urban limits and concentrated growth along transport corridors. A detailed assessment will be made when the "Auckland Plan" is formalised and the very long term network development plan modified accordingly.

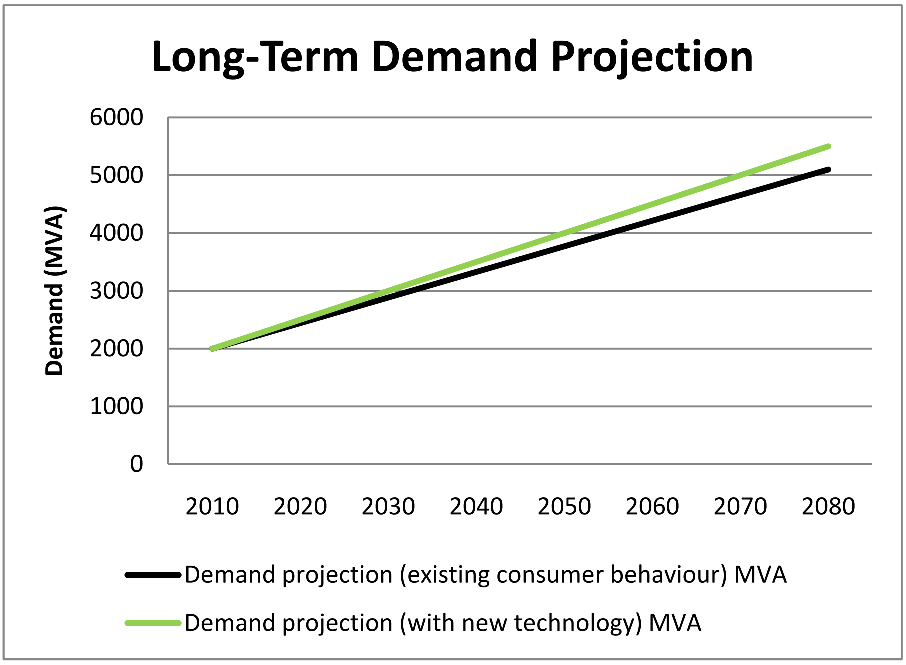


Figure 3-1 : Long-term demand projection[7]

[7] This projection assumes that the average load per ICP will remain relatively constant, which is in line with Vector's analysis of historical consumption patterns as well as expected future behaviour.

3.3.3 Network Architecture

Distribution network architecture can generally be described by two key attributes - voltage levels and network configuration. Reviews of the network architecture for Vector were carried out in 2003/04 (shortly after the merger of Vector and UnitedNetworks Ltd) and in 2007/08. The reviews looked at the appropriate voltage and configuration to be adopted for the development of the Vector electricity network. The following sections summarise the existing and future network architecture.

3.3.3.1 Voltage Levels

The reviews concluded two voltage classes should be retained for the Vector network, namely sub-transmission and distribution voltages.

The sub-transmission system conveys bulk electricity around the network, connecting zone substations to each other and to the transmission grid exit points. Selecting the economically optimal sub-transmission voltage level requires a trade-off between capacity and construction cost. Higher voltage circuits can convey more power, but are more complex and expensive to create and maintain. The appropriate voltage level, therefore, depends on the size and density of loads.

The electricity distribution network distributes electricity from the zone substations to end-users. Given the extent of these networks, and the large number of connections made to them, distribution voltage levels have to be restricted (the cost of higher voltage assets and of connections to these networks is prohibitive). Again there is a trade-off between capacity and construction cost.

The key findings from the 2007/08 review were:

a. Sub-transmission voltage

Except for the very large loads (100MVA or above) with load centres at relative long distances (10km or further) from Transpower's GXPs, zone substations should continue to be supplied at 33kV. When used as sub-transmission network, 22kV circuits restrict bulk supply capacity to levels that are inefficiently low in high density areas like Auckland. Converting 22kV to 11kV is not an effective transformation ratio either.

The medium to long-term sub-transmission strategy is, therefore, to freeze further development of the existing 22kV sub-transmission network. When existing 22kV equipment reaches the end of their lives they will be replaced with 33kV rated equipment. Over time the 22kV will be uprated to 33kV.

The 66kV voltage level is comparable to 33kV as a sub-transmission voltage for the metropolitan parts of Auckland and might have been a good voltage choice if Vector had completely rebuilt the sub-transmission network. Not only is this impractical, given the very substantial investment in 33 kV assets, but a significant part of Auckland also still has a relatively low load density (and will remain so for a long time) which does not economically justify building higher-voltage sub-transmission networks. In addition, 66kV is a non-preferred (internationally) standard voltage that is gradually being phased out by electricity distribution businesses around the world.

For areas with large loads in a relatively confined area, or that are far from grid exit points, the preferred sub-transmission level is at 110kV. At present this only applies to the Auckland CBD and the main commercial area of the North Shore. The Auckland load density does not warrant sub-transmission at higher voltage levels.

b. Distribution voltage

The general distribution voltage level for the Vector network is at 11kV. The load density for most parts of Auckland does not warrant the use of 22kV for distribution, while distribution at lower voltage levels is even less cost-effective. The exceptions are:

- The Auckland CBD, where load density is significantly higher than the rest of the network and also where the area is supplied from the 110kV sub-transmission system. The latter factor makes 22kV distribution a natural choice as this would eliminate the need for an intermediate sub-transmission level; and
- In remote parts of the network where maintaining legal voltage limits is a challenge and uprating to 22kV is a practical and economic solution. Examples are the supply to Piha and Kaukapakapa.

The remaining 6.6kV distribution network in Ponsonby and Pt Chevalier is being uprated to 11kV.

3.3.3.2 Configuration

The review identified that the sub-transmission configuration is very different for the two regions making up the Vector network. However, the distribution configuration is generally very similar. The difference in configuration will also influence how the two regional networks are electrically protected and operated.

a. Southern region

The zone substations in the Southern region are typically supplied by two (and in rare occasions three) transformer feeders from GXPs. Typically there is no sub-transmission switchboard at zone substations. The power transformers at zone substations operate in parallel via the 11kV switchboards. From the distribution switchboards, distribution feeders emanate to supply the distribution network. The distribution feeders are configured in radial formation and are interconnected via normally open switches.

This configuration allows the zone substations to operate as separate, “closed” systems with the ability to back stop each other (take load from adjacent substations) through 11 kV feeders. The level of back stopping depends on the level of interconnectivity.

For the Southern network, there is a significant emphasis on supply security at the sub-transmission level. In the past the sub-transmission network was developed to provide sufficient redundant capacity to maintain supply under single contingency situations at all times, which is comparable to the practice of most Australian networks of similar size and demand characteristics. As a result of the sub-transmission configuration (no 33kV switchboards at zone substations), there is practically no interconnection between GXPs (nor is it possible). In the unlikely event of the loss of GXPs, load cannot be transferred across networks supplied from different GXPs.

Figure 3-2 below shows a typical network arrangement for the Southern region.

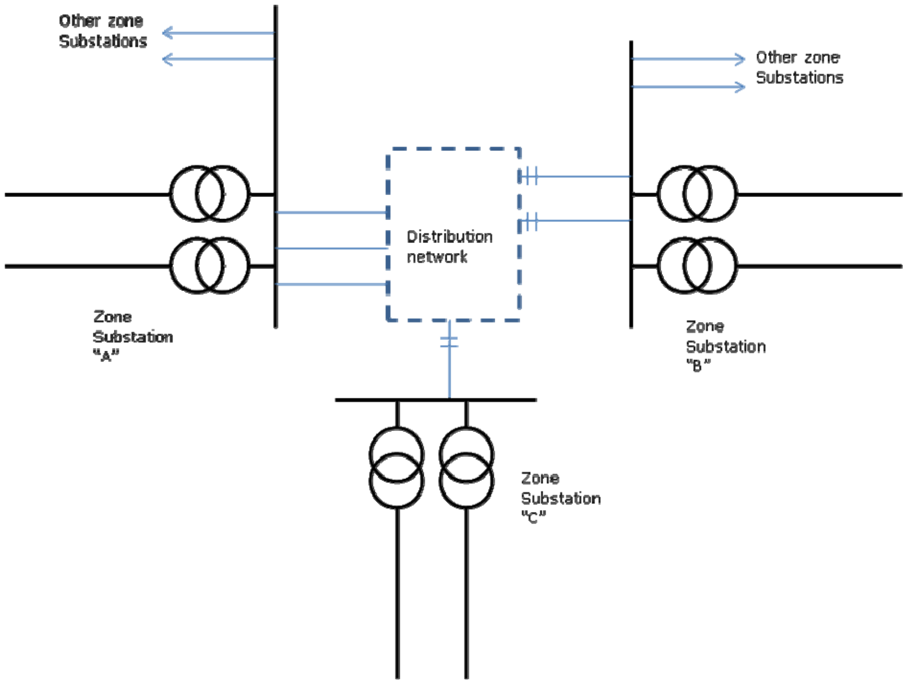


Figure 3-2 : Typical sub-transmission and distribution network arrangement for the Southern region

b. Northern region

The sub-transmission network in the Northern region is based on a mesh formation. A mesh network can be supplied by up to four circuits depending on the load the mesh is designed to supply and the geography of the area. Typically, only a single transformer is installed at the initial stage of development of zone substations. Supply security for the zone substation is provided by backstop capacity from the mesh sub-transmission network as well as from the neighbouring zone substations via 11kV feeders.

Where it cannot be economically justified to complete the mesh in full, which is often the case during earlier stages of development of an area, zone substations are fed from radial transformer feeders. At the next stage of development other legs of the mesh network are installed. When the mesh is formed, the feeders and power transformers are controlled by sub-transmission switchboards.

Meshed networks are especially suitable for low load density areas where demand for no break supply security is relatively low (for example, residential areas), as additional transformers and substations can be inserted into the mesh as and when the demand growth warrants (instead of having to install sub-transmission feeders from GXPs to zone substations). Also in the rural (long distance and low density) parts of the region, the network is typically constrained by voltage before capacity and security thresholds kick in. In these areas, use of smaller size zone substations and "shorter" feeders will help resolve voltage issues that may arise.

Figure 3-3 below shows a typical network arrangement for the Northern region.

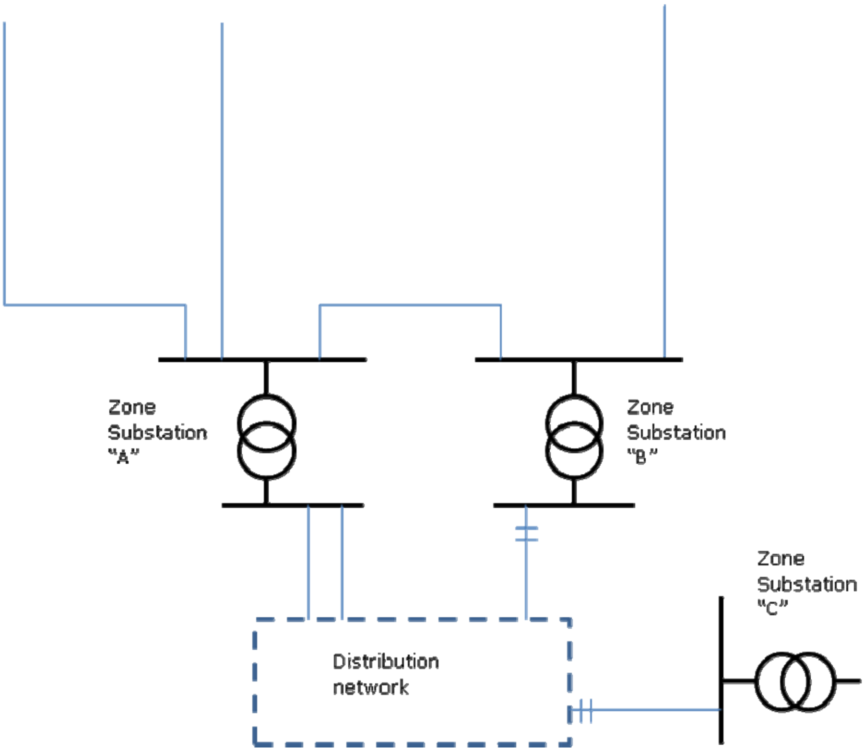


Figure 3-3 : Typical sub-transmission and distribution network arrangement for the Northern region

3.3.3.3 Radial vs Meshed Configuration

The review identified that meshed sub-transmission networks are more economic if the GXP is off to the side of the supply area, whereas the economics tend to favour radial formations if the GXPs are closer to the centre of the supply area.

3.3.3.4 Electrical Protection

Protection schemes designed to serve radial systems are different from those designed for mesh systems, with the latter being substantially more complex and requiring a higher degree of fault-discrimination and ability for localised switching. As a result, the protection systems on the Southern network are simpler than those on the Northern and outages resulting from protection events tend to be less widespread, with shorter restoration times.

Vector's gradual upgrade from electro-mechanical relays to digital relays and further developments in the SCADA network (including RTUs) and communications systems, should over time enhance the ability of the Northern network protection systems and result in higher supply security levels.

3.3.3.5 Effects of Additional Load on Network Architecture

The network architecture reviews carried out in 2003/04 and 2007/08 concluded that the additional demand due to land development in the very long-term does not warrant a change to the existing network architecture (voltage and configuration). The "Network Development Blueprint" projects completed in 2008/09 concluded that the architecture is sufficiently flexible to accommodate additional load to cater for the growth over the next 50 years through a combination of extension (additional substations and feeders) and increase utilisation of existing facilities. The additional load due to new technologies (200~480MVA) is relatively small compared to the long-term growth (~3000MVA) anticipated from additional customers. Change in network architecture is, therefore, not expected to be warranted in the foreseeable future.

3.3.4 Micro Grid

Vector does not consider that the way the regulatory regime is presently being operated provides incentives to improve supply quality above historical levels. There is also little evidence customers are prepared to pay extra for enhanced quality of service. As a result, there is little economic or financial justification to develop a full scale system of micro grids covering the whole of the Vector network from the perspective of improving network reliability. These systems also do not currently offer economically viable alternatives to standard grid connections.

It is, therefore, unlikely that there will be significant roll-out of micro-grids in the Vector distribution area in the near to medium-term future. The strategy for micro grid development will, therefore, likely be directed at particular situations, where over-voltage or reverse power flow arises from localised applications. These will be dealt with on a case-by-case basis.

3.3.5 Long-Term Asset Investment Strategies

Electricity network asset investment decisions are typically made for assets with very long lives. Traditionally, while consumer and network technology remained relatively stable, investments could be made with a reasonable degree of certainty. However, the electricity market is currently entering a phase of change, with rapidly developing consumer applications and network applications following closely behind.

With the development of the future generation of smart home appliances, fast communications, more powerful computers, smart metering and network control systems, customer growth and demand patterns are becoming more uncertain. Some technologies are expected to increase demand while others will lead to reductions. Changes to consumption patterns (summer or winter peaking, morning or evening peaking) affects how the network is planned, operated and managed. Regulatory pressure (to limit return) and investor expectation (to increase return) is driving network companies towards more efficient use of assets and better management of risks.

The new generation of network technology also offers opportunities to enhance asset utilisation and reduce network risks. Initiatives such as network monitoring, remote control and automation are expected to be widely used to enhance the utilisation of the distribution network.

An important initiative that Vector has embarked on (with initial time-of-use tariffs) and which will be further developed in future is to review line charges to provide appropriate incentives to consumers to change their demand pattern, to achieve better utilisation of network assets.

Even in the face of the increased uncertainty about the future, new connections, network capacity augmentation and asset replacement investments remain essential. The following general asset investment guidelines have been adopted to ensure the potential impact of this is minimised (and to minimise the chance of assets being stranded in future):

- The network development strategy is to always aim at deferring investment where this would not breach safety or security standards, is practicable and economically efficient;
- Non-network solutions should always be considered as part of the mix of technological solutions and where feasible, should be embraced;

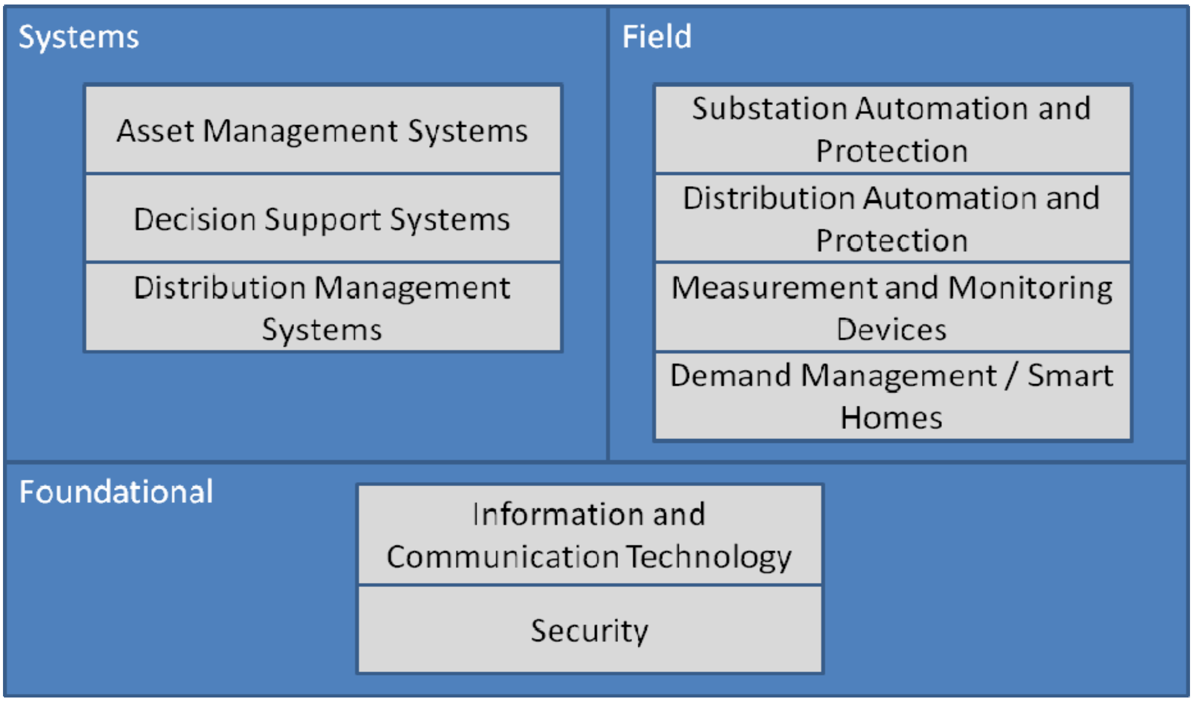
- Where network investment proves to be essential, smaller projects are preferred over larger projects (unless synergies of larger projects present a compelling financial advantage); and
- Unless customers desire higher levels of service, or regulatory incentives in this regard are created, our aim is to maintain the existing levels of service.

3.4 Evolution of the Smart Network

Worldwide there is an immense volume of literature, research and development being produced on the so-called "smart grid" (or smart network, from a distribution utility perspective). Inevitably, widely diverging views abound about what constitutes "smartness" in electricity distribution, and about the nature of future networks. While consensus has yet to emerge, there are a few common themes about the changes that make an evolution to smart networks possible, the main ones being[8]:

- The ability to access more real time information on the status of the network as a result of smart meters being rolled out and the falling cost of various network measuring and monitoring devices;
- Two way communications – interaction between distribution devices such as meters, substations, electronic protection systems, switches and home area networks;
- The ability to provide far greater monitoring, automation, optimisation and fault responsiveness on the network;
- Technological step changes associated with fibre optic communications and other information-based technology/next generation telecommunications; and
- Integration of power systems infrastructure with information and communication systems.

Vector takes a broad view of a smart network as the application of information and communications technology to enhance the network. The elements of the smart grid are summarised in the chart below.



[8] These definitions were adapted from a draft of a document developed by the Electricity Networks Association, titled *"The business case for EDBs to develop smart networks"*, 29 October 2010.

While there are undeniably many exciting developments underway offering various opportunities for enhancing the operation of electricity distribution networks, Vector is somewhat sceptical about the "hype" that seems to surround many discussions on smart networks. Many applications that are now widely being touted as "smart" have already been successfully adopted by Vector (and others) in the past.[9] Vector prides itself on having been "smart" in the past as well and does not see smart networks as a new development, a new type of asset, or a sudden step-change in behaviour. In our view it is rather a further evolution in the long history of distribution networks.

We see the potential benefit from the evolving smart network technology to distribution utilities mainly in the opportunities that these provide in:

- Supporting an efficient asset investment response to an ongoing increase in electricity demand, by increasing the utilisation of existing assets and by better managing peak demand through more effectively spreading the use of electricity[10];
- Providing customers with better means of controlling their use of electricity and utilities with the means of conveying effective price signals to customers to encourage this efficiency;
- Supporting the safe uptake of increasing levels of distributed generation and two-way energy flows in distribution networks[11];
- Improving network reliability through increased automation and flexibility, as well as the ability to rapidly pinpoint fault locations; and
- Improved asset management resulting from increased levels of asset performance information.

Vector is keeping fully abreast of the continuing evolution of smart applications in distribution networks. However, we note the following:

- Under current regulatory arrangements (in spite of the intent of Section 54Q), it is not clear that a strong business case can be made in the New Zealand regulatory environment for major investment in many of the more attractive features of smart networks, specifically where these are intended to improve network reliability and response to outages.[12] These applications include self-healing networks, widespread use of fault locating devices, etc;
- The "hype" that still surround smart networks and the lack of consensus on technology standards or the manner in which various applications will interface leads us to believe it is more appropriate to at this stage focus on particular applications where we see direct economic value, but to still retain a wait-and-see attitude towards a wider investment in smart technologies; and
- At present, the prime benefit of adopting "smart" applications to Vector is the ability it offers to allow network capacity increases to be deferred, by increasing the utilisation of network assets, or by shifting load demand peaks.[13] However, in general the structure of the New Zealand electricity market does not support a sound business case for these investments. This is partly because the full cost involved with the solutions lie with the distribution utility but it can only realise a portion of the downstream benefits realised. The rest of these benefits accrue to

[9] This includes automation of substations, automatic load sharing between adjacent substations, bus-automation, asset condition and status monitoring etc.

[10] This spreading could be over time, reducing peak demand, or by spreading load over adjacent assets.

[11] This occurs when customers sell electricity back into the grid.

[12] There is no certainty Vector will be able to recover its investment in applications intended predominantly to improve network reliability or efficiency.

[13] Shifting load peaks means more growth can be accommodated before Vector's network security standards are compromised.

the transmission system provider and to the electricity generators. In theory contractual agreements between the parties could allow a portion of these wider system benefits to be captured by the investing party, but this has not been a common occurrence in the industry to date.

Taking this into account, Vector will continue on its historical evolution path for smart technologies rather than committing to a large-scale adoption and roll-out of any of the "smart network" technologies.

Likely key areas of focus over the coming 12 months will be:

- Development and testing of network load transfer schemes;
- Evaluation and trialling of dynamic equipment rating;
- Continued evaluation and trialling of battery storage;
- Implementation of continued field monitoring devices;
- Increased data reporting and visualisation to improve decision making; and
- Analysis of premise energy efficiency opportunities.

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Electricity
Asset Management Plan
2012 – 2022

Service Levels – Section 4

[Disclosure AMP]

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4 Service Levels

This section describes the Electricity Distribution Business' performance targets set under Vector's asset management strategy. Performance against these targets is also discussed.

Following commissioning of Vector's Asset Lifecycle Information System (ALIS) in 2010 (see Section 7 for details), Vector is now collecting more disaggregated asset performance data. This will be incorporated in an extended set of asset-based performance measures that will form part of future AMP's.

4.1 Consumer Oriented Performance Targets

Vector is committed to providing a high standard of service and a safe, reliable and secure electricity supply. This challenge requires effective and efficient network solutions to enable Vector to meet this goal with the optimum investment. As such, Vector recognises communication is essential in order to improve and understand what services and products our customers like, what they do not like and what they need.

Customers are widely consulted and are able to provide feedback about their expectations through a variety of contact points:

- Call centre representatives;
- Customer service team representatives;
- Operations and project representatives;
- Service provider/contracting representatives;
- Customer service feedback surveys;
- Customer engagement surveys;
- External publications and websites; and
- Dedicated account management for the very large customers.

4.1.1 Customer Expectations

Keeping engaged and aligned with changing customer expectations is fundamental to optimal asset investment and asset management practices.

Individual customers have different and diverse needs and expectations around supply reliability. For some, interruption frequency is a key consideration. For others, the duration of interruption has real consequences.

In terms of individual requirements, the most significant feedback comes from customer surveys. The results of these surveys provide a basis for setting customer service levels, by drawing out customer preferences around the quality of supply including the number of and duration of outages, as well as the extent to which customers would be prepared to pay for improved reliability.

Results from the 2006, 2008 and 2012 surveys are summarised in Table 4-1 below. Participants were identified as the "person most responsible for making decisions relating to electricity".

The most recent engagement survey, conducted in January 2012 indicates an improvement in customers' overall perception of Vector in the last few years and continues to validate the following general preferences:

- A substantial majority of customers rate the service provided by Vector as adequate or better;
- Most customers are highly satisfied with the value for money experienced regarding their electricity supply; and
- A substantial majority of customers express no desire to pay an additional amount to receive a service with reduced number of outages or reduced duration of outages.

Customer Survey Date	**Mar-06**	**Jan-08**	**Jan-12**		**Jan-12**
	Residential				**Commercial**
Sample size	**2141**	**1500**	**1497**		**160**
Rate the current service provided by Vector as adequate or better	84%	87%	96%		99%
Satisfied with the value for money regarding their electricity supply	81%	76%	81%		95%
Do not wish to pay an additional amount for shorter duration outages	85%	89%	91%		98%
Do not wish to pay an additional amount for fewer outages	79%	84%	89%		99%
Do not wish to pay an additional amount for NO outages	82%	84%	84%		99%
Rate the frequency of outages experienced to be acceptable	76%	62%	71%		70%
Believe they have experienced less than 3 outages over 12 months	71%	58%	58%		91%
Believe they have experienced less than 6 outages over 12 months	89%	78%	79%		98%
Rate the duration of the last outage experienced to be acceptable	66%	56%	52%		38%
Believe the last outage they experienced was less than 3 hours	55%	53%	59%		46%
Believe the last outage they experienced was more than 3 hours	11%	28%	8%		6%

Table 4-1 : Summary of survey results

The first of these two preferences were expressed by a marginally greater proportion of customers in urban areas or in the Southern Region than in rural areas or in the Northern region; conversely, rural or Northern customers were even more reluctant than urban or Southern customers to pay more for fewer or shorter outages.

No clear opinion was apparent from the surveys regarding the acceptability of the number or the duration of outages experienced.

There are some clear insights from the 2012 survey that will be developed into initiatives at a later stage:[1]

[1] The 2012 survey results were only received in January and February 2012 and are still being analysed. A list of possible initiatives based on that feedback will be prepared and the relevant aspects will be addressed in the next Vector AMP.

- Residential customers place more importance on the duration of outages rather than the frequency;
- The most important measure of quality for Residential customers is a high quality power supply – free of voltage dips and surges;
- For commercial customers, the duration and outage of power cuts are equally the most important measures of quality; and
- Commercial customers rate Vector's performance more highly than residential customers, but also have higher expectations in terms of quality of supply.

In addition to these surveys, Vector's larger scale engagements tend to focus on councils and community groups. Vector also surveys its industrial and commercial customers as part of an ongoing initiative to provide effective and responsive account management in line with customers' expectations. More broadly, Vector has implemented a company-wide measure of customer satisfaction and experience. Vector also operates an on-line residential customer feedback panel, which is used to guide certain initiatives.

4.1.2 Customer Service

4.1.2.1 Vector's Customer Service Commitment

Vector has a target set of customer service levels. If these are breached, customers are entitled to a compensatory payment (see Section 4.1.7).

The service standards are specific to the customer/retailer relationship model adopted on the various parts of our network, as indicated in Table 4-2 below.

Vector Target

Customer/Retailer model	Conveyance (Southern)				Interposed (Northern)	
Service level type		CBD / Industrial	Urban	Rural	Urban	Rural
Maximum interruption frequency (per year)		4	4	14	4	14
Maximum interruption duration (hours)		2.5	2.5	3	3	6

Table 4-2 : Vector's service targets

Note that incidents arising as a result of generation and transmission bulk supply failures, or of extreme events (see Section 4.1.6) are excluded from this scheme. While Vector will respond to breaches in terms of the service commitment when they come to its attention, in some cases this may require notification by the affected customer.

Figure 4-1 is a map indicating performance against customer service thresholds, at the distribution transformer level, for outage duration based on the 12 months to the end of August 2011. Figure 4-2 shows performance against outage frequency thresholds based on the same period.

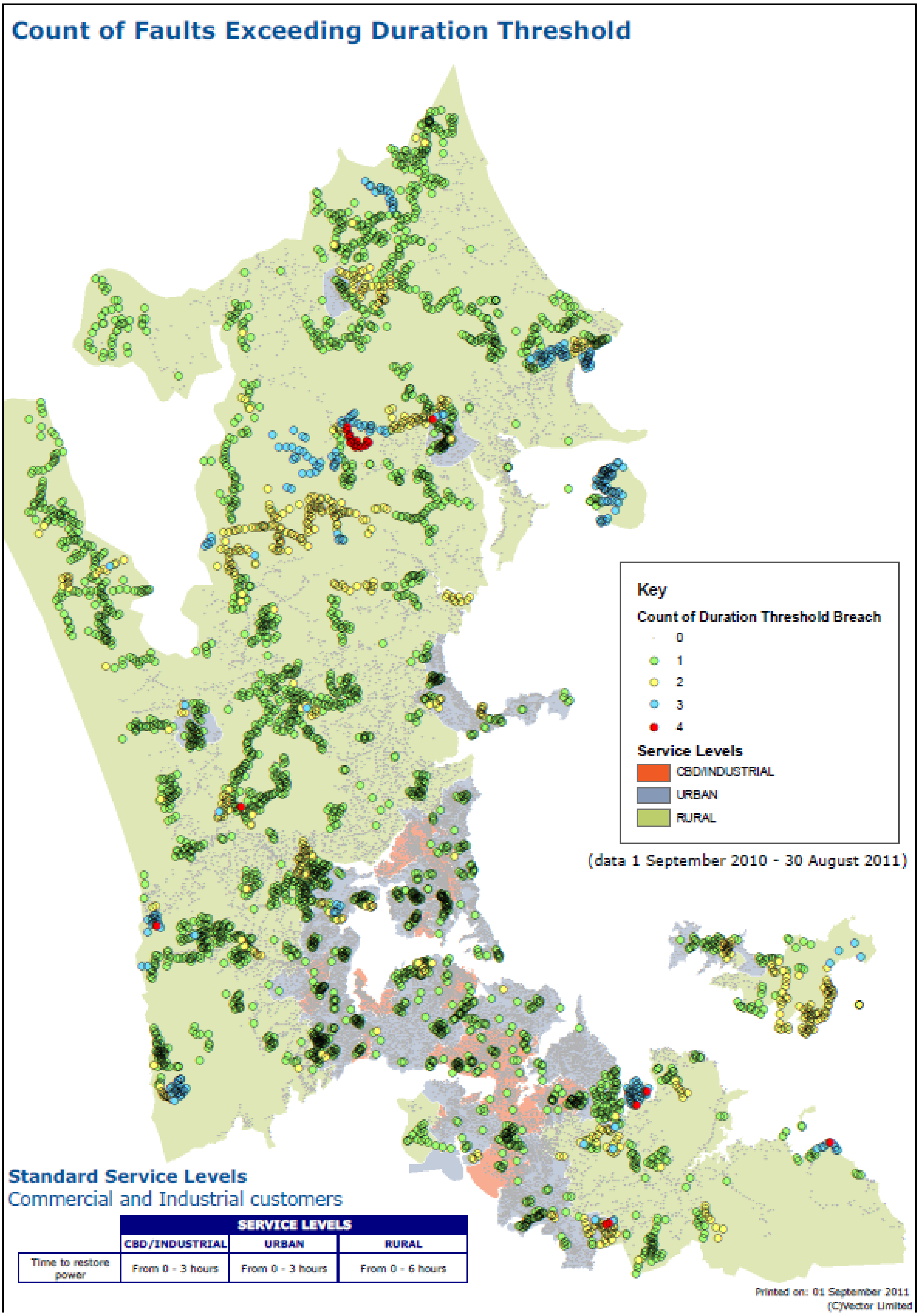

Figure 4-1 : Count of faults exceeding duration threshold

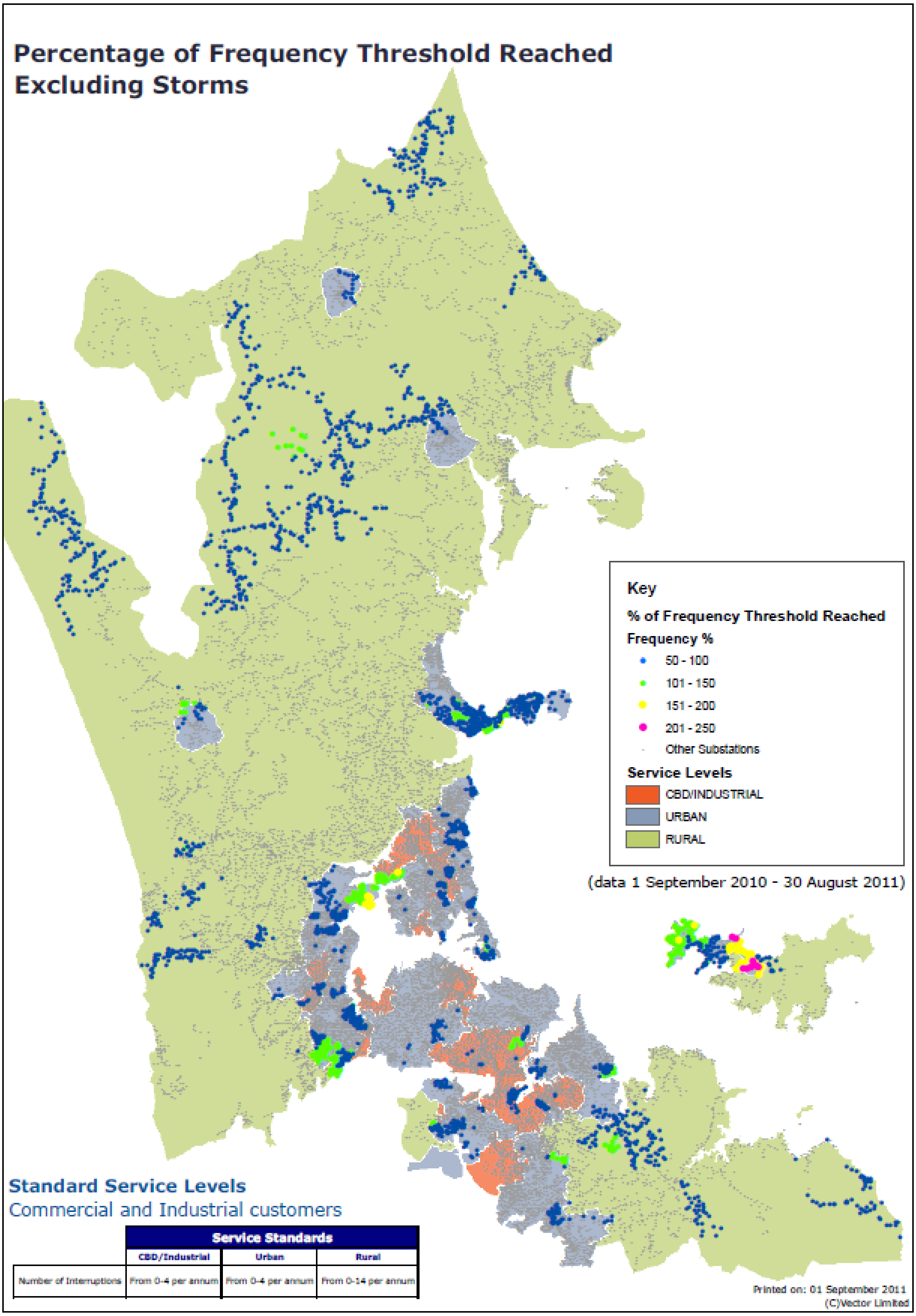

Figure 4-2 : Count of faults expressed as a percentage of frequency threshold

4.1.2.2 Customer Feedback

Vector obtains feedback from Customer Service Monitors, through which we contact a sample of customers who have initiated contact with Vector through our faults process or customer services team.

The survey is divided into a number of sections:

- Overall satisfaction with Vector;
- Satisfaction with the Call Centre (Telnet) for Key Performance Indicator (KPI) purposes; and
- Satisfaction with Vector's Field Service Providers' (FSPs') Service Technician for KPI purposes.

It also includes some branding questions and reliability expectations and occasionally includes a few extra questions about relevant topics we seek the customer's opinion on.

The Call Centre and FSP Service Technician performance scores are divided by region and also further divided by FSP if required. Vector uses this data for monthly performance measures for FSP and Call Centre contracts.

Vector Customer Satisfaction Target

Targets for the Field Services Providers and Call Centre are 85% whilst the target for the Vector overall score is currently 83%.

In deciding the target level of service, Vector takes into account typical industry practice, level of service over the immediate past few years and compliance with targets set by the Electricity and Gas Complaints Commission (EGCC).

Figure 4-3, Figure 4-4 and Figure 4-5 show the historical overall customer satisfaction trends against target by region, the call centre satisfaction against target by region and the service technician satisfaction against target by region.

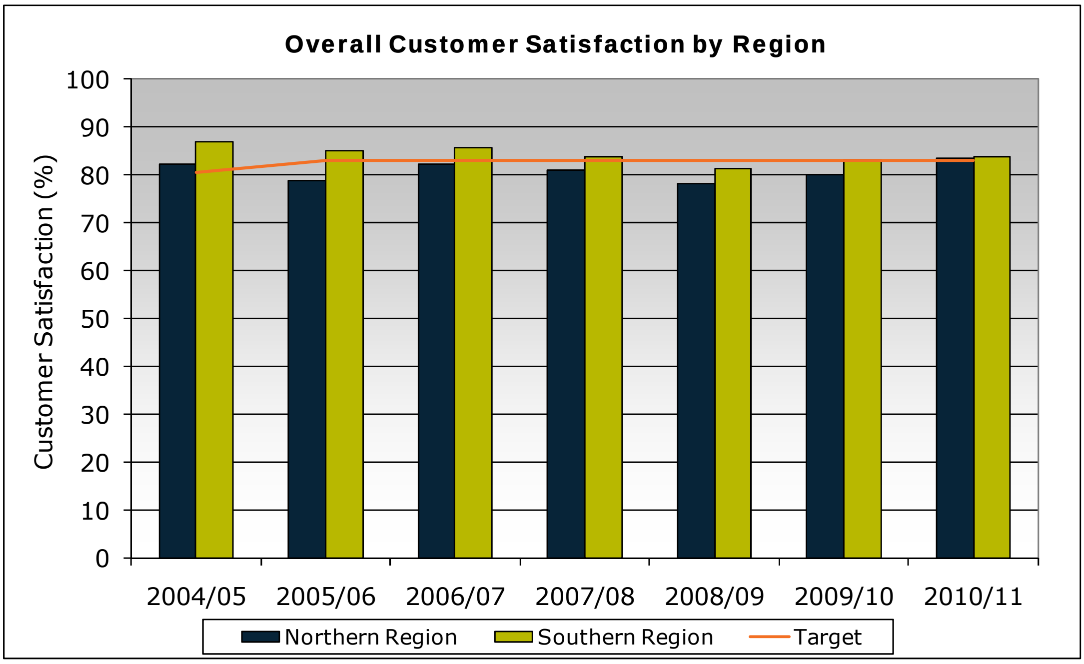

Figure 4-3 : Vector's service targets

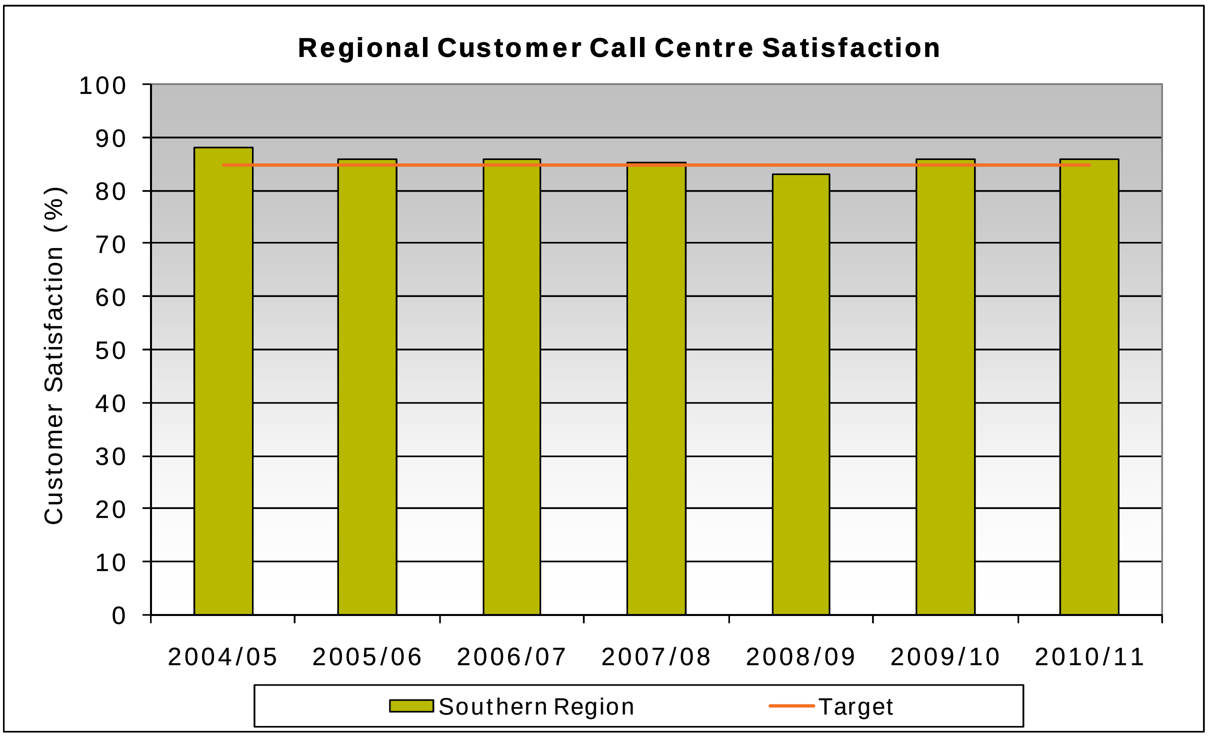

Figure 4-4 : Customer call centre satisfaction

(only Southern region results are shown as the Northern region's interposed use-of-system agreements with energy retailers means that customers do not have direct contact with Vector's call centre)

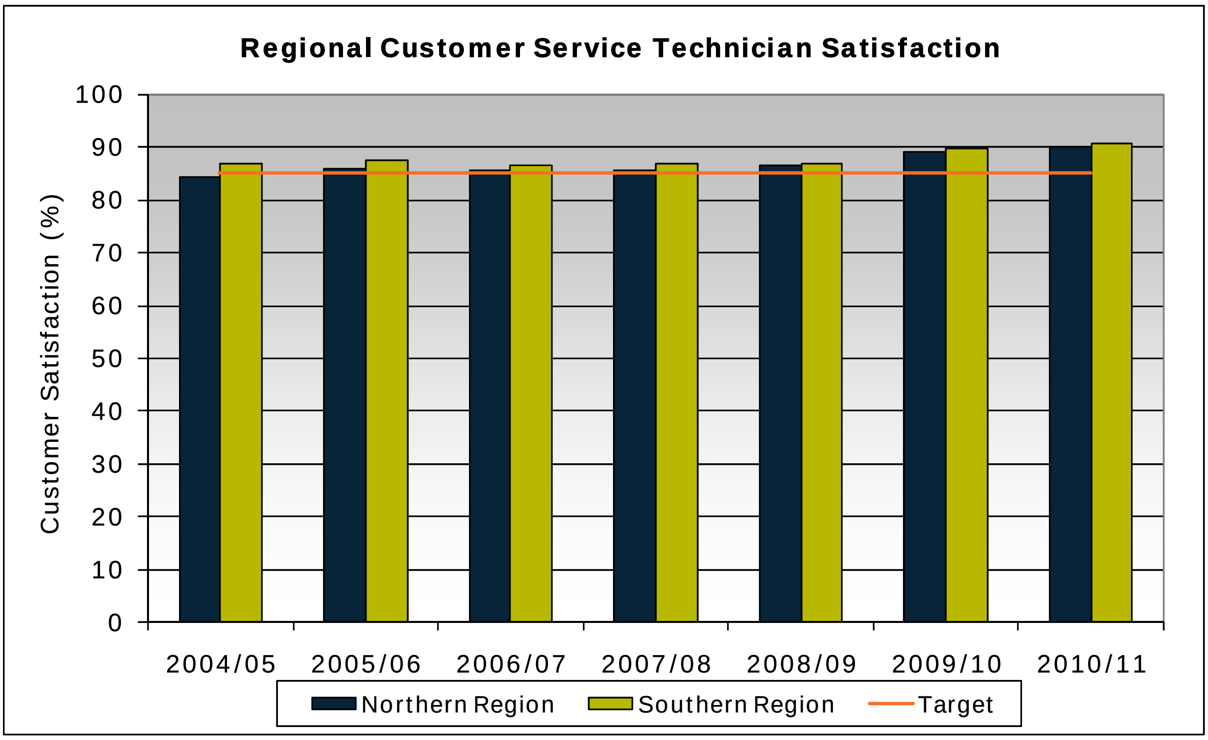

Figure 4-5 : Customer service technician satisfaction

Note that Vector continues with two different business models for customer interaction based on existing use-of-system agreements with energy retailers. In the Southern region customers contact Vector directly for fault and general enquiries around pricing and service. In the Northern region the customer interaction is managed via the customer's energy retailer. Customers contact Vector directly across all networks with tree enquiries, mapping requests and any connection requests around network assets.

4.1.3 Customer Complaints

4.1.3.1 Overall Approach

Although Vector seeks to provide a high standard of service and a reliable electricity supply, there may be times when customers have concerns with their service. In these instances, Vector's Customer Services team is ready to take appropriate actions to manage these concerns, log all reported compliance in relation to the distribution network and coordinate closely with all appropriate areas of the business in resolving complaints and improving the customer experience.

If the cause for concern or complaint is not immediately resolved, it is logged as a formal complaint with our Customer Services team. The Customer Services team is responsible for complaint resolution, identifying trends and raising issues with the appropriate business units in order to implement permanent solutions and prevent recurrence, where appropriate.

Vector adheres to a formal complaint resolution process. Vector's preference is for proactive, consultative and direct engagement with customers via the Customer Services team. Engagement takes the form of meetings with customers or customer representatives to present and discuss areas of concern. A significant number of these discussions are related to supply quality issues. This provides Vector the opportunity to explain historical and current supply quality performance, listen to and understand customer concerns and consult on appropriate actions and future recommendations.

Vector's formal complaint process is as follows:

- Acknowledgement of receipt of the complaint by Vector (see timeframe below);
- Keeping the customer informed with progress in addressing the complaint;
- Attempting to resolve the complaint within the timeframes specified by the EGCC (see below); and
- If the complaint is not resolved within the specified timeframes, informing the customer of the reason for the delay and working towards resolution.

If we have not resolved the complaint within the specified timeframes then the customer is advised of the option of contacting the EGCC.

4.1.3.2 Response Times

Vector attempts to resolve customer complaints to everyone's satisfaction as quickly as possible. Vector's response time target is to resolve >90% of complaints within the timeframes as detailed below. We have two internal targets for complaints:

- Southern region (and other customers who contact Vector directly):
    - Acknowledgement in two working days; and
    - Resolved in ten working days.
- Northern region (where the complaint comes via a retailer):
    - Response to retailer in five working days.

Vector’s Customer Services team is responsible for achievement of these targets and is incentivised via Vector’s KPI programme.

Vector Target

Vector’s response time target is to resolve >90% of complaints within the prescribed timeframes.

In deciding the target level of service, Vector takes into account typical industry practice, level of service over recent years and compliance with targets set by the EGCC.

For 2010/11 2,173 customer complaints were received, of which 2,093 (96%) were resolved within the prescribed timeframe.

These targets are tighter than the industry targets under the EGCC, which stipulates that complaints must be resolved within 20 working days, or 40 working days for complex cases.

4.1.3.3 Customer Complaints – EGCC Complaints

The EGCC (Electricity and Gas Complaints Commission) is an independent body that facilitates resolution between the electricity company and the consumer if the other means of resolution have failed. All customers have the option of contacting the EGCC directly if their complaint has not been resolved to their satisfaction.

In 2010/11, 32 (1.5%) complaints went to the EGCC, of which 27 were resolved under Vector's standard resolution process.

The remaining five complaints required interaction with the EGCC with the following outcomes:

- Four were resolved by settlement;
- One went to Notice of Intention and was upheld.

4.1.4 Call Centre Performance

Vector has two main call centre lines managed by Telnet: the 24/7 Faults Line (0508 VECTOR) and the General Enquiries line (09 303-0626) which is available 7am to 6pm, Monday to Friday.

Vector Target

Service Level Agreements (SLAs) are set as follows for each line based on time to answer a call:

- Faults Line:

  80% of calls answered within 20 seconds on 80% of the days of the month.
- General Enquiries

  80% of calls answered within 20 seconds on 90% of the days of the month.

The SLAs reflect the fact that the faults line has a highly variable and unpredictable call volume.

Telnet is incentivised to achieve these targets through Vector's KPI programme. Figure 4-6 below shows actual response times compared against the targets for both types of enquiries.

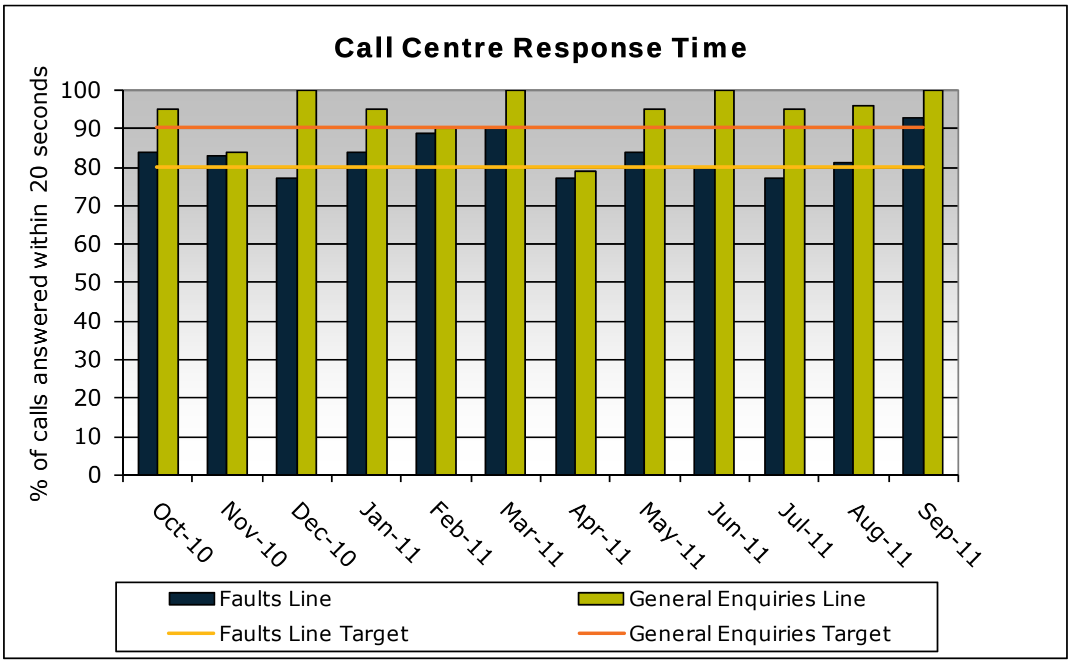

Figure 4-6 : Call centre response time

The call centre response time has shown a similar pattern to last year. Generally response has been on or above target with an increase in faults during the winter months impacting seasonal performance.

The average Call Centre response time for the current year to date shows a marked improvement on 2009/10. In addition, average response time is 83% compared to 76% in 2009/10. This has been helped by the implementation of the enhanced "avalanche" messaging system which has improved the speed in which notification of our knowledge of an incident on the network can be conveyed to callers.

Work is continuing to look at various ways in which the communication of faults to customers can be improved, particularly focussing on the internet connected devices.

4.1.5 Supply Quality Standards

Vector's supply quality objectives are focused on ensuring the required service levels are achieved and maintained in accordance with regulatory requirements. In this context supply quality refers to the magnitude, shape, phase and frequency of the supplied voltage waveform. Vector's supply quality targets are highlighted below.

Vector Target

Supply Quality Parameter	**Standard**
Voltage at point of supply (single phase 230V)	± 6%
Voltage at point of supply (three phase 400V)	± 6%
Frequency of supply (50 Hz)	± 1.5%
Total Harmonic Distortion (of supply voltage) NZECP 36	≤ 5%

Electricity distribution networks remain subject to supply quality disturbances, the most typically observed phenomena being momentary voltage sags.

The source of these disturbances can be highly localised, affecting few customers, or could be generated from distant locations that permeate throughout the supply network. It is impossible to guarantee a perfect power supply free from voltage sags, or other quality of supply issues such as voltage surges or harmonic distortion.

The number of disturbances experienced by any individual customer depends largely on the geographic location of their power supply network. Vector's CBD supply area is served by underground cables and is less exposed to disturbances. Rural or outlying suburban areas typically served by long overhead lines are more susceptible to environmental factors and third party interruptions and are subject to a greater number of disturbances.

Vector's focus is on understanding the cause and effects and dealing with these on a case-by-case basis. Long-term harmonic distortion trends are also monitored at various positions on the network to provide early warning should distortion levels approach maximum acceptable levels. In some areas counter measures have been implemented, such as the installation of Neutral Earthing Resistors (NERs) and enhanced protection schemes.

4.1.5.1 Momentary Voltage Sags

Momentary sag is defined as any recorded event measured at the 11kV zone substation bus which falls below 80% of nominal voltage, regardless of the event's duration. These momentary sags are typically associated with faults on and around the Vector network along with transmitted disturbances from the national grid.

Vector has established supply quality service standards, as shown below, that reflect the different experience and expectation of supply quality of different customer groups, and recognises that business customers have a higher reliance on disturbance-free supply.

Vector Target

Location	Target (sags per year below 80% of nominal voltage)
CBD	≤ 20
Industrial	≤ 20
Urban	≤ 30
Rural	≤ 40

Vector has been proactively monitoring momentary voltage sags at the zone substation 11kV bus level since 2004, and now includes 55 Power Quality Monitors (PQMs) located in key zone substations covering Auckland CBD, industrial, urban and rural locations (plus four mobile units).

Table 4-3 provides a summary of compliance to the published service standards disaggregated by location.

Zone Sub	Location	2006	2007	2008	2009	2010	2011	Target
Quay	CBD	6	26	11	29	3	7	≤20
Victoria	CBD	8	16	9	6	-	2	≤20
Carbine	Industrial	6	18	7	10	6	7	≤30
McNab	Industrial	5	14	5	-	16	11	≤30
Rockfield	Industrial	11	13	4	12	5	9	≤30
Rosebank	Industrial	8	17	14	13	12	10	≤30
Wiri	Industrial	20	15	13	18	6	4	≤30
Bairds	Urban	20	39	25	27	9	9	≤30
Howick	Urban	22	22	12	20	2	5	≤30
Manurewa	Urban	15	23	33	22	9	20	≤30
Otara	Rural	35	25	17	17	8	17	≤40
Takanini	Rural	25	26	28	23	31	27	≤40
Oratia	Rural	-	-	-	-	32	30	≤40
Hillcrest	Residential	-	-	-	-	18	30	≤30
East Coast Bays	Residential	-	-	-	-	4	14	≤30
McKinnon	Commercial	-	-	-	-	7	9	≤20
Westfield	Industrial	-	-	-	-	0	6	≤30
St John[2]	Residential	-	-	-	-		10	≤30
Red Beach	Residential	-	-	-	-	12	30	≤30
Remuera	Residential	-	-	-	-	16	17	≤30
Orakei	Residential	-	-	-	-	4	7	≤30
Greenmount	Industrial	-	-	-	-	4	6	≤30

Table 4-3 : Momentary voltage sags per year at monitored locations

Typical responses to non-compliance to service standards include targeted maintenance (such as vegetation control), network inspections (such as thermal imaging to detect hot spots and weak links), asset renewal/replacement, network re-configuration and protection upgrades (including the installation of additional monitoring and/or protection equipment.

4.1.5.2 Harmonic Distortion

The PQMs also track Total Harmonic Distortion (THD) measured at the 11kV zone substation bus. Excessive THD can adversely affect the expected lifetime of some of Vector's network assets (such as transformers) as well as customers' plant and equipment and may cause sensitive electronic or IT equipment to fail.

The causes of THD may be specific (in the case of an electrically "noisy" or non-linear large industrial load) or dispersed (as in the increasingly widespread use of equipment with electronic power supplies and fluorescent lamps). Table 4-4 shows mean THD calculated as a percentage value on an hourly basis.

[2] St Johns is a newly commissioned zone substation with data for only the last quarter. Annual sag count, therefore, was not recorded.

Zone Sub	Location	2006	2007	2008	2009	2010	2011	Target
Quay	CBD	1.5	1.6	1.6	0.7	1	0.9	≤5.0
Victoria	CBD	1.7	1.6	1.4	0.7	-	0.6	≤5.0
Carbine	Industrial	3.4	3.6	3.5	2.2	2.1	2.2	≤5.0
McNab	Industrial	0.9	1.1	1.6	0.9	0.8	0.8	≤5.0
Rockfield	Industrial	2.9	3.1	3.2	2.9	2.7	2.5	≤5.0
Rosebank	Industrial	3.1	3.5	3.3	2	2	2.0	≤5.0
Wiri	Industrial	2	2.2	2.1	1.2	1.6	1.9	≤5.0
Bairds	Urban	1.5	1.6	1.9	1.3	1.2	1.0	≤5.0
Howick	Urban	2.5	2.6	2.9	2.3	2.2	2.1	≤5.0
Manurewa	Urban	3.1	3.4	3.7	2.6	2.5	2.1	≤5.0
Otara	Rural	1.2	1.4	2.2	1.4	1.3	1.1	≤5.0
Takanini	Rural	2.7	2.6	2.7	1.7	1.6	1.6	≤5.0
Oratia	Rural	-	-	-	1.4	1.5	1.4	≤5.0
Hillcrest	Residential	-	-	-	2.1	2	1.8	≤5.0
East Coast Bays	Residential	-	-	-	2.5	2.4	2.3	≤5.0
McKinnon	Commercial	-	-	-	1.7	1.7	1.6	≤5.0
Westfield	Industrial	-	-	-	-	0.9	0.8	≤5.0
St John	Residential	-	-	-	-	1.4	1.1	≤5.0
Red Beach	Residential	-	-	-	-	2.2	2.0	≤5.0
Remuera	Residential	-	-	-	-	2	1.8	≤5.0
Orakei	Residential	-	-	-	-	2	1.9	≤5.0
Greenmount	Industrial	-	-	-	-	1.5	1.4	≤5.0

Table 4-4 : Mean THD calculated as a percentage value on an hourly basis

THD for most sites have remained fairly constant year on year with no significant changes.

Vector's objective is to have PQM coverage at all zone substations over the next nine years, in order to gain a comprehensive understanding of the causes and impacts of power quality (PQ) issues. The necessary measuring devices are being progressively installed over the planning period and all new zone substations will be equipped with PQ meters.

4.1.6 Supply Reliability Performance

Vector's strategic goal is to ensure supply reliability performance targets are achieved in accordance with regulatory thresholds and customer expectations.

Targets and measures for overall network reliability are defined by the regulatory requirements; whereas Vector's standard service levels consider individual supply reliability expectations.

In the context of average network supply reliability, both the frequency and duration of interruptions are recorded and reported through the following internationally recognised measures:

- SAIDI (System Average Interruption Duration Index): the length of time in minutes that the average customer spends without supply over a year; and
- SAIFI (System Average Interruption Frequency Index): the number of sustained supply interruptions which the average customer experiences over a year.

Both SAIDI and SAIFI are required measures under the default price-quality path applying to Vector under Part 4 of the Commerce Act and have prescribed thresholds.

New Zealand practice requires that both of these measures consider only the impact of sustained interruptions related to high voltage (HV) distribution and sub-transmission network. Low voltage (LV) interruptions are excluded, on the basis that these are highly localised and generally affect only an individual or small cluster of customers. SAIDI and SAIFI include planned and unplanned events, but exclude Transpower or generator related events.

Vector Target

Disclosure Year	09/10	10/11	11/12	12/13	13/14	+5 yrs
SAIDI (Minutes)	104	114	114	114	114	114
SAIFI (Interruptions)	1.63	1.66	1.66	1.66	1.66	1.66

The step increases in SAIDI and SAIFI thresholds from 2010/2011 reflect the reset regulatory regime from 1 April 2010. Figure 4-7 shows the comparison of SAIDI for the current regulatory year to date against the regulatory target expressed as a straight line.

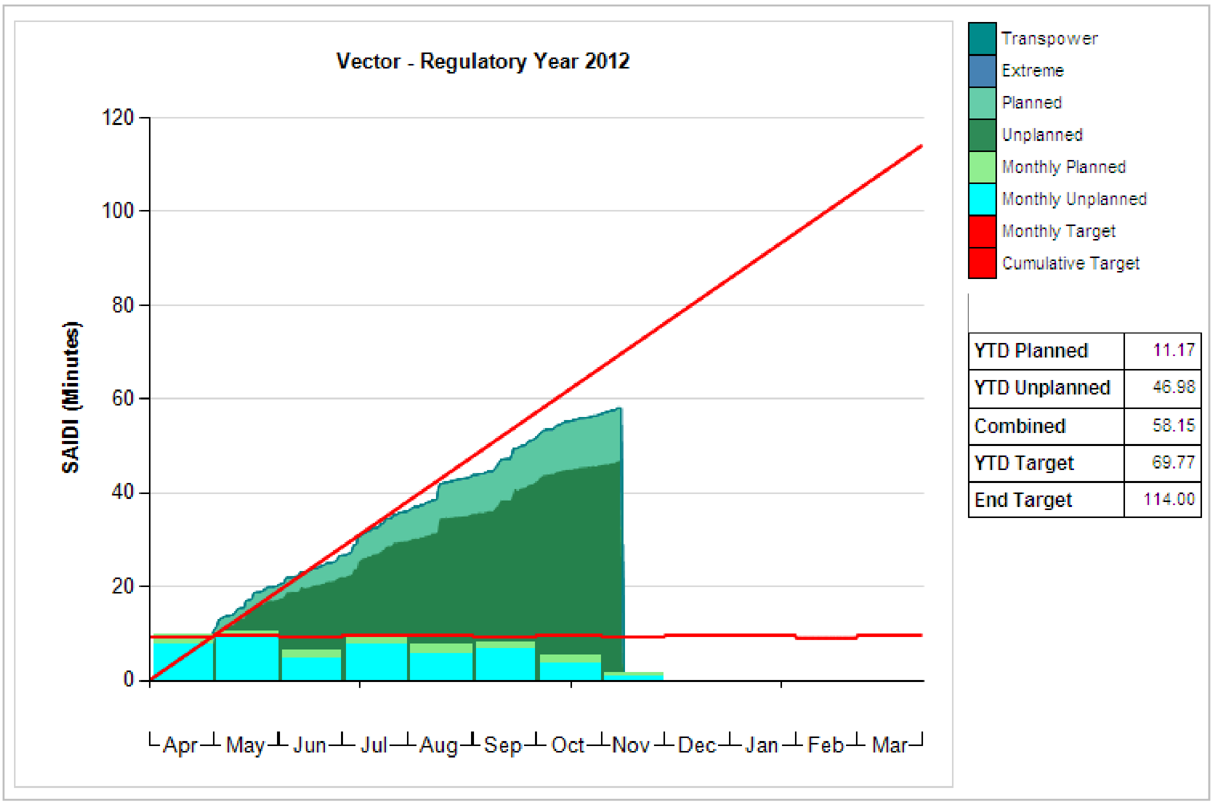

Figure 4-7 : SAIDI during regulatory year 2011/12 compared to regulatory target

In the cumulative graph, the upper light green area represents SAIDI resulting from planned shutdowns. Planned SAIDI has remained similar in the last two years. The lower dark green area shows SAIDI arising from unplanned interruptions. The volatile nature of SAIDI is evident from the month-to-month fluctuations in the monthly bar chart.

4.1.6.1 Trends in Supply Reliability

This section considers longer-term trends in Vector's supply reliability performance and provides a relative impression of how the network has historically performed.

The following Figure 4-8 shows Vector's SAIDI since the inception of information disclosure through to the last complete return. In order to illustrate Vector's underlying performance, "Excluded Events" have been identified, using the Commerce Commission's beta methodology, and "extreme threshold" SAIDI re-introduced.

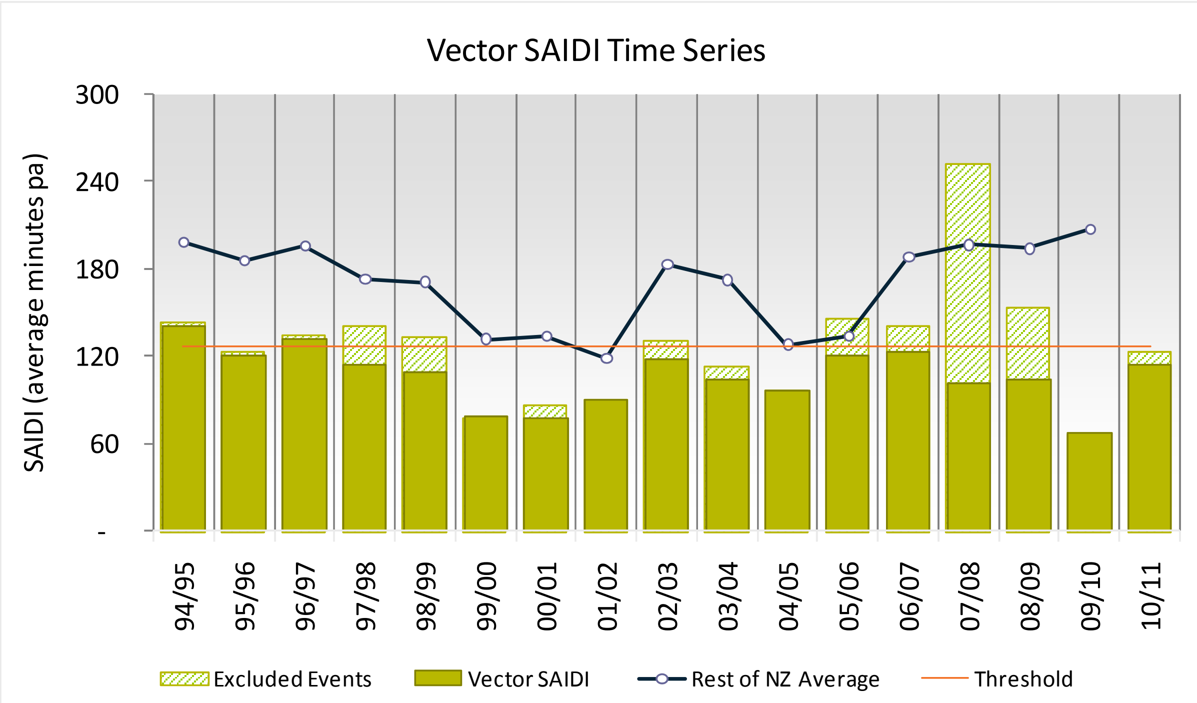

Figure 4-8 : Vector SAIDI time series

Vector's SAIDI compares well against other New Zealand Electricity Distribution Businesses (EDBs). Performance highs and lows are closely mirrored by the rest of New Zealand, indicating underlying country-wide factors, such as weather events.

The exceptional performance in 2009/10 was attributed to a combination of settled weather, the inherent variability of SAIDI, enhanced vegetation control, and the benefits of judicious investment in automated protection devices in recent years, the impact of which may have been somewhat obscured in the prior two to three years by events associated with poor weather. The 2010/11 regulatory year saw a return of more typical weather patterns and SAIDI close to the long run average.

Figure 4-9 below shows each region's historical contribution to Vector's normalised SAIDI i.e. excluding extreme events.

Vector's historic SAIFI performance is presented in Figure 4-10.

In the current regulatory year, 2011/12, both SAIDI and SAIFI are trending towards a lower outturn than in 2010/11.

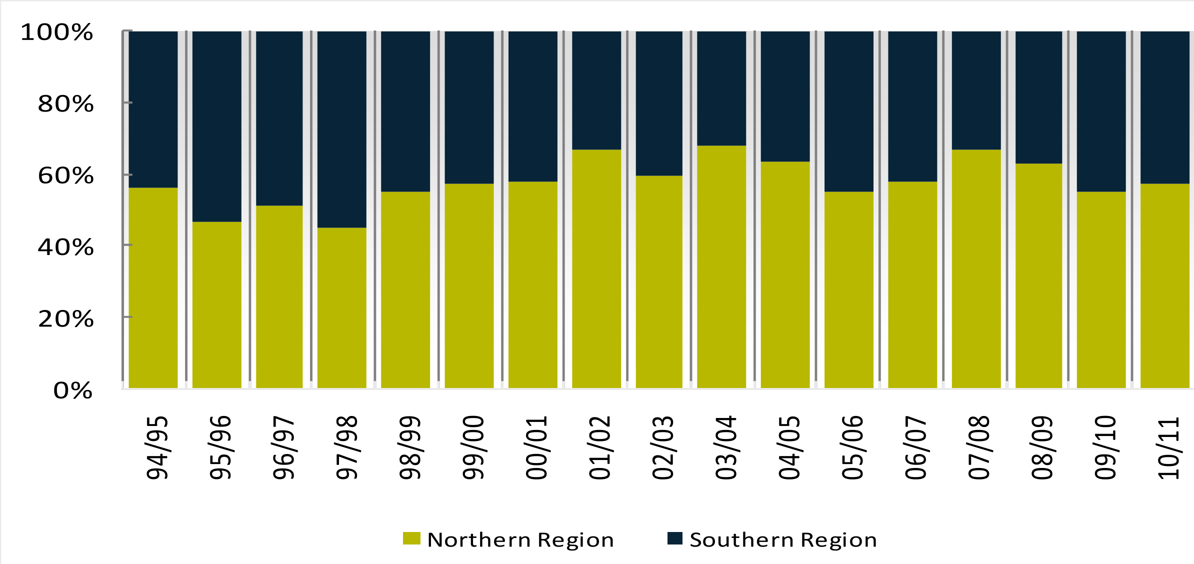

Figure 4-9 : Normalised SAIDI contribution by region

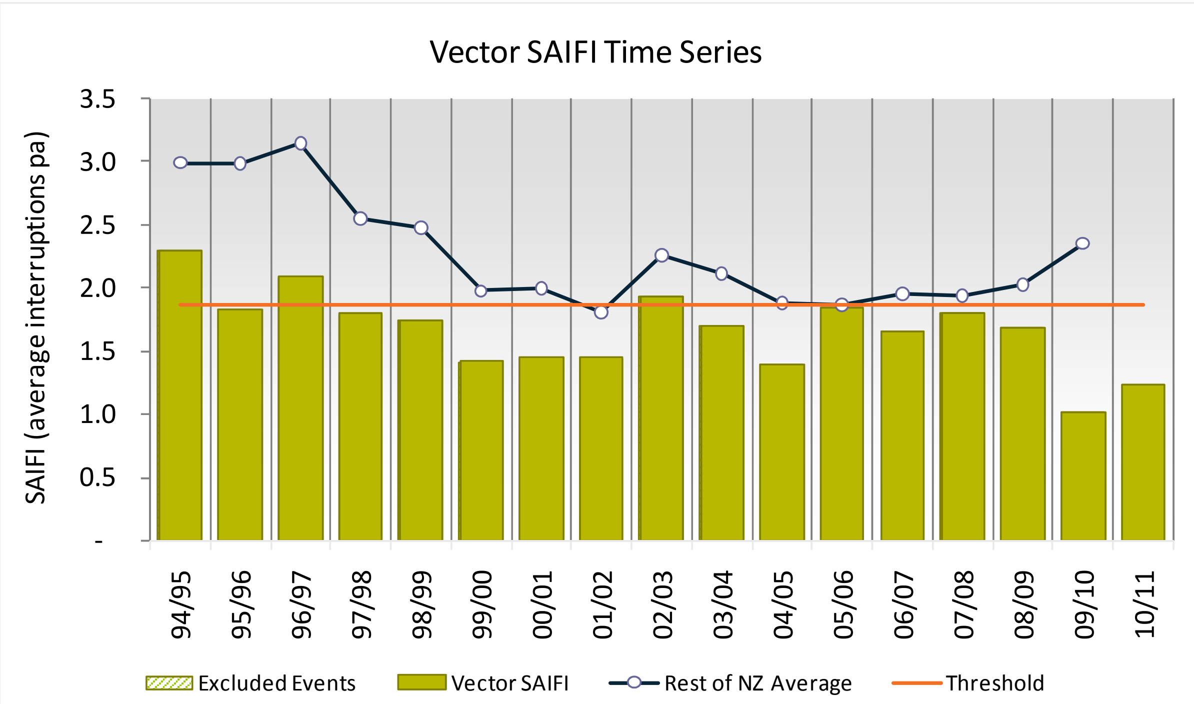

Figure 4-10 : Vector SAIFI time series

4.1.6.2 Causes of Interruptions to Supply

There are a number of reasons why interruptions to supply occur. Typically, on the Vector network, around 95% are unplanned and result from a range of causes including vegetation, animals, third parties, asset condition and adverse weather. Planned interruptions are generally undertaken for maintenance or network upgrade purposes.

Figure 4-11 shows how the impact of major causes of network interruptions has changed over the last 15 years. Each of these causes is considered in depth below.

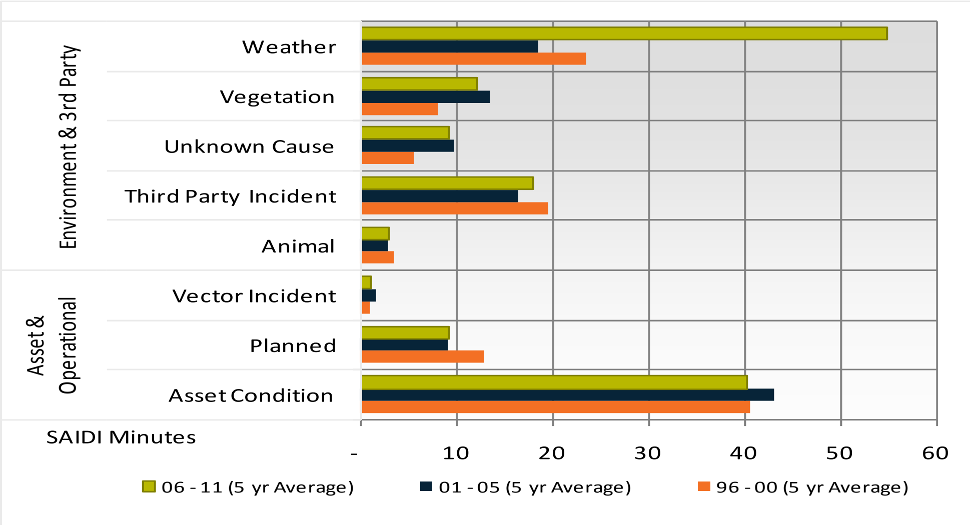

Figure 4-11 : Impact of major causes of network interruptions

- **Weather:** This includes events caused by lightning and wind. The weather represents the single most unpredictable and significant cause of interruptions to the Vector network, with a dramatic increase in events related to extreme weather over recent years (2009/10 being the exception).

- **Vegetation:** This includes faults resulting from overhanging branches and trees caught in power lines. Vector has dedicated a substantial amount of maintenance effort into its cyclic tree cutting and vegetation control programmes. The Electricity (Hazards from Trees) Regulations 2003 have clarified some of the uncertainty around clearance responsibilities and have forced much tighter management and increased education and public awareness. Vector is, however, concerned about some aspects of the regulations which we consider to be unworkable. Vector is actively participating in an industry working group to review the regulations.

- **Third party incidents:** These are caused by external interference, including cars colliding with power poles, vandalism, underground assets dug up by other authorities or trees cut down onto power lines by members of the public. Controls that continue to be put in place include additional network protection devices, increased public education, better coordination around locating and digging near underground assets and relocation or under-grounding of prone or repeatedly-affected assets.

- **Animals:** In most cases sustained interruptions are due to birds or possums. Possums climb along power lines whereas birds will often perch on overhead assets, creating a short circuit when bridging live parts. Many initiatives have contributed to a gradually reducing risk of animal failures, such as vegetation clearance, possum guards on new pole installations in wooded areas, replacement of air-break switches (ABSs) with fully enclosed gas insulated switches, replacement of pin insulators by post insulators with additional clearance.

- **Asset condition:** Although individually extremely reliable, the high quantity of assets installed across the network means that despite all practical efforts there will be some failures related to asset condition. In terms of contributing to the improvements in interruption time, assets with excessive failure rates are targeted for maintenance and renewal programmes, thermal and ultraviolet surveying continues to detect hot and potential breakdown spots, increased network protection devices limit the impact of interruptions and new non-invasive condition based detection techniques help direct risk based maintenance decisions. While underground assets are very reliable, being buried away from the weather and external influences such as trees or cars, overhead asset condition-related failures can be precipitated by weather and third party causes.

- **Planned interruptions:** The five-year average planned SAIDI is low by historical standards, mainly due to live-line "glove and barrier" work practices and the increased use of back-up generation; however in the past three years this trend has reversed, partly due to the implementation of safety-driven operating restrictions on certain equipment types, which necessitated expanded isolation areas. Vector has a programme in place to upgrade the affected equipment.

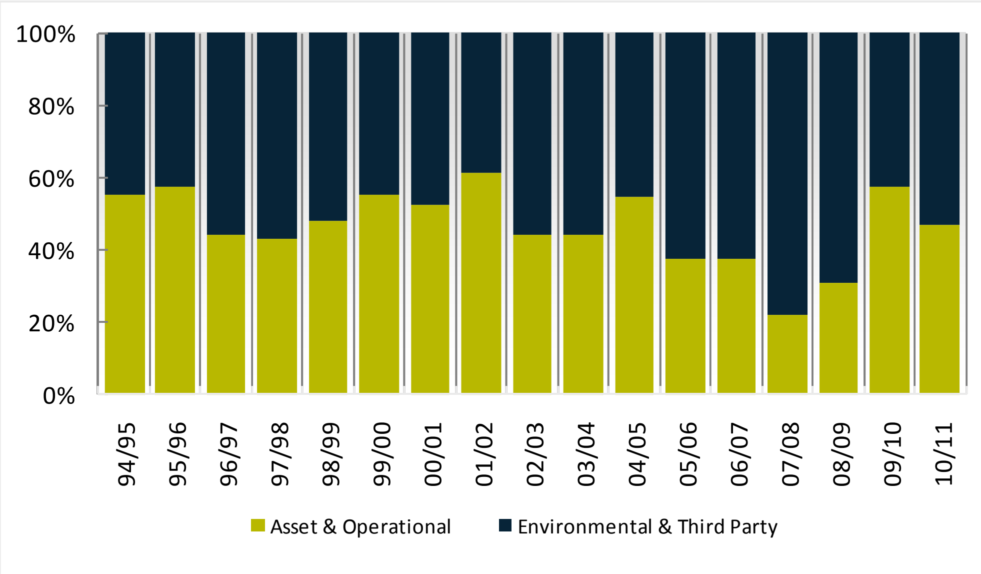

Figure 4-12 : Proportion of SAIDI associated with environmental and third party incidents

4.1.6.3 Factors Outside Vector's Control

The proportion of SAIDI associated with environmental and third party incidents is illustrated in Figure 4-12. Overall, around half of all faults currently stem from environmental and external factors such as extreme weather, lightning, and third party interference (vehicular collisions with power poles, dig-ins, vandalism, un-escorted high load contacting overhead lines).

These are random events and largely beyond Vector's control. Certain operational and network design measures are taken to mitigate the risk. A sustained reduction in failure rate for these fault types would require significant scale penetration of any technical solution, which generally are well down the viability scale in terms of cost/benefit.

Note that while the settled weather of 2009/10 resulted in an increased proportion of asset and operational outages, this is a reflection of the reduced impact of environmental damage, rather than a higher number of other types of faults.

4.1.6.4 Mitigation of Interruptions to Supply

Measures to prevent faults and mitigate their impact include the application of appropriate and effective preventive and corrective maintenance strategies, together with proactive asset replacement programmes. Generally, improved maintenance and asset replacement effort will, over time, result in decreasing numbers of failures.

Approximately half of all faults are considered to be preventable. For example, equipment failure, human error and vegetation contact (other than in storms). The cost/benefit relationship of increased maintenance and asset replacement effort to reduce controllable fault frequency is, however, highly non-linear, with diminishing returns becoming apparent.

4.1.6.5 Reducing Restoration Time

Restoration and repair time is a function of many factors including time to locate the fault, network configuration, switching time, real-time information feeding into the control room, number, skill set and location of fault response field staff and availability of additional resource if the complexity of fault dictates.

Dependent on fault location and time of day, travel time can be a significant factor. For car versus pole incidents involving fatalities, the police now often restrict access to the site for several hours while they complete their crash investigation, which significantly delays the repair and restoration effort.

Vector works with its contracting partners to ensure there is a constant focus on improving fault response times by placing the right staff with the right skill sets in the right places and focussing the response on restoring as many customers as possible, as quickly as possible.

Fault finding time has been reduced through the use of carefully placed automation devices, fault indicators and the use of sophisticated protection relays.

Switching time for fault isolation and supply restoration could be reduced with additional switching staff or control room-administered distributed automation devices, or the deployment of intelligent field switching devices. Should a sufficient incentive exist in future to improve network reliability[3], this will be further pursued.

Finally, repair time is very much a function of fault complexity and available field resources. There is a trade off between a temporary repair with by-pass options such as local generation, or complete repair and restoration. Situations are assessed on a case-by-case basis to determine the most appropriate response.

4.1.6.6 Reducing the Number of Customers Affected by a Fault

To reduce the impact of a network failure, one solution is essentially to break up the network into smaller sections, i.e. with fewer customers between control devices.

This can be achieved by building additional zone substations between existing substations to shorten the feeders, adding additional feeders to reduce the number of customers per feeder or installing additional control devices into feeders to reduce the number of customers affected by any given failure. Automation of these control devices with local intelligence (so-called self-healing network) will also speed up restoration time.

Network automation projects already implemented over the last three years at a cost of around $10 million are saving over 30 SAIDI minutes per annum on an on-going basis, as described below.

[3] Current quality regulation does not support investments in improving network reliability.

4.1.6.7 SAIDI Avoided by Automated Protection Devices

Over the past years Vector has invested heavily in automated protection devices. Between 2006 and 2008, 202 automation devices were commissioned for a total expenditure of $7.85 million. Of the units installed:

- 70 sites operate as functional reclosers;
- 38 sites operate as functional sectionalisers; and
- 94 sites operate as intelligent control points, mostly interconnecting neighbouring feeders.

These units augment the 50 pre-existing reclosers on the network. All sites were selected on the basis of greatest SAIDI benefit per dollar cost.

Vector monitors the performance of these devices in terms of operations and SAIDI which would have been incurred if the device were not installed. The plot in Figure 4-13 is updated daily and available to all Vector staff on the company intranet.

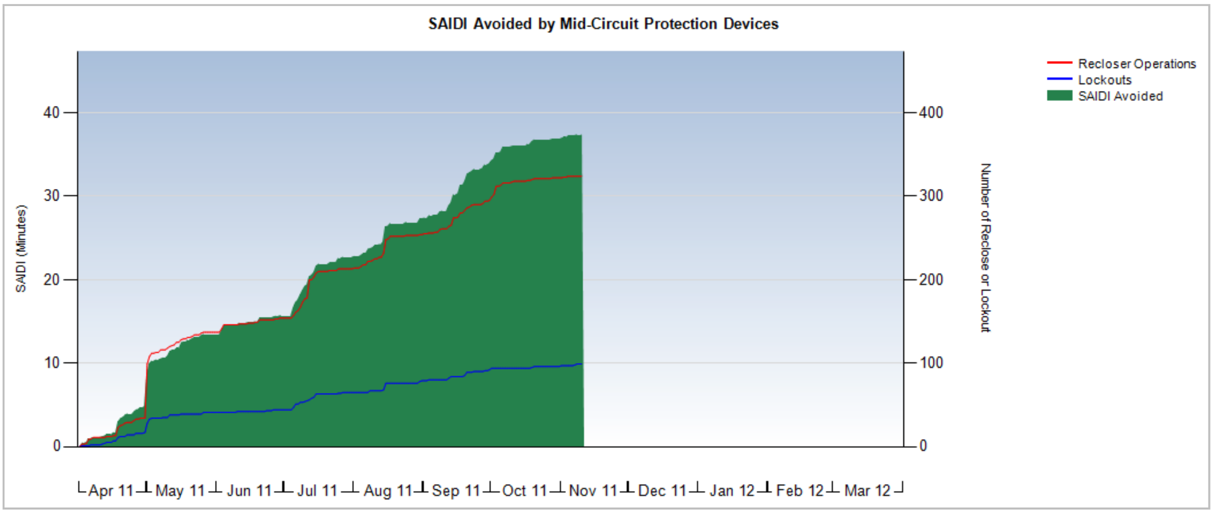

Figure 4-13 : SAIDI avoided by mid-circuit protection devices

(lockouts are operations where a fault could not be cleared by the operation of the recloser)

Figure 4-14 shows the historical SAIDI benefits derived over the course of the programme.

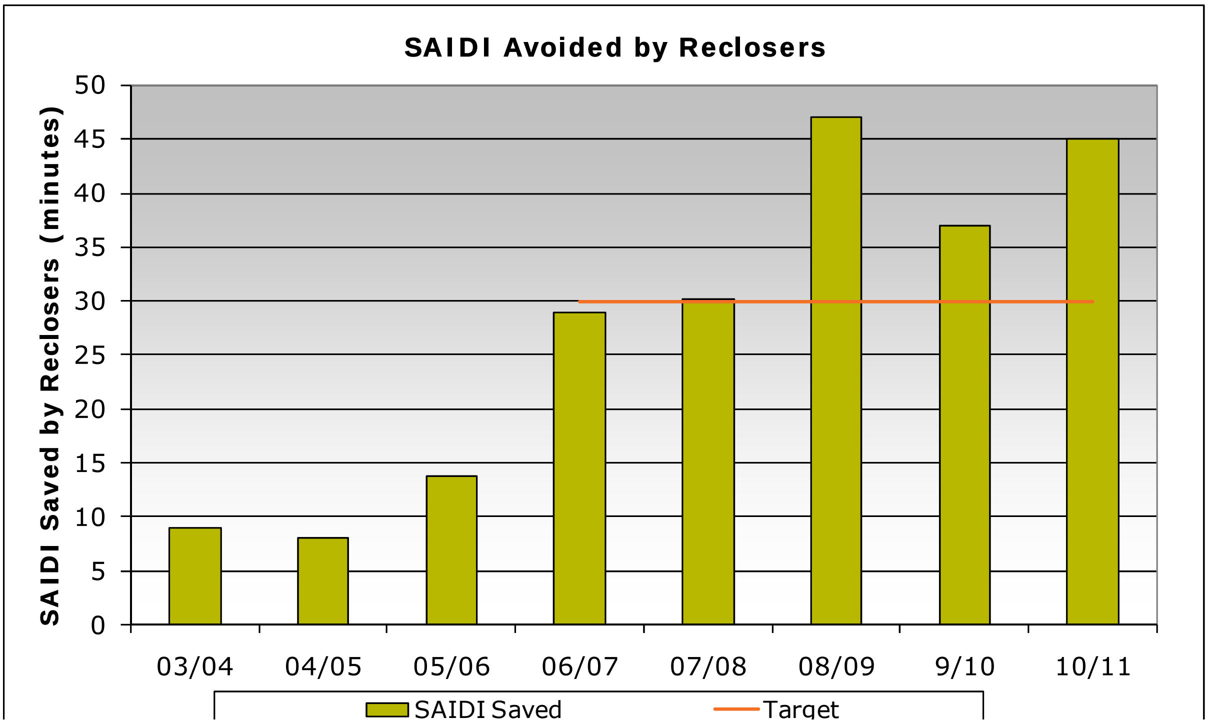

Figure 4-14 : SAIDI avoided by reclosers

4.1.7 Justification of Consumer Oriented Performance Targets

Supply reliability and response targets are normally established by taking into account customer needs on a qualitative basis, due to the complexity and informational requirements of quantifying customer requirements, and relating them to network performance.

As indicated by customer surveys, at present there is no evidence from the Vector customer base to support heightened (or reduced) levels of supply reliability, especially where these would involve increased line charges. In the absence of other drivers or incentives, Vector's quality targets therefore coincide with the regulatory quality targets, which are also based on historical performance levels.

4.1.7.1 Vector Promise and Charter Payments

If Vector fails to meet these service commitment targets, compensation schemes exist to acknowledge the inconvenience to the customer. As per the service targets as summarised in Table 4-2, these compensation schemes are specific to the regional customer/retailer models.

The Southern region scheme is known as the "Vector Promise", under which a payment of $50 for residential customers and $200 for commercial customers (excluding large commercial customers) may be claimed by the customer on Vector's failure to achieve target.

The Northern region scheme is the "Charter Payment" system, under which Vector makes a payment of $40 for residential customers and $100 for commercial customers proactively to the retailer.

Vector takes this commitment seriously and compensation payments of almost $2 million have been paid in the last seven years as shown in Figure 4-15 below.

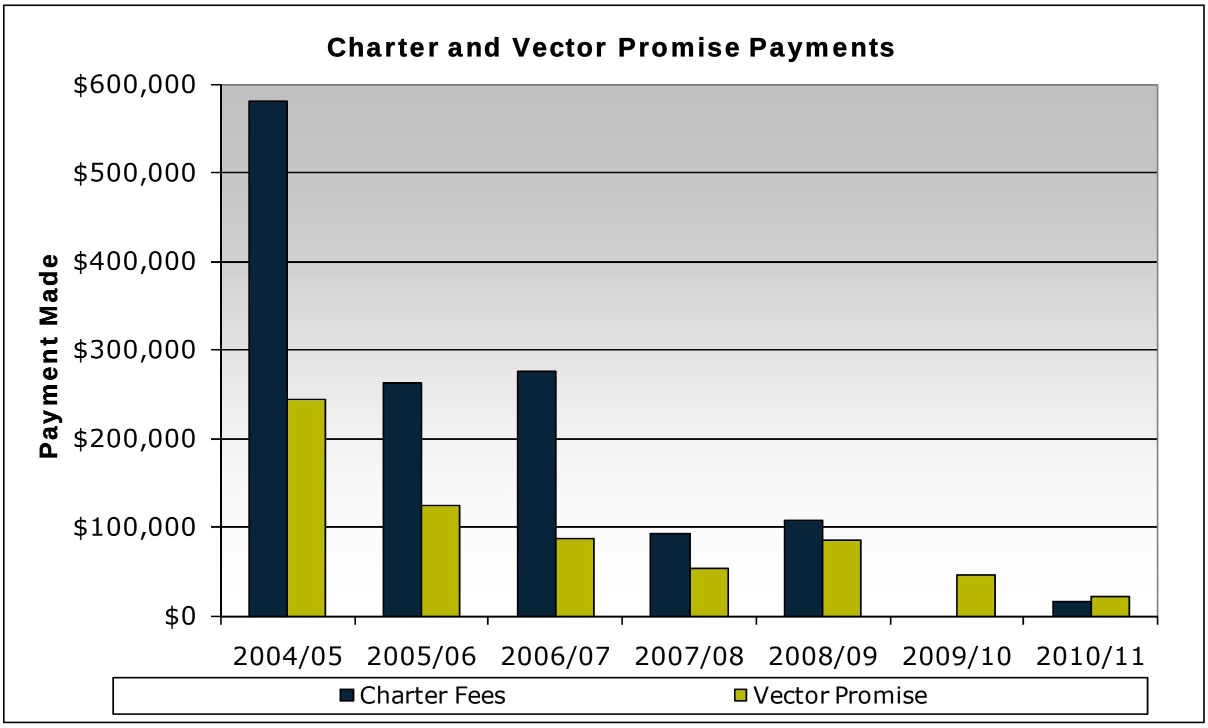

Figure 4-15 : Historic Service Commitment Compensation Payments

4.1.7.2 Enhancing our Performance for the Future

Supply reliability performance improvement programmes continue to address the following:

- Reducing the number of interruptions experienced by customers;
- Reducing the time customers are without electricity (including through expanding the use of remote monitoring and control to allow faster response and restoration times);
- Improving delivered supply quality (including introducing new technologies to reduce the impact of momentary voltage sags);
- Upgrading assets in the worst performing areas;
- Targeting major cause contributors to reduce the frequency of customer interruptions;
- Minimising the use of planned shutdowns by continuing to work live line where possible, and increase the use of generators to avoid outages; and
- Improvements in network and asset management information and related IT systems.

4.1.8 Process for Recording Network Outage Information

Operational responsibility of Vector's sub-transmission and distribution networks rests with the network control team. Resolution of planned and unplanned events is under direction of the duty control room engineer.

All planned and unplanned records are captured by the network control engineer both in hard copy (electricity fault switching log) and electronically (the HVEvents database). The HVEvents database records such fault details as outage type, system level, location, cause, customers without supply and restoration times. To ensure accuracy, each outage record is peer-reviewed by the network control team and/or the network performance analyst. In addition, Vector's external auditors (KPMG), review this process annually and conduct sample checks for accuracy.

At year-end the period's average network customer base is calculated using the Gentrack billing and revenue system (averaging customers at the start and end of the year). The following reliability metrics are extracted from the HVEvents database for disclosure reporting:

- Interruption frequency by class;
- Interruption frequency by voltage level;
- Interruption duration by class; and
- SAIDI/SAIFI/CAIDI (calculated using average customer count).

Figure 4-16 shows the process for recording outage information and the process for auditing the quality of the recorded data.

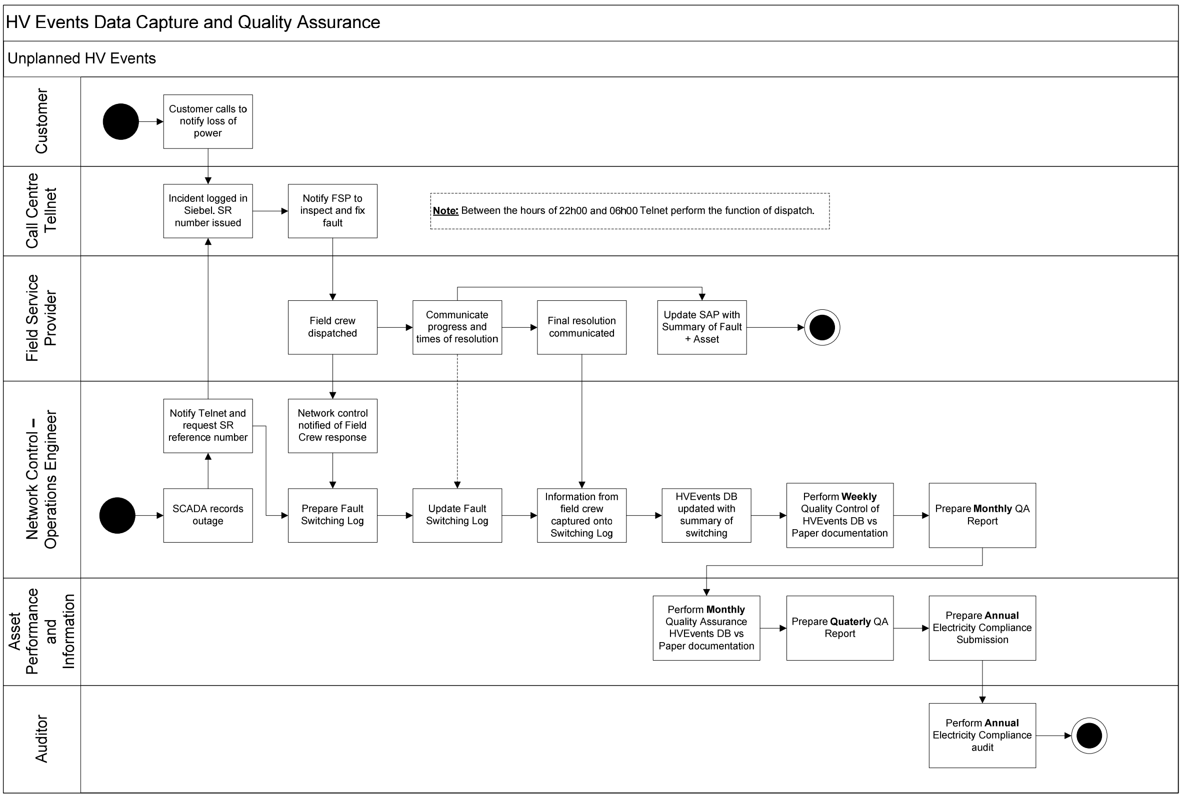

Figure 4-16 : Process for capture and QA of outage information

4.2 Network Performance

4.2.1 Failure Rate

Asset failure (or fault) rate is a direct measure of the number of recordable events per system length, and provides a tool for understanding trends and anomalies in underlying network performance, and is defined as:

> *"The failure rate per 100 km of network length associated with MV distribution and sub-transmission faults."*

The failure rate in 1997/98 was just over 12.5 faults per 100km, increasing to 18.5 faults per 100km for the 2008/09 year. To counter further increases various initiatives have been launched, including cable upgrades and a coordinated "Dig Safe" programme with other utilities and local authorities. It should be noted that the performance in the period 2005 to 2009 were significantly influenced by extreme weather events.

The last two years' solid performance reflects a combination of the period's benign weather and Vector's initiatives taking effect.

Figure 4-17 below shows the Vector network equipment failure rate from 1994/95 through to 2010/11. The figures before the merger of UnitedNetworks and Vector (1994/95 to 2002/03) were the combined results of UnitedNetworks and Mercury Energy[4]/Vector.

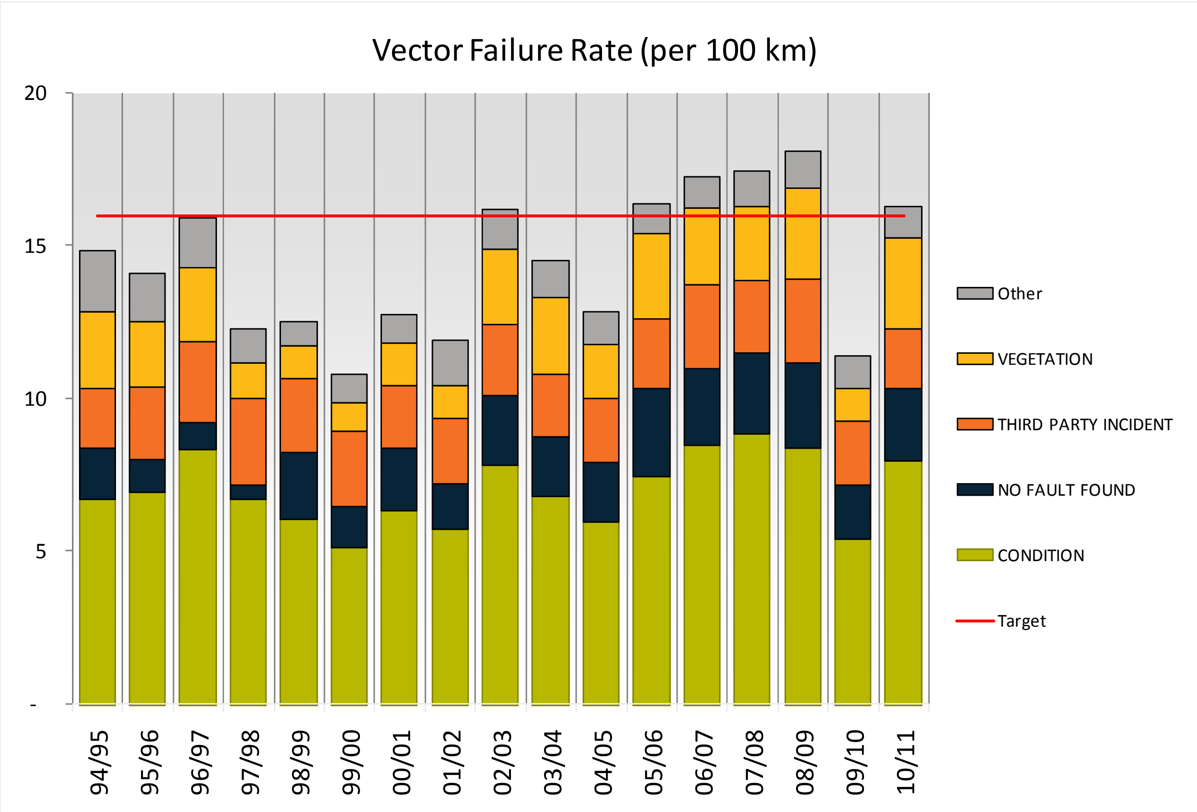

Figure 4-17 : Vector equipment failure rate

Vector has investigated its line failure rate, which appears to lie at the higher end of the New Zealand average. Beyond a few obvious contributing factors (such as weather), to date no single compelling cause could be identified. The statistic appears counter-intuitive to Vector's overall reliability performance, which is significantly better than the New Zealand average.

Underlying this anomaly could be non-technical factors such as measurement and reporting accuracy, or the measurement methodology. Work continues to determine whether there are technical root causes for the fault rate and, should this prove to be the case, a strategy will be developed to address any underlying asset performance issues.

[4] Pre-sale of Vector's retail business and the brand name Mercury Energy.

Vector's Network failure rate target is:

Vector Target

Disclosure Year	10/11	11/12	12/13	13/14	14/15	+ 5 Years
Failure Rate (per 100 km)	16	16	16	16	16	16

It should be noted that not all asset failures lead to supply interruptions. Asset failure rate provides a measurement of how the network performs. Reliability indices such as SAIDI and SAIFI, on the other hand, provide an indication of how often a customer loses supply and how long would it take to restore supply when an interruption occurs.

4.2.1.1 Causes of Network Failures

In general, the reasons for network failures are broadly similar to the reasons for interruptions to customers' supply, as illustrated in Figure 4-18.

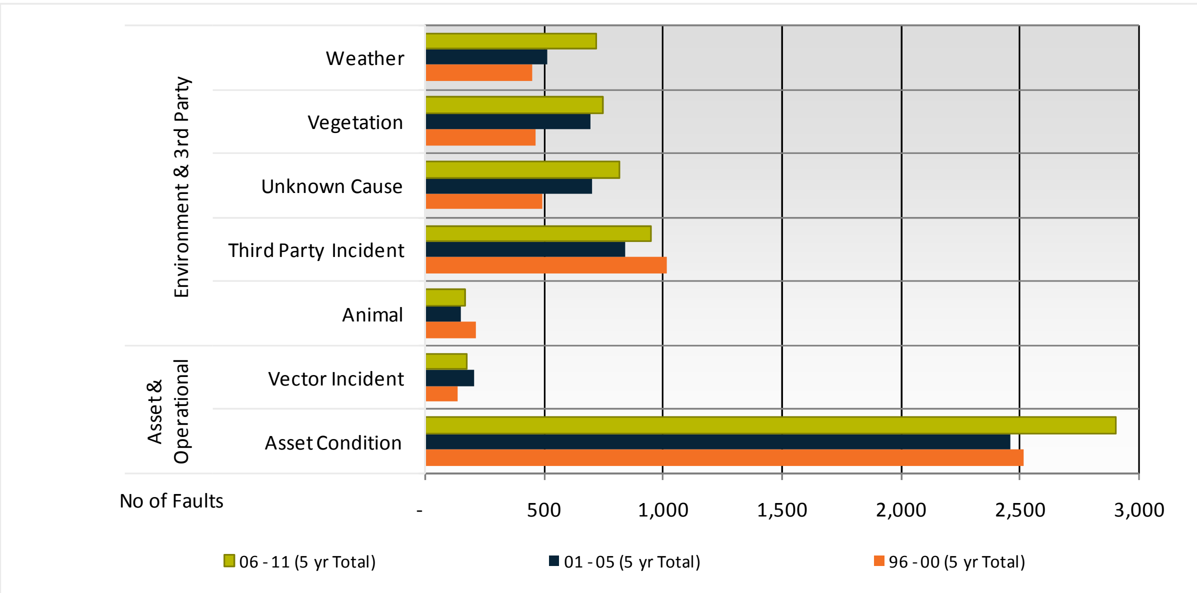

Figure 4-18 : Reasons for network failures

This shows the number of asset failures in each five year period, not the annualised failure rate normalised to the prevailing network length as per the definition.

Three specific causes of network failures are considered in more detail below:

(1) Faults due to Vector incidents – These are the result of mistakes such as switching errors, accidental contact, dig-ins and accidental protection tripping, whether by Vector or Vector's FSPs or other contracting partners.

Figure 4-19 below shows that these incidents remain relatively static at around 35 events per year, corresponding to a failure rate of 0.4/100km.

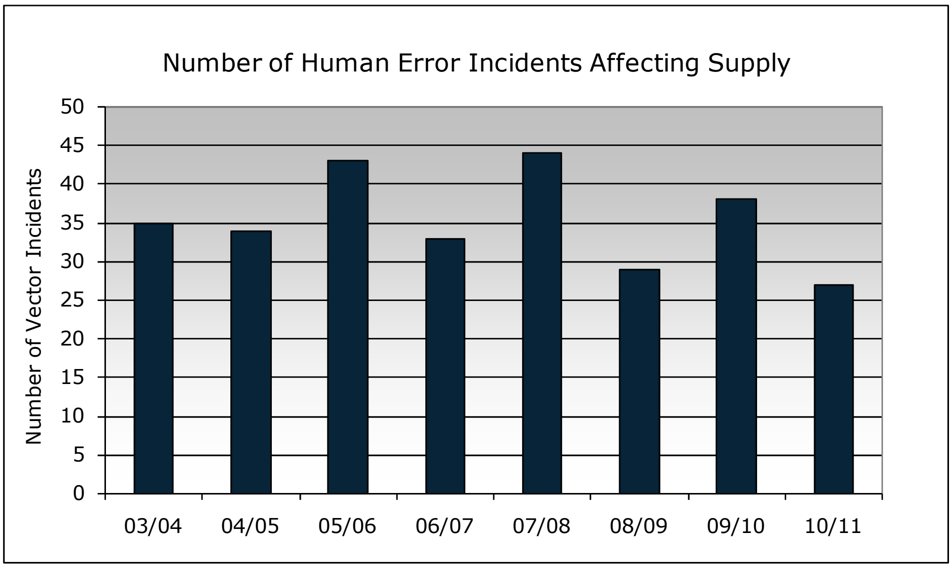

Figure 4-19 : Number of human error incidents affecting supply

This represents approximately 2% of the total failure rate (and a similar proportion of SAIDI and SAIFI). Nevertheless, as these events are within Vector's control, all such incidents are investigated thoroughly, especially those with health and safety, or environmental implications. Permanent corrective actions are implemented where applicable;

(2) Reported Protection Malfunctions - Vector tracks failures where protection either fails or operates in a manner inconsistent with the Control Room Engineer's expectation. In most instances, the apparent protection failure is not the cause of the outage but is a complicating factor. Figure 4-20 shows annual protection malfunction counts and their proportion of total faults.

Each instance where protection is thought to have malfunctioned is flagged to Vector's Protection and Control team for investigation. Corrective actions (including operator training) are implemented to avoid repeat incidents, where applicable.

Historically, the rate of protection malfunctions was considered high. This was partly as a result of the complex, meshed nature of the Northern network and the associated need for sophisticated protection schemes. To address this, Vector embarked on a systematic programme to upgrade the protection schemes for the Northern network to computer-based systems, conforming to best industry practice. The impact of this is starting to show in the improving trend shown in Figure 4-20 below.

Failure rates by type of equipment are being developed and will be progressively introduced now that the ALIS project has been is implemented and exhaustive fault data is being collected (refer to Section 7). This will also allow the monitoring and analysis of defect rates.

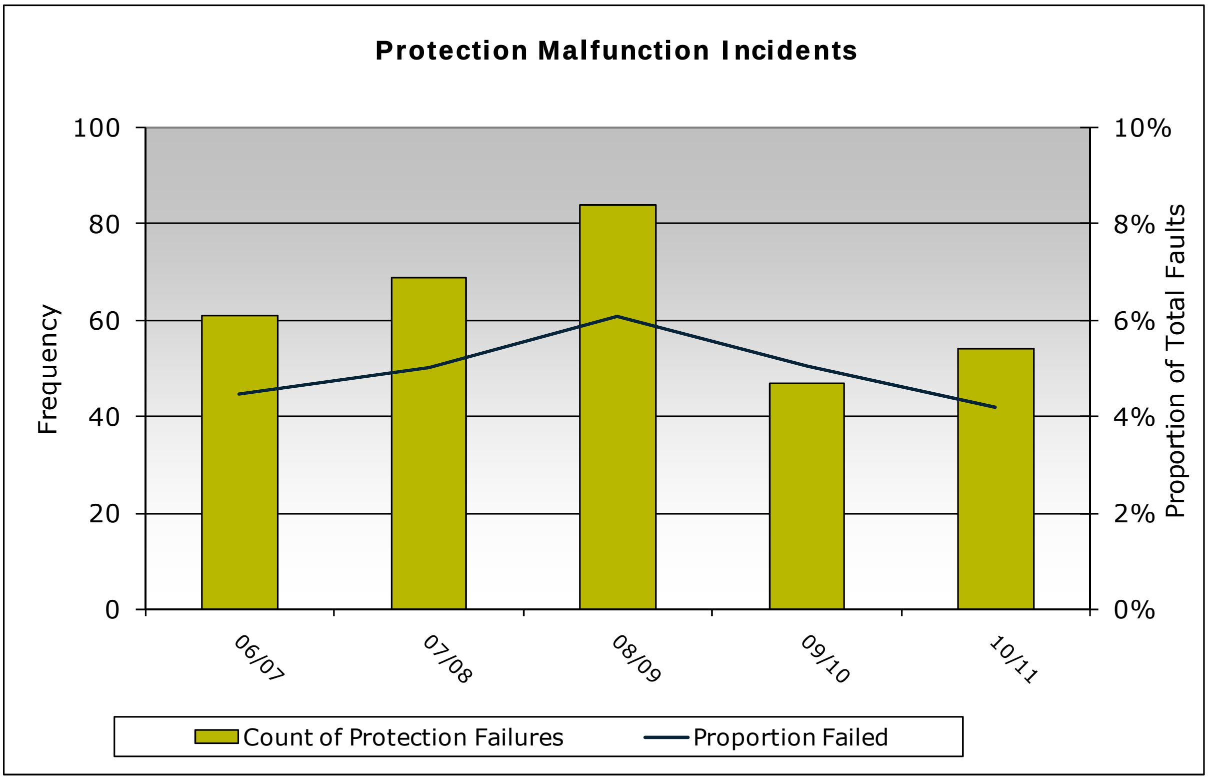

Figure 4-20 : Protection malfunction incidents

(3) Failures due to unknown causes (see Figure 4-21) – these occur when circuit protection devices operate to initiate interruption to customers but, after fault finding and line patrol, no cause can be isolated or observed and the circuit is re-energised. The interruption cause is recorded as unknown although there may be a suspected cause, such as vegetation brushing overhead lines or conductors clashing in stormy weather.

The 2010/11 value has returned to the historical trend following a dip in 2009/10 regulation year shows a decline in both the count of unknown faults and their proportion of total faults. This decrease is most likely a result of benign weather conditions (stormy conditions result in higher numbers of unknown faults) and does not necessarily demonstrate a declining trend.

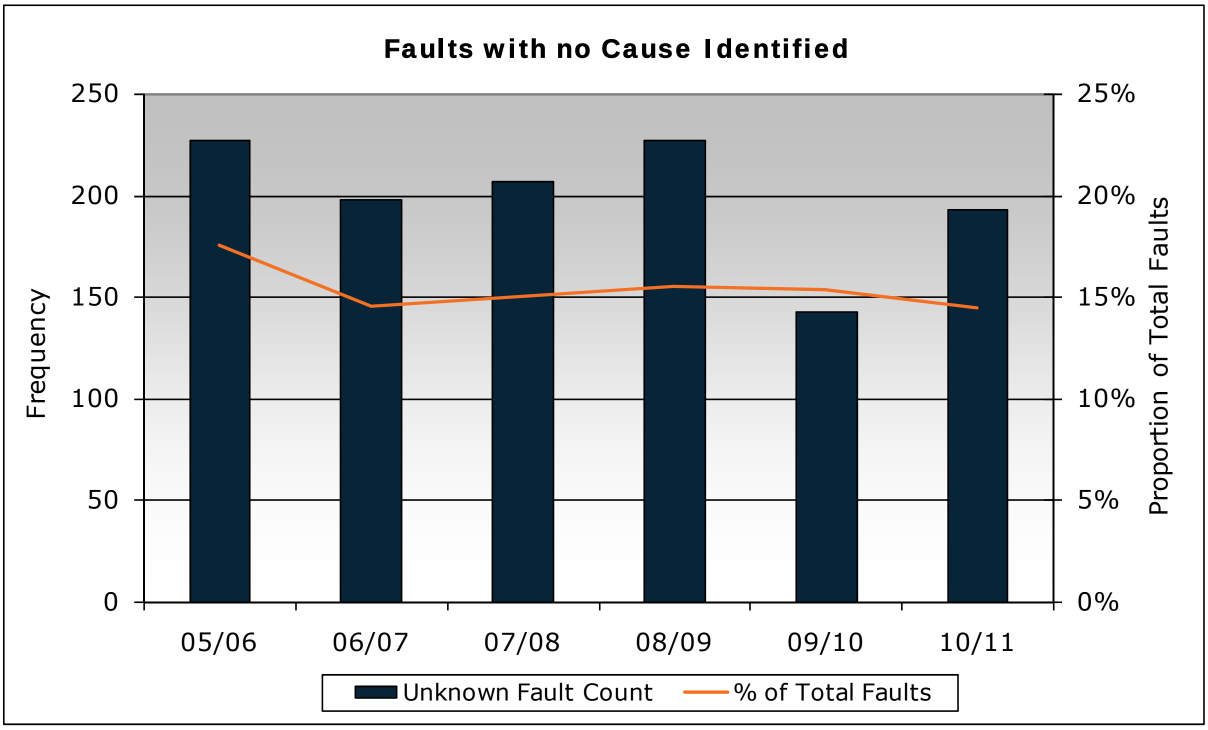

Figure 4-21 : Faults with no cause identified

4.2.1.2 Reporting and Analysis of Network Faults

Vector records interruptions to its HV and medium voltage (MV) network in a fault reporting system, HVEvents (described in detail in Section 7). This system enables analysis of trends and anomalies in the performance of the network down to the distribution transformer level. In Figure 4-22 to Figure 4-24 examples of extracts from HVEvents are illustrated.

In this way, supply reliability performance improvement programmes can be prioritised to address the more significant issues, focussing on those that are theoretically preventable, as described above.

From: 01 Oct 2011 To: 31 Oct 2011

Region: Northern Event Type: Unplanned

1 of 2 100% Find | Next

Monthly Outages

Vector

Report Description: Monthly Outages Report

Report Parameters: From: 01/10/2011 To: 31/10/2011

Region: Northern

Event Type: Unplanned

KEY:	Cust Affec	Vector SAIDI	Max Time Off (mins)
	0	0	0
	1-200	0-0.1	0-120
	200-500	0.1-0.2	120-150
	500-1000	0.2-0.5	150-180
	>1000	>0.5	>180

Event ID	Date	Time	Region	System Level	Location	Substation	Main Reason	Sub Reason	Event Cust Affec	Vector SAIDI	Event Max Time Off
202323	01/10/2011	06:08	Northern	Feeder	26WAIW	Orewa	EQUIPMENT - OH	INSULATOR	642	0.517	1257
202330	02/10/2011	11:56	Northern	Feeder	40FOST	Waimauku	NO FAULT FOUND	PATROLLED	171	0.024	75
202331	02/10/2011	13:48	Northern	Subtrans	(56) 230-783-236	East Coast Rd	EQUIPMENT - OH	INSULATOR	604	0.163	304
202336	02/10/2011	20:32	Northern	Feeder	18WOOD	Laingholm	EQUIPMENT - OH	INSULATOR	1,072	0.341	575
202343	03/10/2011	08:18	Northern	Feeder	40FOST	Waimauku	EQUIPMENT - OH	SWITCH	113	0.054	255
202345	03/10/2011	07:00	Northern	Feeder	27HUAP	Riverhead	EQUIPMENT - OH	TRANSFORMER	4	0.004	475
202351	03/10/2011	12:44	Northern	Feeder	01ARMS	Bush Rd	EQUIPMENT - OH	CONNECTOR	2	0.001	326

Figure 4-22 : Example report from HVEvents showing unplanned events in the Northern region during October 2011

Daily HVEvents Summary

Ve

Report Description: Summary of the HV Events for the specified date range

Report Parameters: From: 09/11/2011

To: 09/11/2011

KEY:	Cust Affec
	0
	1-200
	200-500
	500-1000
	1000+

Unplanned Events

Event ID	Event Start Date Time	Region	System Level	Location	Location code	Main Reason	Sub Reason	Customer Affected	Vector SAIDI	Max Time Off	Faults Last 12 Months
202551	09/11/2011 11:31:00	Auckland	Feeder	Wiri	WIRI 23	NO FAULT FOUND	PATROLLED	38	0.007	103	1
202549	09/11/2011 09:57:00	Northern	Feeder	Keeling Rd	55UTIL	EQUIPMENT - OH	SWITCH	886	0.002	1	2
202550	09/11/2011 07:19:00	Auckland	Feeder	Mangere East	MEAS 15	NO FAULT FOUND	PATROLLED	3	0.001	156	1
202547	09/11/2011 05:30:00	Auckland	Feeder	Hobson	HOBS 16	EQUIPMENT - UG	TRANSFORMER	1	0.001	340	2

Planned Events

Event ID	Event Start Date Time	Region	System Level	Location	Location code	Main Reason	Sub Reason	Customer Affected	Vector SAIDI	Max Time Off	Event Reviewed
202548	09/11/2011 09:33:00	Northern	Feeder	Wairau Valley	42BECR	MAINT/REPLM'T - U/G PLANNED	SWITCH UNIT	89	0.037	223	No
202552	09/11/2011 06:10:00	Auckland	Feeder	Pakuranga	PAKU 6	MAINT/REPLM'T - MINISUB PLANNED	SWITCHGEAR	1	0.000	15	No

Recloser Events

There were no Recloser Events for this date range

Figure 4-23 : Example of daily fault report from HVEvents reporting system

UNPLANNED HV EVENT DETAILS	
Event ID	202336
Date	02/10/2011 20:32 p.m.
Region	Northern
System Level	Feeder
Substation	Laingholm
Location Code	18WOOD
Location Name	WOODLANDS
Main Reason	EQUIPMENT - OH
Sub Reason	INSULATOR
Operational Details	
Contractor	Electrix
Operations Engineer	Paul Hosking
Field Person	John Rossiter
Comments	Pole caught fire and needed repair around the double 11 cct and the 33cct
Service Request Nr	1-310993734
Defect Number	
Location Details	
Street Address	394 HUIA ROAD
Suburb	LAINGHOLM
Closest Asset 1	Pole = 66851
Closest Asset 2	
Fault Trip Details	
Fault Trips	1
Trip Device	Scada CB
Device Nr	18WOOD
Protection Operation	OK
Function	Earth Fault
Protection Comments	
FPI Operation	OK
FPI Comments	

Performance Measure for Event			
Customer Mins	181,767	Vector SAIDI	0.3406
Customers Affec	1,072	Vector SAIFI	0.0020
Max Time Off for	575	Customers over	275

Figure 4-24 : Example of detailed information captured for an individual event in HVEvents

4.2.1.3 Enhancing our Performance for the Future

Ongoing initiatives directed at reducing network failures include the following:

- Making improvements in Vector's management of asset lifecycle information (as described in Section 7);
- Development of network monitoring and control, and related IT systems;
- Upgrading assets in the worst performing areas;
- Evaluating technological developments in network monitoring, protection and control systems and in primary and secondary plant and equipment and implementing where appropriate; and
- Targeting major cause contributors to reduce the frequency of failures.

4.2.2 Asset Utilisation

Asset utilisation in a distribution network is defined as the ratio between the peak demand conveyed by an asset (such as a feeder or a zone substation) and the capacity of the asset. It is a measure of what an asset is actually delivering against what it is capable of delivering. At Vector, utilisation of an asset is measured as the single highest peak demand (after removing any temporary loading due to operational activities) divided by its installed capacity. In the case of substation utilisation, the maximum continuous ratings (MCR) of transformers installed are used. In the case of feeders, the cyclic ratings of the cables or overhead lines are used. The following graphs (Figure 4-25, Figure 4-26, Figure 4-27 and Figure 4-28) show the utilisation of zone substation and feeder in the Southern and Northern regions.

These graphs aim at showing the utilisation of the whole zone substation and feeder population across the two regions to give a view of the utilisation profile of the two regional networks. The utilisation profiles for the past three years (2009, 2010 and 2011) are plotted. Vector has chosen to monitor asset utilisation using a profile approach instead of a single average or median figure as this gives a more holistic picture of the network.

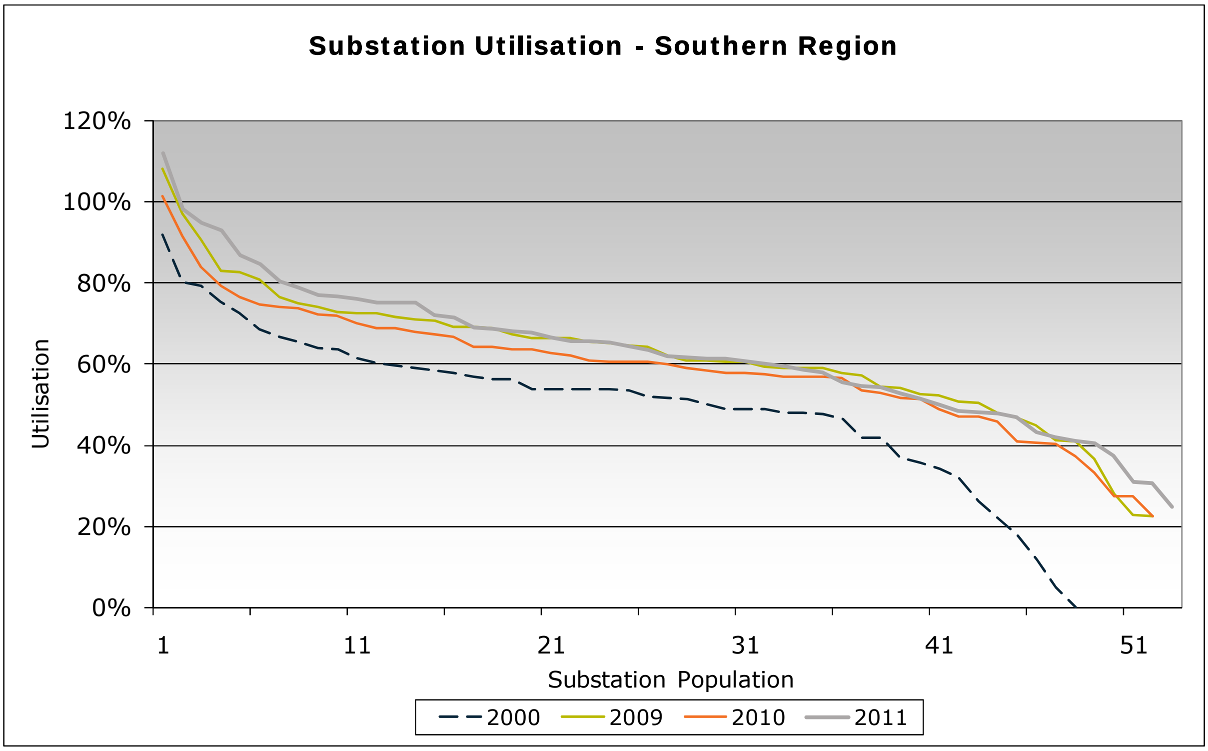

Figure 4-25 : Substation utilisation - Southern region

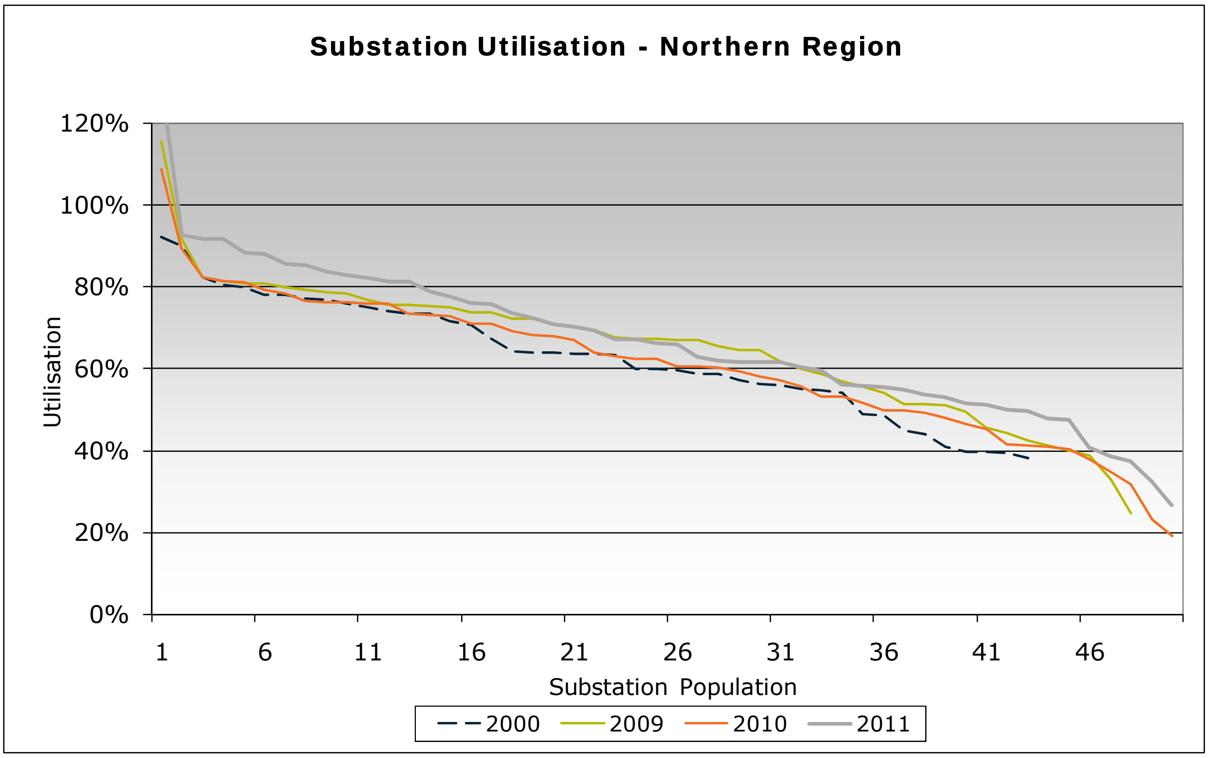

Figure 4-26 : Substation utilisation - Northern region

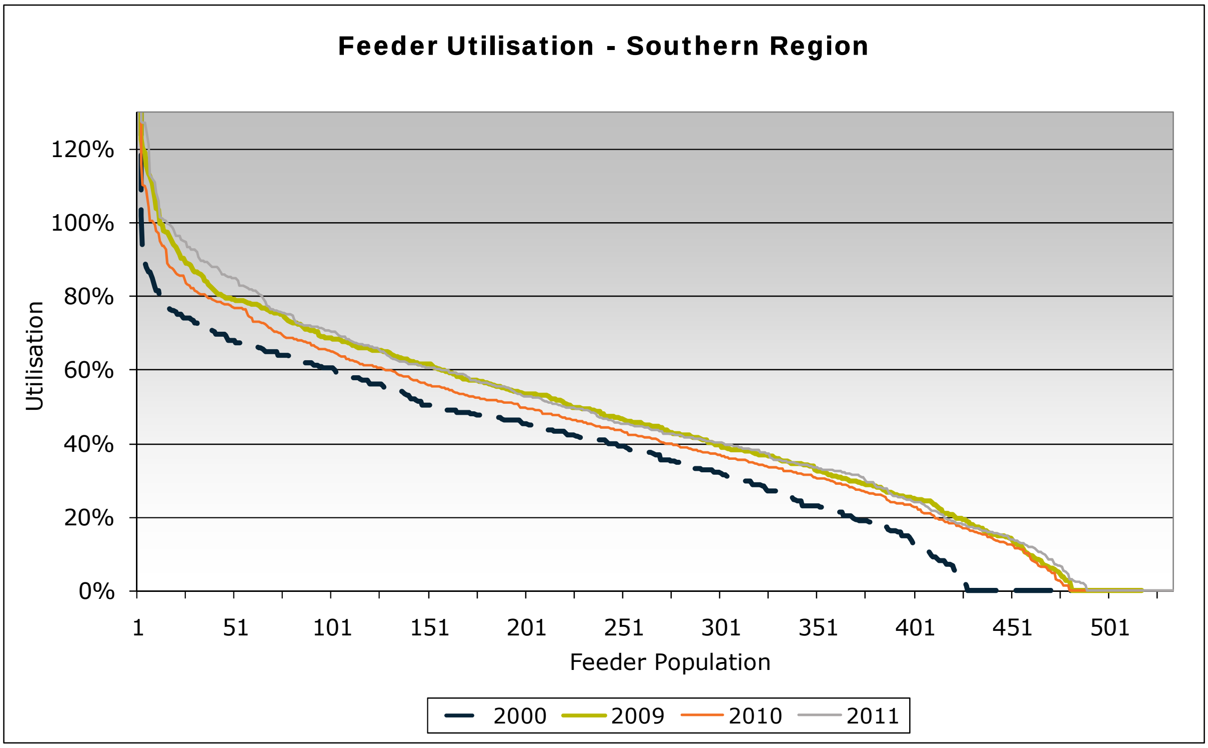

Figure 4-27 : Feeder utilisation - Southern region

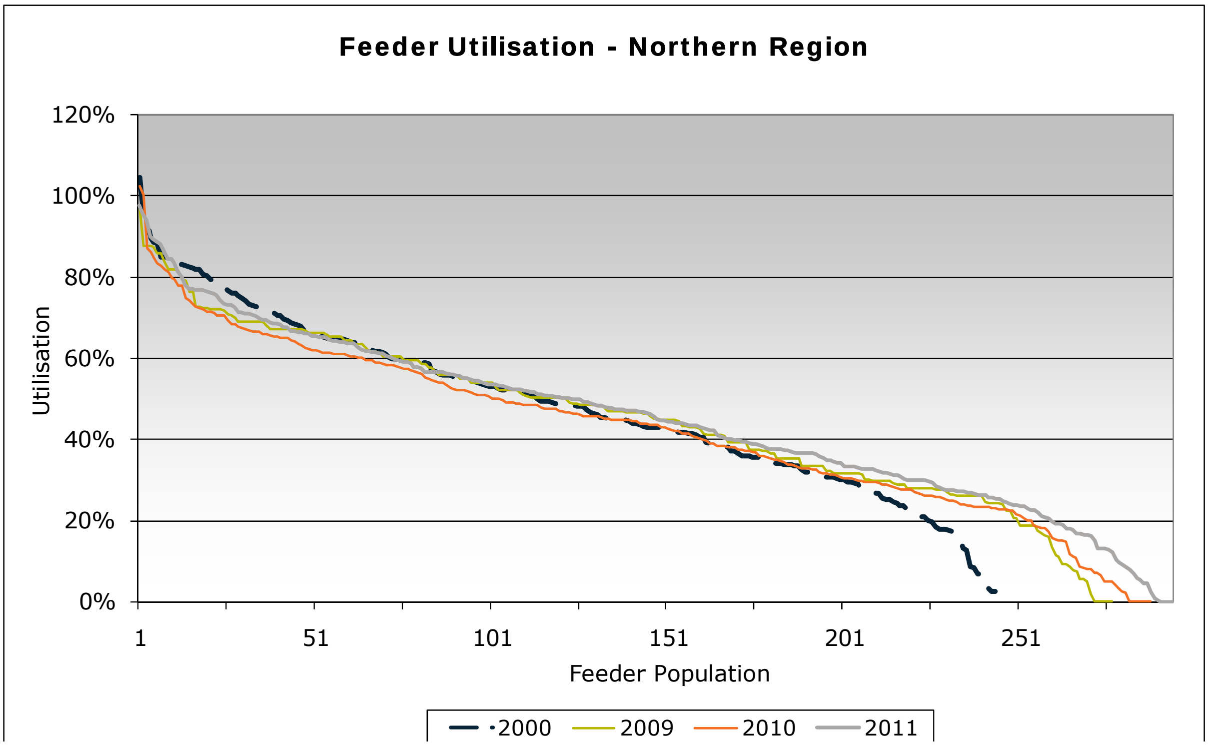

Figure 4-28 : Feeder utilisation - Northern region

The graphs demonstrate that within a network the utilisation of the assets are not uniform. Some substations (and feeders) are better utilised than others. While the ideal situation would be to have the utilisation profile as a flat horizontal line close to the limit of acceptable risk, in practice, geographical and physical constraints and economic factors often preclude network planners from achieving such a goal. The utilisation profile, however, provides the planner an indication of areas where assets are under or over-utilised (a security risk), so appropriate actions (such as load transfer, demand side management, and network reinforcements) can be taken.

The year-on-year utilisation profiles may move up or down due to the effect of weather on peak demands, but as a trend the utilisation of feeders and substations has increased over the years observed. For example, the median utilisation of substations in the Southern region has increased from 54% in 2000 to 63% in 2010. This represents a six percentage point increase (or a 17% increase in utilisation over the past eight years). As the substation capacity used in utilisation calculation is the MCR, utilisation above 100% is acceptable subject to the cyclical nature of the load.

Note that at the lower end of the graph, the results are not entirely reliable due to loss of data in the Plant Information (PI) system collecting and storing the load information. This is currently being addressed by upgrading PI to provide instant notification of missing or non-valid data.

The graphs also show marked difference in utilisation between the two regions. This is largely as a result of legacy issues – the architecture of the networks largely determines the utilisation.

For example, the Northern region has a significantly higher substation utilisation than the Southern region. This reflects the historical differences in sub-transmission design philosophy of the two regions before the Vector/UnitedNetworks merger and the manner in which supply quality and risk is managed.

The apparent higher risk to the Northern region sub-transmission system, as reflected through higher utilisation, is compensated for by the extensive interconnection at distribution level, which is not available on the Southern network. (This is not something that can be identified by utilisation graphs alone.) Caution must therefore be exercised in making simple judgements based on utilisation figures. More than a single measure is required to form a holistic view on the performance of a complex business such as an electricity distribution network.

While Vector is broadly striving to improve utilisation levels, currently no fixed target for utilisation has been set. A fixed target is not realistic given the significant difference in geographical and network topological characteristics, consumption patterns and customer categories served. Instead Vector has chosen to regularly monitor asset utilisation and use the information to focus on assessment of the risks faced by certain parts of the network.

4.2.3 Network Security

"Security" is defined as the ability to supply network load following a fault (or more than one fault) and can be categorised deterministically or probabilistically.

Deterministic security operates in discrete levels, typically defined as having sufficient capacity to supply customers following a single fault ("N-1") or two faults ("N-2").

Probabilistic security takes into account load curves and the likelihood of faults as well, allowing for intermediate security levels between the discrete levels set by deterministic practices.

For Vector's network a combination of deterministic and probabilistic criteria are used. This is described in detail in Section 5.3.

The term "capacity" is used to define the rating of assets caused by physical limitations of the equipment and is generally determined by heating effects.

Three most common ratings are:

- Maximum Continuous Rating (MCR): Equivalent to a constant load applied continuously to the circuit;
- Cyclic rating: Maximum load that can be applied based on the daily cyclic load profile; and
- Emergency rating: Short-term rating (generally two hours) which allows assets to be overloaded for a short period (followed by a cooling period).

Both security and capacity, as means of characterising the network, are very distinct measures from reliability, which is a measure of the ability of the network to supply consumers' requirements as and when required (usually measured in terms of SAIDI/SAIFI), as described in Section 4.1.

As illustrated in Figure 4-29, under normal conditions maximum demand can be delivered. After a network fault has occurred, demand can generally still be met. However, if the fault occurs during peak load times, there may be some interruption, governed by the following design standards:

- Commercial - up to 2% of the time; and
- Residential - up to 5% of the time.

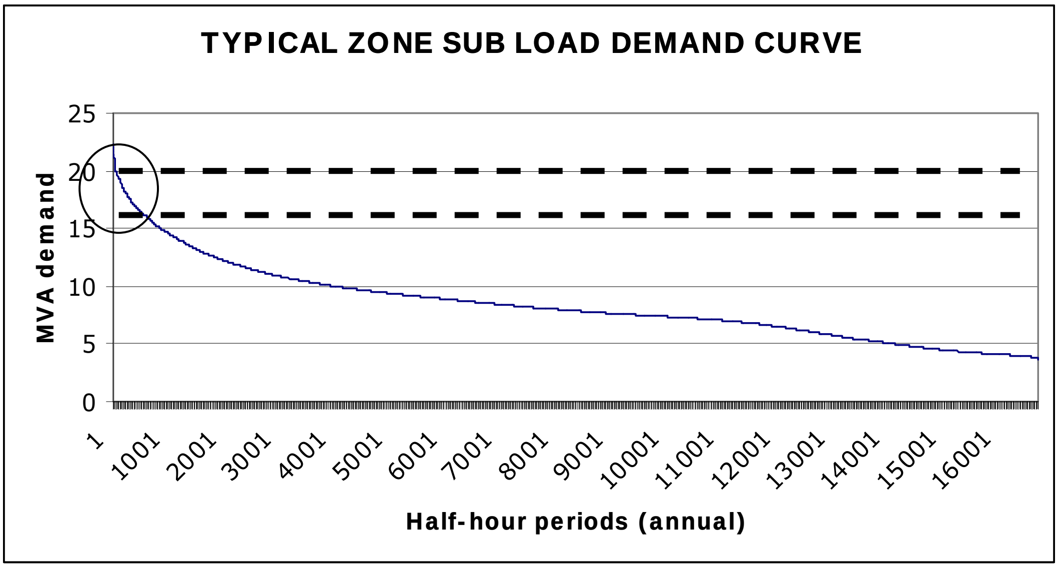

Figure 4-29 : Typical zone sub load demand curve

The upper line indicates normal capacity; the lower line indicates capacity after a single contingency (sub-transmission fault).

Vector's capacity standard is to maintain sufficient network capacity to supply consumers' normal requirements under normal network conditions. In some cases short-term component overloading is accepted, as shown in Figure 4-30 below.

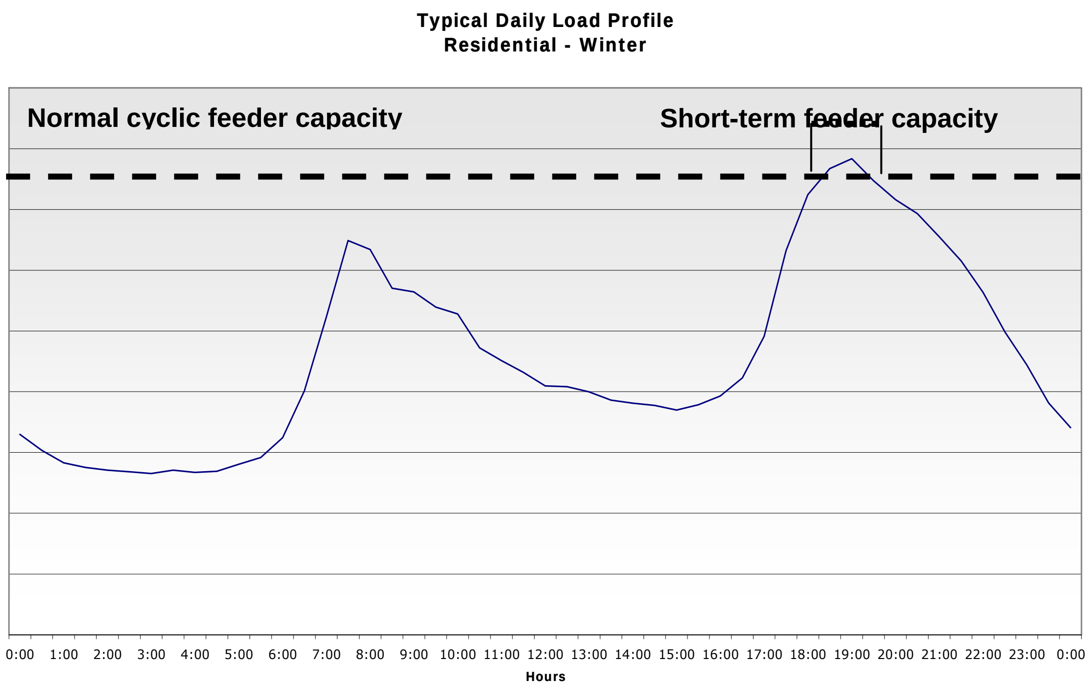

Figure 4-30 : Typical residential (winter) daily load profile

This daily load profile curve illustrates short-term feeder capacity above normal cyclic feeder capacity.

Figure 4-31 below shows the historic number of zone substations operating outside Vector's security criteria during peak demand times.

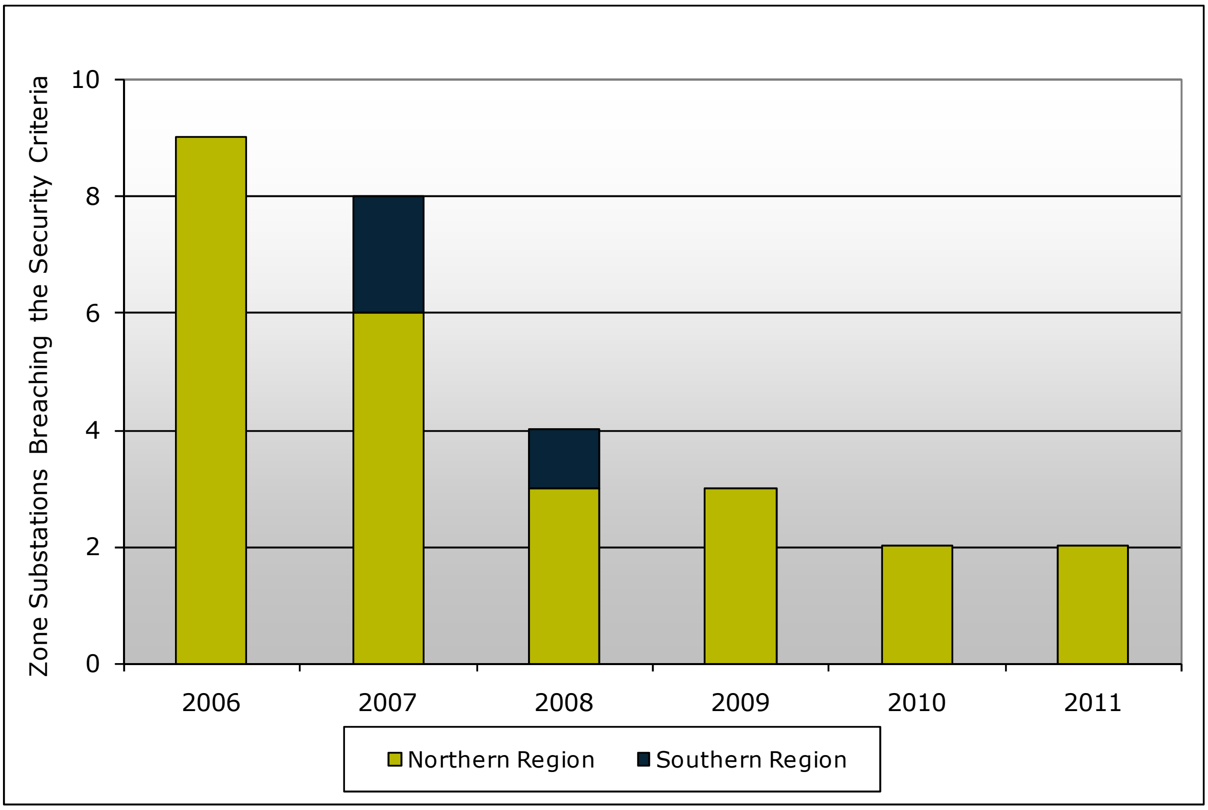

Figure 4-31 : Number of zone substations outside Vector security criteria

The downwards trend demonstrates the effectiveness of Vector's asset investment programme, which over the last 24 months has included three new zone substations and numerous HV feeders. Projects to address the causes of the 2010 and 2011 security breaches are underway through the installation of additional transformers and load transfer via new HV feeders.

4.3 Works Performance Measures

4.3.1 Capital Efficiency

Vector has embarked on a major capital efficiency drive – this is one of the Asset Investment (AI) group's key short and medium-term business goals. Metrics are being established to track progress.

- **Growth Capex Efficiency**

  This metric is designed to track the efficiency of investments made to support growth on the network. The metric needs to take account of investments which are implemented to reduce demand, new technologies (such as distributed generation), as well as smart thinking applied to more traditional solutions.

  The metric will relate to the ratio of annual increase in "effective capacity" to annual capex investment.

  The effective capacity measure will include both actual network capacity and demand side capacity managed e.g. through load control.

- **Asset Integrity Capex Efficiency**

  Replacement of assets due to condition presents a more complex metric, due to the diversity of efficiency measures that may be applied e.g. assets with longer life, lower cost of projects, refurbishment rather than replacement etc.

  The metric will relate to the ratio of annual increase in "asset life value" to annual capex investment.

  The asset life value will be calculated from consideration of asset replacement cost and asset remaining life.

- **Performance Monitors**

  It is important to ensure the drive for capital efficiency does not result in undesirable outcomes. For this reason, the above metrics will be considered in combination with metrics such as SAIFI and asset utilisation percentage.

4.3.2 Capital Works Delivery

Capital work is scheduled physically and financially from the time a project is in proposal stage. Each project is split into a number of stage gates that state delivery expectations from defining the solution, through to final commissioning and close out. These stage gates are monitored monthly and reported to General Manager level. Project Initiators, Engineers and Contract Managers meet on a monthly basis to discuss project progress and issues and roadblocks are quickly escalated.

Once a project is past the solution defining stages and into delivery, the physical and financial forecasts are reviewed and re-set if appropriate. From this time, each part of the project is reviewed in terms of actual delivery against forecast.

To ensure focus remains on delivery of the works programme, our FSPs have profit at risk KPIs associated with delivery against forecast.

Monthly forecasts are compiled for the whole programme of work and circulated to executive level. Actual against forecast is also tracked as part of the executive dashboard metrics.

Each month an exceptions report is submitted to the board, which details the number of active projects with a value greater than $500,000 and their status. This report is designed to provide a no surprises environment, where projects with time or budget issues are highlighted at an early stage.

4.3.3 Field Operations Performance Assessment

A performance incentive scheme has been agreed with Vector's FSPs that is intended to:

- Measure the performance of Vector and the FSPs through the establishment of KPIs and provide appropriate incentives to deliver the required performance by both parties;
- Recognise that the FSPs entitlement to any incentive payment is dependent upon its performance as measured against KPIs, and drive continuous improvement and efficiencies through the annual review of the KPIs and the criteria for those KPIs; and
- Recognise that Vector's performance within key processes is critical to the FSPs' ability to deliver overall results.

Systems have been developed and implemented to provide visibility to both Vector and FSPs on their respective performances against KPIs that employ end-to-end measures.

For each KPI, there is a "meet" and "outstanding" performance incentive level; in some cases there is an additional "not meet" disincentive criterion. KPIs have been established for Vector's FSPs in the following areas, which are described in more detail below:

- Network performance;
- Delivery and quality of works;
- Health, safety, environmental and people;
- Cost management and efficiency; and
- Information quality.

4.3.3.1 Network Performance

The network performance KPI comprises Vector's regulatory SAIDI target (excluding any extreme events that are excluded by the Commerce Commission), and a target around response time to network faults as measured against the various customer service levels.

The targets for onsite response to electricity distribution faults in each customer category are shown in Table 4-5 below.

Customer Category	Target for Onsite Response (minutes)	
	HV Faults	LV Faults
Commercial customers	60	70
Urban residential customers	70	80
Rural customers	80	90

Table 4-5 : Electricity distribution fault targets

4.3.3.2 Delivery and Quality of Works

The KPI for delivery and quality of works provides for assessment of:

- Completion of all reactive, corrective and planned maintenance works to the agreed plans within the agreed timeframes;
- Customer connections from customer initiation within the target periods defined below or to the schedule agreed with the customer;
- Completing Vector initiated network projects within the agreed schedule; and
- Completion of works compliant to industry construction standards, Vector's network standards, national and local codes of practice, resource consents and other conditions without the need for corrective rework.

Vector Target

Customer connections targets:

- For LV connections, provide the quotation back to the customer within five business days of the application being made and complete the installation within ten business days of the customer accepting the quote and all road access approvals, or on date agreed with the customer.
- For larger customer connections, provide proposals to Vector within ten business days once the works scope is agreed with the customer. Vector to package appropriate approvals and forward the offer to the customer within five business days of receiving the proposal.
- Complete the project within the timeframe agreed with the customer.

4.3.3.3 Health, Safety, Environmental and People (for FSPs)

This KPI is defined around minimising lost time injuries, incidents causing injury to a member of the public and environmental incidents resulting in an infringement notice. Implementing employee health initiatives and keeping employee competencies up to date are also included in the measure.

Health and safety management is a core element of Vector's strategic objective of operational excellence, and the target or standard for safety excellence is zero injuries. Vector is continuing to work with its FSPs and contracting partners to identify effective ways to further improve the safety of its electrical networks.

4.3.3.4 Customer Experience

This is rated in terms of keeping appointment times, avoiding EGCC rulings against Vector and maintaining Vector's reputation in the media (taking into account adverse weather that may have affected our ability to perform) and implementing behaviour-based customer service training to the agreed plan.

4.3.3.5 Cost Management and Efficiency

The cost management and efficiency KPI depends on invoicing accurately and on time, and providing accurate information to assist Vector with third party damage claims. There is also a target to deliver annual productivity improvements through developing and implementing initiatives that drive efficiencies in either Vector's or the FSP's business.

4.3.3.6 Information Quality

Finally, the information quality KPI is determined by assessing the accuracy, completeness and timeliness of updates to Vector's information systems, before, during and after the completion of works. Special consideration is given to safety or other significant incidents caused by any network assets not being shown in the correct location in GIS.

Vector Target	
The target times for updating Vector's information systems are:	
Services	3 business days after livening
Subdivisions	2 weeks after livening
Faulted asset repairs	3 business days after livening
Asset replacements	3 business days after replacement
Fault data	1 business day after fault resolution
Zone Substations	2 weeks after livening

4.3.4 Health, Safety and Environment

Vector's policy and overall approach to Health, Safety and Environment (HS&E) is described in Section 8.

In addition to the specific performance measures relating to HS&E that have been put in place with the FSPs, Vector monitors electricity-related public safety incidents and incidents arising from its employees. These incidents are revised monthly to ensure lessons are captured and where appropriate, corrective actions are implemented.

Figure 4-32 below shows the long-term trend in lost time injuries at Vector (including Vector staff, contractors and FSPs) over the last seven years. The figures include both Electricity and Gas network activities.

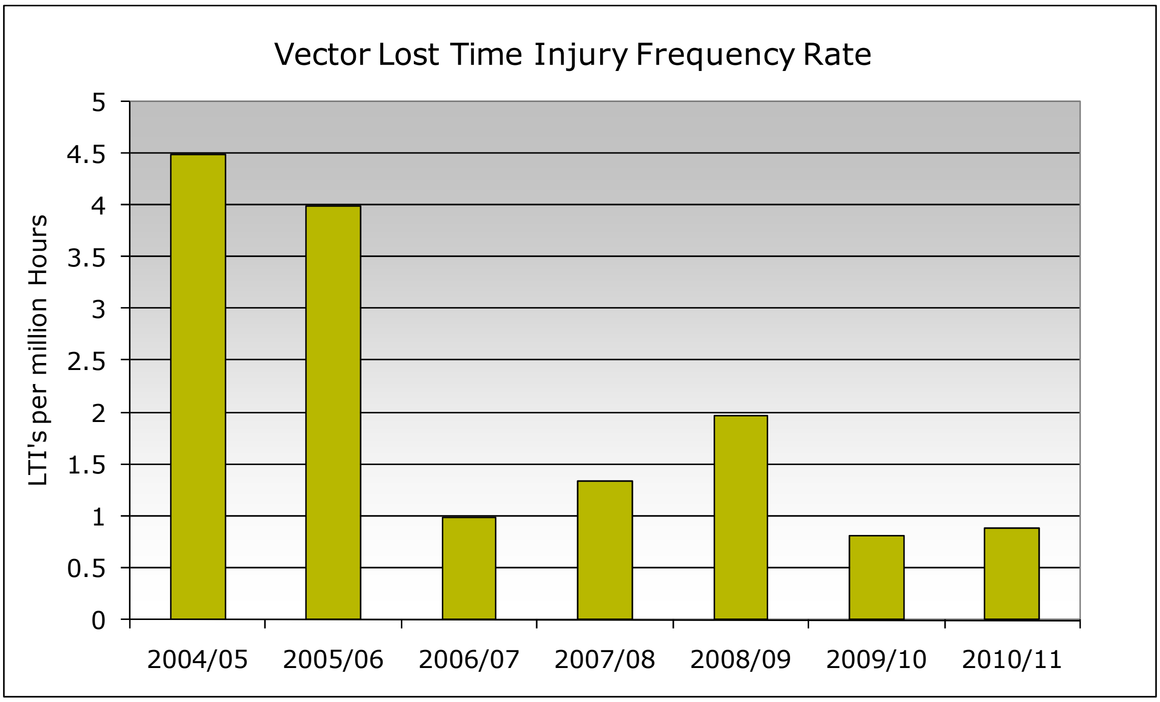

Figure 4-32 : Lost time injuries at Vector (including gas networks)

Note that activities performed in the Wellington Electricity network (divested on 23 July 2008) are also included in this data.

Environmental incidents are also reported, recorded and investigated with any learnings and improvements shared with the FSPs at the safety leadership forum.

Vector Target

Vector's overall health and safety target is to achieve zero lost time injuries.

Vector's environmental target is full compliance with all requirements from local and regional councils to have no prosecutions based on breaches, environmental regulations or requirements.

To progress towards Vector's target of zero injuries in the workplace, Vector is continuing to place a strong focus on ensuring hazards, where ever possible, are eliminated during the design phase, Vector's policies and procedures assist the workforce to deliver the right action at the right time, and to focus on personal behaviours to encourage an individual and team safety culture.

Electricity Asset Management Plan 2012 – 2022

Network Development Planning – Section 5

[Disclosure AMP]

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5. Network Development Planning

Network development relates to growth initiatives which:

- Extend Vector's electricity network to developing areas;
- Increase the network capacity or supply levels of the existing network to cater for load growth or changing consumer demand;
- Provide new customer connections; and
- Address the relocation of existing services when requested by customers, utilities or requiring authorities.[1]

5.1 Background

Auckland is the largest city in New Zealand with a population of 1.4 million people or nearly a third of the total New Zealand population. This population supports 159,000 businesses employing 611,000 staff. The maximum electricity demand in Auckland in 2011 was 1920 MW or 27% of the total demand for New Zealand.

Network Development Planning is the forward-looking activity by which Vector ensures that sufficient electricity network capacity is available to meet customers' present and future requirements safely, efficiently and reliably. While it is predominantly a Vector-driven activity, it is also guided by external strategies such as those documented in the Auckland Plan and the New Zealand Energy Strategy.

The draft Auckland Plan, prepared by the Auckland Council, was made available for consultation in September 2011. The plan forecasts a population increase in Auckland from the current 1.4 million people to upwards of 2 million people over the next 20 years. This expansion is expected to bring with it a corresponding increase in commercial and industrial enterprise growth.

The New Zealand Energy Strategy was released by the Ministry of Economic Development in August 2011. This document outlines a number of key strategies including ensuring a reliable electricity supply, improving energy security by reducing energy demand, reducing greenhouse gas emissions and energy conservation.

The New Zealand Energy Efficiency and Conservation Strategy targets reductions to the commercial and industrial sector energy intensity level with 188,500 homes to be insulated across New Zealand by 2013, and 90% of electricity to be generated from renewable sources by 2025. The policy encourages the use of electric vehicles as a means of reducing dependence on imported oil and as a component of New Zealand's international commitment to reduce carbon emission. This strategy is likely to have a material impact on the manner and level at which electricity will be used in the future by Auckland customers.

5.2 Network Development Processes

Vector's network development process involves the planning of the network, solutions identification, budgeting, solution prioritisation, programme and implementing the planning solutions. This process has been reviewed by a number of independent external specialists in the past few years, with only minor improvements being suggested. These suggestions have been incorporated in our asset management planning.

[1] The main requiring authorities are local authorities, KIWIRAIL and NZTA.

5.2.1 Network Planning Process

Vector's primary objectives in network planning are to identify foreseeable network related security,[2] capacity and power quality (PQ) (voltage levels and distortion) problems and solve in a safe, technically efficient and cost effective manner. These include:

- Power quality, security or capacity issues that may prevent Vector from delivering its target service levels;
- Adequacy of supply to new developments or areas requiring electricity connections; and
- The need to relocate assets, when reasonably required by third parties.

The diagram in Figure 5-1 shows the high level planning and programme implementation processes.

Knowledge of asset capacity and accurate demand forecast enables an assessment of the network's ability to deliver the required level of security and service. Input data comprising past demand information, forecast customer growth, technology trends, demographics, and industry trends are used to produce the demand forecast.

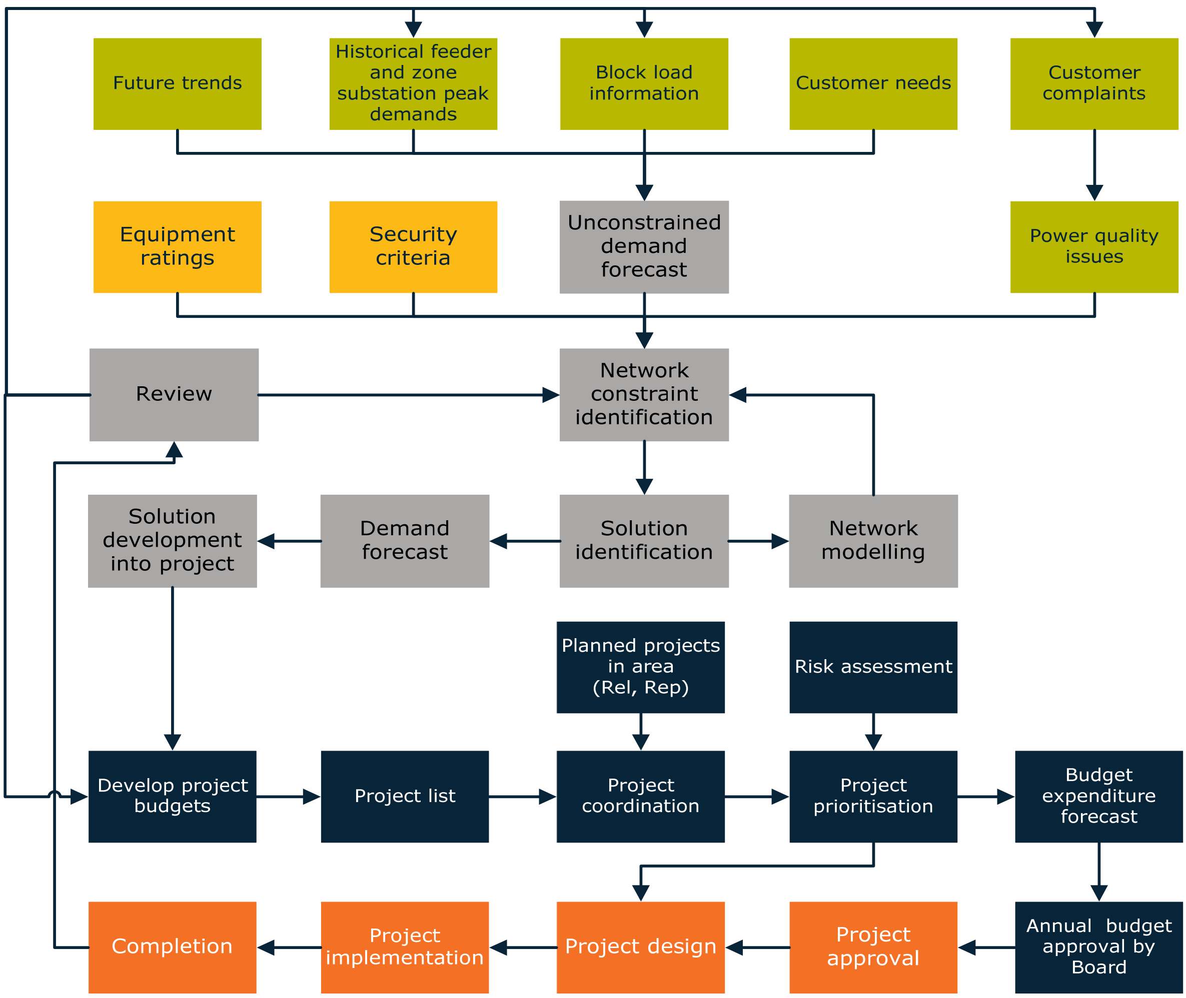

Figure 5-1 : Network development and implementation process

[2] "Security" as used in a planning context means the security of the electricity supply i.e. the likelihood that supply may be lost.

Network capacity and security constraints are addressed with a combination of both asset or non-asset solutions, where the optimal solution may not necessarily result in network augmentation. In evaluating the solutions, the following factors are considered:

- The demand forecast and asset capacity to test against the security criteria to ensure the suitability and adequacy of solutions for security or capacity issues;
- Demand-side options such as load management or customised pricing to reduce demand on the network;
- Automation to expedite load transfer and restoration times;
- Capacitor banks to boost low voltage and provide added capacity in low growth areas;
- Upgrade of specific network assets to relieve capacity constraints eg. upgrade a transformer connection to increase the overall capacity of a substation;
- Using the diversity arising from different load profiles (residential/ industrial/commercial) to reduce overall demand;
- Targeted solutions to satisfy the specific requirements of customers eg. provide a higher security supply across two GXP's to meet customers' security needs;
- Ensuring that, where possible, short-term solutions will meet the long-term needs without asset stranding;
- Considering any operational constraints created by a particular solution eg. a solution may solve a security issue but impose a higher SAIDI penalty under fault conditions;
- Evaluating projects taking into account the time-value of money to ensure the optimal solution is promoted;
- Coordinating the network development programme with other work programmes such as asset replacement to achieve synergy benefits;
- Avoiding reputation damage and consequential financial loss arising from the loss of supply to customers;
- Reviewing major assets due for retirement to ensure their direct replacement meets future network needs; and
- Ensuring recommended solutions are commercially appropriate.

5.2.2 Project Implementation

An effective delivery of the capital works programme, based on an end-to-end delivery process has been established between Vector's Asset Investment (AI) and Service Delivery (SD) groups. The process tracks each project from conceptual design through to site construction and commissioning.

5.3 The Triggers for Network Development Decisions

Network development planning is concerned with ensuring that in the face of changing network requirements, Vector's network performance continues to meet (a) the capacity needs of our customers and (b) prudent safety and reliability requirements as encapsulated in the network policies and standards set by the asset owner. When it is foreseen that any of these criteria are likely to be breached, that would normally constitute grounds for further network development.[3] The network development criteria

[3] Development investments are caused by growth in electricity demand, changing or new customer requirements or the need to relocate services. It is distinct from network integrity investments (mainly

considered when deciding whether a development investment is required are illustrated in Figure 5-2, and summarised below.

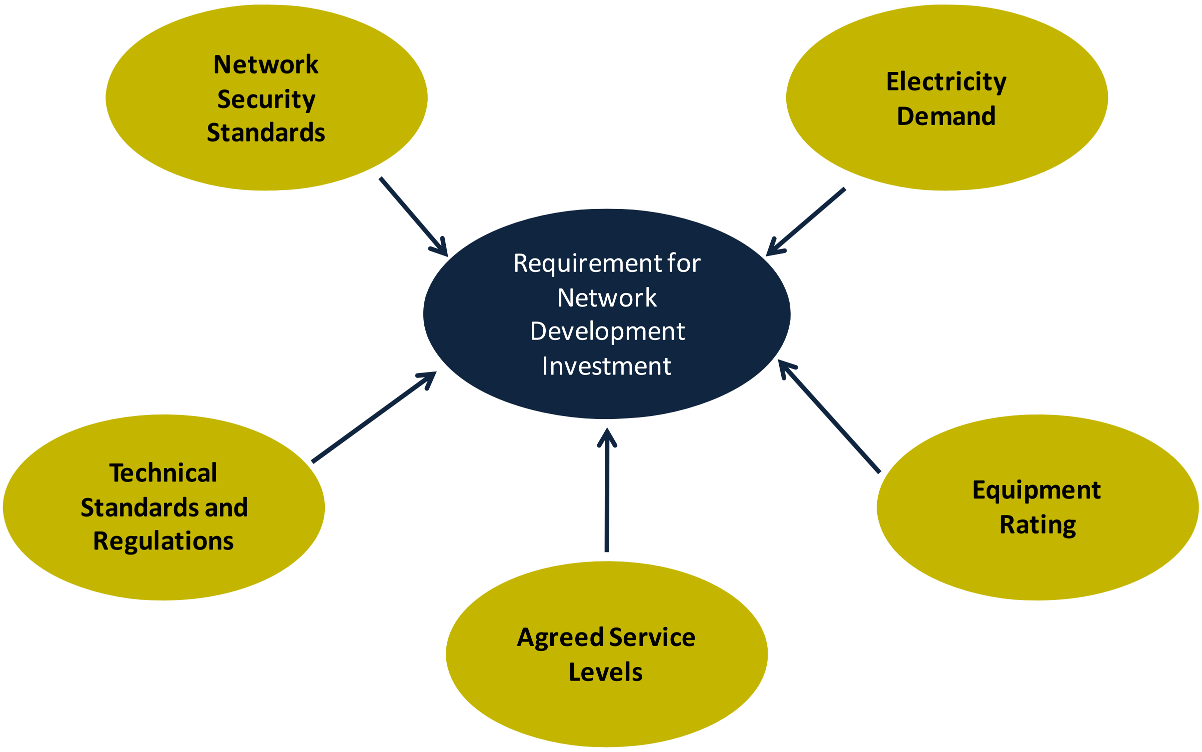

Figure 5-2 : Network development criteria

- **Network security standards:** Vector's security standard specifies the minimum levels of network capacity and levels of asset redundancy required to meet required network reliability levels (see Section 5.3.1);
- **Electricity demand:** This is the maximum level of electricity required by customers. In the longer term, electricity demand usually change over time due to changes in consumer numbers or changes in the electricity consumption levels and patterns of existing customers (driven in turn by factors such as increased or decreased activity, technological changes in connected equipment, societal trends, etc.). In the short term, demand can fluctuate greatly between seasons and years, based on factors such as the weather (temperature is a significant factor), economic activity and energy savings campaigns (see Section 5.3.2);
- **Agreed service levels:** Service levels are established as part of the use of network agreement with retailers and customers. The service levels reflect expected restoration timeframes and fault frequencies (see Section 5.3.5);
- **Equipment rating:** All equipment (transformers, cables, switchgear, etc) has a rated load carrying capacity depending on the demand characteristics and the environment in which the equipment operates. If the ratings are exceeded, assets may malfunction or become unsafe to operate (see Section 5.3.3); and
- **Technical standards and regulations:** These are the regulations and standards that describe the requirements for safely operating the network, as well as the requirements customers must adhere to when connecting to the Vector distribution

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renewal), which are required to ensure that the condition and performance of existing assets remain in accordance with design specifications. The latter type of investments is described in Section 6 of the AMP.

network, and the design standards that Vector applies to its network and the assets used. They include aspects of network design such as subdivision design, acceptable fault levels, voltage levels, power factor, etc to ensure safety while meeting expected service levels (see Section 5.3.4).

Considering these network development criteria in combination, or in some cases individually, could trigger the requirement for network development.[4] Effective network development planning requires potential breaches of the criteria to be identified before they occur, to allow sufficient time for implementation of a development solution to avoid actual breaches. At the same time, it is also inefficient to upgrade networks too far in advance before a potential breach occurs – this leads to under-utilised assets. Accurate demand forecasting and understanding of consumption and other trends is therefore an essential part of network development planning.

Key principles which underlie Vector's network development decision making process include (not in any order of priority):

- Network assets will not present a safety risk to staff, contractors or the public;
- All network assets will be operated within their design rating to ensure they are not damaged by overloading;
- The network is designed to meet statutory requirements including acceptable voltage and power quality levels;
- Customers' reasonable electricity capacity requirements will be met.[5] In addition, the network is designed to include a prudent capacity margin to cater for foreseeable near term load growth;
- Equipment is purchased and installed in accordance with network standards to ensure optimal asset life and performance;
- Varying security standards apply to different areas and customer segments, broadly reflecting customers' price/quality trade-off; and
- Network investment will provide an appropriate commercial return for the business.

In the sections below, the criteria for network development decision making and how these apply to the Vector electricity network are discussed in more detail.

5.3.1 Network Security Standards

Normal deterministic approach to planning accepts an n, n-1[6], etc level of security. This approach ensures there is a clear understanding of the availability and capability of supporting network assets to meet the network demand in the event of a network fault.

Vector has accepted a marginally lower level of security for certain parts of the network, such that supply cannot be maintained at all times following a fault (for a very small proportion of the time, during peak demand periods). The application of this criterion is shown in the security standards table in the following section (Table 5-1).

The purpose of this approach is to support more efficient network reinforcement investments. The combination of maximum demand and security standards set the design threshold that triggers the need for network reinforcement. By accepting the small risk not sustaining supply should a fault occur exactly at peak times, the design

[4] For example, if increases in the forecast electricity demand exceed the capacity of an asset or result in a situation where the failure of a single asset could give rise to power interruptions. Likewise, a request for electricity supply from a large customer constructing a new factory, may give rise to not only construction of a dedicated electricity connection, but also the reinforcement of the surrounding network.

[5] This includes customers with non- standard requirements, where special contractual arrangements apply.

[6] An n-1 security level, for example, means supply will still be maintained after one network component fails.

maximum demand can be materially reduced.[7] This offers significant opportunity to improve asset utilisation and defer network reinforcement.[8]

The Security Standards used for Network Planning are summarised in Table 5-1.

Network Element	Load Type	Primary Voltage	Load Magnitude	Security Limits[9,10]	Ability to Meet Demand after Outage (% of year)	Customer Interruption Duration for Outage
Bulk supply substation	CBD (Quay, Hobson, Liverpool)	110kV	Any	N-1 N-2	100% (1st outage) 100% (2nd outage)	Nil (1st outage) < 5min (2nd outage)
	Urban (Wairau, Kingsland)	110kV	Any	N-1	100%	Nil
Sub-transmission circuits	CBD (Quay, Hobson, Liverpool)	110kV	Any	N-2	100% (1st outage) 100% (2nd outage)	Nil (1st outage) < 5min (2nd outage)
	Urban (Wairau, Kingsland)	110kV	Any	N-1	100%	Nil
	CBD (Quay, Hobson, Liverpool)	22kV	Any	N	Nil	Repair time
	Urban & Rural	33kV, 22kV	> 10MVA	N-1	95% (residential), 98% (commercial/ industrial)	< 5 min
	Urban	33kV, 22kV	< 10MVA	N	Nil	Repair time
		Backstop capacity is, however, provided through the 11 kV distribution network and supply will be restored by manual field switching in accordance with times set out in the Service Level Standards, subject to the 95% (residential) and 98% (commercial/industrial) capacity availability figures.				
	Rural	33kV, 22kV	< 10MVA	N	Nil	Repair time
Zone substation	CBD (Quay, Hobson, Liverpool)	22kV	Any	N-1 N-2	100% (1st outage) 100% (2nd outage)	Nil (1st outage) < 5min (2nd outage)
	Urban & Rural	33kV, 22kV	> 10MVA	N-1	95% (residential), 98% (commercial/ industrial)	< 5 min
	Urban	33kV, 22kV	< 10MVA	N	Nil	< 5 min
		Backstop capacity is, however, provided through the 11 kV distribution network and supply will be restored by manual field switching in accordance with times set out in the Service Level Standards, subject to the 95% (residential) and 98% (commercial/industrial) capacity availability figures.				
	Rural	33kV, 22kV	< 10MVA	N	Nil	Repair time

[7] The extent of reduction depends on the duration for which such a risk would be deemed acceptable.

[8] The conventional deterministic approach requires sufficient asset capacity to meet full peak demand, even if this occurs for a few half hours per year.

[9] Circuit rating is set by the post contingency, healthy circuit, cyclic rating.

[10] Applies to "credible contingencies" only

Network Element	Load Type	Primary Voltage	Load Magnitude	Security Limits[9,10]	Ability to Meet Demand after Outage (% of year)	Customer Interruption Duration for Outage
Distribution feeder	CBD	22kV, 11kV	Any	N-1	100%	< 2 hrs
	Urban	11kV	> 1MVA overhead > 400kVA underground	N-1	95% (residential), 98% (commercial/ industrial)	< 3 hrs Northern < 2.5 hrs Southern
	Urban	11kV	< 1MVA overhead < 400kVA underground	N	Nil	Repair time
	Rural	11kV	> 2.5MVA overhead	N-1	95%	< 6 hrs Northern < 3 hrs Southern
	Rural	11kV	< 2.5MVA overhead	N	Nil	Repair time
Distribution substation	CBD	11kV	Any	N	Nil	Repair time
	Urban	11kV	Any	N	Nil	Repair time
	Rural	11kV	Any	N	Nil	Repair time

Table 5-1 : Network security standards

Security standards are specified by broad groupings based on load magnitude, encompassing sub-transmission and distribution. Security levels at each of these levels are typically in line with international industry best practice. Where the highest level of security is required, multiple concurrent faults must occur before customer supply is lost. In Vector's case, this level of security is reserved solely for the sub-transmission within the Auckland Central Business District (CBD).

Outside the CBD a higher level of risk is accepted. The network is designed such that for commercial or industrial areas, should a sub-transmission, distribution feeder or zone substation fault occur, supply can be fully restored 98% of the time.[11,12] For 2% of the time, at peak demand periods, it may not be possible to fully restore supply until repairs have been carried out. For residential areas full capacity can be supplied for 95% of the time.

As noted above, this approach implies a security level marginally lower than the more conventional N-1 design approach, but from a network utilisation and economic efficiency perspective, it is far superior. The added risk that an outage may occur during peak demand periods is minor.

An exception is made to this security standard for urban or rural feeders with low demand[13], where the installation of redundant assets cannot be financially justified.[14] In these cases restoration of supply generally requires rectifying the fault.

[11] Restoration may, in some instances, lead to a short (less than 5 minute) outage, to allow network switching.

[12] Note that this applies to sub-transmission, zone substation or feeder faults only. Should a fault occur on a distribution substation or on the low voltage network, the same level of network redundancy does not exist, and outages may be experienced while fault repairs are carried out.

[13] <4MVA total peak load for areas fed from overhead circuits and <400kVA for areas fed from underground networks. The difference in load magnitude reflects the average time required to restore supply on overhead and underground networks.

[14] Unless specifically required by customers, in which case special commercial arrangements are made to recover the additional costs from the requiring customer(s).

Zone substation security levels are based on a threshold of 10MVA. For substations with a demand smaller than 10MVA, single transformer substations are used that only provide an N level security. In these cases, the design philosophy is to restore supplies after a fault from adjacent zone substations, using the 11kV distribution network backstop capability, up to the maximum level of 10MVA. (Zone substations with demand higher than 10MVA will have more than one power transformer, providing N-1 security.)

Another important consideration in the security standard is the design restoration times (as distinct from service level targets). These relate to the time required to restore supply after a network fault, to restore full capacity. For the sub-transmission networks, these times are generally short (see Table 5-1), and are based on automated switching that will transfer load automatically following a fault, or through remote switching initiated by Operations staff. At distribution feeder and substation levels, automated switching facilities are not as readily available and manual field switching may be required, resulting in longer possible restoration times.

5.3.1.1 Accepted Breaches of the Security Standards

Vector accepts a small number of instances where the distribution network security standards will be breached, which affect our network designs. These generally relate to one of the following four situations:

- Loss of bulk supply to all or part of Vector's network. Vector cannot realistically mitigate against a major loss of generation or transmission capacity. Such events will, therefore, lead to outages on the distribution network.
- The network development programme is generally based on forecast demand estimates and investments are made as far as realistically possible on a just-in-time principle. This approach seeks to avoid security breaches arising from growing demand, while at the same time avoiding too-early investment and hence under-utilised assets. In some instances, however, external factors (such as more load growth than foreseen at the time of planning) may lead to the timing of investments not exactly coinciding with the moment at which a security standard is exceeded. Security standards may, therefore, be breached until commissioning of the new required assets takes place.
- The security standards are based on an optimal trade-off between network reliability and the cost of providing electricity distribution services.[15] This, in turn, requires an evaluation of the energy at risk during credible outage events and the cost involved to reduce the risk. There are (a small number of) parts of Vector's distribution area where the provision of our standard security standards would be highly uneconomic. These are generally areas with very low consumer and/or consumption density, often remote from our main distribution network. To upgrade supplies to these areas to Vector's normal security standards would, therefore, require material additional recovery contributions from the customers affected. For these areas, the security standards may, therefore, be relaxed.[16,17]
- There are a number of credible but highly unlikely contingency events that may occur on a distribution network, that would almost inevitably give rise to extensive and extended outages. These are the so-called HILP (high-impact, low-probability)

[15] In several surveys, carried out over an extended period, Vector's customers indicated they are satisfied with existing reliability levels and do not want Vector to improve on this if it means increasing the price of distribution services.

[16] The difference in supply reliability for different parts of the network are also reflected in the security standards themselves, but there may be instances where even these standards have to be further relaxed to provide an economic supply to consumers.

[17] Customers who do require a higher level of supply reliability have the option to negotiate a special contract with Vector, that would reflect the extra cost involved to provide this through their line charges or through an upfront investment requirement.

events that would have a widespread impact, but would be inordinately expensive to avoid (if indeed possible) and where the likelihood of their occurring is so low this expenditure cannot be realistically justified. HILP events that Vector, therefore, accepts which could lead to major power outages include:

- Destruction of the Penrose/Liverpool tunnel and all circuits within. This would leave the CBD supply exposed[18];
- Failure of a tower or structure on the double circuit 110kV overhead line feeding Wairau substation in the North Shore, which would leave a shortfall in supply capacity for the North Shore[19];
- Loss of multiple transmission/ sub-transmission cables in a common trench. Vector has a number of double circuits feeding zone substations which share a common trench. In theory, a single event could, therefore, damage more than one circuit[20];
- Complete failure of a 110kV, 33kV, 22kV, or 11kV busbar at a substation, which would affect multiple circuits[21]; and
- Total loss of a zone substation (single or multiple transformers) through a force majeure event such as an earthquake, flood or plane crash.[22]

For all these cases, the risks are managed to the fullest practical extent possible and contingency plans are in place to minimise the impact of the event.

5.3.1.2 Impact of Network Configuration on Security Levels

Vector takes supply from the transmission grid at the various GXPs. The sub-transmission network of the two network regions at Vector has been developed using different configurations, due to legacy network designs. Dual radial-fed transformer feeders have been widely used in the Southern region whereas a mesh configuration has been the dominating Northern region design.

There are a number of substations in the Northern region equipped with a single transformer. These substations rely on the distribution network to provide the necessary back-up to maintain the required security level. The distribution network (in both regions) is configured in radial formation. The radial feeders are interconnected via normally open switches to provide backstops from either the same substation or a neighbouring substation.

5.3.2 Electricity Demand Forecasting

The electricity demand forecast is a projection of future demand based on historical demand information, known and anticipated consumption trends and societal or economic factors that influence the manner in which electricity is used. It is a key factor in network development decisions.

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[18] Work is underway for the creation of a new GXP at Hobson St in the CBD. Once this is in place (planned for mid 2014) the risk will be fully mitigated.

[19] Work is underway for the creation of a new GXP at Wairau Park substation. Once this is in place (planned for mid 2013) the risk will be fully mitigated.

[20] In practice, these circuits are well separated and instances of more than one underground circuit being damaged through one incident are extremely rare. The cost of providing redundant trenching is prohibitive.

[21] The busbar is the point in a substation to which all circuits are connected and while a degree of redundancy and busbar protection can be provided, this is not practical or economically feasible in the great majority of cases.

[22] All substations are designed to stringent earthquake and flood level requirements, but it is not possible to completely mitigate against major external events. This has been graphically illustrated in the recent Christchurch earthquake.

For forecasting purposes it is useful to split demand into that arising from two distinct categories – the large consumers (industrial and large commercial) and mass market (residential and small commercial ICPs).

5.3.2.1 Forecasting for Large Customers

On average, Vector receives only a few new large-customer connection requests (or requests for substantial demand increases from existing customers) every year. However, because of the size of many of these customers, their requirements can have a major impact on available spare network capacity at a localised level.

For large consumers, demand is driven by the nature and size of their operations, and their operating cycles. From a network perspective, the individual demand patterns for these larger customers therefore tend to be relatively constant over time (ignoring seasonal variability), only changing materially if extensions (or deletions) are made to the installations, or when there are major variations in the economic environment, that cause accelerated or slowed down production.

Peak demand forecasts for this sector, therefore, assume a constant base profile. Overlying this base, stepped demand changes are added or subtracted. The demand steps are based on the expected connection of new large customers (or disconnection of existing customers) or material operational changes at existing customers. The size of the forecast discrete steps is based on information gained about the individual connections.

Accurate demand forecasting for the large customer category, therefore, relies advance knowledge of discrete load changes. Our Key Account Managers engage in ongoing discussions with existing or potential customers to ensure their future plans are included in demand forecasts. New customers, with significant capacity requirements, will generally approach Vector well in advance of the time of connection to ensure capacity is available when required[23].

In instances where Vector is aware of future developments (eg subdivisions) allowance will be made in the demand forecast even if individual capacity requirements are not yet finalised.

In the cases of significant developments where the decisions by the developer to proceed with the project is still uncertain, Vector will use its judgement based on past experience with the particular developer, the prevailing property market condition, information on demand for such development in the local area, etc. to decide if the total (or a portion of the) demand as requested by the developer should be included in the demand forecast. In some cases the estimated impact of the development will be spread out to minimise the impact of the uncertainty. The physical works on site however starts only after the supply contract is signed by the customer. The uncertainty in timing of the customer projects may mean that the budgeted amount of expenditure might get postponed to the following financial year.

5.3.2.2 Forecasting for Mass Market Customers

The dominant factors driving mass market demand over time are connection numbers, the type of connections and the average individual electricity demand curve[24] associated with the different types of connections (which varies between areas).

[23] Or run the risk that the required capacity may not be available at the time they want to connect.

[24] Note that the term "demand curve" in an electrical engineering context refers to the maximum actual electricity consumed, measured over time, usually shown in specific time intervals. (See Section 2.2 for examples.) It is not to be confused with the economist interpretation of a demand curve (which is usually read in conjunction with a supply curve).

Residential connection numbers closely follow population trends, although the average number of people per connection can vary over time and between areas. Small commercial ICP numbers also tend to follow population size. Based on Vector's analysis, population growth and hence ICP numbers on a network-wide as well as GXP-wide level demonstrate a high correlation with time (i.e. growth in customer numbers tend to be linear when viewed over a long period). The average demand curves for customers vary between the types of customer and between different areas. There is also a material difference between summer and winter demand curves. However, the curves themselves have remained remarkably consistent over time and for the purpose of forecasting over the AMP planning window demand can reasonably be assumed to remain constant[25].

There are some further statistically significant factors that influence short-term individual demand, such as weather patterns and economic cycles. However, the predictive value added by considering these factors in addition to ICP numbers and historical average demand curves, especially for the longer term view required for network investment planning, is small.[26]

ICP forecasts are, therefore, the primary factor for mass market electricity demand forecasts. These forecasts are largely based on population growth data provided by Statistics New Zealand household projections. Vector's distribution area is divided into small pockets of land aligning with Census Area Units (CAUs). Population, employment and load composition (eg. proportion of residential and commercial/industrial) is determined per CAU area and are pro-rated across the feeders supplying the particular CAU.

The average demand per ICP for an area is derived from historical demand levels, and is assumed to remain constant for the planning period. The average figure is reviewed on an annual basis.

5.3.2.3 Forecast New Customer Connections

As noted above, the dominant drivers for electricity demand in the Auckland region are the number of ICPs on the network and discrete step-changes in large customer demand. The bulk of ICPs are constituted by residential and to a lesser degree commercial customers.

Historical population and ICP growth in Vector's distribution area is indicated in Table 5-2. Over time there has been a small increase in the overall population/ICP ratio, supported by a trend observed in recent years of an increased number of people per ICP.

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[25] There is some evidence of minor growth in the average demand curve in some areas, or of a shift from winter to summer peaks, but this is not sufficient to have a material impact on investment decisions over the forecasting period.

[26] In addition, forecasting these external factors with an acceptable degree of accuracy is problematic.

	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	FY11	FY12[27]
Auckland population ('000)	1237.7	1267.4	1297.2	1326.9	1349.6	1372.2	1394.9	1417.5	1440.2	1462.7
ICP's ('000)	476.8	488.0	495.3	504.1	512.4	518.5	523.4	528.4	532.6	536.4
Population /ICP ratio	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7
Average annual population growth ('000)	29.7	29.7	29.7	29.7	22.7	22.7	22.7	22.7	22.7	22.5
Annual ICP growth ('000)	7.3	11.2	7.3	8.8	8.3	6.0	4.9	5.0	4.2	3.8
Ratio of Population growth/ICP growth	4.1	2.6	4.1	3.4	2.7	3.8	4.6	4.5	5.4	6.0

Table 5-2 : Population and ICP trends in the Vector distribution area

Statistics NZ has projected population growth figures that will see the population of Auckland exceed 2 million people by 2031, which translates to 1.88 million within the Vector distribution area.[28]

Application of the current population/ICP ratio (2.7) to the Statistics NZ population forecast, assuming linear growth, produces an ICP increase of around 8,400 per annum. However, in recent years – as indicated in Table 5-2 – the population to ICP ratio has increased such that in the current year the ratio is 6.0, well above the minimum of 2.6 in FY04.

In Figure 5-3, the uncertainty associated with these forecasts[29] based on the range of historical ICP ratios over the last ten years, can vary by almost 70,000 ICPs.

Accurately forecasting ICP numbers is, therefore, difficult. In addition, conflicting business requirements are based on ICP forecasts:

- ICP forecasts drive Vector's energy and, hence, revenue forecasts. Prudency dictates that these forecasts should be at the conservative (lower) end of the possible ICP range. Over-forecasting will lead to worse than forecast financial performance; and
- From an asset investment perspective, conservative planning would dictate that forecasts at the highest end of the possible range. Under-forecasting will lead to under-investment and security of supply breaches.

To closely reflect the differing growth on the Northern and Southern networks, ICP forecasts have been calculated for each network. The aggregated Vector forecast is shown in Figure 5-3. The supporting ICP numbers are shown in Table 5-3. The process used for deriving these numbers is as follows:

- Upper ICP forecast - using the highest proportion of ICP growth /population growth ratio for the last 10 years;
- Lower ICP forecast - using the lowest proportion of ICP growth /population growth ratio for the last 10 years; and

[27] FY12 values are a combination of actual and forecast values as the actual values were not known at the time of compiling this document

[28] Part of Franklin District is classified as within the Auckland region but is outside Vector's reticulation area

[29] Assumes constant annual population increase

- Mid-point – taking the mid-point between the upper and lower ICP forecasts.

ICP growth for network planning purposes is assumed to lie at the mid-point of the indicative range. While this represents some risk of security level breaches should growth be more rapid than assumed, this is deemed acceptable given the significant degree of redundancy on the network (and hence that a security of supply breach is unlikely to automatically cause an outage). In addition, the asset investment plan is updated on an annual basis, reflecting actual ICP growth in the previous year. At the relatively low ICP growth rate foreseen, the impact of a one-year delay in investment is unlikely to be severe.

The Vector ICP growth forecast prepared by the Commercial Group – used for connection and revenue planning – is set at a slightly lower rate than Asset Investment forecast to reflect the historical values. Annual ICP forecasts for both Asset Investment and Commercial converge by FY16 but as Figure 5-3 shows the two charts run in parallel due to forecast ICP difference in the earlier years.

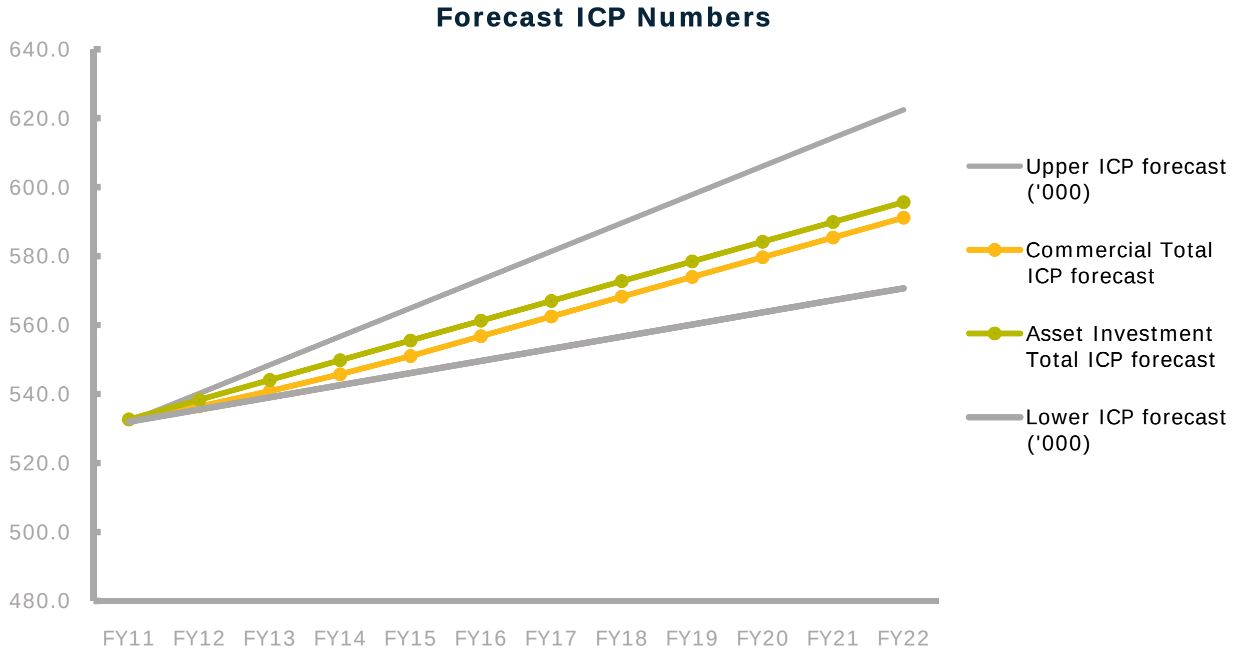


Figure 5-3 : Range of ICP forecasts

	FY11 Actual	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Population forecast ('000)	1440.2	1462.7	1485.2	1507.7	1530.2	1552.7	1575.2	1597.6	1620.1	1642.5	1665.0	1687.2
Population forecast growth ('%)		1.6%	1.5%	1.5%	1.5%	1.5%	1.4%	1.4%	1.4%	1.4%	1.4%	1.3%
Commercial ICP forecast ('000)	4.4	3.8	4.5	4.9	5.3	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Commercial Total ICP forecast	532.6	536.4	540.8	545.7	551.0	556.8	562.5	568.2	573.9	579.7	585.4	591.1
Commercial ICP growth ('%)		0.7%	0.8%	0.9%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Asset Investment ICP forecast	4.4	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Asset Investment Total ICP forecast	532.6	538.3	544.1	549.8	555.5	561.3	567.0	572.7	578.4	584.2	589.9	595.6

	FY11 Actual	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Asset Investment ICP Percentage increase		1.1%	1.1%	1.1%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Upper ICP forecast ('000)	532.0	540.2	548.4	556.7	564.9	573.2	581.4	589.6	597.8	606.1	614.3	622.4
Lower ICP forecast ('000)	532.0	535.5	539.0	542.5	546.1	549.6	553.1	556.6	560.2	563.7	567.2	570.7

Table 5-3 : ICP forecasts used by Vector

5.3.2.4 Impact of Embedded Generation on Electricity Demand

The number of generation applications processed in the 12 months to the end of 2011 is given below:

- 10kW or less : 18
- greater than 10kW : 3
- The below 10kW generators are Photo Voltaic (PV) installations whereas the greater than 10kW are fossil fuelled generators. This low level of fossil fuelled distributed generation development (compared to the rate of load growth) is expected to persist until such time that the cost of embedded generation becomes sufficiently attractive to entice installation. At present, and in the near future, the impact of embedded generation on Vector's future demand projection is therefore negligible.
- The installation of PV panels on the other hand is expected to grow at an increasing rate as the price of PV is expected to reach network-parity in the next few years. However the impact of PV on demand forecast is relatively minor as PV generation does not generally coincide with the network peak demand.

5.3.2.5 Impact of Demand Management on Electricity Demand

Vector has been using load control systems (ripple control systems, pilot wires, cyclo load control system) to manage network demand (by switching residential water heating systems) for over fifty years. Load control systems are also used to control street lighting. The effect of demand reduction due to the existing load control systems has already been captured in the current demand forecast on the basis that the load control strategy is not expected to change in the foreseeable future[30].

With increasing application of two way communication, fibre–to-the-home, home energy management systems, smart appliances, smart meters and smart grids expected to emerge over the medium-term, it is expected that customer involvement in managing demand at their premises will become more significant. This change from a network direct control mode to a customer interactive mode of demand management will evolve, and could create more uncertainty on how demand can be managed.

Vector will over the coming years continue to conduct pilot projects to monitor customer behaviour and the impact of intelligent devices on managing their loads. This will guide out demand management strategy for the future. Vector also anticipates that, in the short term at least, increasing electricity demand on the network will continue to outstrip capacity added by embedded generation or through increasingly efficient energy consumption. Network capacity cover will therefore have to be continually monitored, to ensure sufficient supply.

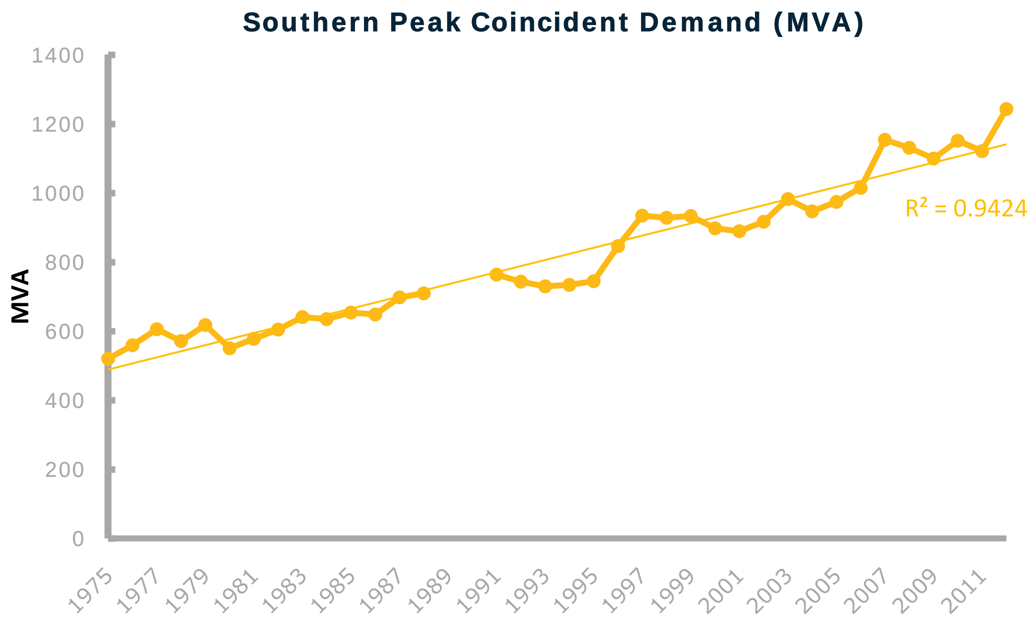
[30] This view will be revisited should the incentives or requirements of the market or regulatory environment change materially with respect to controlling network peak demand.

Changes to demand management, increasing demand, are likely to outway the changes to embedded generation, decreasing demand, at least in the short term leading to the need for careful monitoring of capacity cover.

5.3.2.6 Long-Term Observed Electricity Demand

In Figure 5-4 and Figure 5-5 below the long-term demand growth on the Southern and Northern distribution networks is indicated. As will be noted, although there are significant short-term fluctuations in demand, over time the growth is remarkably closely correlated with time (R^2 levels in excess of 95%). Over this period the population in Vector's supply areas has grown at a relatively linear rate as well. The figures, therefore, confirm the strong relationship that exists between electricity demand and population, and by implication ICP numbers. The trends also indicate that over time, at a highly aggregated network level, the influence of large customers on demand also tend to grow with population levels.

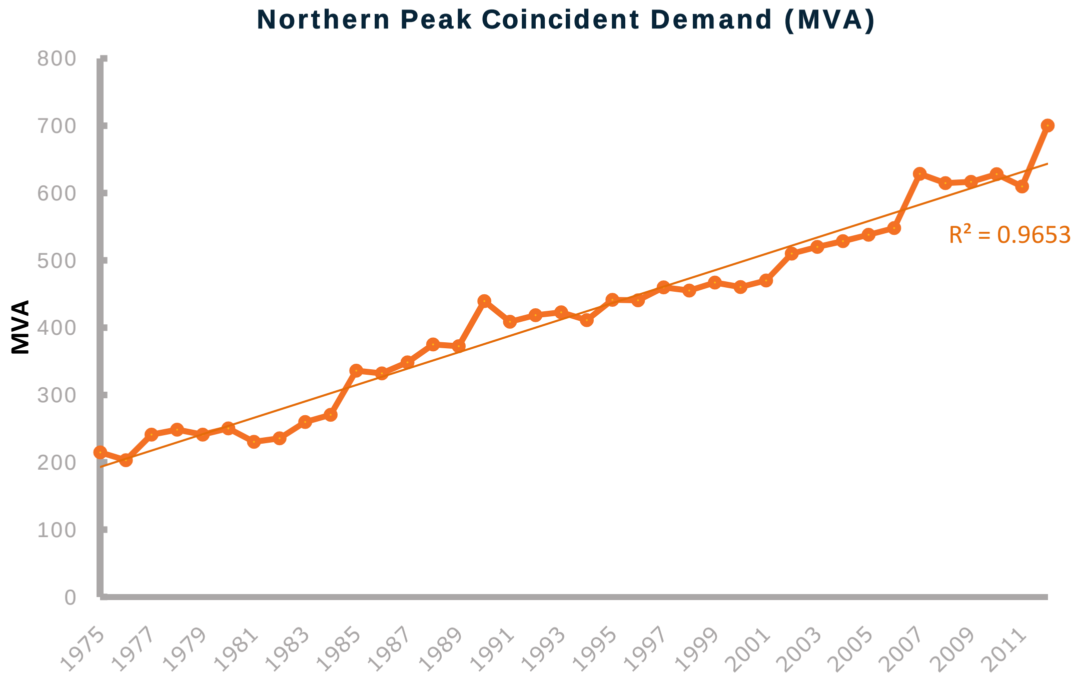
The demand trends could change over time, but such changes are likely to be very gradual and are unlikely to have a material impact on the short to medium-term planning window.



Notes : (a) Due to data problems, demand for 1988 and 1989 was not available

(b) The indicated correlation is with time

Figure 5-4 : Southern electricity network demand trend



Note : The indicated correlation is with time

Figure 5-5 : Northern electricity network demand trend

During August 2011, the Vector network experienced a very sharp increase in maximum demand over a three-day cold-snap – resulting in the highest demand ever observed on the network. The impact of this is clearly visible in Figure 5-4 and Figure 5-5.

5.3.2.7 Demand Forecasting at Different Voltage Levels

In Figure 5-6 a schematic overview is provided of Vector's electricity demand forecasting approach, at different levels of network aggregation. A spreadsheet based model has been developed in which the actual forecasts are currently prepared.

Due to natural short-term fluctuations in electricity demand and the inherent uncertainties associated with demand forecasting, consistently achieving an optimal investment point for network reinforcements is unlikely and situations may therefore still arise where actual demand exceeds forecast demand and the security standards are therefore breached (for short periods). However, with the level of redundancy and switching flexibility that exists in the network, the ability to shed some load, and the relatively slow rate of growth, this does not represent a material risk to network operations or reliability.[31]

5.3.2.8 Demand Forecasting at a Network or GXP Level

For forecasting electricity demand at a network or GXP level, the following factors are important.

[31] A lower-risk approach could be to bring investments somewhat forward from the programme indicated by consideration of the demand forecasts and required security levels. Vector's analysis indicates that this would in general not be economically prudent.

- As illustrated in Figure 5-4 and Figure 5-5 above, the historical demand growth trends on the Vector network have been remarkably linear over time. Although the fluctuations around the linear growth trend are material, they tend to be relatively short-term in nature – certainly much shorter than the average life of electricity distribution assets.

  The results are replicated at a GXP level[32];
- Vector is continually monitoring emerging trends in energy consumption and appliances. At present, we have not identified any factor that should materially influence average individual peak consumption in the near future – although it is recognised that in the medium term factors such as increased use of electric vehicles are likely to materially impact demand[33]; and
- Population forecasts for Auckland indicate a relatively constant growth rate for the next 20 years.

Given the above, Vector believes that asset investment decisions at a network or GXP-level can be realistically based on assuming a linear demand growth pattern, using historical growth rates as basis. Investments at this level would typically relate to new GXPs, or major sub-transmission reinforcements.

5.3.2.9 Demand Forecasting at a Disaggregated Level

Most of Vector's growth-related investments are required at a much more disaggregated network level.

a. Zone substation and feeder level

At a zone substation or feeder level, factors such as changes in the customer mix (for example when commercial activity in a previously mainly residential area increases), or the impact of single large customers can be material on overall forecasting. In addition, as part of network development it is often necessary to reconfigure the network, thus moving customers between zone substations or feeders. The short-term impact of external factors such as weather patterns or economic cycles is also more noticeable at a zone-substation level – where customers often tend to be quite similar in nature, and spread over a limited geographical area, and hence likely to be subject to, and respond to, the same factors in the same manner.

However, even at a zone substation or feeder level of disaggregation, the underlying demand patterns are still relatively stable, and predominantly based on ICP numbers. Taking the above into account, Vector's demand forecasting approach at this level can be summarised as follows.

- In the absence of specific information that would indicate material changes in future demand (such as the addition or removal of a large customer, or a new subdivision planned for an area), future demand is forecast to be based on historical demand trends (with an emphasis on experience over the last five years), while adding the forecast future demand resulting from ICP growth.

[32] There are incidents when major load shifts at a GXP level can occur – for example when a new GXP is connected to the network – but these are infrequent, discrete step-changes which can be relatively easily accounted for in the forecasts.

[33] This is in the absence of major expansion of load shedding schemes, or incentives for consumers to reduce peak demands.

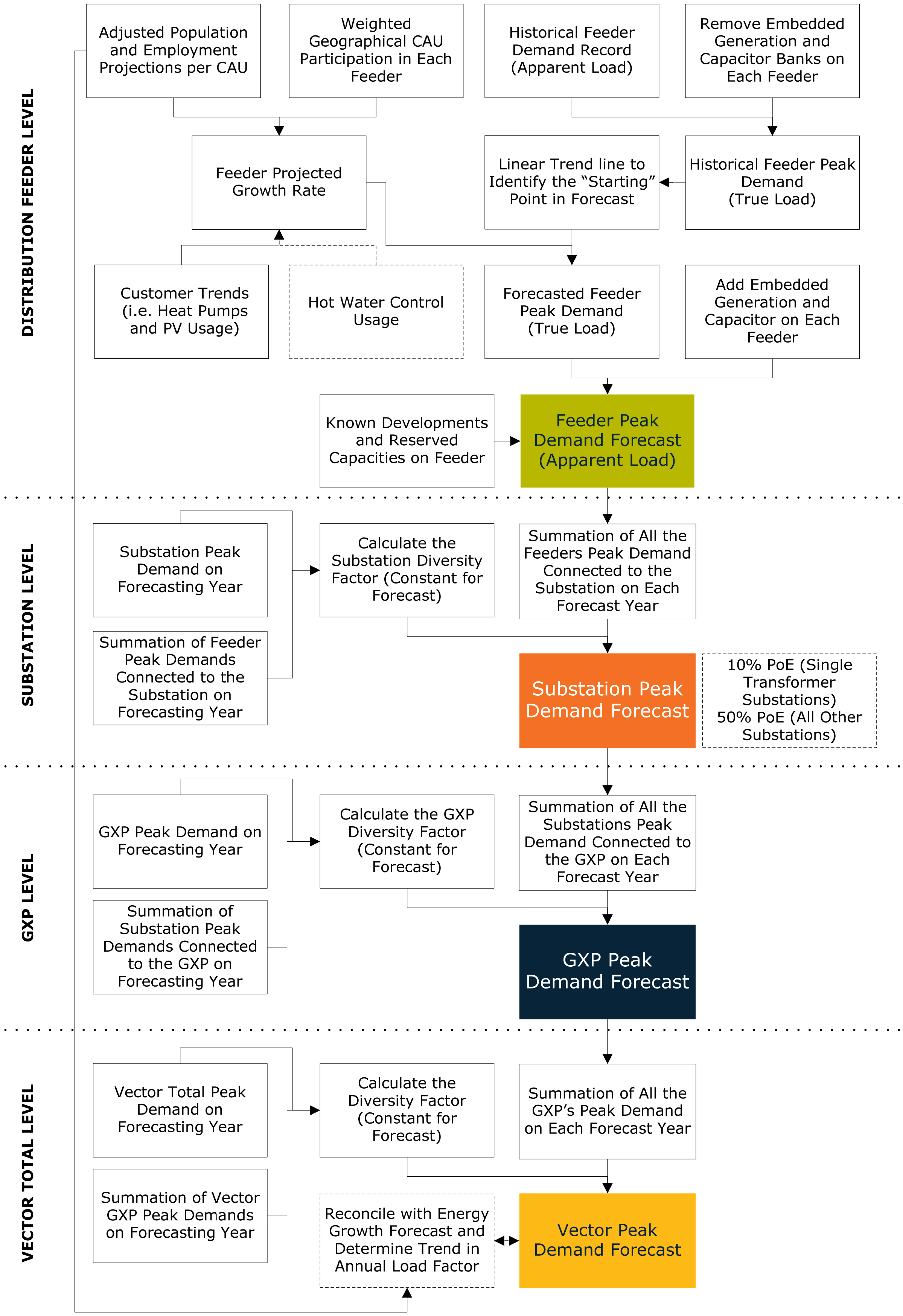


Figure 5-6 : Schematic representation of the Vector load forecasting process

- Where substantial additional (or reduced) loads are likely to arise over the planning period, this is superimposed over the underlying demand trend for a substation or feeder. Such loads are generally forecast based on discussions that Vector has with its large customers, developers and consultants about possible forthcoming developments, and an internal assessment is made about the likelihood of such developments. Significant load pattern changes can also occur due to network reconfigurations.
- The potential demand impact of short-term fluctuating factors, such as weather patterns and economic cycles are not individually accounted for, but are taken into account through considering historical demand curves, specifically the potential that these have to add to demand peaks.[34] The degree of redundant supply capacity that exists is also taken into account:
  - For dual transformer substations – where a high degree of supply capacity redundancy exists, future demand forecasts will generally be set at the average of the indicated historical demand trends (a P50 level, or 50% probability of exceedance). This implies a relatively high likelihood that demand may exceed the N-1 capacity (or security standard) of a substation for a short period prior to it being reinforced. However, given the available redundancy this is highly unlikely to lead to outages.
  - For single transformer substations, the demand forecasts are set at a P90 level of the indicative historical demand curve range (a 10% probability remains that capacity may be exceeded). This reflects the lower capacity of these substations to manage higher than rated load – thereby effectively bringing forward the point at which they have to be reinforced. Once the substation is reinforced, the substation reverts to a P50 forecast.
- Feeder load is forecast on a P50 principle. Forecast demand is matched against spare backstop capacity from adjacent feeders to ensure there is sufficient capacity to meet the security requirements as shown in the Security Standards (Table 5-1). The ability to move "open-points" and shift load to adjacent feeders ensures that unexpected load caused by short-term effects, such as adverse weather, can adequately be catered for with a P50 model, avoiding a more conservative P90 forecast approach.
- Both summer and winter demand forecasts are prepared. The summer demand forecast is required to reflect the lower network capacity during warm periods;
- Adjustments are made for known, one-off network demand distortions such as brief high load due to load transfers, large load increases/decreases, installation of capacitor banks or embedded generation. Evident errors in historical data are also corrected;
- Network-connected, embedded generators are assumed to maintain current operating patterns. The impact of new embedded generation will be reflected in forecasts as information becomes available. Existing generation at landfill sites is monitored and decommissioning plans are reflected in the demand forecast;
- Vector has a load management system that can directly influence demand. However, at present the load management system is predominantly used to shed load during contingency conditions or where there is a short-term risk that network capacity may be exceeded;

[34] Networks have to be able to adequately cope with peak demand periods, and demand troughs are, therefore, of less interest for planning purposes.

- The impact of emerging technologies and associated possible changes in energy consumption patterns are continually being assessed. Vector's best current view on this (see Section 3 for a discussion) has been accounted for in the demand forecasts.[35] Vector also conducts what-if analyses on the demand forecasts to test the impact on investment plans should material changes in energy consumption occur. Realistic scenario assumptions do not indicate a need for material changes in the current investment plan.

b. Distribution transformer and low voltage level

At the lowest level of disaggregation load forecasting is generally only done at the time of installing the assets – based on the anticipated final number of customers that will be connected. Should demand exceed the capacity of installed assets, the assets will be replaced or the local low-voltage network will be reinforced.

5.3.2.10 Demand Forecast for the AMP Period

The forecast zone substations and bulk in-feed substations demand is provided in Table 5-5 and Table 5-6 for summer and winter peak demand projections respectively. Overall network demand forecast is indicated in Table 5-4. The total load forecasts are an aggregation of P50 load forecasts. These forecasts are based on the ICP forecasts discussed above, and known large customer changes. As can be seen in the tables below, summer actual peak load is listed in financial year 2011. This is because at the time of composing this AMP, the summer peak for financial year 2012 had not yet been assessed (the FY12 summer period is between Nov-11 to Feb-12). Hence the tables below reflect the most recent actual season and the resulting 10-year forecasts.

Substation	Actual	Forecast Demand (MVA) - Summer									
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Total Vector[36]	1324	1342	1374	1403	1431	1452	1473	1491	1509	1524	1538
Total Northern	391	388	398	408	419	424	429	434	439	444	447
Total Southern	948	969	992	1011	1028	1045	1060	1074	1087	1098	1109
Substation	**Actual**	**Forecast Demand (MVA) - Winter**									
	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Total Vector	1943	1911	1939	1968	1997	2025	2053	2081	2108	2133	2150
Total Northern	700	656	664	671	678	685	692	699	706	713	718
Total Southern	1243	1218	1238	1259	1281	1301	1321	1341	1361	1378	1390

Table 5-4 : Overall Vector network demand forecast (coincident peak)

[35] At present, the only technology potentially causing a material impact on demand within the planning period is the increased use of heat pumps.

[36] Coincident peak. Does not include Lichfield load

Substation	Actual	Forecast Demand (MVA) - Summer									
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Atkinson Road	10.6	10.6	10.9	11.2	11.6	11.7	11.8	11.9	12.0	12.0	12.1
Auckland Airport	16.5	20.7	21.8	23.0	24.1	26.4	28.8	29.9	30.9	31.9	36.4
Avondale	17.8	17.9	18.1	18.3	18.5	18.7	18.8	18.9	19.0	19.1	19.3
Bairds	17.2	16.7	17.0	17.4	17.5	17.7	17.9	18.0	18.2	18.3	18.5
Balmain	5.1	5.2	5.3	5.5	5.7	5.8	5.8	5.9	5.9	6.0	6.0
Balmoral	10.3	9.6	9.6	9.7	9.7	9.8	9.8	9.9	9.9	10.0	10.0
Belmont	7.7	7.6	7.8	8.1	8.3	8.4	8.4	8.5	8.6	8.6	8.7
Birkdale	12.8	13.3	13.7	14.1	14.6	14.7	14.8	14.9	15.1	15.2	15.3
Brickworks	8.1	8.2	8.4	8.5	8.7	8.8	8.9	8.9	9.0	9.1	9.1
Browns Bay	8.0	8.5	8.8	9.1	9.5	9.6	9.7	9.8	10.0	10.1	10.2
Bush Road	22.0	22.5	22.7	22.9	23.1	23.2	23.4	23.5	23.6	23.8	23.9
Carbine	25.3	18.5	18.7	18.8	18.9	19.0	19.0	19.1	19.2	19.3	19.3
Chevalier	9.2	10.7	10.8	10.8	10.9	11.0	11.0	11.1	11.1	11.2	11.2
Clendon	12.1	12.6	12.8	13.1	13.1	13.2	13.3	13.4	13.5	13.5	13.5
Clevedon	2.0	2.5	2.6	2.7	2.9	2.9	3.0	3.0	3.1	3.2	3.2
Coatesville	5.9	6.2	6.4	6.6	6.9	7.0	7.1	7.2	7.2	7.3	7.4
Drive	16.1	16.9	17.0	17.3	17.6	17.9	18.1	18.4	18.5	18.6	18.7
East Coast Road	11.3	9.8	10.0	10.3	10.6	10.7	10.7	10.8	10.9	11.0	11.1
East Tamaki	15.2	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
Forrest Hill	10.0	10.0	10.3	10.6	11.0	11.1	11.2	11.3	11.3	11.4	11.5
Freemans Bay	17.3	17.0	17.2	17.9	18.6	18.8	18.9	19.0	19.2	19.3	19.5
Glen Innes	5.9	6.0	6.4	6.4	6.5	6.6	6.6	6.7	6.8	6.8	6.9
Greenhithe	7.7	8.1	8.5	8.9	9.4	9.6	9.9	10.2	10.4	10.7	10.9
Greenmount	38.0	36.0	36.3	36.7	36.8	36.9	36.9	37.0	37.1	37.1	37.0
Gulf Harbour	4.2	4.1	4.3	4.4	4.5	4.6	4.6	4.7	4.7	4.8	4.8
Hans	23.4	22.5	22.9	23.2	23.4	23.7	23.9	24.1	24.3	24.4	24.6
Hauraki	5.3	4.7	4.9	5.0	5.1	5.2	5.2	5.3	5.3	5.4	5.4
Helensville	9.0	9.2	9.5	9.9	10.2	10.4	10.5	10.7	10.9	11.0	11.1
Henderson Valley	18.9	19.5	19.9	20.3	20.7	21.0	21.2	21.4	21.7	21.9	22.1
Highbrook	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.0	6.0	6.0	6.0
Highbury	7.6	7.8	7.9	8.1	8.3	8.4	8.5	8.6	8.7	8.8	8.9
Hillcrest	18.2	18.9	19.3	19.7	20.1	20.4	20.6	20.9	21.1	21.4	21.5
Hillsborough	0.0	10.5	10.6	10.7	10.8	10.9	10.9	11.0	11.1	11.1	11.2
Hobson 110/11kV	22.2	22.5	22.9	23.3	23.7	23.8	24.0	24.1	24.2	24.3	24.5
Hobson 22/11kV	20.5	21.0	21.5	22.0	22.5	22.8	23.0	23.2	23.5	23.7	24.0

Substation	Actual	Forecast Demand (MVA) - Summer									
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Hobson 22kV	81.0	84.5	86.9	89.6	92.8	94.6	96.3	97.6	98.8	100.1	101.3
Hobson 22kV distribution	7.0	7.9	8.8	9.5	10.7	11.8	12.9	13.5	14.0	14.6	15.2
Hobsonville	12.3	12.8	13.2	13.6	14.0	14.2	14.4	14.5	14.7	14.9	15.0
Hospital	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Howick	21.9	22.0	22.5	23.0	23.2	23.4	23.6	23.8	24.0	24.1	24.3
James Street	12.7	12.8	13.1	13.4	13.8	13.9	14.0	14.1	14.2	14.4	14.4
Keeling Road	7.6	7.8	7.9	8.1	8.2	8.3	8.4	8.4	8.5	8.6	8.6
Kingsland	18.6	18.8	19.0	19.4	19.7	19.9	20.0	20.2	20.4	20.5	20.7
Kingsland 22kV	34.8	37.9	38.2	38.7	39.2	39.4	39.7	39.9	40.2	40.5	40.7
Laingholm	5.8	6.0	6.2	6.4	6.5	6.6	6.6	6.7	6.7	6.8	6.8
Liverpool	46.1	45.8	46.6	47.4	48.2	48.5	48.8	49.1	49.4	49.7	50.0
Liverpool 22kV	80.9	85.7	87.7	89.5	91.3	92.6	94.0	94.9	95.7	96.9	98.0
Liverpool 22kV distribution	9.7	15.1	16.1	16.8	17.5	18.4	19.3	19.7	20.1	20.8	21.4
Mangere Central	19.7	20.8	21.2	21.5	21.7	21.9	22.0	22.2	22.3	22.4	22.5
Mangere East	15.2	16.5	17.0	17.6	17.9	18.3	18.6	19.0	19.3	19.6	19.9
Mangere West	16.6	15.8	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.1
Manly	9.3	9.3	9.5	9.8	10.1	10.2	10.2	10.3	10.4	10.5	10.6
Manukau	24.0	23.6	24.1	24.5	24.8	25.2	25.5	25.9	26.2	26.5	26.7
Manurewa	27.4	27.3	28.0	28.7	29.0	29.3	29.6	29.9	30.2	30.4	30.6
Maraetai	3.8	3.6	3.7	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7
McKinnon	20.5	21.0	21.5	22.1	22.7	23.2	23.6	24.1	24.6	25.1	25.3
Mcleod Road	8.1	7.5	7.6	7.8	8.0	8.1	8.2	8.3	8.4	8.5	8.5
McNab	40.5	41.2	42.1	42.4	43.2	43.7	44.3	44.9	45.1	45.2	45.4
Milford	4.8	5.2	5.4	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.2
Mt Albert	6.0	4.3	4.4	4.4	4.5	4.5	4.5	4.5	4.6	4.6	4.6
Mt Wellington	17.8	19.1	19.9	20.1	20.4	20.5	20.7	20.8	20.9	21.1	21.2
New Lynn	10.2	10.2	10.5	10.8	11.1	11.2	11.4	11.5	11.6	11.8	11.9
Newmarket	34.1	36.1	40.1	40.9	42.5	44.2	46.0	47.8	49.7	51.6	52.7
Newton	16.4	16.3	16.6	16.8	17.1	17.2	17.4	17.5	17.7	17.8	18.0
Ngataringa Bay	6.5	7.0	7.0	7.1	7.2	7.2	7.2	7.2	7.3	7.3	7.3
Northcote	4.7	4.9	5.0	5.2	5.3	5.4	5.4	5.5	5.5	5.6	5.6
Onehunga	10.4	10.9	11.5	11.6	11.7	11.8	11.9	12.0	12.1	12.1	12.2
Orakei	12.2	12.5	12.8	13.2	13.6	13.7	13.8	13.8	13.9	13.9	14.0

Substation	Actual	Forecast Demand (MVA) - Summer									
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Oratia	3.6	3.7	3.8	3.9	4.1	4.1	4.1	4.2	4.2	4.2	4.3
Orewa	8.4	8.4	8.7	9.0	9.4	9.5	9.7	9.8	10.0	10.1	10.2
Otara	25.7	24.4	24.9	25.4	25.6	25.8	26.0	26.2	26.5	26.6	26.7
Pacific Steel	52.2	53.2	53.2	53.2	53.2	53.2	53.2	53.2	53.2	53.2	53.2
Pakuranga	15.3	15.8	16.4	16.9	17.3	17.6	18.0	18.4	18.8	19.1	19.5
Papakura	17.5	17.6	17.8	18.1	18.2	18.3	18.4	18.6	18.7	18.7	18.8
Parnell	8.7	8.5	8.7	8.8	8.9	9.0	9.5	9.9	10.4	10.9	11.0
Ponsonby	10.6	10.0	10.0	10.1	10.2	10.2	10.3	10.3	10.4	10.5	10.5
Quay	24.7	22.4	23.6	25.2	26.8	28.6	28.8	28.9	29.1	29.3	29.4
Quay 22kV	29.9	29.7	30.9	32.6	34.2	36.0	36.6	37.3	37.9	38.5	38.8
Quay 22kV distribution	7.1	8.9	9.1	9.3	9.5	9.6	9.7	9.8	9.8	9.9	10.0
Ranui	4.7	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Red Beach	7.1	7.5	7.8	8.0	8.3	8.4	8.4	8.5	8.6	8.7	8.8
Remuera	15.7	15.8	16.2	16.9	17.6	18.5	19.4	20.3	21.2	21.7	21.8
Riverhead	7.1	8.3	8.7	9.0	9.3	9.5	9.7	9.9	10.1	10.3	10.4
Rockfield	15.0	16.1	16.2	16.4	16.5	17.7	19.0	20.2	21.5	21.6	21.7
Rosebank	19.5	21.3	21.5	21.7	21.8	21.9	22.0	22.2	22.3	22.4	22.5
Sabulite Road	11.4	11.2	11.6	11.9	12.3	12.5	12.6	12.8	12.9	13.1	13.2
Sandringham	13.3	13.4	13.5	13.6	13.7	13.8	13.8	13.9	14.0	14.0	14.1
Sandringham 22kV	23.6	23.1	23.3	23.4	23.6	23.7	23.8	23.9	24.0	24.2	24.3
Simpson Road	4.6	4.4	4.5	4.7	4.9	4.9	5.0	5.0	5.1	5.1	5.2
Snells Beach	4.5	4.8	4.9	5.1	5.3	5.4	5.4	5.5	5.6	5.7	5.7
South Howick	16.6	16.8	17.2	17.5	17.6	17.7	17.8	17.9	18.0	18.0	18.1
Spur Road	8.2	8.5	8.8	9.2	9.6	9.7	9.9	10.1	10.3	10.5	10.7
St Heliers	11.7	11.8	11.9	12.0	12.1	12.2	12.3	12.4	12.4	12.5	12.6
St Johns	10.3	10.7	12.1	13.6	14.5	15.3	16.1	16.9	17.7	18.3	18.6
St Johns 33kV	32.7	33.4	35.2	37.0	38.3	39.3	40.2	41.1	42.0	42.7	43.1
Sunset Road	15.2	15.0	15.2	15.5	15.7	15.8	15.9	16.0	16.1	16.2	16.3
Swanson	7.6	8.3	8.6	8.9	9.3	9.4	9.5	9.7	9.8	9.9	10.0
Sylvia Park	15.4	17.1	17.3	17.4	18.3	19.3	20.2	21.1	21.6	22.1	22.2
Takanini	13.7	14.4	14.7	15.0	15.1	15.2	15.3	15.5	15.6	15.7	15.8
Takapuna	9.6	9.6	9.7	9.9	10.0	10.1	10.3	10.4	10.5	10.7	10.8
Te Atatu	13.3	11.1	11.5	11.9	12.3	12.5	12.7	12.8	13.0	13.2	13.3
Te Papapa	24.8	23.5	23.7	23.8	24.0	24.1	24.2	24.3	24.4	24.5	24.6
Torbay	5.4	5.4	5.7	5.9	6.1	6.2	6.3	6.4	6.4	6.5	6.6
Triangle	11.7	12.3	12.7	13.1	13.5	13.7	13.9	14.1	14.3	14.5	14.6

Substation	Actual	Forecast Demand (MVA) - Summer									
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Road											
Victoria	27.7	27.7	28.1	28.6	29.1	29.3	29.4	29.6	29.7	29.9	30.1
Waiake	5.8	5.8	6.0	6.1	6.3	6.4	6.5	6.5	6.6	6.7	6.7
Waiheke	6.9	7.1	7.4	7.6	7.7	7.8	8.0	8.1	8.2	8.2	8.3
Waikaukau	5.3	5.0	5.1	5.3	5.5	5.6	5.7	5.7	5.8	5.9	5.9
Waimauku	5.1	5.3	5.5	5.7	5.9	6.0	6.1	6.2	6.3	6.4	6.5
Wairau	17.2	14.6	14.8	15.0	15.2	15.4	15.5	15.6	15.8	15.9	16.0
Wairau 110kV	85.0	82.5	84.3	86.3	88.3	89.2	90.1	91.0	91.9	92.8	93.3
Warkworth	12.5	12.5	12.9	13.2	13.6	13.8	14.0	14.2	14.4	14.6	14.7
Wellsford	6.1	6.0	6.2	6.3	6.5	6.6	6.7	6.8	6.8	6.9	7.0
Westfield	31.0	30.0	30.3	30.6	30.9	31.1	31.2	31.4	31.6	31.7	31.9
White Swan	18.6	18.1	18.3	18.5	18.6	18.7	18.9	19.0	19.1	19.2	19.3
Wiri	36.8	38.8	39.3	39.8	40.2	40.6	41.0	41.4	41.9	42.2	42.5
Woodford	7.3	7.7	7.9	8.0	8.2	8.3	8.4	8.5	8.6	8.7	8.7

Table 5-5 : Summer peak demand projection for the bulk supply substations and zone substations for the Northern and Southern regions

Substation	Actual	Forecast Demand (MVA) - Winter									
	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Atkinson Road	21.1	20.2	20.3	20.4	20.6	20.7	20.8	20.9	21.0	21.1	21.3
Auckland Airport	15.3	16.6	17.7	18.8	19.9	21.0	22.2	24.5	26.8	27.9	28.9
Avondale	32.1	30.3	30.6	30.9	31.2	31.5	31.8	32.1	32.4	32.7	32.9
Bairds	25.3	24.0	24.2	24.4	24.7	24.9	25.1	25.3	25.5	25.7	25.9
Balmain	9.9	9.4	9.5	9.6	9.7	9.7	9.8	9.9	10.0	10.0	10.1
Balmoral	18.4	18.5	18.6	18.7	18.8	18.9	19.0	19.1	19.2	19.3	19.4
Belmont	14.8	14.6	14.7	14.8	14.9	14.9	15.0	15.1	15.2	15.3	15.3
Birkdale	24.7	24.1	24.2	24.4	24.5	24.7	24.8	25.0	25.1	25.3	25.4
Brickworks	10.9	9.8	9.9	10.0	10.1	10.2	10.2	10.3	10.4	10.5	10.5
Browns Bay	15.6	15.2	15.3	15.5	15.7	15.9	16.1	16.2	16.4	16.6	16.7
Bush Road	23.5	24.4	24.5	24.7	24.8	25.0	25.1	25.3	25.4	25.6	25.7
Carbine	16.8	16.1	16.2	16.3	16.5	16.6	16.7	16.8	16.9	17.0	17.1
Chevalier	17.4	19.6	19.7	19.9	20.0	20.1	20.2	20.4	20.5	20.6	20.7
Clendon	21.0	21.1	21.2	21.3	21.5	21.5	21.6	21.7	21.8	21.9	22.0
Clevedon	3.1	3.3	3.4	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.6
Coatesville	10.5	10.4	10.5	10.7	10.8	10.9	11.0	11.1	11.3	11.4	11.5
Drive	30.4	29.9	30.0	30.5	30.9	31.4	31.8	32.2	32.4	32.5	32.7

Substation	Actual	Forecast Demand (MVA) - Winter									
	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
East Coast Road	18.0	17.5	17.6	17.7	17.8	17.9	18.1	18.2	18.3	18.4	18.5
East Tamaki	16.4	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1
Forrest Hill	19.6	18.7	18.8	19.0	19.1	19.2	19.3	19.4	19.6	19.7	19.8
Freemans Bay	20.6	19.6	19.8	20.6	21.4	21.7	22.0	22.2	22.5	22.8	23.0
Glen Innes	12.3	11.8	12.3	12.5	12.7	12.8	13.0	13.2	13.4	13.5	13.6
Greenhithe	14.3	14.7	15.1	15.6	16.1	16.5	16.9	17.3	17.7	18.2	18.5
Greenmount	39.9	38.0	38.2	38.4	38.7	38.8	38.8	38.9	39.0	39.1	39.1
Gulf Harbour	7.9	7.6	7.7	7.7	7.8	7.8	7.9	8.0	8.0	8.1	8.1
Hans	26.1	24.7	25.0	25.3	25.6	25.8	26.1	26.3	26.5	26.7	26.9
Hauraki	9.2	8.8	8.8	8.9	9.0	9.1	9.2	9.3	9.4	9.4	9.5
Helensville	14.1	14.0	14.2	14.4	14.6	14.8	15.0	15.2	15.4	15.7	15.8
Henderson Valley	19.8	18.8	19.0	19.2	19.3	19.5	19.7	19.9	20.1	20.3	20.4
Highbrook	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Highbury	11.1	11.2	11.4	11.5	11.6	11.7	11.9	12.0	12.1	12.2	12.3
Hillcrest	24.3	24.3	24.6	24.9	25.1	25.4	25.7	26.0	26.2	26.5	26.7
Hillsborough	19.7	16.8	16.9	17.1	17.2	17.4	17.5	17.6	17.8	17.9	18.0
Hobson 110/11kV	18.6	18.8	19.2	19.7	20.1	20.4	20.8	21.2	21.6	22.0	22.1
Hobson 22/11kV	17.8	18.3	18.8	19.4	19.9	20.4	20.9	21.5	22.0	22.6	22.8
Hobson 22kV	76.7	80.0	82.5	85.3	88.7	91.4	94.2	96.5	98.8	101.2	102.5
Hobson 22kV distribution	5.8	7.2	8.1	8.8	10.0	11.1	12.4	13.1	13.8	14.6	15.2
Hobsonville	21.4	20.5	20.8	21.1	21.4	21.6	21.8	22.1	22.3	22.6	22.8
Hospital	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Howick	44.9	41.5	41.7	42.0	42.3	42.5	42.8	43.1	43.3	43.6	43.8
James Street	21.5	20.9	21.1	21.2	21.4	21.5	21.7	21.8	21.9	22.1	22.2
Keeling Road	13.1	14.1	14.2	14.3	14.4	14.6	14.7	14.8	15.0	15.1	15.2
Kingsland	24.3	23.9	24.2	24.7	25.2	25.5	25.7	26.0	26.3	26.6	26.8
Kingsland 22kV	60.4	59.8	60.3	61.0	61.7	62.2	62.7	63.2	63.7	64.2	64.6
Laingholm	10.0	9.8	9.8	9.9	9.9	9.9	10.0	10.0	10.1	10.1	10.1
Liverpool	41.2	40.9	41.6	42.4	43.2	43.9	44.7	45.4	46.2	47.0	47.3
Liverpool 22kV	77.6	77.8	79.4	80.7	82.1	83.6	85.1	86.7	88.3	90.1	91.3
Liverpool 22kV distribution	9.3	9.5	10.0	10.2	10.4	10.9	11.4	11.9	12.4	13.1	13.8
Mangere Central	28.1	28.6	28.9	29.2	29.5	29.6	29.8	30.0	30.2	30.4	30.5
Mangere	28.7	27.6	28.0	28.4	28.8	29.3	29.8	30.3	30.8	31.3	31.8

Substation	Actual	Forecast Demand (MVA) - Winter									
	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
East											
Mangere West	18.5	17.4	17.5	17.5	17.6	17.6	17.7	17.7	17.7	17.8	17.8
Manly	16.8	16.4	16.5	16.6	16.8	16.9	17.0	17.1	17.2	17.4	17.5
Manukau	30.7	29.0	29.4	29.8	30.2	30.6	31.0	31.4	31.8	32.2	32.6
Manurewa	52.0	51.0	51.4	51.8	52.3	52.6	53.0	53.4	53.8	54.2	54.5
Maraetai	7.4	6.4	5.2	5.4	5.6	5.7	5.9	6.1	6.3	6.5	6.7
McKinnon	21.8	21.3	21.8	22.3	22.8	23.3	23.8	24.3	24.8	25.3	25.5
McLeod Road	14.8	14.2	14.3	14.5	14.6	14.8	15.0	15.1	15.3	15.5	15.6
McNab	47.2	48.0	48.8	49.2	50.1	50.9	51.8	52.6	53.0	53.5	53.7
Milford	8.6	8.8	8.9	9.0	9.1	9.2	9.4	9.5	9.6	9.7	9.8
Mt Albert	11.4	8.5	8.6	8.6	8.7	8.8	8.8	8.9	9.0	9.1	9.1
Mt Wellington	21.0	22.2	22.9	23.2	23.5	23.8	24.1	24.4	24.7	25.0	25.2
New Lynn	14.2	14.3	14.4	14.6	14.7	14.9	15.0	15.2	15.3	15.5	15.6
Newmarket	36.7	38.0	41.6	45.3	47.1	48.9	50.8	52.7	54.5	56.4	57.7
Newton	19.8	19.1	19.4	19.7	20.0	20.3	20.6	20.9	21.2	21.5	21.7
Ngataringa Bay	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.3	9.3	9.3	9.3
Northcote	9.3	9.3	9.4	9.5	9.6	9.7	9.8	9.9	9.9	10.0	10.1
Onehunga	14.9	15.5	16.2	16.4	16.6	16.7	16.9	17.1	17.3	17.5	17.6
Orakei	24.8	24.8	25.4	26.0	26.6	26.9	27.1	27.2	27.3	27.5	27.6
Oratia	5.8	5.8	5.9	5.9	5.9	6.0	6.0	6.0	6.1	6.1	6.2
Orewa	15.6	15.4	15.6	15.9	16.1	16.4	16.6	16.8	17.0	17.3	17.4
Otara	33.5	30.5	31.1	31.6	32.2	32.5	32.8	33.1	33.4	33.8	34.0
Pacific Steel	55.8	55.8	55.8	55.8	55.8	55.8	55.8	55.8	55.8	55.8	55.8
Pakuranga	26.2	26.1	26.4	26.8	27.1	27.6	28.2	28.7	29.2	29.8	30.3
Papakura	27.1	25.3	25.5	25.6	25.7	25.9	26.0	26.1	26.3	26.4	26.5
Parnell	11.5	10.7	10.8	11.0	11.1	11.3	11.8	12.4	13.0	13.6	13.7
Ponsonby	18.0	16.2	16.3	16.4	16.5	16.6	16.6	16.7	16.8	16.9	17.0
Quay	23.4	21.6	22.8	24.4	26.1	28.0	28.4	28.8	29.3	29.7	29.9
Quay 22kV	32.7	29.9	31.1	32.8	34.4	36.3	37.2	38.1	39.1	40.0	40.3
Quay 22kV distribution	7.3	8.4	8.7	8.9	9.2	9.4	9.6	9.8	10.1	10.3	10.4
Ranui	9.7	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Red Beach	15.0	15.5	15.6	15.8	16.0	16.1	16.3	16.4	16.6	16.7	16.8
Remuera	30.0	29.8	30.4	31.6	32.7	33.8	35.0	36.1	37.3	38.0	38.7
Riverhead	10.9	11.0	11.2	11.5	11.7	11.9	12.1	12.4	12.6	12.8	13.0
Rockfield	19.2	20.5	20.7	20.8	21.0	22.4	23.8	25.2	26.6	26.8	26.9
Rosebank	23.4	24.4	24.6	24.8	25.0	25.1	25.3	25.5	25.7	25.9	26.0
Sabulite	21.4	21.2	21.4	21.6	21.9	22.1	22.4	22.6	22.8	23.1	23.3

Substation	Actual	Forecast Demand (MVA) - Winter									
	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Road											
Sandringham	24.0	22.6	22.8	22.9	23.1	23.2	23.4	23.5	23.6	23.8	23.9
Sandringham 22kV	43.6	39.7	39.9	40.2	40.5	40.7	40.9	41.1	41.4	41.6	41.8
Simpson Road	5.6	5.0	5.0	5.1	5.2	5.2	5.3	5.3	5.4	5.5	5.5
Snells Beach	6.3	6.3	6.4	6.5	6.5	6.6	6.7	6.8	6.9	6.9	7.0
South Howick	33.8	30.9	31.0	31.2	31.3	31.4	31.5	31.6	31.7	31.8	31.9
Spur Road	12.8	12.9	13.1	13.4	13.7	13.9	14.2	14.4	14.7	14.9	15.1
St Heliers	25.0	24.4	24.6	24.8	24.9	25.1	25.3	25.5	25.6	25.8	26.0
St Johns	17.4	18.0	19.9	21.9	23.1	24.5	25.9	27.3	28.7	30.0	30.4
St Johns 33kV	58.7	53.4	55.6	57.8	59.4	60.9	62.2	63.6	65.0	66.3	66.9
Sunset Road	18.8	18.4	18.5	18.6	18.7	18.8	18.9	19.0	19.1	19.2	19.3
Swanson	13.4	13.3	13.5	13.6	13.8	14.0	14.2	14.3	14.5	14.7	14.8
Sylvia Park	16.2	18.1	18.2	18.4	19.4	20.4	21.5	22.5	23.1	23.7	23.7
Takanini	16.6	17.2	17.3	17.5	17.7	17.9	18.1	18.3	18.4	18.6	18.8
Takapuna	9.0	8.9	9.0	9.1	9.3	9.4	9.5	9.6	9.7	9.9	9.9
Te Atatu	22.7	22.4	22.7	23.0	23.3	23.6	23.9	24.2	24.5	24.9	25.0
Te Papapa	24.6	23.2	23.4	23.6	23.8	24.0	24.2	24.3	24.5	24.7	24.8
Torbay	10.5	10.5	10.7	10.8	11.0	11.1	11.2	11.3	11.5	11.6	11.7
Triangle Road	18.2	18.4	18.6	18.9	19.2	19.4	19.6	19.9	20.1	20.4	20.5
Victoria	23.1	23.8	24.2	24.7	25.2	25.6	26.0	26.5	26.9	27.4	27.6
Waiake	10.4	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	10.9	10.9
Waiheke	10.8	10.2	10.4	10.5	10.6	10.7	10.9	11.0	11.1	11.3	11.4
Waikaukau	7.7	7.3	7.4	7.5	7.6	7.6	7.7	7.8	7.9	7.9	8.0
Waimauku	6.9	6.7	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.6
Wairau	17.1	16.2	16.3	16.5	16.6	16.7	16.9	17.0	17.2	17.3	17.4
Wairau 110kV	140.2	137.0	138.2	139.4	140.6	141.8	143.0	144.2	145.4	146.6	147.4
Warkworth	17.7	17.9	18.2	18.4	18.6	18.9	19.1	19.3	19.6	19.8	20.0
Wellsford	8.9	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9
Westfield	29.4	29.9	30.2	30.6	31.0	31.3	31.6	31.9	32.2	32.5	32.7
White Swan	30.4	30.1	30.3	30.5	30.7	31.0	31.2	31.4	31.6	31.8	32.0
Wiri	38.6	35.9	36.4	36.8	37.2	37.5	37.9	38.2	38.6	39.0	39.3
Woodford	9.4	9.5	9.6	9.7	9.8	9.9	10.0	10.1	10.2	10.3	10.3

Table 5-6 : Winter peak demand projection for the bulk supply substations and zone substations for the Northern and Southern regions

5.3.3 Equipment Rating

To enable the capacity of the delivery points (zone substations and feeders) to be assessed, it is necessary to a have a reliable assessment of the capacities of the major network components.

All equipment (transformers, cables, switchgear, etc) has a rated load carrying capacity depending on the demand characteristics (flat, fluctuating or cyclic) of the load they serve and the environment in which the equipment operates (ambient temperature, proximity with other equipment, ability for heat dissipation, etc.). The overall capacity of a circuit is based on the capacity constraint of the individual components.

Where load patterns allow, the circuit capacity takes into account cyclical or short-term capacity ratings, rather than the flat, long-term rating. This allows lower capacity equipment to be used in areas where peak demands do not persist for extended periods.

Peak and cyclical demands are, therefore, taken into account in Vector’s demand forecasts.

The major network components include:

- Underground cables;
- Overhead lines;
- Transformers; and
- Switchboards.

Determining the capacities of these network components requires a detailed assessment of each sub-component. (For example, in assessing the capacity of a transformer, ratings of the bushings, tap changer, and other accessories are also assessed to ensure the sub-component with the lowest rating which determines the overall asset rating is identified.)

The following paragraphs describe how the capacities of the network components are assessed. In all cases, asset capacities are not only assessed at normal full-load ratings the cyclical and/or short-term ratings are also determined.

5.3.3.1 Cables

The analysis of MV cable ratings is complex, due to the major influence of external factors such as cable type and circuit configuration, installation practices, surrounding soil composition and moisture content, solar gain, proximity of other circuits and preloading conditions. Vector uses the cable rating modelling tool “CYMCAP”, a product of CYME Corp of Canada to perform ampacity and temperature rise calculations for power cable installations. This software tool is used to determine the maximum current power cables can sustain without causing deterioration or failure of their electrical properties.

5.3.3.2 Overhead Lines

Environmental and operating conditions play a large part in determining the capacity of overhead lines. Factors such as temperature (minimum, maximum, average), wind velocity and solar gain, coupled with initial sag and tension calculations, determine maximum operating ratings, while factors such as humidity, pollution level, altitude and rain levels affect the insulation and support designs. Vector uses the methodology defined in IEEE Standard 738:1993 for calculating conductor ratings.

A computer package called “CONAMP” is used to determine the maximum rating of OH conductors.

5.3.3.3 Transformers

Technical specifications for the purchase of power transformers reflects Vector's network planning standards and network operating practices. Transformer specifications have varied over the years from the very early versions of British Standard BS-171 to the latest Australian Standard AS-2374, resulting in different thermal and loading guides for transformers conforming to the various standards.

Southern region power transformers have been designed around a base rating (usually ONAN) with a two hour extended operating (emergency) rating. The intent of the extended operating range is to provide overload capacity for a limited time to allow time for network switching to mitigate the conditions.[37]

Northern region power transformers were specified following a British standard based on a 12/24 hour cyclic rating scheme. This is interpreted as a maximum operating rating without additional overload or emergency rating.

Power transformers purchased since 2004 have been based on Vector Specification ENS-0120 which is an adaption of AS-2374 to Vector's specific requirements. Under this specification, transformers can operate up to 150% of nameplate rating for up to two hours (provided that the pre-contingent loading is no more than 75% of the nameplate rating), with a 120% of ONAN for normal cyclic loading.

Regardless of the transformer specification, Vector has three operating temperature limits:

- Top oil temperature - 105ºC;
- Conductor hot-spot temperature - 125ºC; and
- Metallic part temperature - 135ºC.

Subject to the transformer operating within these temperature limits, the transformer capacities are reviewed in accordance with load profiles to determine whether higher ratings may be achieved without marked degradation of transformer lives.

5.3.3.4 Switchboards and Switchgear

Indoor electrical distribution switchboards and outdoor switchgear are manufactured and tested to varying international and domestic electrical standards. Switchboard testing is based on nominal (environmental) operating conditions whereas switchgear (primarily outdoor apparatus) takes into consideration an extended operating environment.

Switchboards and switchgear on the Vector network can be operated to the manufacturers' nameplate values. These ratings are derived by the OEM type tests performed to the Standards specified when the equipment is purchased.

5.3.3.5 Fault Level

A fault on the network would generally result in high current flowing into the faulty component. The maximum current that can flow determines the required fault level of components. The effects of a fault current impact on the network component in the following manner:

- Heating effect: The fault current creates localised heating in the vicinity of the fault. The magnitude of the heating varies in proportion to the duration of the fault, resistance of the network component and the square of the fault current;

[37] It should be noted that the two hour emergency rating is not the same on all power transformers on the network. The OEM type test certificates and design specification need to be referred to determine the two hour emergency rating.

- Magnetic force: The large magnetic field caused by the fault current manifests itself as mechanical stress on the components leading to mechanical failure; and
- Arc breaking: The ability of the network isolation devices on the network to isolate the fault and interrupt the fault current.
- Network components have to be designed to withstand the mechanical forces and heating effects that will be experienced during fault conditions. If, during a fault, fault levels are exceeded, this can lead to catastrophic failure of equipment with severe associated health and safety risks. Equipment is, therefore, purchased to meet the maximum fault levels (prospective fault level) expected on the network. These are shown in Table 5-7.

Supply Voltage	Prospective Fault Current
110kV	31.5kA
33kV	25.0kA
22kV sub-transmission	25.0kA
22kV distribution	20.0kA
11kV distribution	13.1kA

Table 5-7 : Fault levels

Fault levels are determined through a combination of factors, mainly by the fault capacity of the bulk supply points, the impedance between a fault and the point of supply and the type of fault that occurs. Vector's distribution network is designed and built around the values stated in the above table. Should the fault levels change in future[38], it will likely involve very significant network upgrade expenses. (In Section 2.3.2.4 the actual calculated fault levels at Vector's zone substations are listed.)

Fault levels can also be exceeded in localised areas where substantial levels of distributed generation (including solar cell generation) are connected to the distribution network. Vector, therefore, has to monitor the impact of generation devices and limits exist on how much capacity can be connected to the network (without requiring investment in fault limiting devices).

5.3.4 Technical Standards and Regulations

The distribution of electricity in New Zealand is regulated though a number of standards and codes. These have to be adhered to and therefore taken into account as part of the network planning process. Some of the key requirements that impact significantly on network planning are discussed below.

In addition, Vector has also published a Distribution Code, in which it sets out the obligations on customers that connect to its distribution network and explains network parameters that customers should be aware of when designing their own installations and connection points.

5.3.4.1 Voltage Limits

Regulation 28 of the Electricity (Safety) Regulations 2010 requires that standard LV supply voltages (230V single phase or 400V three phase) must be kept within +/-6% of the nominal supply voltage, calculated at the point of supply except for momentary

[38] This is outside of Vector's control.

fluctuation. Supplies made at other voltages by agreement with the retailer or the customer and must be kept within +/-6% of the agreed nominal supply voltage except for momentary fluctuation, unless agreed otherwise with the retailer or the customers.

Design of the network takes into account the voltage variability due to changes in loading and embedded generation under normal and contingency conditions.

5.3.4.2 Power Factor

The Connection Code promulgated by the Electricity Authority as Part 8 of the Electricity Industry Participation Code 2010 requires the power factor of the load at Henderson, Albany and Wellsford GXPs be maintained at unity during peak demand times. For the other GXPs, the power factor is required to remain at a minimum of 0.95 lagging.

The ability to maintain unity power factor is unachievable in practice, and not economically efficient when compared with the small benefit it brings[39]. Vector has been granted an exemption[40] from the System Operator pending the agreement of a practical conclusion of the issue.

The Transmission Pricing Advisory Group (TPAG) tasked by the Electricity Authority to recommend a preferred transmission pricing option recommended (in respect to power factor) the removal of the unity power factor requirement and replace it with a minimum power factor of 0.95 lagging together with a kVAr charge. The Electricity Authority will consult on the matter prior to finalising a decision.

5.3.4.3 Power Quality

AS/NZS 6100 - Electromagnetic Compatibility, Parts 3.2 – 3.7 specify levels of harmonic content and voltage flicker which are acceptable on the network. These have been adopted by Vector.

5.3.4.4 Distribution Code

Vector has published the Distribution Code[41] on its website. The code specifies the requirements that customers connected to the distribution network must comply to ensure safety of other users of the network and the quality of the service delivered. It also provides reference to earthing, connection to Vector's network, load signalling equipment and frequencies, requirements for the connection of embedded generation, demand control and management, contingency planning and operational coordination between parties using the network, network safety and general planning information.

5.3.5 Service Levels

Vector has developed a set of standards that specify the minimum service levels that apply to customers connecting to its network[42].

- These service levels are described in the "Use of Network Agreement" (UNA) on the Northern network between Vector and Retailers, and the "Network Access

[39] Due to the fluctuating nature of electricity loads (even at peak), the difficulty of fine-tuning reactive compensation schemes, and the sophisticated in-time response that will be required to remain operating at even near unity power factor, the current ruling is impractical. On top of this, it is likely to be very expensive, which may lead to material increases in electricity pricing to our customers.

[40] The exemption expires on the 1 April 2013 but is conditional on Vector meeting a power factor of 0.975 lagging or 0.97 leading, at these sites during system peaks.

[41]http://www.vector.co.nz/sites/vector.co.nz/files/090227%20Distribution%20Code%20update%20Feb%2009.pdf

[42] More demanding service levels can be provided should customers require. For these situations special contracts and associated pricing arrangements are agreed to.

Agreement" (NAA) on the Southern network between Vector and our customers. They reflect the expected restoration timeframes and fault frequencies[43] [44] as mentioned on our website;

- The restoration timeframes are shown in Table 5-1 in the column "customer interruption outage duration" as targets for evaluating solutions to network security constraints. By factoring in target restoration timeframes into the network solutions, it ensures that we continue to meet service levels; and
- Fault frequencies are managed through targeted maintenance and asset replacement programmes and are described separately in Sections 4 and 6 of this Asset Management Plan.

5.4 Project Prioritisation

The planning process results in a list of network projects and non-network solutions. These projects, along with others submitted from other groups (asset replacement, overhead to underground conversions, customer connections etc) are evaluated against a project prioritisation matrix (see Section 9). The project prioritisation matrix considers company-wide factors such as operational, health and safety, environmental, legal, financial, reputational and regulatory risk to develop a priority ranking for the project.

The resulting list of projects becomes an input for the capital works programme. For network growth projects, the project priority is generally in the following order (from high to low):

- Avoiding capacity breaches that could lead to asset damage/eliminating unsafe situations;
- Avoiding breaches of electricity regulations (such as LV levels, etc);
- Avoiding capacity breaches that do not result in damage to assets;
- Avoiding supply security breaches;
- Enhancing network efficiency (including works programme synergy); and
- Opportunist implementation of long-term development opportunities (such as installation of cable ducts when other authorities do trenching work and are prepared to accommodate Vector in this).

5.4.1 Planning Under Uncertainty

A number of precautions are taken to mitigate the risks of long-term investments in an uncertain environment. Apart from normal business risk avoidance measures, specific actions taken to mitigate the risks associated with investing in networks include:

- Acting prudently: Make small incremental investments and defer large investments as long as reasonably possible (reinforce distribution feeders rather than build zone substations). The small investments must however conform with the long-term investment plan for a region and not lead to future asset stranding;
- Multiple planning timeframes: Produce plans based on near, medium and long-term views. The near term plan is the most accurate and generally captures load growth for the next three years. This timeframe identifies short-term growth patterns and leverages off historical trends. It allows sufficient time for planning,

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[43] Residential service standards on the Southern network
http://www.vector.co.nz/sites/vector.co.nz/files/Service%20Standards%20Residential%201009.pdf

[44] Commercial service levels on the Southern network
http://www.vector.co.nz/sites/vector.co.nz/files/Service%20Standards%20Business%201009.pdf

approval and network construction to be implemented ahead of the new network demand.

The medium-term plan looks out ten years, capturing regional development trends such as land rezoning, new transport routes and larger infra-structure projects. The medium-term plan also captures society's behavioural changes such as the adoption of heat pumps and new technologies (eg. PV panels, electric vehicles (EVs), etc) and global trends (eg. climate change, energy conservation, etc).

The long-term plan looks at growth patterns within the region at the end of the current asset lifecycle, say 40 years. A top-down approach predicts probable network loads within the region and superimposes zone substations and GXPs to meet these loads. The objective is less to develop accurate load forecasts and more to provide a long-term development plan identifying future zone substation and GXP requirements;

- Review significant replacement projects: For large network assets, rather than replace existing end-of-life assets with the modern equivalent, a review is carried out to confirm the need for the assets, the size and network configuration that will meet Vector's needs for the next asset lifecycle; and
- Use of non-network solutions where possible, to improve network utilisation and capital efficiency. Load control or shifting is a good example – moving demand from one time segment to another or from one feeder or substation to another without adversely affecting the customer, while deferring the need for new network investment.

The larger customer initiated projects can have a significant impact on the demand forecast and, therefore, the timing of capital investments. However unlike network growth projects where the timing is determined by Vector, the timing of the customer projects are dictated by the customer. Except for the near term projects, there is often a high degree of uncertainty both in terms of required demand and the date the demand will be required. Including new customers' demand forecasts without critically evaluating these, very often leads to an over-optimistic assessment of forecast demand, which if followed, would lead to a premature investment in additional capacity.

Vector's approach to these projects is to apply a weighting to the customers demand expectations, based on an assessment of the likelihood of the project proceeding in any particular year. This weighted demand assessment is included in the demand forecast. While some projects will still not proceed in the expected year, this tends to balance out the conservative provision included for those that do proceed.

5.5 Non-Traditional Network Solutions

While most of network development solutions tend to result in conventional asset investments – extensions of existing networks, using current (but traditional) assets – non-traditional solutions are also considered, and often applied, as part of the network development planning process. The most often-used forms of non-traditional options are discussed below.

5.5.1 Demand Management

Vector's load control strategy aims to offer:

- Network performance improvements by shedding interruptible loads (with customer agreement) in the event of faults. This allows load to be reduced without depriving customers of supply altogether;
- Improved capital efficiency and asset utilisation by reducing network peak demands. This defers the need for capital investment for additional network capacity; and

- Offering tariffs that take advantage of off-peak electricity consumption.

Some of the existing load management assets have been in service since the early 1950's. Progressive changes to the transmission pricing methodology in 2006 has meant that load control to contain GXP demands is no longer the key driver, nor the revenue earner it used to be to support the load control system. At present the system is predominantly used to shed load during contingency situations or where there is a short-term risk that network capacity may be exceeded.

The reliability of the Northern network pilot-wire based load control equipment means that it is unsuitable as a means of capex deferral, while the ripple based load control has limited coverage and is rather coarse for managing demand excesses (ie load control is applied across the entire substation rather than limiting it to the overloaded feeder). Hence it has not been used as a means of deferring capex investment. Ripple control on the Southern network is applied at a GXP level requiring control to be applied across multiple substations to perhaps manage the demand on only one distribution feeder. Again load control is not used on the Southern network to defer capital investment

Demand management will have an increasing role in the future, but with increasing application of two way communication, fibre–to-the-home, home management systems, smart appliances, smart meters and smart networks expected to emerge over the medium-term, further investment in conventional load control plants needs to be carefully considered.

5.5.2 Embedded Generation

Embedded generation refers to those generation connected to the Vector network either directly or via a customer's installation and are capable of exporting electricity into the network. Local generation is generally installed to provide a higher level of security than that offered by the network. The generation capacity is usually less than the customer's demand and is designed to support critical loads during contingency situations until the mains supply is restored.

There are a number of generators on the network but most are designed to operate as either back-up supplies in the event of power outages (these generators are not normally connected to the network) or are small (e.g. residential PV installations). The characteristics of back-up generation are they are generally 50kVA to 500kVA diesel generator sets which may or may-not have network synchronising capability to allow for no-break changeover when the power is restored. They are designed to run for a few hours during short duration power outages.

A number of the larger premises (such as Auckland Hospital, Watercare (Mangere)) have back-up generation with synchronising capability and can operate in parallel with the network but the owners choose to use these plants either for emergencies or to offset their own power needs rather than export energy.

The only generation plants that export energy within Vector's network in significant quantities are the land-fill generation plants at Rosedale, Whitford, Redvale and Greenmount. This generation has been factored into the demand forecast but due to the location of their respective connection points to the network, they have not offset any reinforcement projects.

The uptake of residential PV has been very low with very few applications being received. Their connection is randomly distributed throughout the network rather than clustered in any localised area and is therefore having minimal effect on the network.

5.5.2.1 Embedded Generation Connection Policy

To facilitate connection of embedded generation, Vector has posted its embedded generation connection procedures on its website. The procedures are based on the requirements contained in Part 6 of the Electricity Industry Participation Code 2010. The website also contains information to help the customer to understand the requirements for connection.

Vector's policy for connection of embedded generation to its network includes:

- The presence of embedded generation must not restrict Vector's switching operations on the network;
- Metering equipment installed at embedded generating stations must comply with the requirements of the Electricity Industry Participation Code;
- Embedded generation connected to the Vector network must comply with the requirements of all relevant Regulations and Electrical Codes of Practice, and the relevant requirements specified in the Electricity Industry Participation Code;
- Installation and operation of embedded generation equipment must comply with Vector's Distribution Code; and
- Installation and operation of embedded generation equipment must comply with all requirements as specified in Vector's "Technical Requirements for Connection of Distributed Generation".

Over the course of next year we intend to streamline the process for the connection of these smaller distributed generation installations. Vector's main concerns are the injection of harmonics on the network and ensuring operating voltages are maintained within the regulatory limits.

5.5.3 Non-Network and Non-Capacity Options

Vector is continually considering alternatives to investing in network solutions to meet customers' capacity and security requirements. Alternative solutions include non-network solutions or non-capacity network solutions.

Non-capacity solutions refer to those network solutions that do not involve investment in major network assets such as lines, cables or transformers. It includes demand side solutions independent of the Vector network. However, with the exception of embedded generation, non-network opportunities investigated to date have generally not been economically viable or sufficiently technically robust.

Some non-network solutions are being considered or trialled and other developments are being monitored with a view to being an early adopter (rather than first mover) of new technology once international evidence indicates that the technology is viable and reliable. Solutions adopted to avoid major network investment are being monitored and are described in the paragraphs below.

5.5.4 Automatic Load Transfer Schemes (Non-Capacity)

By making use of the different load profiles (residential/industrial) of neighbouring substations, Vector has been able to develop an automatic load transfer scheme to transfer load from a substation to another (of different load characteristics) with only a small increase in the demand of the recipient substation. The automation also enables the load transfer to take place within a fraction of a minute allowing the operators to utilise the short-term (higher) ratings of the assets. The automatic load transfer scheme applied to the Onehunga area enabled deferment of Hillsborough substation by seven years.

Suitable other areas for similar load transfer are being investigated on an ongoing basis to:

- Remove capacity constraints caused by asset components to improve the overall capacity of an asset;

- Explore integrated solutions with customers. Sometimes their initial requirements can be relaxed without any major compromise. This can lead to substantial cost savings;
- Develop short-term solutions that will migrate to a longer term solutions without asset stranding; and
- Leverage off other projects to gain synergies eg. asset replacement, undergrounding, road re-alignment or new road construction activities.

5.5.4.1 Load Shedding (Non-Capacity)

Vector's security standard allows zone substations to be loaded above their firm capacity for a percentage of the time, to maintain load while reconfiguring the network following a fault. To ensure assets are not damaged by overloading in the process, emergency load shedding schemes have been developed to shed load automatically. Load is restored via the SCADA when demand reduces to within equipment capacity.

5.5.4.2 Renewable Solutions (Non-Network)

PV panels, wind driven micro turbines and solar water heating all offer the potential for customers to reduce energy purchases from the grid. Currently PV panels are too expensive for widespread uptake for residential applications but the cost of these panels is reducing rapidly. Solar water heating is another means of utilising natural resources to reduce energy supplied from the network, but compared to PV it is not as versatile and this is expected to limit its development. Micro wind turbines have not yet proved economically viable.

These solutions will likely contribute to a reduction in overall energy consumption but will not always reduce peak demands. An energy storage system (such as rechargeable batteries) will help to utilise the renewable energy to reduce peak demand, but they are not yet economically viable. The development of these technologies is being closely monitored.

5.5.4.3 Interruptible Load (Non-Capacity)

An ability to interrupt customer demand during network contingencies or peak demand periods will enable Vector to avoid significant network reinforcements. Viable commercial arrangements are required to encourage customers to offer their load for shedding. An alternative is to invite load aggregators to offer "shedable" customer load and make it available at times when the network capacity is constrained. Aggregation is carried out by third parties who would contract with Vector to guarantee a minimum quantity of shedable load.

Vector is exploring options with individual customers and aggregators to develop viable interruptible load models.

5.5.4.4 Smart Metering (Non-Network)

Retailers have started to replace the largely mechanical legacy residential electricity meters with electronic "smart" units. This is being rolled out over the next few years. Current smart metering technology allows two way communications between the meter and the meter owner, which gives huge potential for improving meter reading accuracy and frequency, a better understanding of load patterns, time-of-use tariffs, outage notification etc.

These meters can also offer opportunities for demand side management. Not only can load control signals be issued to domestic appliances (including hot water cylinders presently controlled through load control systems), but customers can also be provided with a continuous indication of their energy usage. The latter, combined with tariff structures that encourage off-peak consumption, can lead to a win-win situation for consumers and distribution utilities – lower energy costs and better load factors.

Full realisation of these benefits is still some way off, but Vector is developing trials to assess what potential exists and will also work with retailers on developing more effective tariff structures.

5.5.4.5 Smart Technologies (Non-Network)

Investigations on a number of technologies such as smart appliances, home energy management systems and smart networks are ongoing to identify how we can use these technologies to help manage peak demands on the network. (See Section 3 for a more in-depth discussion.)

5.5.4.6 Mobile Generator Connecting Unit (Non-Network)

As an alternative to large network investment, or to defer large network investments, Vector considers the use of generation to make up any security shortfall and has applied this in the past. Modular generation of 200kVA - 1MVA generator capacity are generally sized for ease of transportation and have the capability to connect onto the LV network. The motor/generator fits into a 20ft container, making transport to site easy. These units are ideal to support load during LV network faults, while repairs are made to the network.

Vector has developed two mobile generator connection units (MGCUs) each capable of connecting up to 2.5MW of generation for feeding into the 11kV network during emergencies. This helps to enhance the security and reliability of the network in areas where security is below N-1. Significant standby and fuelling costs are, however, currently preventing these generators from being widely used.

5.5.4.7 Energy Substitution (Non-Network)

Energy substitution is the transference of consumption from one energy source to another. Examples include using reticulated gas or LPG instead of electricity for cooking and water or space heating. While the commercial and industrial sectors are receptive to multi-fuel options particularly where financial benefits result, the residential sector is less enthusiastic to change, largely due to the initial investment required. More detailed investigations are required, including the option of providing customer incentives to switch, before it can be confirmed that energy substitution is an economically viable option to network infrastructure investment.

5.5.4.8 Voltage Regulator/Capacitors (Non-Capacity)

Capacitors are installed on the network as a means of injecting reactive power to improve the network power factor and mitigate excess voltage drop. Traditional approaches rely on banks of capacitors switched into the network as the voltage drops outside preset limits. Technology advancements with fast switching power electronics has resulted in the development of static VAR[45] compensators (SVC), static compensators (STATCOM) and more recently dynamic VAR compensators (D-VAR) as refinements on capacitor banks.

Voltage regulators are used to boost the voltage on distribution circuits and are generally used in conjunction with capacitor banks. Their key application is on long distribution lines where significant LV problems are experienced. Capacitors and voltage regulators are effective means of solving LV problems in remote areas. If the voltage problem is

[45] VAR is volt ampere reactive

caused by excessive loading, other solutions such as increasing the size of conductors need to be carefully considered.

Vector has a number of capacitors and voltage regulators in use on its network and will continue to use them in appropriate situations. For example, the plans being finalised to install a second voltage regulator and capacitor bank on the Piha line to mitigate potential LV problems. This approach will defer the construction of a second 5km circuit to partially offload the existing lines.

5.5.4.9 Remote Area Power System (Non-Network)

Electricity supply to remote areas with very low load densities using a conventional network approach is very expensive. Alternatives such as local generation with a combination of diesel, mini hydro, renewable generation, PV, micro wind, batteries, bottled gas, etc could be a more economically attractive alternative.

The application of these alternative technologies is very dependent on the specific circumstance and needs to be assessed on a case-by-case basis.

5.6 Network Development Plan

The network development plan for the planning period is discussed in the following sections. Given the accuracy of information available and advanced planning concluded, planning for the first 24 months is at the most detailed level. The plan for the next three years (2015-2017) is somewhat less detailed, while the plans for the remaining five years is at a high level only.[46]

The development projects are discussed per GXP or per sub-transmission network. Only major projects are separately discussed – those with an estimated value of more than $1,000,000.

5.6.1 Vector Transmission Plan

Vector takes supply from Transpower at twelve GXPs to supply its sub-transmission networks in Auckland. A thirteenth GXP exists in Tokoroa to the Fonterra factory (Lichfield). Auckland also has five bulk supply substations as part of its sub-transmission network to supply the various metropolitan population and business centres. The electricity supply into Auckland from generation in the central North Island and the South Island is provided by six 220kV circuits and two 110kV circuits. All eight circuits terminate onto the 220kV bus and 110kV bus at Otahuhu GXP. Two major generating stations exist in Auckland, namely Southdown and Otahuhu. No significant operative generation exists north of Auckland.

The Northern network has five GXPs, viz: Wellsford, Silverdale, Albany, Henderson and Hepburn and one bulk supply point, namely Wairau Road substation.

The Southern network has seven GXPs, viz: Takanini, Wiri, Otahuhu, Pakuranga, Mangere, Penrose and Roskill. Hepburn is shared with the Northern network. In addition, Vector has four internal bulk supply points, at Kingsland substation and within the CBD (Liverpool, Quay St and Hobson substations).

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[46] Vector acknowledges that the Commission's AMP Requirements 4.5.5e, 4.5.5f and 4.5.5g (analysis of options considered) suggests that a full options analysis should be provided for all material growth projects over the whole AMP planning period. However, given the size of the Vector network, the annual growth expenditure and the number of projects such an analysis would have to include, we do not have sufficient planning resources available to fully meet this requirement and do not believe that it is economically efficient to expand our team for this purpose. Vector has therefore (for economic reasons) decided to only focus its option analysis for AMP purposes on near term, large projects.

Transmission into Auckland, existing GXPs, and the cross-isthmus 220kV (NAaN) cable that will supply two new GXPs at Hobson and Wairau substations, are shown in the geo-schematic Figure 5-7.

Recognising the demand growth in the region, Transpower is undertaking major reinforcements of the grid to Northern Auckland and Northland. The North Island Grid Upgrade Project (NIGUP) and North Auckland and Northland (NAaN) projects were approved by the Electricity Commission and are currently in progress. The NIGUP project involves constructing two 400kV rated circuits from Whakamaru to a terminal station at Whitford (Brownhill Rd transition station), in South Auckland. From there two 220kV circuits will run to Pakuranga substation. The 400kV circuit will initially operate at 220kV, and will be uprated to 400kV when warranted by the demand. This project is scheduled for commissioning in 2012.

The NAaN project comprises a 220kV XLPE cable circuit between Transpower's Pakuranga substation to Penrose and then Albany 220kV substations. Two new GXPs for the Vector network will be leveraged off the NAaN circuit to cost effectively maintain security of supply standards and allow for load growth in the long-term in Auckland's CBD (Hobson) and on Auckland's North Shore (Wairau). Over the long-term the NAaN project also allows for a 2nd 220kV cable to be installed between Penrose and Albany.

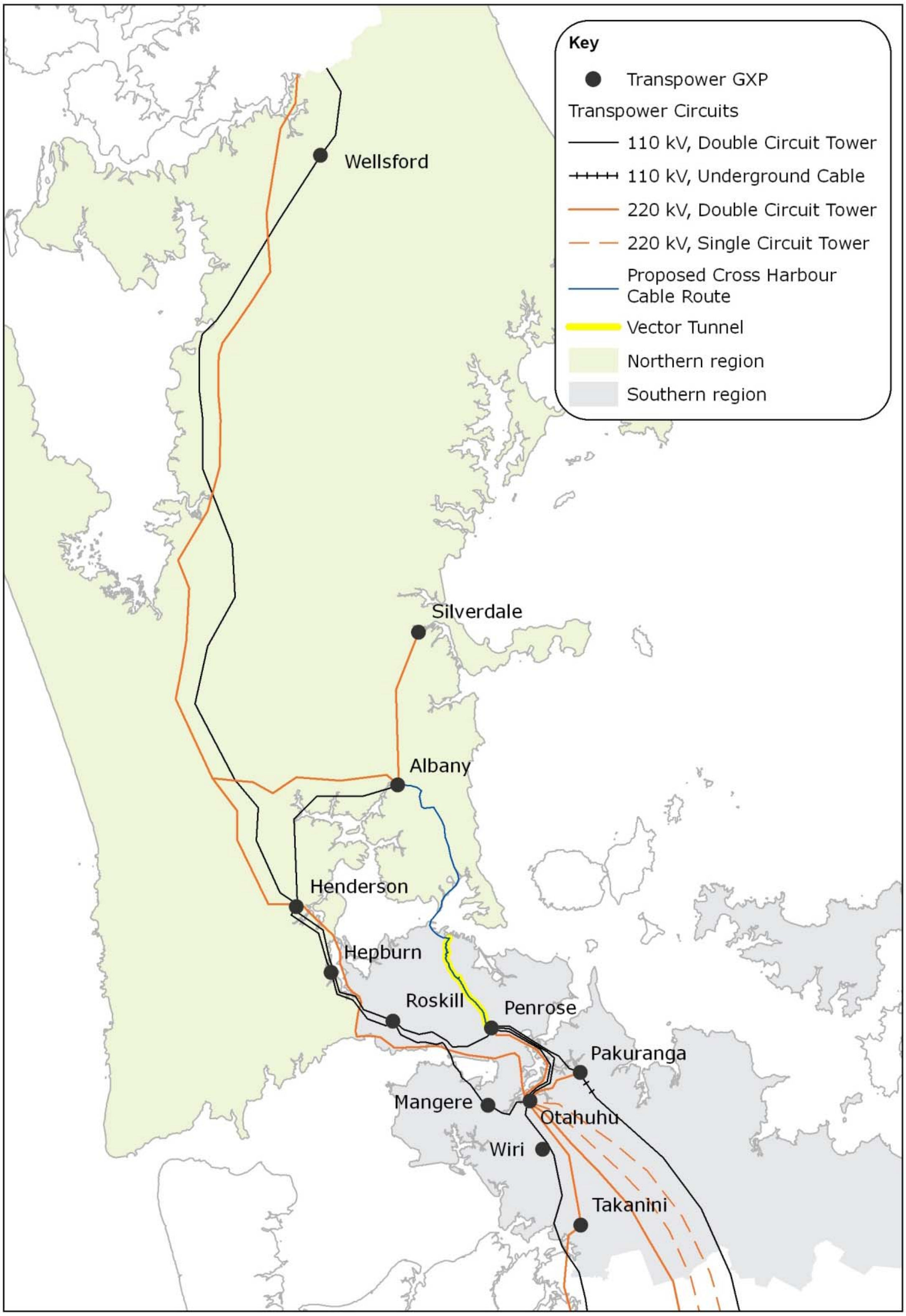

Figure 5-7: Transmission into Auckland and GXPs in Auckland

The Wairau GXP is scheduled for completion in 2013 and the Hobson GXP in 2014. Figure 5-8[47] shows the NIGUP and NAaN projects (in red).

[47] Figure taken from the Transpower 2010 annual plan and used with the permission of Transpower

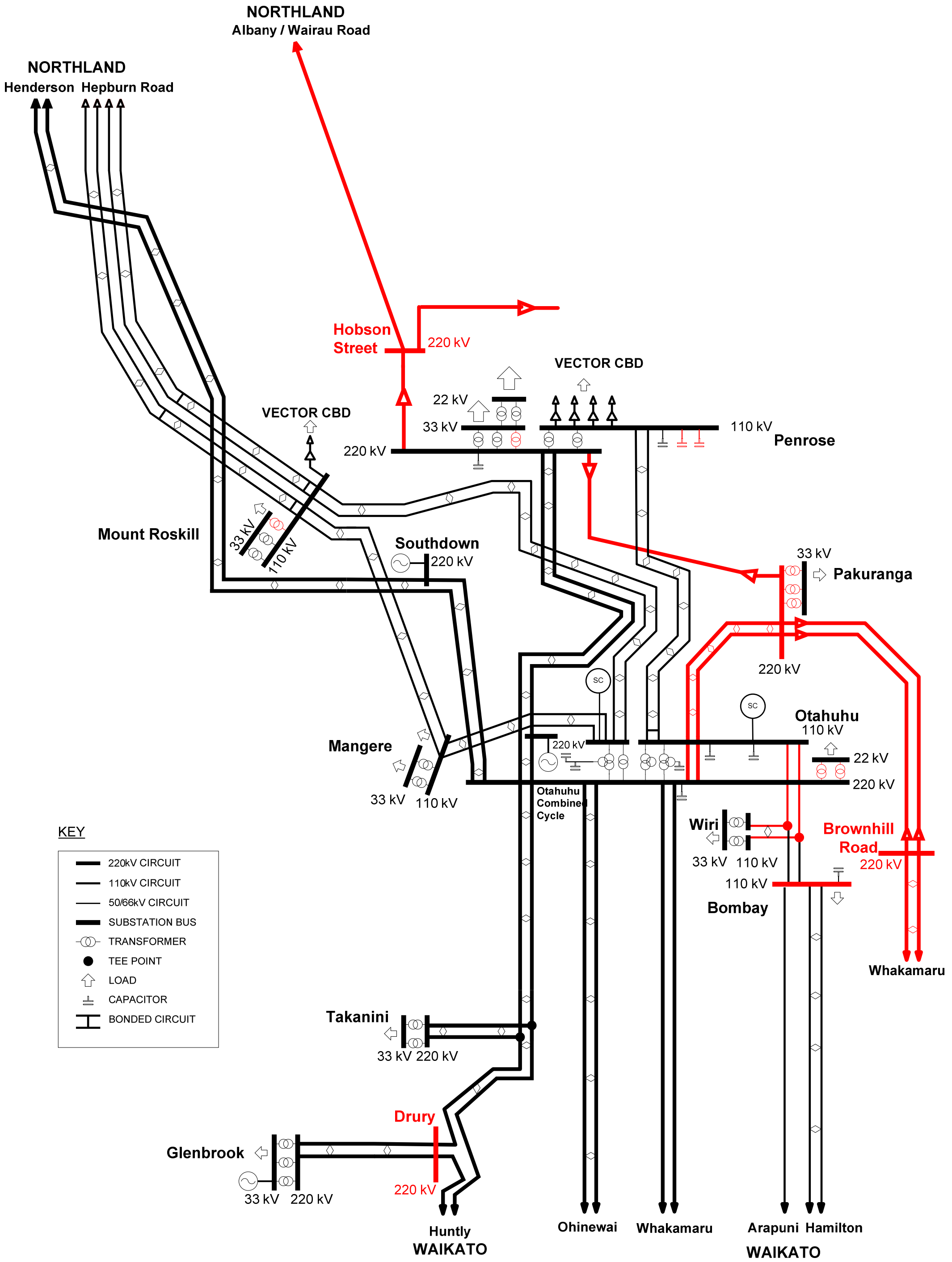

Figure 5-8: Auckland Transmission: NIGUP and NAaN circuits[48]

5.6.1.1 Grid Exit Points

Table 5-8 and Table 5-9 show the winter and summer peak demands at GXPs and the installed and firm capacity at each of these supply points.

[48] Figure taken from the Transpower 2010 annual plan and used with the permission of Transpower

Grid Exit Point	Supply Voltage	Installed Transformer Capacity (MVA)	Firm Capacity[49] (MVA)	2011 Winter Peak Demand (MVA)
Albany	110kV			140
Albany	33kV	3x120	234	162
Henderson	33kV	2x120	135	127
Hepburn	33kV	1x85 + 2x120	245	140
Lichfield	110kV			9
Mangere	110kV			56
Mangere	33kV	2x120	118	107
Otahuhu	22Kv	2x50	59	64
Pakuranga	33kV	2x120	136	153
Penrose	110kV			198
Penrose	22kV	3x45	90	55
Penrose	33kV	1x169[50] + 2x160 + 1x200	429	343
Roskill	110kV			59
Roskill	22kV	2x70 + 1x50	141	140
Silverdale	33kV	1x120 + 1x100	109	83
Takanini	33kV	2x150	123	117
Wellsford	33kV	2x30	31	31
Wiri	33kV	2x100	107	83

Table 5-8 : Grid Exit points - winter loads

Grid Exit Point	Supply Voltage	Installed Transformer Capacity (MVA)	Firm Capacity (MVA)	2011 Summer Peak Demand (MVA)
Albany	110kV			85
Albany	33kV	3x120	234	107
Henderson	33kV	2x120	135	74
Hepburn	33kV	1x85 + 2x120	239	89
Lichfield	110kV			7
Mangere	110kV			52
Mangere	33kV	2x120	118	87
Otahuhu	22KV	2x50	59	46
Pakuranga	33kV	2x120	136	103
Penrose	110kV			204
Penrose	33kV	1x169 + 2x160 + 1x200	406	273
Penrose	22kV	3x45	90	53
Roskill	110kV			34
Roskill	22kV	2x70 + 1x50	141	73

[49] Firm capacities supplied by Transpower

[50] The 169MVA 220/33kV transformer operate on normally open standby mode

Grid Exit Point	Supply Voltage	Installed Transformer Capacity (MVA)	Firm Capacity (MVA)	2011 Summer Peak Demand (MVA)
Silverdale	33kV	1x120 + 1x100	109	46
Takanini	33kV	2x150	123	86
Wellsford	33kV	2x30	31	21
Wiri	33kV	2x100	107	70

Table 5-9 : Grid Exit points - summer loads

5.6.1.2 Vector-Owned Bulk Supply Points

Vector also has five bulk supply substations (110kV) to supply its sub-transmission networks in Auckland and two customer dedicated 110kV supplies (Pacific Steel and Lichfield). These bulk supply substations, listed in Table 5-10 and Table 5-11, are connected to the grid but are some distance away. Both Hobson and Wairau bulk supply points will be upgraded to GXPs by 2014. These projects are stated in more detail further on in this section.

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	Firm Capacity (MVA)	2011 Winter Peak Demand (MVA)
Hobson[51]	22kV	2x65[52]	80[53]	76.7[54]
	11kV		25	18.6
Kingsland	22kV	2x60	60	60.4
Lichfield	11kV	2x20	24	8.5
Liverpool	22kV	2x75+1x60	114[55]	77.6
Pacific Steel	33kV	70+40	40	55.8
Quay	22kV	1x60[56]+2x50	48	32.7
Wairau Road	33kV	3x80	160	140.2

Table 5-10 : Internal Vector bulk supply points - winter demand

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	Firm Capacity (MVA)	2011 Summer Peak Demand (MVA)
Hobson	22kV	2x65	80	81.0
	11kV		25	22.2
Kingsland	22kV	2x60	60	34.8
Lichfield	11kV	2x20	24	8.7

[51] The two 65MVA three winding transformers operate in parallel with the 60MVA transformer (unit T3B) at Quay substation via 22kV interconnector cables.

[52] These are three winding transformers with two secondary windings supplying 40MVA at 22kV and 25MVA at 11kV

[53] Firm capacity includes the capacity of unit T3B (60MVA) at Quay substation.

[54] The load includes Hobson substation 22kV, Liverpool substation 22kV lower bus and Quay substation 22kV lower bus.

[55] Firm capacity reduced due to uneven load sharing of transformers.

[56] This 60MVA transformer (unit T3B) operate in parallel with the two three winding transformers at Hobson substation via 22kV interconnector cables and is independent of the two 50MVA transformers at Quay substation.

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	Firm Capacity (MVA)	2011 Summer Peak Demand (MVA)
Liverpool	22kV	2x75+1x60	114	80.9
Pacific Steel	33kV	70+40	40	52.2
Quay	22kV	1x60+2x50	33	29.9
Wairau Road	33kV	3x80	160	85.0

Table 5-11 : Internal Vector bulk supply points - summer demand

5.6.2 Northern Sub-Transmission Network

Security of supply to Wairau Rd will be enhanced by connecting the Hobson/Albany 220kV circuit to this site, creating a new GXP. This will address an existing HILP risk associated with a pole failure on the double circuit 110kV line currently feeding Wairau substation. Construction work commenced in 2011 with a scheduled commissioning date of June 2013. In future, Wairau will be able to be supplied from either Penrose or Albany.

No further new GXPs or extensions to the sub-transmission network are planned in the Northern area for the AMP planning period.

5.6.2.1 Projects Planned (Transpower Projects)

a. Projects – next five years

- **Wairau substation**

  Establish a 120MVA 220/33kV GXP in conjunction with Transpower and installation of a new indoor 33kV switchboard to replace the existing outdoor board

- **Wellsford substation**

  Upgrade the protection equipment of the transformers to increase the n-1 capacity to 37/39MVA (summer/winter)

b. Projects – long term

- **Silverdale**

  Replace 100MVA transformer

- **Rodney**

  Establish a new GXP

- **Huapai**

  Establish a new GXP

- **Wellsford**

  Replace the existing two 110/33kV transformers

5.6.3 Southern Sub-Transmission Network

The Southern network has seven GXPs; Roskill, Penrose, Pakuranga, Mangere, Otahuhu, Wiri and Takanini. Although the CBD is geographically viewed as being in the Southern region it is described separately above for the reason that the network in and to the city is more complex, extensive and load intensive. A GXP exists in Tokoroa to supply a Fonterra facility (Lichfield GXP).

No GXPs are planned in the Southern region for the short-term planning period.

A GXP is planned at Southdown in the long-term (2022) and in the southern precinct of Newmarket (2020) which will take load off the Penrose GXP. In line with the development strategy for the sub-transmission network the capacities of the future GXPs will be limited to 120MVA. Load at the Penrose GXP will be limited to 240MVA.

Vector owns and operates two 110kV 0.25 sq inch Copper-conductor oil-filled cables with summer/winter ratings of 80/51MVA from Roskill GXP to Kingsland substation. The cables connect to two 60MVA 110/22kV transformers.

5.6.3.1 Projects Planned (Transpower Projects)

a. Projects – within five years

- **Pakuranga**

  Replace 33kV switchboard and install 3rd 220/33kV transformer.

- **Penrose**

  Replace 33kV switchboard.

- **Mangere 33kV**

  Outdoor to indoor conversion of switchgear.

- **Mt Roskill 22kV**

  Outdoor to indoor conversion of switchgear.

- **Penrose**

  End of life transformer replacement

- **Takanini**

  Outdoor to indoor conversion of switchgear.

- **Wiri**

  End of life transformer replacement and outdoor to indoor conversion of switchgear

b. Projects – within five to ten years

- **Otahuhu**

  Install a third transformer.

- **Mangere**

  Install a third 110/33kV transformer.

- **Wiri**

  Replace two existing 110/22kV transformers.

- **Mt Roskill**

  Replace the existing 50MVA transformer.

- **Otahuhu interconnecting transformer**

  End of life transformer replacement (Transpower project).

c. Projects – long-term

Although the long-term projects fall outside the planning period of the AMP, preliminary indications are that the following projects will be required between 2020 and 2030. (This may influence interim network developments as well.)

- **Newmarket**

  Establish a 110/33kV bulk supply point at Newmarket.
- **Southdown**

  Establish a new 220/33kV GXP.
- **Browns Hill**

  Establish a new 220/33kV GXP.

5.6.4 Wellsford 33kV

5.6.4.1 Background

Vector takes supply from the Wellsford 33kV bus via two 220/33kV 30MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 31/31MVA and three zone substations are supplied from this 33kV bus, viz., Wellsford, Warkworth and Snells Beach.

The summer and winter load forecasts are listed in Table 5-12.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Wellsford 33kV	31	21	21	21	22	23	23	23	24	24	24	24
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Wellsford 33kV	31	31	32	32	32	33	33	34	34	34	35	35

Table 5-12 : Wellsford 33kV summer and winter load projections

There are two 33kV overhead lines supplying the Warkworth substation. As the circuits are close together in places, there is also a risk of both circuits being taken out by the same event (common mode failure such as a tree falling over). However, vegetation management alongside the lines means that this risk is being managed. In the longer term it is planned to construct a third 33kV circuit between Wellsford and Warkworth substations on a different route.

There are three sites for future zone substations supplied from this GXP – one at Big Omaha (Leigh Road), one at Tomarata (opposite Domain) and one in Warkworth (Glenmore Drive). The site at Omaha South was purchased some time ago and the load has developed further to the south at Matakana. It would be desirable to sell the Omaha South site and purchase a new site closer to the load centre at Matakana. This new site would enable the new substation to be ring fed on the 33kV network and allow the 11kV feeders to easily integrate into the existing network.

There is planned growth in the Mangawhai Heads and Te Arai areas which may affect the timing of the Tomarata substation. Proposals for developing Te Arai have been scaled back and may not be a significant load in future. Voltage drop on the rural 11kV network has been identified as a growing issue and additional 11kV voltage regulators and/or capacitor banks will be investigated and installed as required.

A new substation will be required at Sandspit in 2018 to offload and backstop Snells Beach substation. Snells Beach substation is a single transformer substation and the load in the area peaks over the summer period. Options for a 33kV ring (Southern Ring) between Warkworth, Sandspit, Snells Beach, Glenmore Drive and back to

Warkworth have been investigated and a preferred option selected, as indicated on the plan below. The third 33kV circuit from Wellsford to Warkworth will improve the security of supply to the substations supplied from the Warkworth 33kV bus.

The geo-schematic diagram in Figure 5-9 shows the proposed supply arrangement in the Wellsford area.

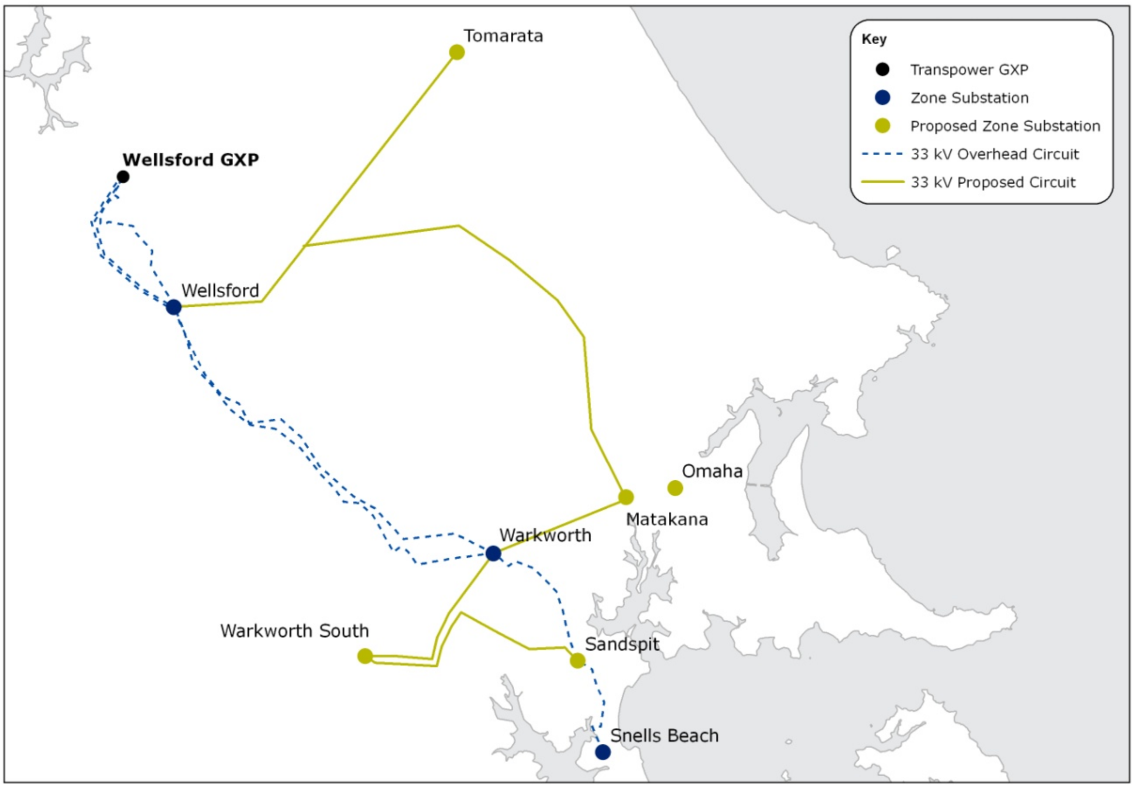

Figure 5-9 : Existing and proposed supply arrangement in the Wellsford area

5.6.4.2 Projects Planned

a. Projects – Within the next five years

- **Warkworth - New 11kV feeder to reinforce the Warkworth industrial area** (FY13)

  The Woodcocks Rd area is the industrial heart of Warkworth and has been developing rapidly over the last few years. The two main feeders supplying this area (Woodcocks and Limeworks) are very heavily loaded and cannot be fully backstopped during peak load times. Reinforcing the Limeworks feeder will allow additional backstopping to the Snells Beach substation and defer the need for the Sandspit substation. The long-term plan to reinforce this area is to establish a new zone substation in Glenmore Road. The existing Warkworth substation is about 5km away to the east and the available 11kV feeder capacity into this area is inadequate. This project is to install a new 33kV cable from Warkworth substation to Woodcocks Road and initially operate this new feeder at 11kV. This will provide temporary relief to the 11kV network until the zone substation is required. Given the forecast load for this area and the industrial load, non-network options are not economically viable.

  Other options investigated include 11kV reinforcement from Warkworth substation but as well as being expensive; it limits future 33kV reinforcement to Glenmore Rd.

The Warkworth South substation could be established now but the preferred option takes a staged approach to establishing this substation.

- **Warkworth - Matakana 11kV feeder reinforcement** (FY15)

  The Matakana 11kV feeder from Warkworth substation is a very long semi-rural feeder with limited backstopping. The load on this feeder is quite high and growing. It is proposed to reinforce this feeder so it can be split in two to improve the backstopping. The option chosen is to underbuild a section of an 11kV existing feeder which is constructed at 33kV. This will allow the new feeder to be commissioned at 11kV but uprated to 33kV to supply the new substation at Matakana in the future. An added advantage of this option is to improve the backstopping to Snells Beach substation which is also heavily loaded. Other options investigated include establishing the Matakana substation but this cannot be justified at this stage. There are no non-network options which will resolve the backstopping issues.

- **Warkworth South – new zone substation** (FY17)

  Warkworth zone substation was established about 5km to the east of Warkworth township. Over the years, Warkworth township has expanded to the west and east meaning the load centre has moved further from Warkworth substation. There are currently three 11kV feeders supplying this area and they are now in need of reinforcement (see new feeder planned for 2012). Warkworth substation switch room is fully extended and the long-term plan for supplying the Warkworth area is to establish new zone substations at Warkworth South (Glenmore Rd) and at Sandspit. The area is largely rural and has some very long feeders which creates voltage regulation issues. Establishing a new zone substation at Warkworth South will provide additional capacity at the load centre and enable some of the very long feeders to be offloaded and shortened.

- **Warkworth - Whangateau 11kV feeder reinforcement Keeling Rd zone substation** (FY14)

  The Whangateau 11kV feeder from Warkworth substation is a very long semi-rural feeder with limited backstopping. The main backstop for this feeder is the Tomarata feeder from Wellsford and, during contingency events, low voltage is an issue. In conjunction with the Matakana feeder reinforcement project (see above) it is planned to install a backstop from Omaha Beach (which is supplied by a spur line) to the Whangateau feeder. This provides a backstop for Omaha Beach and also a backstop for the Whangateau feeder. Other options such as voltage regulators and capacitor banks will be investigated to see if they can solve any of the supply issues. This is a security of supply issue and non-network options are not viable.

b. Projects – Within the five to ten years

- **Sandspit – new zone substation** (FY18)

  The existing supply to the Sandspit and Snells Beach areas is from Snells Beach substation. This is a single transformer substation with a 7.5MVA transformer installed. The substation is currently about 80% loaded and will require reinforcement in the next few years. New subdivisions have been developed in this area and more are planned. However, with the slow-down in the economy, development of new subdivisions has slowed substantially. There are two main reinforcement options for improving the supply to Snells Beach. The first option is to reinforce the Snells Beach substation with a second transformer. This would involve constructing a new 33kV line from Warkworth substation to Snells Beach to improve the security of supply. The second option is to construct a new substation at Sandspit which is mid way between Snells Beach substation and Warkworth substation. This new substation would be able to offload Snells Beach substation and make provision for future load growth in the area. A new 33kV line will be required to be constructed from the Sandspit substation to the Warkworth South substation to provide a secure supply to the substation. This is the preferred option.

The two 11kV feeder projects mentioned above will improve the backstopping to Snells Beach substation and may mean that the Sandspit substation can be deferred beyond 2018. Non-network options have been considered but are not viable alternatives to network reinforcement.

5.6.5 Silverdale 33kV

5.6.5.1 Background

Vector takes supply from the Silverdale 33kV bus via two 220/33kV transformers, one rated at 100MVA and the other rated at 120MVA. The N-1 capacity limit (winter/summer) of this GXP is 109/109MVA and six zone substations are supplied from this 33kV bus, viz., Orewa, Manly, Spur Rd, Gulf Harbour, Red Beach and Helensville.

The summer and winter load forecasts are listed in Table 5-13.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Silverdale 33kV	109	46	45	47	48	50	51	51	52	53	54	54
Name	Firm Capacity	Actual	Forecast Demand (MVA) - Winter									
		FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Silverdale 33kV	109	83	79	80	81	82	83	84	85	86	87	88

Table 5-13 : Silverdale 33kV summer and winter load projections

Red Beach substation was commissioned in December 2007 and Gulf Harbour in January 2009. Several other zone substations are planned to be supplied from this GXP. These are at Kaukapakapa, Wainui (Silverdale North) and Waiwera. The Kaukapakapa substation is planned for 2017 when security at Helensville is forecast to be breached. However, this assumes the Waimauku substation reinforcement project is commissioned in 2012. There are no firm plans for the Silverdale North (Wainui) substation at this stage but it is planned to purchase a site within the next few years. An area has been identified for the Waiwera substation but land has not been purchased.

The geo-schematic diagram in Figure 5-10 shows the proposed supply arrangement in the Silverdale area.

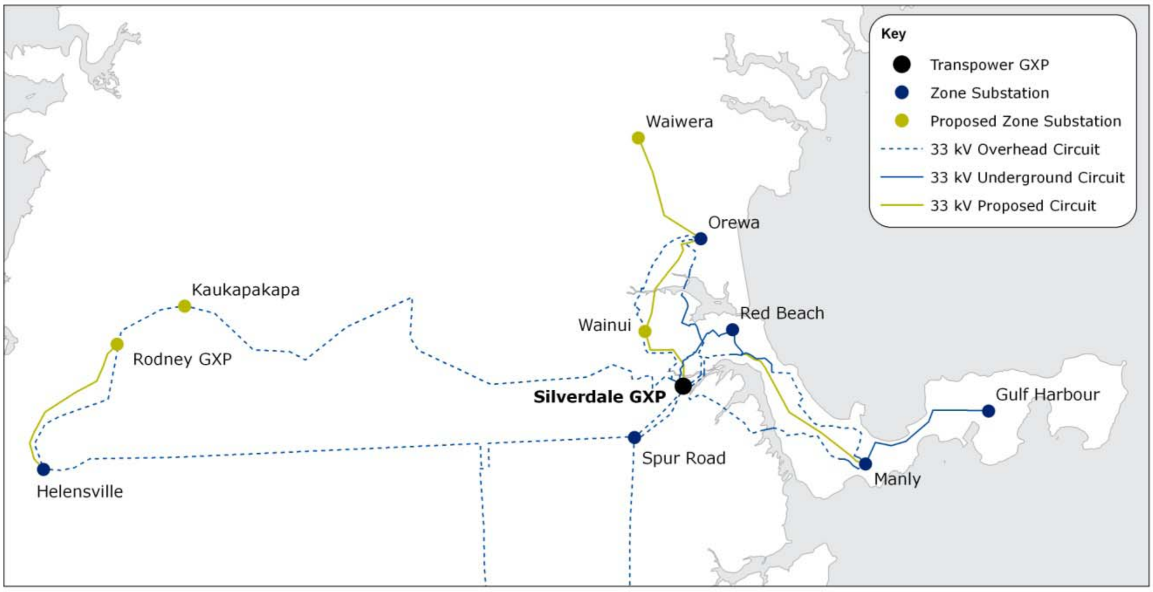

Figure 5-10 : Existing and proposed supply arrangement in the Silverdale area

5.6.5.2 Projects Planned

a. Projects – Within the next five years

- **Orewa - Weranui 11kV feeder** (FY12)

  The Waiwera 11kV feeder from Orewa zone substation is a very long feeder supplying a largely rural area. The Hatfield 11kV feeder requires reinforcement and various options have been investigated. Load flow analysis shows that over the next two to three years, the loads in both summer and winter will increase considerably. Any large loads proposed at Waiwera township and thermal area will be difficult to supply.

  The Waiwera feeder is constructed at 33kV for the first several kilometres and allows for a future zone substation. The plan was to underbuild the existing Waiwera feeder as far as Hillcrest Road and then split the feeder into two. This would provide immediate relief for the existing feeders and also allows for the future zone substation.

  Further analysis of the options indicated that it would be possible to transfer the Waiwera feeder load onto adjacent feeders – one from Orewa substation and one from Red Beach substation. This work has almost been completed and the original project will no longer proceed. It will be deferred until the load increases sufficiently to justify the project which is currently beyond the end of the planning period.

- **Manly – Wade River feeder reinforcement** (FY13)

  The Wade River 11kV feeder from Spur Rd substation supplies across the Weiti River to close to Manly substation. This was built to offload Manly substation which was heavily loaded before it was reinforced from Red Beach and Gulf Harbour substations. It is now possible to install a new feeder from Manly to offload the Wade River feeder and restore the open points to a more normal configuration. The Pine Valley feeder from Spur Rd supplies the industrial area of Silverdale and requires offloading. The Wade River feeder will achieve this once it is offloaded to Manly substation.

The other advantage of this new feeder is that it offloads Spur Road substation which is heavily loaded. This defers the need to install a second transformer at Spur Rd substation. A second transformer at Spur Rd substation is one option for supplying the Silverdale North subdivision as an option instead of the new Wainui substation (see discussion below).

- **Red Beach – second 33/11kV transformer** (FY14)

  Red Beach substation was commissioned in 2007 with a single 33/11kV transformer. This substation has been able to offload the adjacent substations of Manly and Orewa and supply some of the new load coming on stream in the Silverdale North subdivision. The Silverdale North load is expected to grow over the next few years and by 2014 a second transformer will be required to maintain the security of supply to the area. This will allow this substation to continue to support Orewa substation and supply Silverdale North until the Wainui zone substation is commissioned. The substation was designed with space for a second transformer.

  Other options considered include bringing forward the Wainui substation. This would be a very expensive option. It is not possible to supply more load from the Spur Rd substation as this substation is also a single transformer substation and heavily loaded. Non-network options are not economically viable given the large area of land being developed into residential subdivisions.

- **Orewa – Savoy 11kV feeder reinforcement** (FY15)

  The load forecast indicates that during this period, the Savoy and Maire Rd feeders will require reinforcement to comply with security criteria. It is expected that the northern end of the Silverdale North subdivision (Millwater) will develop quickly and will require additional capacity. A feeder cable has been previously laid a large part of the way and this project will take advantage of this cable.

  The district plan allows high density development along the Orewa foreshore which will increase the load significantly. The Fantail Court feeder from Red Beach substation supplies part of the Orewa business area and is getting highly loaded. Reinforcement from Orewa substation with a new feeder is a cost effective way of reinforcing the area. Another possible option is to install a new 11kV feeder from Red Beach substation. However, this is likely to be more expensive. Non-network options are not considered viable for this project.

- **Wainui - substation land** (FY15)

  The long-term plan for the Silverdale area indicates that a new zone substation will be required at Silverdale North (Wainui), especially when the business park proceeds. This land is required to secure a site for the future zone substation. With the economic downturn, load growth has been slower than expected and Red Beach substation can supply the additional load once it gets reinforced with a second transformer. This land purchase will ensure that a new zone substation can be built in the future to reinforce Red Beach, Orewa and Spur Rd substations. Options considered include a second transformer at Spur Rd substation but this is some distance from the load centre. It is expected that the business park load could be 10-15MVA of load which means that non-network options are not viable.

- **Kaukapakapa – establish substation** (FY17)

  The load forecasts indicate that by 2017 a new zone substation will be required at Kaukapakapa to reinforce and offload Helensville substation.

5.6.6 Albany 33kV

5.6.6.1 Background

Vector takes supply from the Albany 33kV bus via three 220/33kV, 120MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 234/234MVA and eleven zone substations are supplied from this 33kV bus, namely, Coatesville, Waimauku, Bush Rd, James St, Forrest Hill, Sunset Rd, East Coast Rd, McKinnon, Browns Bay, Waiake and Torbay. The summer and winter load forecasts are listed in Table 5-14.

Additional substations will be required in the future at Albany, Rosedale, Glenvar, Northcross and Albany Heights.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Albany 33kV	234	107	106	108	111	114	115	116	117	119	120	121
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Albany 33kV	234	162	162	163	165	167	168	170	171	173	175	176

Table 5-14 : Albany 33kV summer and winter load projections

The geo-schematic diagram in Figure 5-11 shows the proposed supply arrangement in the Albany and Wairau areas.

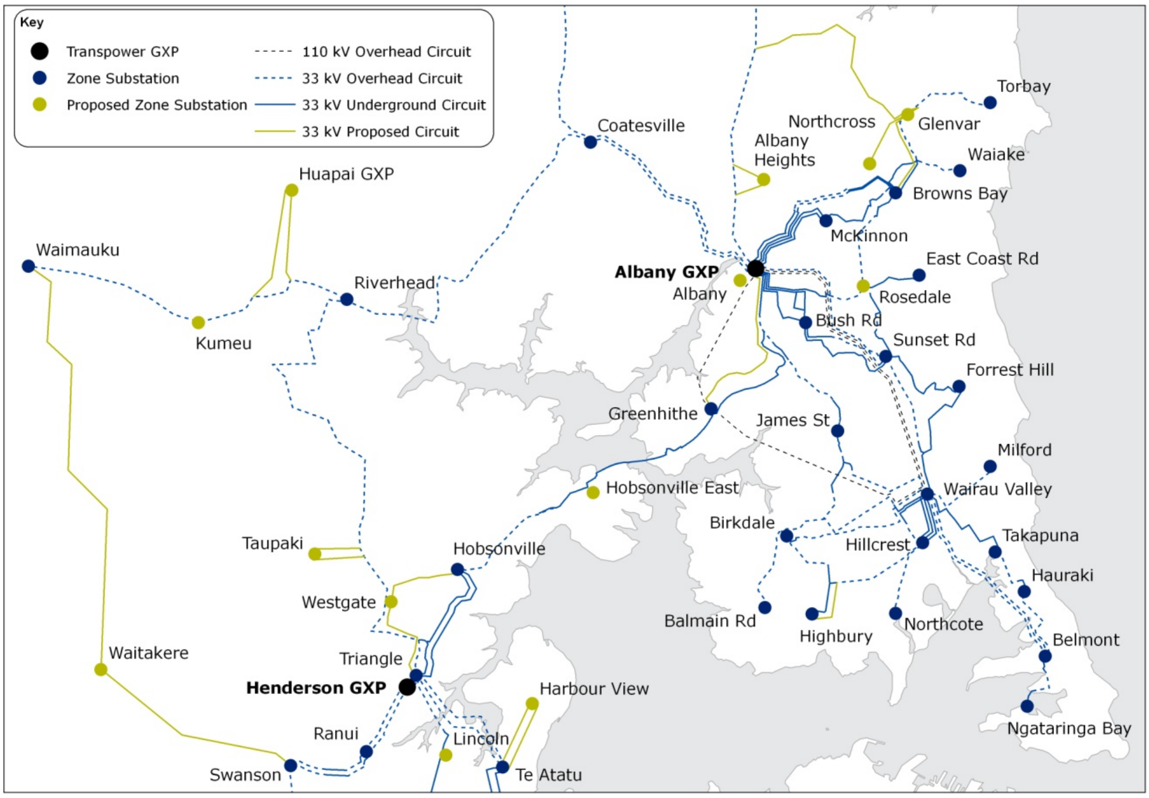

Figure 5-11 : Existing and proposed supply arrangement in the Albany and Wairau areas

5.6.6.2 Projects Planned

a. Projects – Within the next five years

- **Rosedale substation** (FY14)

  The area around Rosedale Road, between the motorway and East Coast Road, has developed rapidly over the last five years. The bulk of this area is business zoned land. The 11kV feeders supplying this area are approaching capacity and need augmenting to provide sufficient backstopping capability. Additional capacity is required as there is still further land for development.

  The two recommended options from the list below were a new zone substation with a single 33/11kV transformer at Rosedale or a second 33/11kV transformer at East Coast Road substation. Both of these options would reinforce the area but the Rosedale option has the additional benefits of being able to backstop and offload Bush Road and McKinnon substations.

  The land for the substation is intended to be purchased during early 2012, with construction starting shortly thereafter.

  The following options were investigated:

  - Establish a new zone substation in Old Rosedale Road, close to the motorway. A site is currently under negotiation. This site provides the ability to interconnect with Bush Road and McKinnon substations and backstop these adjacent substations. It can also backup both East Coast Road and Sunset Road substations;
  - Increase the capacity at East Coast Road substation. This option is practical but a second 33kV supply would be required to provide security of supply to the substation. This can be achieved with a cable from Rosedale Road about 1.5km away but would require a 33kV switching station by the motorway. The cost difference between establishing Rosedale substation and reinforcing East Coast Road substation is minimal. However, reinforcing East Coast Rd substation places the network capacity on the edge of the load centre, rather than the centre as in the case of Rosedale substation. Therefore, the Rosedale substation is the preferred option;
  - Use load control to reduce the load on the feeders. A large proportion of the load supplied in the Rosedale area is business load which has very little controllable load, such as hot water load. Commercial options are not currently in place and realistically are unlikely to be able to defer the proposed substation; and
  - Transfer load to adjacent substations. This is not a realistic option without increasing the capacity of adjacent substations. McKinnon and Bush Rd are unsuitable for expansion at this time.

- **Waimauku substation** (FY12)

  Waimauku substation is a rural substation and has a single 7.5MVA 33/11kV transformer which is loaded to more than 80%. There is a single 33kV line supplying the substation from Riverhead. Further residential subdivisions are planned for the Waimauku area and reinforcement is required.

  The proposed solution at this stage is to install a second 33/11kV transformer at Waimauku. This will provide adequate capacity and enable Waimauku to be able to backup Helensville substation in emergencies. A separate project will be initiated to install additional 11kV feeders.

  The following options were investigated:

- Transfer load: There are few options available for transferring load. The closest substation is Riverhead which has two 7.5MVA transformers and a load of 9.6MVA. The distance between the two substations is 8.5km. To benefit, the new feeder would have to connect the two substations. This is a costly option with a cabled feeder costing around $2.5 million. An overhead feeder would have to be double circuit on existing poles, which has reduced reliability and is vulnerable to outside influences such as a car verses pole (as is the 33kV supply). This option is not a cost effective option;
- Install a second transformer at Waimauku: The plan is to install a second transformer at Waimauku. The additional transformer capacity will address immediate capacity constraints, but in the longer-term a duplicate 33kV supply from Swanson is needed to repair the security issues. The existing 33kV supply is quite reliable and it is planned to defer the second 33kV line until Waitakere substation is commissioned in 2019. The ex-Titirangi 10MVA transformer is to be used at Waimauku. This option resolves the issues at Waimauku for some years and has the added benefit of increasing the backstopping to Helensville and Riverhead substations;
- Install a larger transformer: It would be possible to replace the existing 7.5MVA transformer with a larger transformer, such as a 12.5MVA unit. The switchgear is limited to 15.2MVA. This would resolve the capacity problem at the substation but a second transformer and a second 33kV line would still be required to mitigate security issues; and
- Non-network options: No feasible non-network options have been identified.

- **Stapleford Crescent 11kV feeder** (FY12)

  This project has been initiated to transfer load from Torbay substation to Browns Bay substation. This option is a cost effective way of deferring the zone substation at Glenvar Rd. This project was commissioned in October 2011.

- **McKinnon - the Avenue 11kV feeder** (FY13)

  The Avenue feeder is supplied from McKinnon substation in the Albany basin. One section of The Avenue feeder contains a spur line with 12 transformers. This contravenes Vector's security of supply standard. This area is still developing with new residential subdivisions and this project is required to provide a backstop to this feeder by connecting through to the Redvale feeder from Spur Rd substation.

- **Greenhithe – 33kV reinforcement** (FY13)

  Auckland Transport has initiated a project to widen a 3.6km section of Albany Highway. This includes undergrounding the existing electricity assets. The current 33kV supply to Greenhithe substation is teed onto the Albany GXP -James St substation 33kV circuit. Once the road is widened, it will not be possible to retain the tee and it is proposed to install a new cable from Schnapper Rock Rd through to Albany GXP, a distance of 2km. Options considered:

  - Retain the 33kV tee. To do this would require some ground mounted 33kV switchgear. This requires space on the berm which is limited and the switchgear would be vulnerable to damage from traffic. The other alternative would be to take three cables up a pole. This is very unsightly and creates a hazard for traffic. This is not a preferred option.
  - Install a new cable to Albany GXP which is the long term plan. Given that road works will be occurring, there will be synergies in getting the 33kV cable extended and it is an appropriate time to install the cable. This will strengthen the 33kV network and is the preferred option.

- **Glenvar substation** (FY17)

  This project, originally planned for 2010, has been deferred by offloading Torbay substation onto Browns Bay substation. The Stapleford Crescent feeder will be installed from Browns Bay substation during 2011.

  Torbay substation has a single 33/11kV transformer and the transformer is more than 80% loaded. A shortfall of 3.6MVA of load cannot be backstopped upon the loss of the transformer. New subdivisions are planned to the north of Torbay substation which will add a further 7.5MVA of load. Reinforcement of the area is required.

  The proposed solution at this stage is to install a new 11kV feeder from Browns Bay and defer a new zone substation at Glenvar until the load at the Long Bay subdivision grows sufficiently to warrant reinforcement. Glenvar substation has the advantage of being able to offload Torbay substation, supply part of the new subdivisions at Long Bay and also reinforce to the west and north where further load growth is expected.

  Auckland Council is planning extensive road works in and around Glenvar Rd and ducts will be installed during these works for the future substation.

  The following options were investigated:

  - Install a second transformer at Torbay. This is a feasible option and would provide capacity for the proposed new subdivision. However, it is expensive and has limited benefits for the rest of the network;
  - Establish a new zone substation at Glenvar with a single 33/11kV transformer. This option offloads Torbay substation, supplies part of Long Bay subdivision and can supply new developments to the west of East Coast Road. It is planned to reinforce the 33kV supply to the area as part of this option which provides a backup supply to the Browns Bay 33kV bus;
  - Load control. Tests were carried out to determine how much load can be shed using the pilot network for turning off hot water supplies. There are limitations as to how much and how long the hot water supplies can be cut. Whilst load control is useful to control load during network contingencies it is not a long-term solution to the anticipated load growth.

b. Projects – Within five to ten years

- **Coatesville – Second Transformer** (FY18)

  A second 33/11kV transformer (10MVA) is planned for Coatesville substation. The existing transformer has sufficient capacity but the 11kV backstop security shortfall increases to an unacceptable level over this period.

- **Waimauku 33kV line** (FY19)

  A new 33kV line will be installed from Swanson to Waimauku substation to provide a 33kV backstop to Waimauku substation. This will occur when the Waitakere substation is commissioned.

5.6.7 Albany 110kV (Wairau Substation)

5.6.7.1 Background

Supply to Wairau zone substation is taken from Albany GXP at 110kV. The N-1 capacity limit (winter/summer) of this GXP is 143/143MVA and eleven zone substations are supplied from this 33kV bus, viz., Ngataringa Bay, Northcote, Highbury, Balmain, Birkdale, Milford, Wairau Valley, Takapuna, Hauraki, Belmont and Hillcrest. At Wairau there are two 110/33kV 36/45/80MVA transformers and one 110/33kV 45/80MVA transformer. The 110kV supply consists of a single circuit overhead line via the suburbs of Greenhithe, Glenfield, Marlborough and Wairau Valley rated at 82MVA (summer) and a double circuit overhead line taking a different route via the suburbs of Albany, Meadowood, Forrest Hill, and the Wairau Valley.

Each of these two circuits has a summer rating of 62MVA. The three transformers can each operate at a cyclic rating of 80MVA which provides a firm 160MVA capacity for N-1 transformer contingencies. Load has been shifted to the 33kV bus at Albany, reducing the load on the 33kV bus at Wairau to 130MVA in anticipation of the construction of a GXP at Wairau Rd. Once built, the firm capacity will be 200MVA and mitigate the HILP risk of the double circuit 110kV line failure. The forecast 110kV load is shown in Table 5-15.

Name	Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Albany 110kV	143	85	82	84	86	88	89	90	91	92	93	93
Name	**Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Albany 110kV	143	140	137	138	139	141	142	143	144	145	147	147

Table 5-15 : Wairau 110kV summer and winter load projections

The proposed GXP will consist of a single 220/33kV 120MVA transformer which will be supplied from a 220kV cable between Penrose and Albany that will be diverted to 220kV switchgear at Wairau. The GXP transformer can be supplied from either Penrose (via Hobson) or from Albany.

The ultimate load over the long-term, beyond this planning period, is expected to be 240MVA (fed from three 120MVA transformers).

The areas around Takapuna and Devonport are supplied by four zone substations via three 33kV circuits from Wairau 110/33kV substation. The three circuits form a ring supply to achieve better security of supply to the Takapuna commercial centre.

The main developments are occurring in the area supplied from Wairaua Smales Farm and the adjacent North Shore Hospital site. Some high rise developments have occurred at Takapuna and it is expected that Takapuna substation will need a second transformer within the next five years as the load continues to grow and Takapuna needs to offload adjacent substations such as Hillcrest.

Following the upgrade of the 33kV lines between Wairau and Albany via James Street, James Street substation is now supplied from Albany substation and backed up from Wairau.

A project has recently been implemented to improve the security of supply on the Wairau to Birkdale 33kV circuits. This involved supplying Balmain substation from a new 33kV CB at Birkdale. It is planned to operate the three 33kV circuits in parallel to improve the security of supply to the area and reduce SAIDI. A second project is planned to install a second transformer at Highbury and this may affect how the 33kV network is configured.

5.6.7.2 Projects Planned

a. Projects – Within the next five years

- **Highbury – 11kV reinforcement** (FY12)

  It was originally planned to install a second transformer at Highbury substation in 2012. However, through 11 kV reinforcement projects, this project can be deferred until 2018. The 11kV reinforcement will ensure that the substations of Highbury, Northcote and Balmain can be fully backstopped. The area is supplied by Birkdale, Balmain, Highbury and Northcote substations. The Birkdale substation is fully developed. Options investigated include a second transformer at Highbury, Balmain or Northcote substations or a new zone substation or additional 11kV feeders.

  The additional 11kV feeders will be installed as part of this project to offload the Birkenhead feeder from Northcote substation and reinforce the interconnection between Highbury substation and the two adjacent substations of Northcote and Balmain. Northcote substation has an 11kV backstop shortfall and the additional feeders will resolve this issue.

- **Birkdale – larger transformers** (FY13)

  The peak load on Birkdale substation was 24.7MVA in FY12. This substation has 2x12.5MVA transformers and larger transformers are required. There are rating issues with the 11kV switchgear and it may also be need to be replaced to match the rating of the new transformers. The substation site is quite constrained and further investigation is required to determine the final solution. Options investigated are as follows:

  - Establish a new substation at Beach Haven. Whilst this would offload Birkdale substation, it is extremely difficult to connect into the existing 11kV network because of undersized 11kV circuits.
  - Transfer load to James St substation. James St substation is still heavily loaded even though some load has been transferred to Greenhithe substation. This option is not a long term solution.
  - Upgrade Birkdale substation. The long term forecast for the area indicates that one substation will supply the load. Reinforcing this substation is an economic solution, will be able to support Balmain substation and is the preferred option.

- **Belmont – new 11kV feeder** (FY14)

  The 11kV backstopping for Ngataringa Bay substation is becoming inadequate and reinforcement is required. Ngataringa Bay substation supplies the Devonport area around the Naval Base and has a single 12.5MVA transformer. The area was reinforced in 2004 from Belmont substation with a new 11kV feeder and additional capacity is now required.

  Reinforcement of Devonport is not easy given the geographical features of the area. There is only one main road and one side road into Devonport. The existing 33kV supply to Ngataringa Bay substation is across the bay using a submarine cable. Several options are being investigated for the reinforcement:

  - Install a new 11kV cable from Belmont substation. This could be via the existing road network or across Ngataringa Bay with a submarine cable;
  - Ngataringa Bay substation could be reinforced with a second transformer; or
  - Generation could be installed at Ngataringa Bay.

At this stage the most cost effective option is a new 11kV cable installed from Belmont substation which has sufficient capacity to supply the whole of the Ngataringa Bay substation load.

b. Projects – Within five to ten years

- **Highbury – second transformer** (FY18)
  - Following the installation of new 11kV switchgear and three additional 11kV feeders at Highbury, a second transformer is required to ensure the substation is fully backstopped in an emergency. This project has been deferred from 2012 following a revised 11kV reinforcement project being implemented.
- **Takapuna – second transformer** (FY18)

  The load at Takapuna and the surrounding area is expected to continue to grow. Various options were investigated but installing a second transformer at Takapuna, including three 11kV feeders to offload surrounding substations, is considered to be the most cost effective solution to reinforcing the area. Other options include reinforcing Wairau substation with larger transformers and transferring load from Hillcrest substation to Wairau substation.

5.6.8 Hepburn Road 33kV

5.6.8.1 Background

Vector takes supply from the Hepburn 33kV bus via three 110/33kV transformers, 2x120MVA and 1x100MVA transformer. The N-1 capacity limit (winter/summer) of this GXP is 245/239MVA and ten zone substations are supplied from this 33kV bus, viz, Brickworks, New Lynn, Atkinson Rd, Laingholm, Oratia, Waikaukau, Henderson Valley, Keeling Rd, McLeod Rd and Sabulite as well as Rosebank in the Southern network. Additional future substations will be required at Titirangi and Green Bay.

The summer and winter load forecasts are listed in Table 5-16.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Hepburn 33kV	239	89	89	91	93	95	96	97	98	98	99	100
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Hepburn 33kV	245	140	150	151	153	154	155	157	158	159	161	162

Table 5-16 : Hepburn Road 33kV summer and winter load projections

The geo-schematic diagram in Figure 5-12 shows the proposed supply arrangement in the Hepburn area.

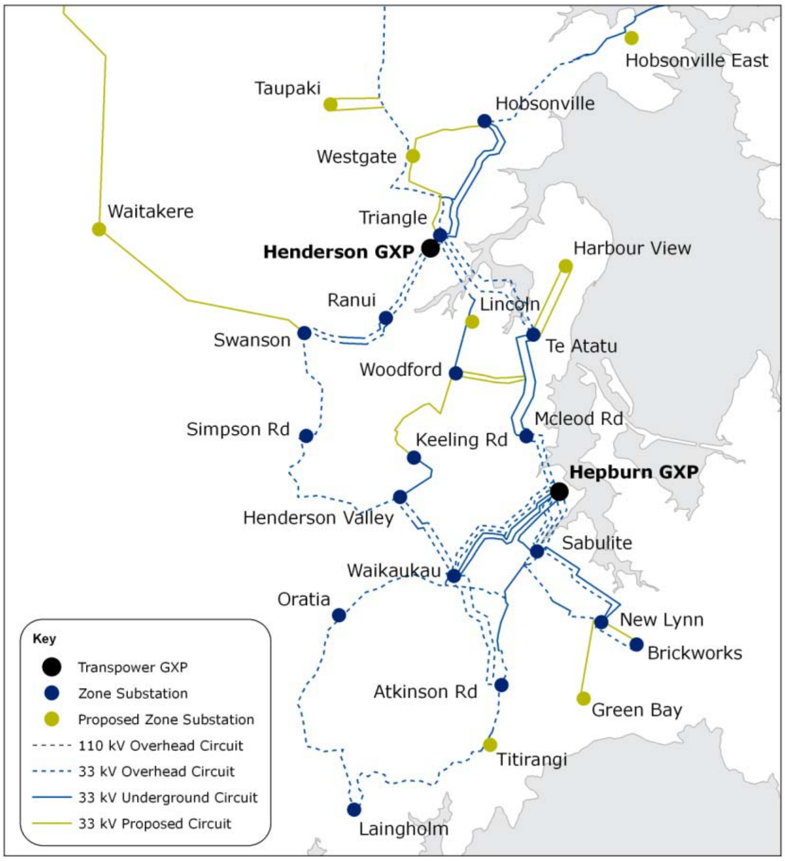

Figure 5-12 : Existing and proposed supply arrangement in the Hepburn area

5.6.8.2 Projects Planned

a. Projects – Within the next five years

- **Brickworks – first transformer** (FY13)

  Brickworks substation is in poor condition and is planned to be redeveloped – refer to Section 6 for details. The long term plan for this substation is to install two 15MVA transformers directly supplied from New Lynn 33kV switchboard. As part of Brickworks substation renewal project, the existing 10MVA transformer will be replaced with a new 15MVA transformer to allow for future growth expected in the area, until such time that a second transformer is required.

- **Brickworks – second transformer** (FY16)

  Brickworks substation currently has a single 12.5MVA 33/11kV transformer (1966) with a peak load in FY12 of 10.9MVA. The substation has been offloaded by 3MVA to Avondale substation to reduce the load. The area adjacent to the substation is now being developed as a high density residential subdivision (1,500 dwellings) with an expected load increase of around 4MVA. In addition, a new business load is being planned close to the substation which is around 3MVA. These additional loads mean a second 33/11kV transformer will be required for Brickworks substation to maintain the security of supply to the area. A new 11kV feeder is also required as part of this project to supply the load of the new subdivision.

- **Keeling Rd zone substation** (FY14)

  This project is to install a second transformer. This substation was commissioned in 2003 with a single transformer with the aim of transferring load from the

Henderson Valley zone substation. The peak load in FY12 was 13.1MVA and will increase with planned transfers of load from McLeod and Sabulite substations to manage the load on these substations as well. Options investigated include:

- Installing a second transformer at McLeod substation. This substation is very highly loaded and requires reinforcement or offloading. This substation has a very small site and installing a second transformer is not very practical. Offloading is a better option.
- Installing larger transformers at Sabulite substation. The load on this substation in FY12 was 21.4MVA on 2x12.5MVA transformers. There is space for installing larger transformers but reactors have recently been installed at this substation and load transfer is the preferred option of reinforcement.
- Installing a second transformer at Keeling Rd substation. This substation has been designed to accommodate two transformers and there is space in the switchroom for the 33kV switchgear. It is planned to connect the 33kV through to Woodford substation. The second stage of this project will occur when the 33kV is connected from Woodford substation to Hepburn GXP, creating a 33kV ring from Hepburn GXP.

- **Atkinson Rd – new 11kV feeder** (FY15).

  The Waikaukau substation load in FY12 was 7.7MVA on a 7.5MVA transformer. One option is reinforce the substation is to install a second transformer at Waikaukau substation. However, this substation is not centrally located and getting additional 11kV feeders from this substation will be expensive. Another option is the new feeder from Atkinson Rd substation. This substation has recently been redeveloped with 20MVA 33/11kV transformers. It is planned to use the additional capacity from this substation to reinforce the 11kV network (Kaurilands feeder) and also offload the Waikaukau substation. Non network options are not considered to be economic.

- **Rosebank - 11kV reinforcement to improve security at Rosebank north** (FY16)

  The 11kV network in Rosebank north area is lack of backstop capacity under contingency conditions due to geographical location which means no backstopping feeders from north end of the peninsular. This project is to install an 11kV new cable from Te Atatu substation to Rosebank north area terminating to distribution switchgear, and three 11kV cables from the switchgear to existing 11kV network. A phase shifting transformer will be installed at Te Atatu connecting between 11kV switchboard at Te Atatu and the 11kV new cables to Rosebank north. Completion of this project will create a cable link between Te Atatu and Rosebank north therefore provide sufficient backstop capacity to the 11kV network in the area.

  Future proofing ducts will be installed for this purpose in SH16 widening project to be carried out by NZTA, taking advantage of the synergies

b. Projects – Within five to ten years

- **Oratia – new 11kV feeder** (FY18)

  The existing 11kV feeder supplying Piha is from Henderson Valley substation and has a large section of residential load on the feeder. The feeder is heavily loaded and requires reinforcement. Oratia substation is physically closer to Piha and a new feeder to reinforce Piha from Oratia substation is planned. The new feeder would reduce the load on the feeder and improve the reliability of supply to Piha. This new feeder would be underground along the Piha Rd (6km).

5.6.9 Henderson 33kV

5.6.9.1 Background

Vector takes supply from the Henderson 33kV bus via two 220/33kV 120MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 135/135MVA and nine zone substations are supplied from this 33kV bus, viz., Triangle Rd, Ranui, Swanson, Woodford, Hobsonville, Te Atatu, Riverhead, Greenhithe and Simpson Rd.

The summer and winter load forecasts are listed in Table 5-17.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Henderson 33kV	135	74	76	79	81	84	85	86	87	89	90	91
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Henderson 33kV	135	127	117	119	120	122	124	126	127	129	131	132

Table 5-17 : Henderson 33kV summer and winter load projections

Ranui substation has recently been commissioned. Additional substations will be required at Westgate in 2014, Waitakere in 2019 and Hobsonville East in 2019. Land in the Hobsonville area has recently been rezoned allowing more intense development. In addition, new substations will also be required for the Waterview tunnel north portal (2016) and Rosebank North (2017).

In the long-term, it is planned to establish a new GXP at Huapai to supply part of the area currently supplied from Henderson. As well as the three substations mentioned above, new substations will also be required at Taupaki and Harbour View.

The geo-schematic diagram in Figure 5-13 shows the proposed supply arrangement in the Henderson area.

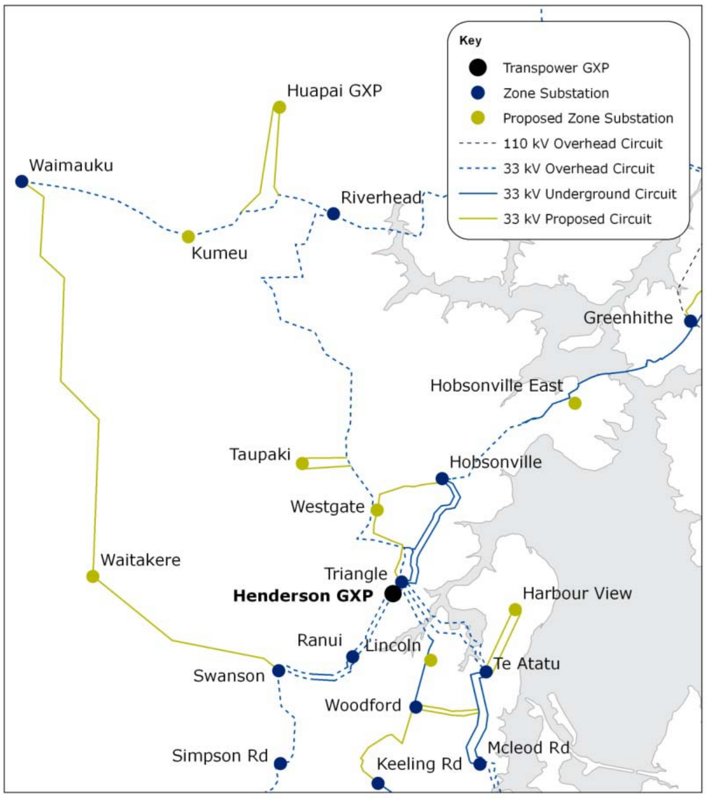

Figure 5-13 : Existing and proposed supply arrangement in the Henderson area

5.6.9.2 Projects Planned

a. Projects – Within the next five years

- **Hobsonville - New 11kV feeder** (FY12)

  The Oreil Ave feeder from Hobsonville supplies the Westgate shopping centre. The feeder is 90% loaded over the summer period and requires reinforcement to supply planned load increases. There are a number of options available.

  - Reinforce the network from Riverhead substation. This is quite a small rural substation about 8km to the north of the new developments. There is limited spare capacity at this substation and development is planned in the Riverhead area. There are a number of technical issues and this option is not recommended;
  - Reinforce the network from Triangle Rd substation. This substation is very heavily loaded and does not have any spare capacity to supply additional load. This is not a practical option;
  - Reinforce the network from Hobsonville substation. This is a feasible option in the short term but it is not a long term solution to supply the Massey North development which is anticipated to lead to 10-20MVA of load; and
  - It is planned to install a new 11kV feeder from Hobsonville substation to offload the Oreil Ave feeder. However, the feeder will be 33kV rated so that when the Westgate substation (refer below) is commissioned, the new feeder will form a 33kV link between Hobsonville and Westgate substations.

- **Hobsonville East Land Purchase** (FY13)

The long-term plan indicates that a zone substation will eventually be required to supply the new load developing between the existing Hobsonville substation and Greenhithe substation. Currently Greenhithe substation is supplying across the Greenhithe bridge to the old Hobsonville airbase. As this area is redeveloped, additional capacity will be required and this will be supplied temporarily by the new Clark Rd feeder mentioned above. However, in the medium to long-term a new substation will be required and this project is to purchase some land for the new substation.

- **Hobsonville – Clark Road 11kV feeder reinforcement** (FY14)

  Most of the Clark Road feeder was decommissioned when the overhead line was uprated to 33kV to supply Greenhithe substation. The area currently supplied by this feeder is supplied from the new Greenhithe zone substation. In the longer term, a new zone substation will be required at Hobsonville East to meet the demand of the Hobsonville development. However, to delay the need for this substation, a new underground Clark Road feeder will be re-established. Ducts for the cable will be progressively installed with Auckland Transport road alterations in Hobsonville Rd.

  The area between Westgate and Hobsonville Airbase has been rezoned to allow for commercial and residential development adjacent to the new Greenhithe motorway. This will be a substantial load increase and will not be able to be supplied from the Hobsonville zone substation.

- **Waitakere zone substation** (FY16)

  This project is to establish a new zone substation at Waitakere Village. The primary purpose of this new substation is to offload the Swanson zone substation and reinforce the Bethells Road 11kV feeder.

The main options investigated were:

  - Install a second 33/11kV transformer at Swanson and install a new 11kV feeder to reinforce the Bethells Road feeder;
  - Establish a new zone substation closer to the load centre; and
  - Defer Waitakere substation by splitting the Bethells Rd feeder and further offload to Ranui substation.

- **Westgate zone substation** (FY16)

  This project is to establish new zone substation. The Massey North area has recently had the zoning changed to allow for the commercial and residential development to be expanded significantly. The existing substations supplying the area are getting heavily loaded and additional capacity is required to supply the new load.

  The currently preferred solution is to establish a new zone substation at Westgate. This would allow the existing Hobsonville substation to supply load further to the east until the Hobsonville East substation is built. The options for the reinforcement project include:

  - Increase the capacity at Hobsonville substation with larger transformers. While this is possible, the supply to the substation is limited by the 33kV cables. Given the large loads expected in this area, this would only be a short-term measure;
  - Increase the capacity at Triangle Rd substation. Whilst feasible, the load centre is several kilometres north of this substation, making 11kV reinforcement expensive. In addition, there is no space in the substation for additional 11kV CBs to supply new 11kV feeders; and

- Establish a new substation at Westgate. This option has the advantage of having the new capacity at the load centre. It is proposed to interconnect the 33kV cables with Hobsonville substation, so that the 33kV link to Greenhithe has sufficient capacity to supply both Hobsonville East substation and Greenhithe substation in emergencies.
- Non-network solutions which may potentially resolve the capacity issues in this area are still under investigation.

- **Te Atatu – new transformers** (FY17)

  The load forecasts indicate that new 20MVA 33/11kV transformers are required at Te Atatu substation to comply with Vector's security criteria. Te Atatu substation was rebuilt several years ago and new 11kV switchgear installed. However, the 33/11kV transformers were retained. It is now time to replace these transformers with larger units. Options considered:

  - Offload the substation to adjacent substations. The three closest substations (McLeod Rd, Triangle Rd and Woodford Ave) do not have spare capacity. In fact, load is being transferred to Te Atatu substation to resolve network loading issues.
  - Construct a new zone substation on the Te Atatu peninsula. This is the long term solution for reinforcing the area but this is an expensive option and is not justifiable at this stage.
  - Install a second transformer at Woodford Ave substation and transfer load. Woodford Ave substation is currently supplied by a single 33kV cable. This option would require 33kV cabling work which would be quite expensive (see Woodford Ave project below).
  - Install a second transformer at McLeod Rd substation and transfer load. The site is very constrained and it is not practical to install a second transformer at McLeod Rd substation.
  - Upgrade the transformers at Te Atatu substation from 12.5MVA units to 20MVA units. This is the lowest cost option and allows Te Atatu to support the adjacent single transformer substations.

b. Projects – Within five to ten years

- **Hobsonville East – new substation** (FY19)

  The load forecasts indicate that a new zone substation is required at Hobsonville East. This substation is required to supply the new load at Hobsonville Point and the new industrial area developing between Hobsonville Rd and the new motorway.

- **Lincoln Rd – land purchase** (FY20)

  Development occurring in the Lincoln Rd area indicates that a new substation will be required. This project is to purchase land for the new zone substation. The timing of the new substation will depend on what other reinforcements occur in the area.

- **Woodford Ave – additional transformer** (FY21)

  An additional 33/11kV transformer is planned for Woodford substation together with the associated 33kV switchgear and 33kV link from the Hepburn-Te Atatu 33kV cable.

5.6.10 Penrose 110kV (Auckland CBD)

5.6.10.1 Background

Vector takes supply from Penrose GXP at 110kV for bulk supply to the Auckland CBD and at 33kV and 22kV for local distribution to a number of zone substations in the area surrounding the Penrose substation.

5.6.10.2 CBD - Subtransmission

At present, Auckland CBD has three bulk supply substations, viz. Hobson, Liverpool and Quay substations, all fed with Vector-owned 110kV cables. The load forecast for the Penrose GXP is shown in Table 5-18 below.

Name	Actual	Forecast Demand (MVA) - Summer								
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Penrose 110kV	211	217	222	229	236	241	245	227	250	253	257
Name	**Actual**	**Forecast Demand (MVA) - Winter**									
	FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Penrose 110kV	198	197	203	209	215	222	227	232	237	242	245

Table 5-18 : Penrose 110kV summer and winter load projections

The bulk supply to Liverpool substation is from Transpower's Penrose GXP by means of two 110kV 237MVA cable circuits in Vector's Penrose tunnel to 110kV GIS switchgear in Liverpool. Three 110/22kV transformers (2 x 75MVA and 1 x 60MVA), supply a 22kV switchboard at Liverpool. Three 22/11kV transformers are connected to the 22kV bus to supply an 11kV bus at Liverpool. Furthermore two 22kV substations, Victoria and Newton, are supplied from the 22kV switchboard at Liverpool.

The bulk supply to Hobson substation is from Vector's 110kV switchgear in Liverpool by means of two 150MVA cable circuits in the Liverpool-to-Hobson tunnel directly onto two 110/22/11kV transformers rated at 65MVA each (40MVA at 22kV and 25MVA at 11kV). The installed transformer capacity is 130MVA and the N-1 capacity is 65MVA. 22kV and 11kV switchboards are supplied from the two transformers. Two 22/11kV transformers also supply the 11kV switchboard at Hobson. Furthermore Freeman's Bay 22kV substation is supplied from the 22kV bus at Hobson.

The bulk supply to Quay substation is from Penrose GXP by means of two 110kV gas-filled cables directly onto two 50MVA 110/22kV transformers at the time of compiling this AMP. The transformers are rated 50MVA but limited to 30MVA by operational constraints placed on the two gas-filled cables due to their physical condition. These assets will be retired due to raising of Orakei Bridge by KiwiRail in Feb 2012. A decision was made to retire the cables and associated transformers instead of relocating to the new bridge as it would have been very costly to relocate the old cables. Furthermore a 60MVA 110/22kV transformer, commissioned in 2010, is supplied from Liverpool substation via a 120MVA cable. This circuit can also be supplied from Roskill substation. A project is underway to install a second 60MVA transformer at Quay St to be supplied via the same 110kV cable that is currently supplying the existing transformer at Quay Street. Parnell 22kV substation is supplied from the Quay St 22kV switchboard.

The security standard for the CBD sub-transmission network is "N-1 no break" and "N-2 switched" with a restoration in accordance with the targets in Table 5-1. The long-term plan for the CBD is to install three[57] 60MVA transformers in each bulk supply substation sufficient to supply a peak of 120MVA in each substation to maintain N-1 no-break security. To achieve N-2 switched security in the CBD the development plan entails the installation of 22kV interconnector cables with a capacity of 60MVA, between the three bulk supply substations. In the event of loss of a 2nd transformer at a substation (N-2), i.e. down to 60MVA, the 22kV interconnectors from an adjacent substation will be used to take up load. Figure 5-11 below shows that the goal of establishing 22kV interconnector-cables between bulk supply substations has been partly achieved.

At Quay St substation a 2nd 60MVA 110/22kV transformer is planned for commissioning in early 2012 after which the two existing aged 50MVA 110/22kV transformers will be retired. A 3rd 60MVA transformer is not warranted at Quay St for the short term but is planned for the long term.

At Hobson substation the two 110/22/11 40/25MVA transformers are sufficient to provide N-1 security for the short-term but projected load growth requires a third 110/22kV 60MVA transformer to be commissioned soon after completion of the GXP works in 2014. An enclosure for the 3rd transformer forms part of the construction works for the new GXP at Hobson.

Figure 5-14 below is a schematic diagram of the existing sub-transmission network in the CBD. The diagram shows the 110kV sub-transmission circuits and the 22kV interconnectors.

The peak demand in Auckland's CBD traditionally occurs in the summer months and more specifically in the period January to around the end of March. Summer peak demand is primarily caused by air-conditioning plant, and the winter peak through heating. The projected peak demand for the three bulk supply substations in the CBD are shown in Table 5-19.

[57] No more than 3 transformers are allowed to be connected in parallel to a 22kV bus to maintain fault levels to acceptable levels due to downstream distribution switchgear constraints

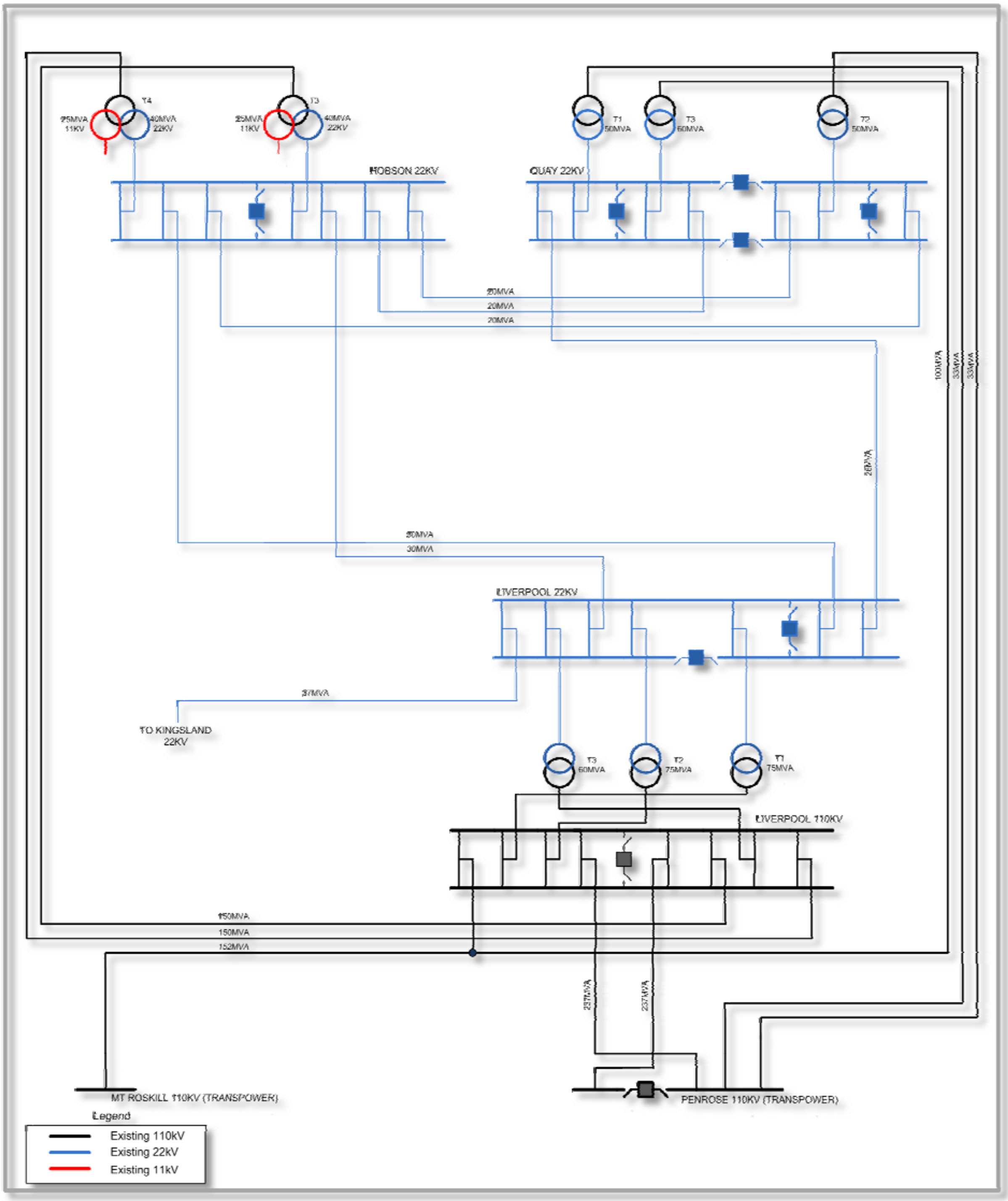

Figure 5-14 : Existing sub-transmission network in and to CBD – schematic

The total installed transformer capacity in Liverpool substation is 210MVA. Because of the difference in transformer impedances of the two new 75MVA transformers (T1 and T2) with that of transformer T3 (60MVA) and the resultant non-optimal load-sharing, the theoretical N-1 capacity of 135MVA is actually in the order of 114MVA. Once transformer T3 is replaced with a unit of similar rating and impedance to that of T1 and T2, the N-1 transformer capacity will be 150MVA. The current 114MVA N-1 capacity will suffice until transformer T3 is replaced.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Hobson	80[58]	81	85	87	90	93	95	96	98	99	100	101
	25	22	22	23	23	24	24	24	24	24	24	24
Liverpool	114	81	86	88	89	91	93	94	95	96	97	98
Quay Street	33	30	30	31	33	34	36	37	37	38	39	39
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Hobson	80	77	80	83	85	89	91	94	96	99	101	103
	25	19	19	19	20	20	20	21	21	22	22	22
Liverpool	114	78	78	79	81	82	84	85	87	88	90	91
Quay Street	48	33	30	31	33	34	36	37	38	39	40	40

Table 5-19 : Hobson, Liverpool and Quay Street summer and winter load projections

The theoretical installed transformer capacity at present in Quay St is 160MVA but limited to 120MVA because of the operational constraint on the gas-filled cables (to be decommissioned in February 2012) from Penrose that supply transformers T1 and T2. These two transformers will be replaced with a newer 60MVA transformer in early 2012 which will provide N-1 transformer capacity. The firm capacity of 60MVA at Quay St is sufficient to supply the load from Quay St well into the future. The two transformers at Quay St are vulnerable for a loss of the 110kV cable from Roskill via Liverpool. A 110kV cable will be installed from Hobson St soon after the new GXP and 110kV switchboard is established at Hobson. This will provide full N-1 redundancy in terms of the 110kV cables to Quay St substation.

The long-term CBD development plan also makes provision for the establishment of a 110kV bus at each bulk supply substation with a 110kV cable between the 110kV buses to provide redundancy in the event of a failure of a 110kV cable-circuit. This long term plan will be implemented through a staged approach, predicated on load growth.

For a loss of supply from Penrose, the Auckland CBD will be supplied by means of a 190MVA 110kV cable from Mt Roskill to Liverpool and Quay St. Furthermore, a 37MVA 22kV cable exists from Kingsland to Liverpool substation plus load will be transferred via 11kV backstop circuits to Newmarket and Kingsland substations. This arrangement will suffice to supply the CBD for a loss of the Penrose cables until completion of the Hobson GXP in 2014. The new GXP at Hobson is scheduled to come on-line in June 2014. Vector will establish a new 110kV node (GIS switchgear) at the substation, which will enable it to be supplied from either Penrose or Albany via the 220kV NAaN cable circuit. This will address loss of supply to the CBD for an event of loss of Transpower's Penrose 110kV bus or failure of both Vector's 110kV cables in the tunnel. The 220kV NAaN cable from the north, i.e. from Transpower-Albany substation via Vector's Wairau substation will maintain supply to the CBD for an HILP event of failure of the Vector tunnel. Transpower's 250MVA 220/110kV interconnecting transformer at Hobson substation will be sufficiently rated to supply the load at Hobson substation as well as the load at Liverpool substation and Quay St substations.

Figure 5-15 below depicts the intended sub-transmission network into the CBD after completion of the new GXP at Hobson substation. The diagram also shows the 3rd transformer at Hobson substation and the 110kV cable from Hobson to Quay St.

[58] Hobson transformers are three winding transformers, the first row indicates the loading on the 110kV/22kV transformer capacity and expected load on the 22kV busbar, where as the first row indicates 110kV/11kV transformer capacity and expected load on the 11kV busbar

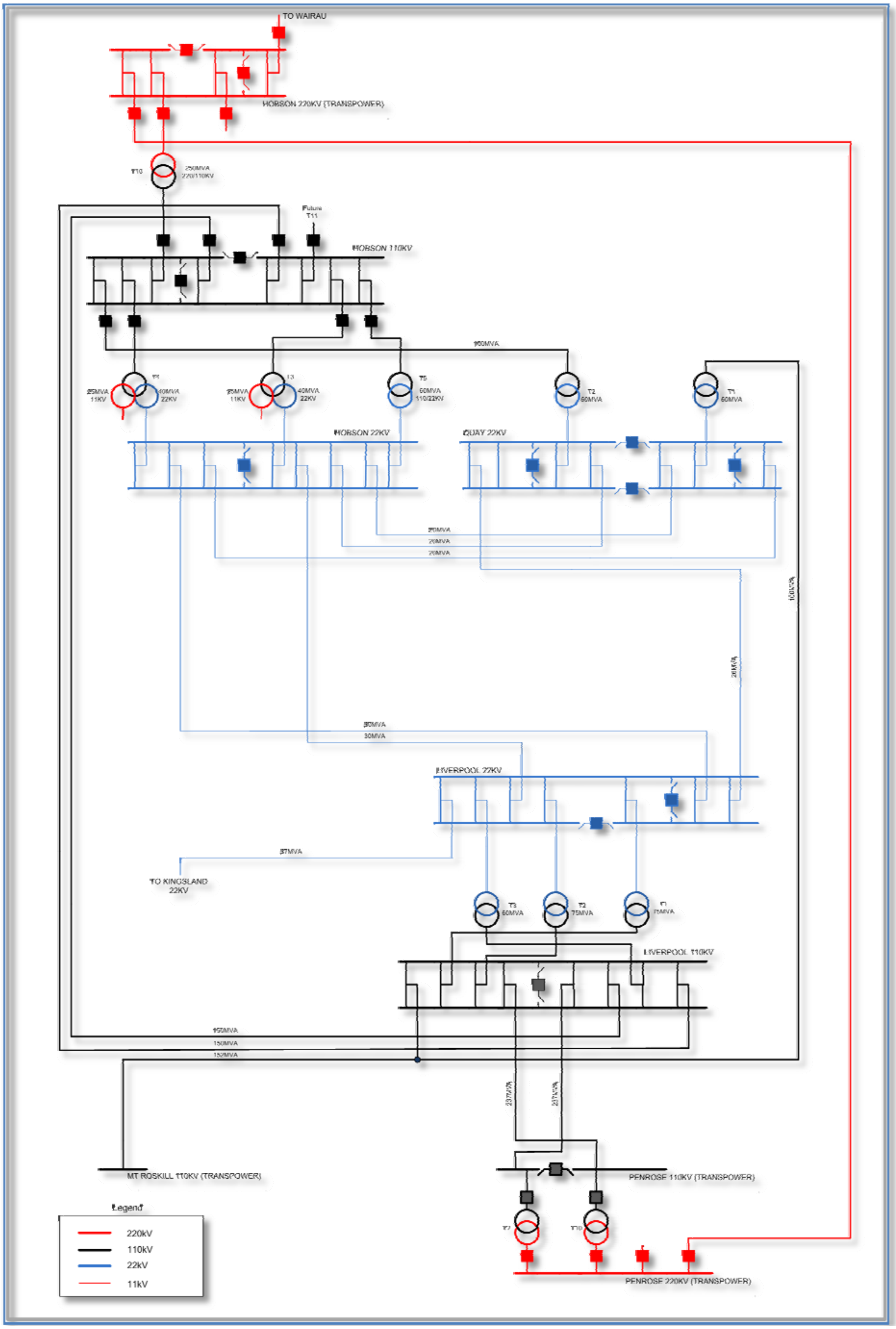

Figure 5-15 : Sub-transmission network in and to CBD - post 2015

5.6.10.3 Long-Term CBD Development Strategy

In the long term, load-growth at Quay St is expected to require the installation of a third transformer at which time a 110kV GIS bus will be established at Quay substation to enable the connection of a third or more transformers. KiwiRail has approached Vector with regard to a 36MVA supply for rail electrification for the CBD's rail network and future expansion of this network and Ports of Auckland have approached Vector with regard to extensions at the Auckland port. The long term plan is to establish 110kV buses at each of the bulk supply substations to provide the ability to transfer load via the 110kV network.

The network development strategy for the CBD (towards the end of the AMP planning period) makes provision for the establishment of a further CBD zone substation in the area around the southern end of Hobson and Nelson Streets and around Cook St, called Hobson-West. This substation will initially be developed as a 22kV node by connecting into the existing 22kV interconnector cables between Hobson and Liverpool substations but as load grows will be developed into a 110kV supplied zone substation. Hobson-West will need to be developed when the load at Hobson substation approaches the firm capacity (N-1) level of 120MVA[59].

The long-term plan also makes provision for the installation of a 22kV switchboard at Victoria substation. At present Victoria substation is supplied from the Liverpool 22kV bus and supplies commercial load in the eastern parts of the Auckland CBD. With the long-term strategy of migrating to a 22kV distribution network in the CBD this substation is strategically located as a marshalling point for the 22kV network in this area. The existing aged 22kV interconnector cable between Quay and Liverpool substation rated 24MVA will be replaced and a 2nd 22kV interconnector cable installed to supply the proposed 22kV bus at Victoria substation. Replacement of the existing 22kV interconnector and installation of a new interconnector will establish 60MVA of 22kV capacity between Quay and Liverpool substation which is in line with the CBD development plan.

Figure 5-16 depicts the planned sub-transmission network in the CBD over the long-term.

[59] The firm capacity at Hobson is 65MVA but will be boosted to 125MVA once the 3rd 110/22kV transformer (60MVA) is installed

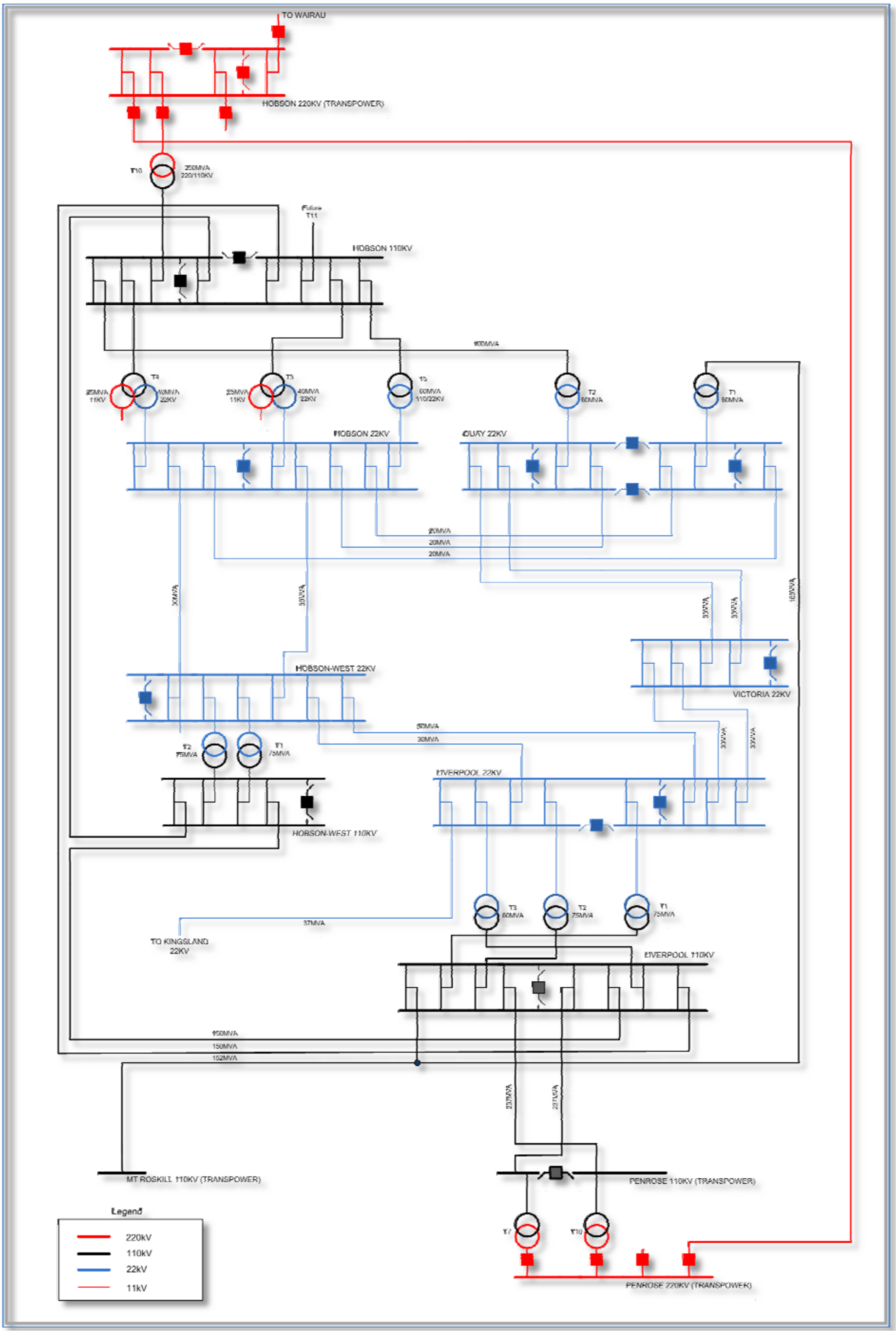

Figure 5-16 : Sub-transmission network in and to CBD – long-term

5.6.10.4 Projects Planned at Subtransmission Level

a. Projects – Within next five years

- **Penrose 110kV GXP** (FY12)[60]

  Upgrade the 110kV bay equipment in the Transpower 110kV bays on the Penrose to Liverpool 110kV cables to the emergency rating of the cables.

- **Penrose 33kV GXP** (FY12, FY13)

  Install a new indoor 33kV board by Transpower, to replace the existing 33kV outdoor structure. Vector's existing 33kV sub-transmission cables will be relocated to the new switchboard.

- **Penrose tunnel** (FY12)

  Install fire sprinklers at 220kV and 110kV cable joints in the Penrose tunnel.

- **Hobson substation** (FY12, FY13, FY14)

  Establish a 250MVA 220/110kV GXP including required civil works, ancillary works, installation of a 110kV GIS switchboard and transfer of existing 110kV cables to the GIS switchboard. Scheduled commissioning date for the GXP is June 2014.

- **Hobson substation** (FY14)

  Install a 3rd 60MVA 110/22kV transformer to allow for load-growth and maintain the transformer capacity security to N-1 level (this transformer is ex-Liverpool T3).

- **Quay substation** (FY12)

  Install a 2nd 60MVA 110/22kV transformer. This transformer will be supplied via the existing 100MVA 110kV XLPE cable from Liverpool which supplies the existing 60MVA unit at Quay until the installation of a 110kV cable from Hobson. Retire the two existing Penrose-Quay St 110kV gas-filled cables.

- **Quay substation** (FY14)

  Install a 110kV 1000mm² XLPE cable from Hobson substation 110kV GIS to the 2nd 60MVA transformer at Quay St

- **Liverpool substation** (FY14)

  Replace the 60MVA transformer T3 with a new 75MVA transformer with impedance that matches transformers T1 and T2 and relocate transformer T3 to Hobson substation

- **Liverpool substation** (FY15)

  Install a 2nd 22kV interconnector between Liverpool substation and Quay St substation to establish full 22kV interconnector capacity

- **Victoria substation** (FY17)

  Install a 22kV switchboard and cut and join to 22kV interconnectors between Quay St and Liverpool substations

- **Quay substation** (FY15)

  Second stage of the 22kV switchboard extension to provide feeders for future network reinforcement.

b. Projects – Within five to ten years

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60 Transpower projects that directly affect Vector

- **Establish a GXP in Newmarket** (FY20)

  It is proposed to establish a GXP at Newmarket to supply high density commercial/industrial load in the area. The long-term strategy is to transfer load from the Penrose 33kV bus to the proposed GXP (as well as later on to a proposed Southdown GXP) as sub-transmission assets are retired and replaced due to age/condition.

- **Liverpool substation** (FY16)

  Extension of the 22kV switchboard to cater for the conversion of the 11kV network in the CBD to 22kV.

c. Projects – Long term

- **Quay substation**

  Installation of a 2nd 110kV cable from Hobson to Quay substation

- **Hobson West substation**

  Establish a 110/22kV bulk supply substation in the lower Hobson, Nelson and Cook St precinct.

5.6.10.5 CBD - Distribution

At present the bulk of the load in Auckland CBD is supplied by the 11kV distribution network, supplied from four zone substations, Hobson, Liverpool, Victoria and Quay. The distribution network comprises 11kV radial feeders from the four zone substations, forming a meshed network with open switch points between feeders.

From 2004, further development of the 11kV distribution network in the Auckland CBD was suspended in favour of the progressive roll-out of a 22kV distribution network. This was required to provide sufficient capacity and security to meet long-term load growth, in a cost-effective manner. Future distribution network extensions are installed with 22kV rated equipment, even where they are temporarily operated at 11kV, until a 22kV connection can be made.

Network reinforcement in the CBD is driven by 11kV feeder load and new connection requests. Existing 11kV substations are progressively transferred to the 22kV network as the 11kV assets reach the end of their economic lives, or when additional distribution capacity is required to cater for demand growth. Figure 5-17 indicates the planned extent of the future 22 kV network in the CBD.

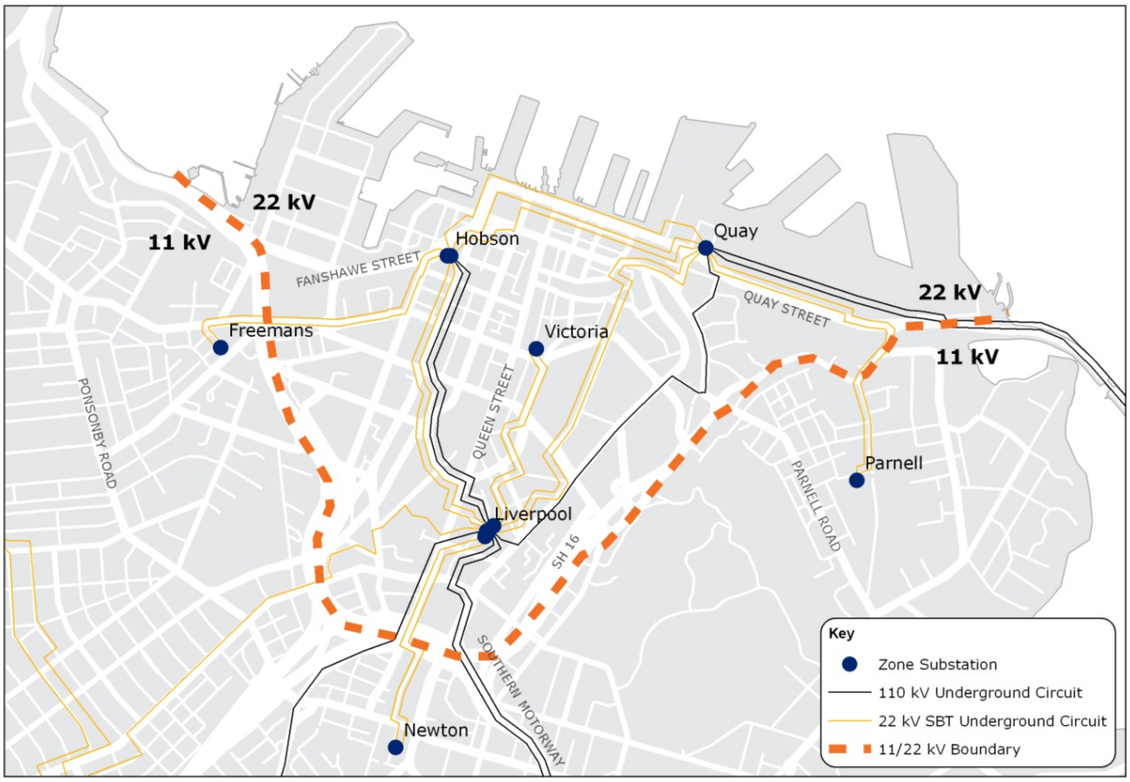

Figure 5-17 : CBD area designated for 22kV distribution

5.6.10.6 Projects Planned at Distribution Level (CBD)

a. Projects - Ongoing

- **Hobson - 22kV extension to Tank Farm** (ongoing)

  The Auckland Waterfront Development Agency (AWDA) plans to progressively develop the Tank Farm area into a commercial hub over a 15 year timeframe. The 11kV network has insufficient capacity to supply the load resulting from this development. Two 22kV distribution feeders were installed from Hobson substation to the Fanshawe Street/Beaumont Street area in 2008, with the intention of extending northwards as customer load dictates. A third 22kV feeder is planned, again driven by customers' demand requirements.

- **Auckland CBD 22kV network extension and 11kV to 22kV load transfer** (ongoing)

  Vector is progressively replacing end-of-life 11kV assets with 22kV network assets, while ensuring new customer are also installed at 22kV. While the new customer connections are financed from the connections budget, this project ensures 22kV network is available for the connection to be made.

b. Projects – Within next five years

- **Hobson – HP data centre supply** (FY13)

  HP data centre at Nelson St with a demand of 1MVA is currently supplied by 11kV feeders from Hobson substation. HP requests Vector to upgrade their security of supply at the site from the existing Vector's standard of N-1 (with break) to N-2 (with break). They also requested more capacity to be available for future load increase. This project is to reinforce and connect the data centre to the existing

22kV distribution network in the area and to install a new 22kV feeder to meet the requirements of the customer.

- **Liverpool – new 22kV feeders to Telecom Mayoral Drive** (FY16)

  The Telecom Exchange in Mayoral Drive is supplied by 11kV feeders from Liverpool substation, with a demand of 5MVA. Telecom plans to progressively expand the exchange and has indicated a long-term forecast that will require two new 22kV feeders from Liverpool substation. As it is a customer driven project, the timing is subject to customer's programme, but at this stage it is scheduled for 2016.

- **Hobson - extension of the 22kV switchboard** (FY16)

  This project proposes extending the 22kV switchboard at Hobson substation to cater for the increased 22kV distribution capacity requirements in the CBD. The project is linked with the establishment of a new grid exit point in 2014, and the installation of an additional 110/22kV transformer for additional capacity in 2015.

- **Liverpool - Medical School supply stage 2** (FY15)

  A new 11kV feeder from Liverpool substation to the Medical School in Grafton will be required to meet load growth arising from forecast expansion plans. This load is expected to increase to 7MVA by 2015. This is a customer driven project so the timing is provisional.

- **Quay - Ports of Auckland supply** (FY17)

  Ports of Auckland ten year plan indicates a demand increase to 11MVA by 2017, and upwards of 20MVA in the medium-term. To meet the projected demand, a new 22/11kV zone substation is anticipated. This is a customer project, so the timing and proposed solution is provisional at this stage

d. Projects – Within five to ten years

- **Hobson/Quay - Queens Wharf supply** (FY21)

  A new 22kV distribution feeder is to be installed to supply the Queens Wharf development. Timing is dependent on the customer and is therefore provisional at this stage.

5.6.11 Penrose 33kV

5.6.11.1 Background

Penrose 33kV GXP supplies 12 zone substations, viz. Carbine, Drive, McNab, Mt Wellington, Newmarket, Orakei, Remuera, Rockfield, St Heliers, St Johns, Te Papapa and Sylvia Park. It also supplies a 33kV switching station at St Johns and a 22kV board (at Penrose) supplying Glen Innes, Onehunga and Westfield.

Figure-5-18 below shows the existing 110kV, 33kV and 22kV sub-transmission networks supplied from this GXP.

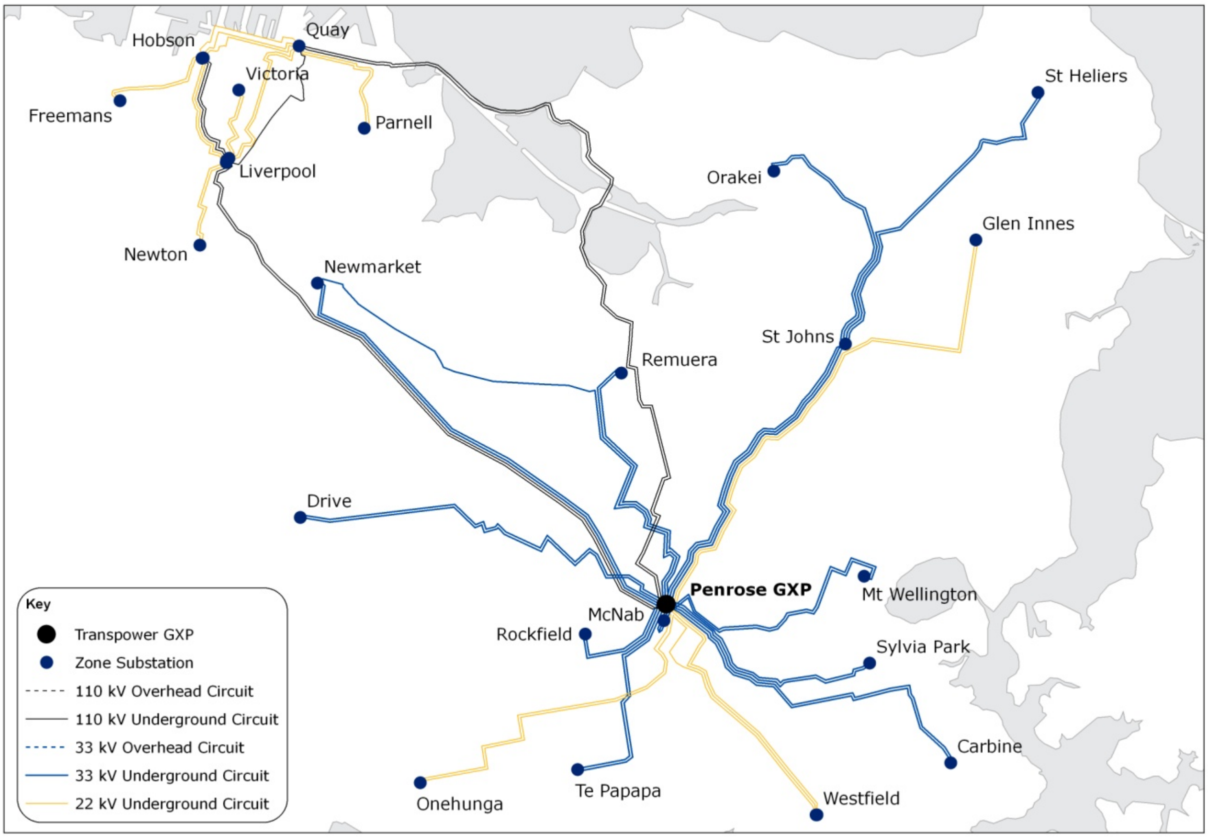

Figure-5-18 : Existing sub-transmission network at Penrose area

Table 5-20 shows the summer and winter load forecasts at the GXP.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Penrose 33kV Combined	406	273	273	283	288	294	301	308	315	320	325	327
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Penrose 33kV Combined	429	343	347	357	366	374	384	393	402	410	416	420

Table 5-20 : Penrose 33kV summer and winter load projections[61]

The long-term plan is to reduce demand on the Penrose 33kV bus through the establishment of new GXP's at Southdown and Newmarket. Further, it is intended to phase out Penrose 22kV either by transferring to Penrose 33kV, Southdown or Newmarket GXP's. While a 220kV GXP already exists at Southdown, Vector does not take a supply from it. The impact on Penrose 33kV demand is shown in Table 5-21.

[61] Forecast demand without factoring in the impact of Newmarket and Southdown GXP

Name	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Newmarket		55	56	58	59	60	62	62
Southdown					48	48	48	48
Penrose 33kV	402	355	360	362	316	318	320	322

Table 5-21

Name	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Newmarket		55	56	58	59	60	62	62
Southdown					48	48	48	48
Penrose 33kV	402	355	360	362	316	318	320	322

Table 5-21 : Proposed load reduction at Penrose 33kV

The relocation of the Lion Breweries to Ormiston Rd from Newmarket has reduced the demand on Newmarket substation. However the proposed expansion of the Westfield Shopping Centre at 307 Broadway and redevelopment of the ex-Lion Breweries site is anticipated to add significant load. The capacity shortfall will be addressed by the establishment of Newmarket South substation in 2016.

Part of Ellerslie Racecourse has been earmarked for development and this is expected to trigger the construction of Ellerslie zone substation. Industrial load growth in Te Papapa and Westfield area is on-going and is expected to result in a capacity shortfall towards the end of the planning period. A new substation in the vicinity of Southdown is proposed to address this issue.

5.6.11.2 Projects Planned

a. Projects – Within next five years

- **Sylvia Park – new 11kV feeders to offload Westfield feeders** (FY12)

  Four feeders at Westfield substation, Westfield 2, 8, 14 and 18, are heavily loaded and will exceed 80% - 90% of feeder capacity from 2013. Transfer of load onto adjacent feeders was investigated and dismissed as an option. Two new 11kV feeders are proposed from Sylvia Park substation to offload the Westfield feeders 2, 8 and 18 in 2013.

  Installing new feeders from Westfield substation was investigated as an alternative, but was discounted as a costlier option.

- **Rockfield - extend NZFP feeders to offload McNab feeders** (FY12)

  Load on McNab feeders 8 and 16 have reached 90% and 80% respectively of capacity in 2010. Load transfer will provide a short term solution but new capacity is required to meet the long-term security. It is proposed to extend one of the three ex-NZFP feeders from Rockfield to offload these McNab feeders. The ex-NZFP feeders are spare at present after the relocation of this customer. Alternative solutions investigated include the installation of new feeders from McNab or Rockfield substations. These options are costlier than the proposed solution.

- **Newmarket South – land purchase** (FY13)

  It is planned to establish a new substation in the Newmarket South area (refer to Newmarket South substation below) in 2016. Land needs to be purchased for this substation and although this was planned for FY12, it has been deferred due to viaduct re-construction works by NZTA. The purchase delay will not affect the proposed completion date of the new substation.

- **Newmarket - new 11kV feeders to supply Farmers redevelopment** (FY13)

  The Westfield Group has planned a commercial redevelopment of the "Farmers" site in Broadway, Newmarket. The customer has requested a 6.5MVA in 2013. This project is to install two 11kV new feeders from Newmarket substation to supply this load in the short to medium term. Longer term, the load will be transferred to the proposed substation at Newmarket South, following its commissioning in 2016.

- **Newmarket South – establish a new substation** (FY16)

  Newmarket substation is a three 20MVA transformer substation, loaded to a maximum of 37MVA. The load has decreased with the relocation of Lion Breweries to Ormiston Road, but a combined residential/commercial development is planned on the vacated site with eventual demand in excess of the Breweries demand. Newmarket substation is ideally suited to supply this site.

  Westfield Group has indicated further load increases for its shopping mall at the south end of Newmarket, which, when combined with the Lion Brewery site re-development, will push the demand above the secure capacity of Newmarket substation. Feeders from adjacent Remuera and Drive substations are heavily loaded, and while the option remains to install additional feeders, there is insufficient capacity at these substations to meet the additional demand. These substations are also remote from the commercial load centre in Newmarket.

  A new zone substation (Newmarket South substation) is proposed at the south end of Newmarket with a commissioning date of 2016. The supply to Newmarket South substation will initially utilise Newmarket's 33kV feeders until capacity constraints trigger an upgrade. Establishing a new 110kV bulk supply substation at Newmarket supplied from Penrose 110kV is proposed for 2020.

  The new substation was initially planned to be commissioned in 2014. The project has now been deferred to 2016 due to lower than forecast demand and delays arising from the customer-driven Westfield Mall development.

  Following the establishment of Newmarket South substation and re-development of the Lion Breweries site, Newmarket substation will be located at the load centre. Newmarket South will offload Remuera and Drive substations and supply the Westfield complex.

  Other options have been investigated including (i) reinforcing existing Newmarket substation and (ii) establishing a new zone substation at Ellerslie. The NPV ranking analysis shows both options are less cost efficient than the proposed solution for long term.

- **Rockfield - NZ Technology Park supply** (FY16)

  Development of the New Zealand Technology Park is proposed at Penrose. The new load is estimated to be 6MVA and will be supplied by extending two ex-NZFP feeders. The timing of this project is provisional at this stage as it is subject to the customer's development timeframe.

b. Projects – Within five to ten years

- **Ellerslie – establish a new zone substation** (FY18)

  Load growth associated with the commercial development at Ellerslie racecourse will initiate the establishment of a new zone substation at Ellerslie. This substation will provide capacity to offload feeders from adjacent substations of Remuera, McNab and Drive. The new substation was planned to be commissioned in 2015, but has been deferred to 2018 due to delays arising from the Ellerslie racecourse development.

Alternatives investigated include the installation of additional feeders from McNab substation. However, McNab is already a three transformer substation and supplies adjacent industrial areas. Adding the Ellerslie load onto McNab (43MVA on three 20MVA transformers) will cause this substation to breach security levels.

Adding Ellerslie demand to Remuera, Drive, or Rockfield substations were further options investigated. Remuera, Drive and part of Rockfield's load is residential load and adding further transformer capacity to cater for the additional Ellerslie load will push fault levels to unacceptable levels. Any capacity increases at these substations will initiate substantial upgrading work including building alterations to accommodate additional switchgear, new higher-rated 11kV switchboards, sub-transmission circuit reinforcement and long distribution cables. These options are costly compared with the Ellerslie substation preference.

- **Te Papapa - 11kV reinforcement** (FY20)

  Organic growth increases arising from industrial customers in the Alfred Street area is expected to exceed the capacity of Te Papapa feeder 11 by 2020. Load transfers are impractical as adjacent feeder, Onehunga 8, is already heavily loaded. The proposed solution is to install a new 11kV feeder from Te Papapa substation in 2020 and re-distribute the load across this and adjacent feeders.

  An alternative solution was to connect the feeders to Onehunga substation. This option will create capacity constraints at Onehunga substation, caused by limitations on the sub-transmission cable capacity.

- **Newmarket – ex-Lion Breweries site development supply** (FY21)

  This project is to extend the existing 11kV feeders from Newmarket substation to supply load arising from the re-development at the ex-Lion Breweries site in Newmarket. The timing of this project is subject to the customer's development timeframes.

- **Newmarket – establish a new 110kV bulk supply substation** (FY20)

  - The existing Newmarket, Newton and Drive zone substations supply the Newmarket commercial centre and fringe area. Load at Newmarket substation is expected to increase in the near and medium term future, mainly due to the proposed expansion of Westfield shopping centre around Broadway and redevelopment at ex-Lion Breweries site. To address this in the short-term, it is proposed to establish a new substation at Newmarket South.
  - The load forecast shows the combined load from the four substations will reach 100MVA around the year 2025 – thus necessitating a new bulk supply point. Given the scale of the load and the location of the four substations, Newmarket becomes an ideal location for a GXP. The plan is to establish a bulk supply substation next to Newmarket South substation and install a 110kV circuit, a 110/33kV 60MVA transformer and a 33kV switchboard at Newmarket 110kV bulk supply substation. The bulk supply substation will initially supply Newmarket and Newmarket South substations.
  - Existing 33kV circuits between Penrose GXP and Newmarket substation will be used initially to back up the single transformer bulk supply substation. Drive and Newton substations will be connected to Newmarket bulk supply substation when the existing subtransmission circuits reach end-of-life and new circuits are required.
  - Connection of Drive and Newton substations will trigger the installation of the second 60MVA 110kV transformer. This is beyond the planning period

- **Southdown – establish a new GXP** (FY21)

  To relieve the heavily loaded 33kV bus at Penrose GXP, it is proposed to establish a 33kV supply from Transpower's GXP at Southdown. The intention is that as the sub-transmission supplies to Onehunga, Te Papapa, and Westfield substations are replaced due to age or capacity, they are replaced with 33kV rated equipment and connected to Transpower Southdown rather than Penrose. While Southdown GXP exists as a connection point for Mighty River's Southdown generating plant it does not have the infrastructure to provide a 33kV supply to Vector at this time.

  Preliminary investigations indicate it is cost effective to connect Onehunga, Te Papapa and Westfield substations to Southdown than to Penrose, due to shorter sub-transmission cabling distances. Transpower's costs need to be reviewed separately. It is anticipated a fourth zone substation will also be required from this site.

  Further study will be carried out in conjunction with the asset replacement program and reinforcement timetable.

5.6.12 Penrose 22kV

5.6.12.1 Background

Penrose 22kV GXP supplies three zone substations, viz. Glen Innes, Onehunga, and Westfield. Table 5-22 shows the summer and winter load forecasts at the GXP.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Penrose 22kV	90	53	52	54	54	55	55	56	56	56	57	57
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Penrose 22kV	90	55	56	57	58	58	59	60	60	61	62	62

Table 5-22 : Penrose 22kV summer and winter load projections

The long-term plan is to progressively transfer load from the Penrose 22kV bus to the Penrose 33kV bus in conjunction with the 22kV asset replacement programme, and phase out Penrose 22kV GXP eventually.

5.6.12.2 Projects Planned

No expenditure is forecast within this planning period on the Penrose 22kV sub-transmission network.

5.6.13 Roskill 110 kV (Kingsland)

5.6.13.1 Background

Roskill GXP provides a 110kV supply to Kingsland 110/22kV substation and a separate 22kV supply to a number of Vector substations. Vector also takes a 110kV supply to Liverpool in the CBD, supporting the existing dual 110kV supplies from Transpower Penrose. The sub-transmission network supplied from Roskill is shown in Figure 5-19.

There are two 110/22kV 60MVA transformers and two 22/11kV 20MVA transformers installed at this substation. Two 22/11kV transformers (Kingsland zone substation) are supplied from the 22kV switchboard. Two zone substations, Chevalier and Ponsonby, are remotely supplied from the Kingsland 22kV switchboard via 22kV sub-transmission cables. Table 5-23 shows the summer and winter load forecasts at the substation 22kV switchboard and the sub-transmission network fed from Kingsland is shown in Figure 5-20.

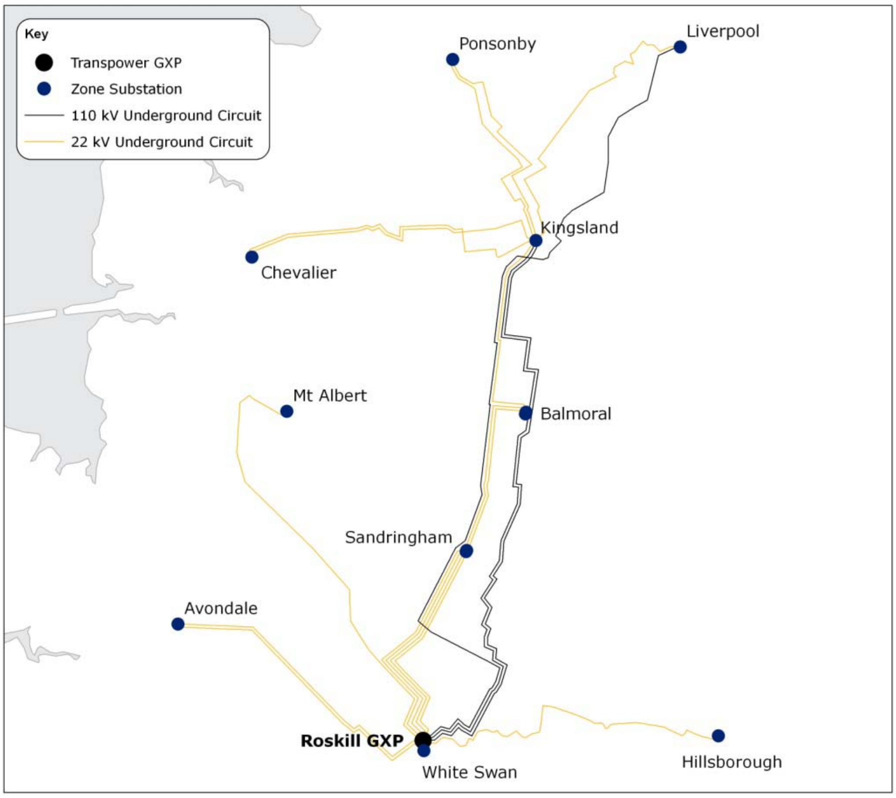

Figure 5-19 : Existing sub-transmission network at Roskill GXP

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Kingsland 22kV	60	35	38	38	39	39	39	40	40	40	40	41
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Kingsland 22kV	60	60	60	60	61	62	62	63	63	64	64	65

Table 5-23 : Kingsland 22kV summer and winter load projections

NZTA's Waterview tunnel construction project is expected to add around 24MVA load in total to the 110kV bus at this GXP (4MVA through Kingsland 22kV and 20MVA through Roskill 22kV) during construction period 2012 ~ 2016. Reinforcement has been carried out to increase the capacity at Chevalier and Avondale substations for this purpose (refer to individual projects for more details). A permanent supply to the Waterview tunnel of approximately 8MVA, is expected to be supplied from the Roskill 22kV bus after 2016.

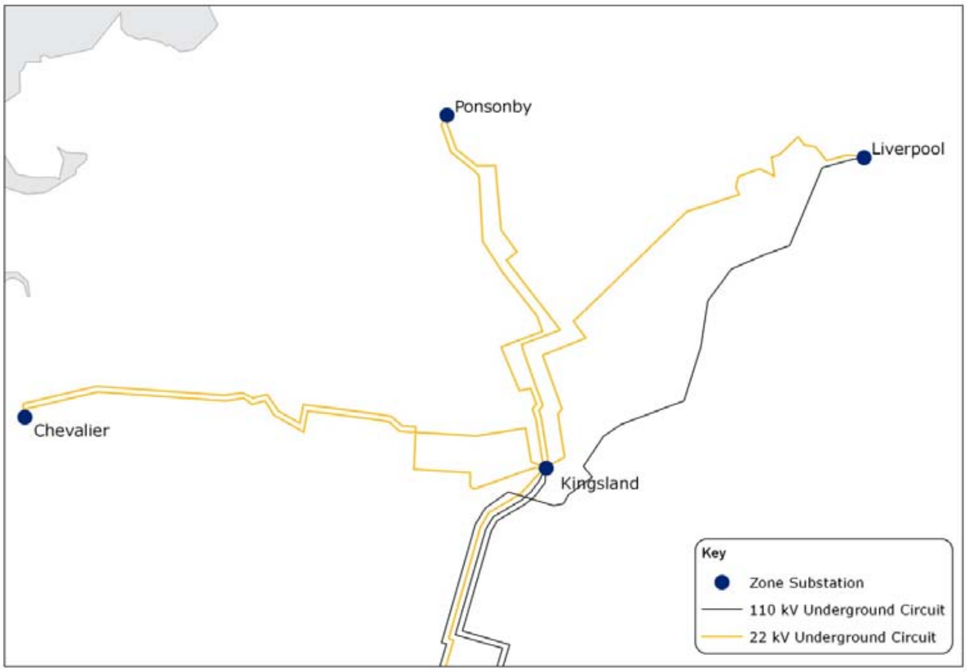

Figure 5-20 : Existing sub-transmission network connecting to Kingsland 110/22kV substation

5.6.13.2 Projects Planned

a. Projects – Within next five years

- **Waterview tunnel supply** (FY11 - FY15)

  The New Zealand Transport Authority (NZTA) plans to build a road tunnel on SH20 between Waterview and Sandringham. The project comprises two phases, provision of power supplies to construct the tunnel and motorway, and the permanent power supply necessary to meet the operational requirements of the tunnel. Table 5-24 summarises the power requirements of each phase:

North Portal Supply	Load	Timeframe	Security of supply	Source GXP
Construction	20.0MVA (combined)	Q3 2011 to 2015/16	N/A	Roskill
Permanent	8.0MVA[62]	2015/16	N-1 with auto switching	Roskill
South Portal Supply	**Load**	**Timeframe**	**Security of supply**	**Source GXP**
Construction	4.0MVA (combined)	Q3 2011 to 2015/16	N/A	Roskill
Permanent	8.0MVA	2015/16	N-1 with auto switching	Hepburn or Henderson

Table 5-24 : Power supplies required for the Waterview tunnel

There is insufficient capacity within the existing network to meet the tunnel demand for both the construction and permanent supplies. A number of options have been investigated to provide the capacity necessary while avoiding asset

[62] Total load is expected to be 8MVA but N-1 security doubles this requirement. Final supply configuration has still to be established

stranding on completion. Further synergies have been investigated to leverage off other planned projects to arrive at the most favourable outcome that provides the optimal and cost efficient solution. The preferred long-term plan is outlined below:

- **Chevalier - second 22/11kV transformer and a new 11kV feeder** (FY12)

  This project has been completed.

  Once the northern portal permanent supply is connected in 2015, the construction supply capacity at Chevalier will become available. This capacity will be used to support load at Mt Albert and Rosebank substations, deferring forecast upgrades to both of these substations.

- **Avondale – new 33kV switchboard (operated at 22kV)** (FY13)

  To meet the electrical demand of the Waterview Tunnel Boring Machine (TBM), a new 33kV cable has been installed (operated at 22kV) from Avondale to the south portal. A 33kV switchboard has yet to be installed at Avondale that will connect to the Roskill-Avondale sub-transmission supply and provide supply for the TBM. Forecast demand for the TBM is 16MVA and is required until completion of the tunnel in 2016.

  Once the construction project is completed, the 33kV circuit may be used to provide a permanent supply to the south portal of the tunnel or alternatively, extended to form a new sub-transmission circuit to supply Mt Albert substation replacing the existing sub-transmission cable from Roskill GXP around 2020. The Waterview Tunnel Alliance has yet to confirm their permanent supply requirements to the south portal.

- **Te Atatu – north portal permanent supply** (FY16)

  NZTA have indicated they require 100% redundancy for the permanent power supplies to each of the tunnel portals. For security NZTA have requested each portal be supplied from a different GXP. The south portal will be supplied from Transpower Roskill while the north portal will be supplied from Transpower Hepburn Rd or Henderson via Te Atatu. From Te Atatu substation, a new 33kV cable will be installed along the SH16 motorway in conjunction with planned widening activities. A 33/11kV substation will be established at the north portal.

  The construction supply installed from Pt Chevalier to the north portal is unsuitable as a permanent supply - like the south portal it is also fed from Transpower Roskill.

b. Projects – Within five to ten years

- **Mt Albert sub-transmission cables replacement** (FY20)

  Subject to the permanent power supply requirements to the south portal, the plan is to extend the Avondale/south portal 33kV circuit from New North Road/Henden Ave intersection to Mt Albert substation to supply Mt Albert when the existing sub-transmission circuit is replaced.

  Alternatives include installing a replacement 33kV circuit from Sandringham substation to Mt Albert substation along the same route as existing cables. This option is not preferred due to the higher cost arising from the longer cabling distance.

5.6.14 Roskill 22kV

5.6.14.1 Background

Zone substations included in this group are Avondale, Balmoral, Hillsborough, Mt Albert, Sandringham and White Swan. Table 5-25 shows the summer and winter load forecasts at the GXP.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Roskill 22kV	141	73	82	83	84	84	85	85	86	86	87	87
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Roskill 22kV	141	140	130	131	132	133	134	135	136	137	138	139

Table 5-25 : Roskill 22kV group summer and winter load projections

The long-term plan is to upgrade Roskill sub-transmission voltage from 22kV to 33kV. Where sub-transmission assets are replaced, or upgraded, 33kV rated assets will be substituted and operated at 22kV until Roskill is fully uprated to 33kV.

NZTA have requested 20MVA to supply to the Tunnel Boring Machine (TBM) during Waterview tunnel construction period from 2012 ~ 2016. Reinforcement has been carried out at Avondale substation for this purpose.

Westfield is planning an extensive expansion of the St Lukes shopping mall, requiring extra capacity from Balmoral substation.

Hillsborough substation was commissioned in 2010 as a single transformer substation. The load on this substation is such that in 2015 backstop capacity will be inadequate to support this substation. In anticipation of the second transformer being required, spare ducts were installed with the original 33kV rated sub-transmission cable and the substation was designed for a second transformer.

5.6.14.2 Projects Planned

a. Projects – Within the next five years

- **Avondale – new 33kV board** (FY13)

  A 33kV board is to be installed at Avondale substation to supply the 16MW Tunnel Boring Machine during Waterview tunnel construction period. Refer to the Waterview tunnel project discussion in Section 5.6.13 above for details.

- **Hillsborough – 2nd transformer and 33kV circuit** (FY14)

  A second transformer and 33kV circuit will be installed at Hillsborough substation to address forecast security issues at this substation in 2014.

- **Balmoral – new 11kV feeder to St Lukes** (FY14)

  A new 11kV feeder is to be installed from Balmoral substation to supply additional load arising from expansion of the St Lukes Shopping Mall. This is a customer driven project with timing set by the customer.

b. Projects – Within five to ten years

- **Mt Albert – sub-transmission circuit replacement** (FY20)

  It proposes to extend the Avondale 33kV circuit supplying the Tunnel Boring Machine during Waterview tunnel construction to Mt Albert substation when the existing sub-transmission circuit between Roskill GXP and Mt Albert is due for replacement due to age / conditions. Refer to the Waterview project discussion in Section 5.6.13 above for details.

5.6.15 Pakuranga 33kV

5.6.15.1 Background

Transpower's Pakuranga 33kV bus is supplied by two 110/33kV 120MVA transformers with an N-1 capacity limit of 136/136MVA (winter/summer). As part of the North Island Grid Upgrade Project (NIGUP) Transpower will be upgrading Pakuranga to 220kV. The two existing 110/33kV 120MVA transformers will be replaced with three 220/33kV 120MVA transformers providing 240MVA, firm capacity.

The summer and winter load forecasts are listed in Table 5-22 and a layout of the sub-transmission arrangement from the GXP is shown in Figure 5-21.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Pakuranga 33kV	136	103	101	103	104	105	106	106	107	108	108	109
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Pakuranga 33kV	136	153	145	146	147	148	149	149	150	151	152	153

Table 5-26 : Pakuranga 33kV summer and winter load projections

Five zone substations are supplied from Pakuranga - East Tamaki, Greenmount, Howick, Pakuranga and South Howick.

Between 2012 to 2015, a growth initiative is planned for the Howick area supported by the Auckland Manukau Eastern Transport Initiative (AMETI) roading project. It is possible this may have a slight growth impact on Howick substation maximum demand. Due to this uncertainty no provision has been made in the demand forecast at this time.

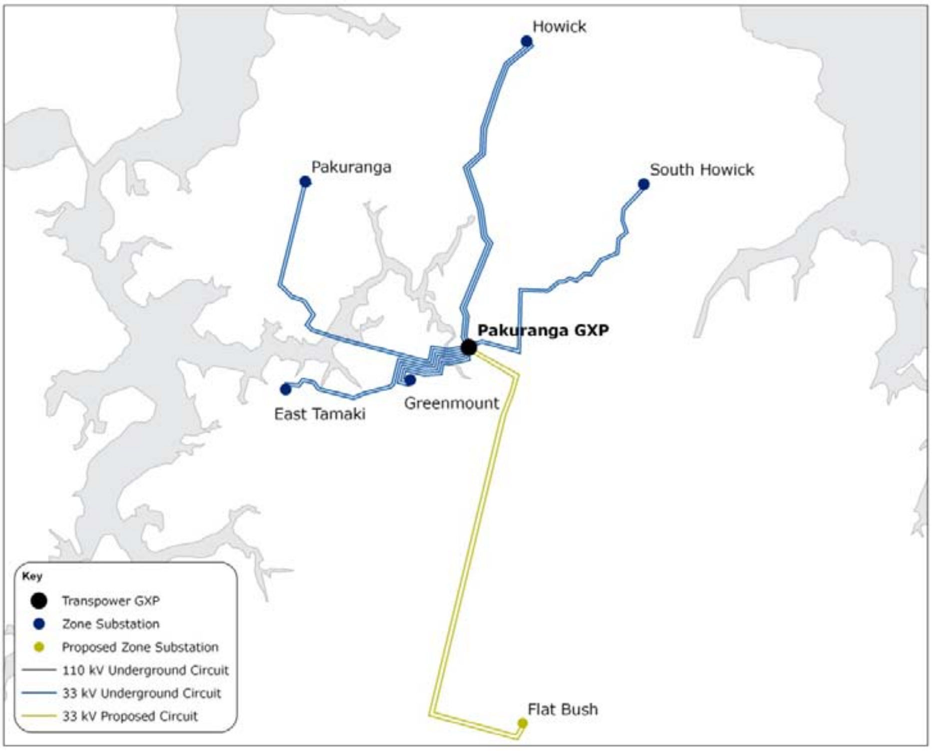

Figure 5-21 : Existing and proposed supply arrangement in the Pakuranga area

5.6.15.2 Projects Planned

a. Projects – Within the next five years

- **Flatbush zone substation** (FY15)

  The Flat Bush area (see Otara substation below) is experiencing moderate load growth and this trend is expected to continue as land is made available for development. It is expected that Flat Bush area will accommodate a population of about 40,000 by 2020. Developments in the area include residential housing, a town centre and multi storey residential apartments. Demand in the long term in this area is estimated at 30 to 40MVA. To meet the Flat Bush load growth it is proposed to install a new zone substation near the proposed Flat Bush Town Centre by 2015 (FY15). This new substation will be supplied from Pakuranga GXP.

5.6.16 Otahuhu 33kV

5.6.16.1 Background

Vector takes supply from the Otahuhu 22kV bus via two 220/22kV 50MVA transformers. The N-1 firm capacity limits (winter/summer) of this GXP is 59/59MVA. The summer and winter load forecasts are listed in Table 5-27.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Otahuhu 33kV	59	46	45	45	46	47	47	47	48	48	48	49
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Otahuhu 33kV	59	64	59	60	61	62	62	63	63	64	64	65

Table 5-27 : Otahuhu 22kV summer and winter load projections

Two zone substations and a switching station are supplied from the Otahuhu 22kV bus, namely, Bairds, Otara and Highbrook.

The FY12 peak demand at this GXP was 64MVA, 5MVA above the firm capacity limit of the GXP. Greenmount embedded landfill generation plant is connected via Otara substation and is currently generating approximately 1.8MW. Taking this into account, the full peak load in the area in 2011 was 65.8MVA. The capacity of the two transformers is 100MVA, but the firm capacity is limited by the 22kV incomer cable ratings and transformer bushings. Transpower have signalled the replacement of the two 220/22kV transformers in their Annual Planning Report[63].

The geo-schematic diagram in Figure 5-22 shows the existing supply arrangement in the Otahuhu area.

[63] 2011 Annual Planning Report, Transpower New Zealand, Chapter 8, pp123

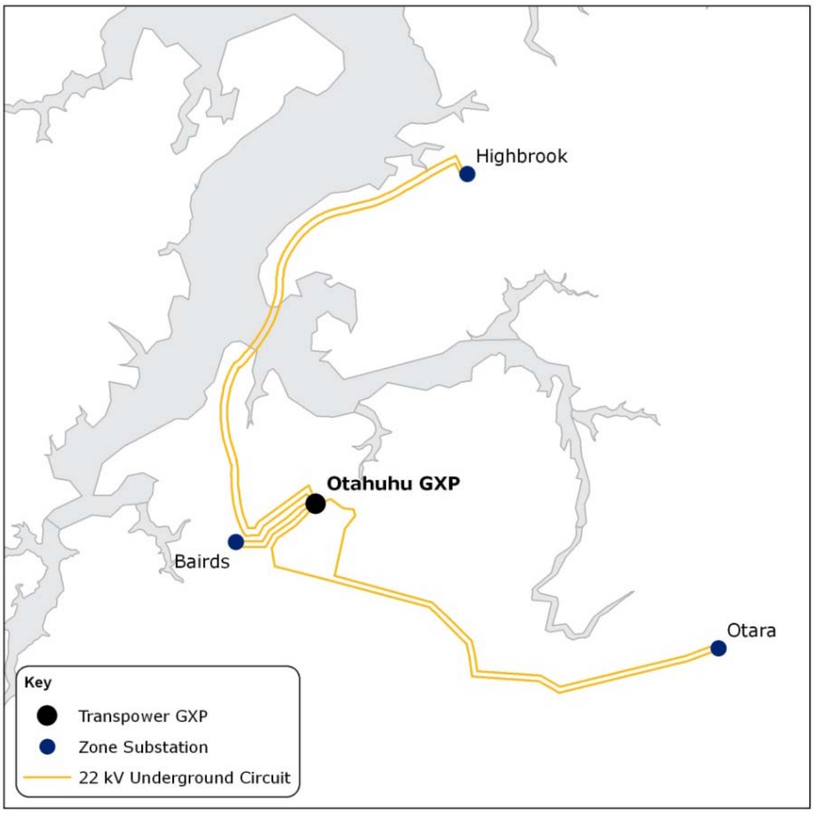

Figure 5-22 : Existing supply arrangement in the Otahuhu area

Otara substation supplies the Flat Bush area, which is experiencing moderate load growth. The growth trend is expected to continue due to the development adjacent vacant and this substation will exceed it short term capacity in 2016, triggering the construction of Flat Bush substation. Approximately 15MVA of capacity will released at Otara following the construction of Flat Bush substation (construction expected in 2015) and will be used to supply the industrial area to the north.

Highbrook Business Park was developed as a premium commercial/industrial estate that can accommodate large range of businesses. Highbrook is unusual as it is the only development within Auckland's distribution area with the exception of the CBD where the reticulation voltage is 22kV. A switching station has been established, supplied by two 22kV cables laid from Otahuhu GXP, to provide an N-1 capacity of 23MVA. Current load is about 5.5MVA.

In April 2011, Goodman Property Trust announced a new stage in the development of the Highbrook Business Park, "The Crossing". The Crossing is a 24700m^2 of mixed use development that will combine 62 serviced apartments with 17,300m^2 of commercial office space and 4,400m^2 of retail and hospitality type amenity. This project will be completed in discrete stages.

5.6.16.2 Projects Planned

a. Projects – Within five to ten years

- Otara – new 11kV feeder along Ormiston Road (FY19)
- The Otara #7 feeder and Otara #2 feeder cannot be backstopped successfully using adjacent feeders after winter 2019 and winter 2020 respectively. By installing a new 11kV feeder along Ormiston Road, Otara substation can provide security to both of these feeders.

- Alternative solutions include a new feeder from Greenmount substation, or alternative load transfers. A new 11kV feeder along Ormiston Road is the most cost effective solution.

5.6.17 Mangere 33kV

5.6.17.1 Background

Vector takes supply from the Mangere 33kV bus via two 110/33kV 120MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 118/118MVA. The summer and winter load forecasts are listed in Table 5-28.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Mangere 33kV	118	87	91	93	96	98	101	103	105	107	108	113
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Mangere 33kV	118	107	107	109	111	113	115	117	120	123	125	126

Table 5-28 : Mangere 33kV summer and winter load projections

The 2011 winter peak demand was 107MVA. Vector supplies five zone substations from Mangere 33kV bus, namely, Auckland Airport, Hans, Mangere Central, Mangere East and Mangere West and also a major customer (Pacific Steel) directly from the 110kV bus. The winter peak load will exceed the transformers' firm capacity in 2018.

This load is forecast to increase to 126MVA towards the end of the planning period due mainly to the anticipated development of the area surrounding Auckland Airport.

The geo-schematic diagram in Figure 5-23 shows the existing supply arrangement in the Mangere area.

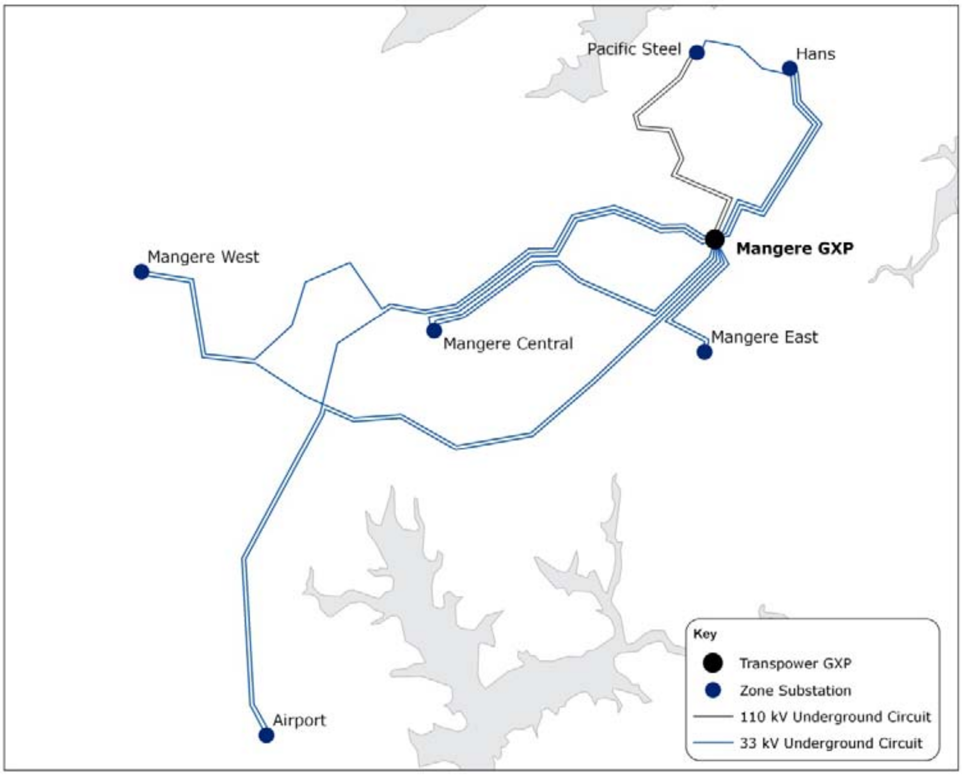

Figure 5-23 : Existing supply arrangement in the Mangere area

Auckland Airport (AIAL) substation is dedicated to supply the Auckland airport demand. Peak demand in 2011 was 16.5MVA. The projected demand towards the end of the planning period is about 51.8MVA. The substation capacity is contracted to the AIAL to supply the airport operation and the industrial/commercial development around the airport. AIAL has advised Vector of major planned extensions in the short to medium term future.

Due to the criticality of the airport supply, AIAL require a full N-1 security. A third 25MVA transformer was scheduled to be installed in 2011 but this project has been postponed (by AIAL) for the current year. Once the third transformer has been installed the supply to the site will be constrained to 38MVA by the two incoming cables. A third sub-transmission feeder is forecast for 2018 and will increase the security level of the AIAL complex to 50MVA. This is a customer operated substation and the projects are initiated in accordance with the customer timeframes.

Middlemore Hospital has indicated increased demand over the next ten years, and is forecast to require up to 6.9MVA by 2020. Discussions are continuing with the customer, particularly around back-up supplies and distributed generation requirements.

Mangere Central substation is expected to exceed its installed capacity in summer 2014 (FY14). It is intended to transfer some of the load to Mangere West substation to relieve Mangere Central Substation. Forecast developments[64] for the area include re-zoning Paynes Island reserve, corner of Bader Drive and Mascot Avenue and corner Court Town Close and Bader Drive, which will allow for community, retail use and residential use. A further five areas have been identified for development.

If these developments eventuate a third transformer will be required in Mangere Central substation. Depending on load growth the installation of 3rd transformer will take place towards the end of planning period.

5.6.17.2 Projects Planned

a. Projects – Within the next five years

- Mangere West – Extend Mangere West #2 feeder (FY14)
- Mangere Central #10 feeder cannot be backstopped successfully using adjacent feeders after winter 2013. Extending the Mangere West #2 feeder will provide security to the Mangere Central #10 feeder and also provide security to Mangere Central #18 feeder, which is expected to exceed its security limits by 2017.
- Alternatives considered included installing a new feeder from Mangere Central substation, installing a new feeder from Mangere West substation, and interconnection to alternative distribution feeders. Extending Mangere West #2 feeder is the most cost effective solution.

b. Projects – Within five to ten years

- Mangere East - Rearrange Mangere East #15 and #13 feeders (FY18)
- Mangere East #15 feeder cannot be backstopped successfully using adjacent feeders after winter 2018. Reconfiguring Mangere East #15 feeder and Mangere East #13 feeder will address this problem.
- Options include installing a new feeder from Mangere East substation to connect to the Mangere East #15 feeder, or to interconnect to adjacent feeders to transfer load. Reconfiguring Mangere East #15 and #13 feeders is the most cost effective solution.
- Mangere Central - Install a 3rd transformer in Mangere Central Substation (FY18)

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[64] Auckland Council Plan

Mangere Central is a fast growing area especially due to new developments around Auckland Airport. To meet the demand in this area it may be necessary to upgrade the existing Mangere Central substation by installing a third transformer. Current forecasts indicate this will be required in 2018.

Alternatives considered include transferring load to Mangere West and Mangere East substations.

5.6.18 Wiri 33kV

5.6.18.1 Background

There are two 110/33kV 50/100MVA transformers installed at Wiri GXP. The 110kV supply to this GXP is obtained via a tee off from the two Bombay to Otahuhu 110kV lines. The capacity to Wiri is limited by the capacity of these 110kV lines and how they are operated. The N-1 capacity limits (winter/summer) of this GXP are 92/101MVA. The 2011(F12) winter peak demand was 83MVA. The present load projection indicates the demand on this GXP will not exceed its capacity (subject to capacity issues external to the site being addressed) during the planning period.

The summer and winter load forecasts are listed in Table 5-29. The geo-schematic diagram in Figure 5-24 shows the existing supply arrangement in the Wiri area.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Wiri 33kV	92	70	72	73	75	75	76	77	78	78	79	80
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Wiri 33kV	101	83	79	80	81	82	82	83	84	85	85	86

Table 5-29 : Wiri 33kV summer and winter load projections

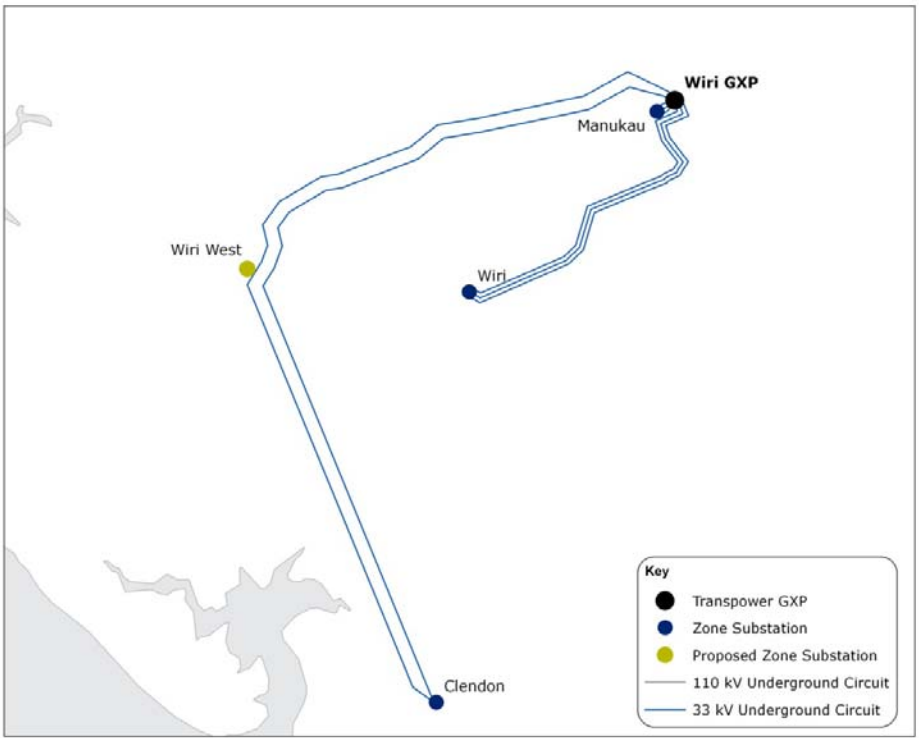


Figure 5-24 : Supply arrangement in the Wiri area

Three zone substations are supplied from this Wiri 33kV bus, namely, Manukau, Wiri and Clendon.

Major developments are occurring along Ash Road, McLauglins Road and Hobil Ave. This year, two large capacity connections were made to AMCOR and PMP Print, each requiring 4MVA. Further demand requests have been received from Wiri Women's Prison and the Manukau Institute of Technology. The growth from these collective developments will determine whether Wiri West substation is required before the end of the planning period.

Clendon substation has recently been commissioned and comprises two 33/11kV 20MVA transformers. The 33kV cables were designed to accommodate the capacity of a future substation at Wiri West.

5.6.18.2 Projects Planned

a. Projects – Within five to ten years

- Establish Wiri West Substation (FY20)

  The 2011 Draft Auckland Plan has identified the areas around Roscommon Road and west of Wiri as major development business areas with high growth potential. To meet this demand it is forecast that a new substation (Wiri West) will be required in 2020.

5.6.19 Takanini 33kV

5.6.19.1 Background

Vector takes supply from the Takanini 33kV bus via two 220/33kV 150MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 126/126MVA.

The 2011(F12) peak demand was 117MVA. The winter peak load is expected to reach the transformers' N-1 capacity in 2022 (FY23). The transformers' capacity is currently limited by protection equipment constraint. Transpower has plans to resolve this issue by 2016.

Table 5-30 shows the summer and winter load forecasts at the GXP.

Name	Firm Capacity	Actual	Forecast Demand (MVA) - Summer									
		FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Takanini 33kV	126	86	88	90	92	93	94	95	96	97	98	99
Name	**Firm Capacity**	**Actual**	**Forecast Demand (MVA) - Winter**									
		FY12	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Takanini 33kV	126	117	114	114	115	116	117	118	119	120	121	122

Table 5-30 : Takanini 33kV summer and winter load projections

The geo-schematic diagram in Figure 5-25 shows the existing and proposed supply arrangement in the Takanini area.

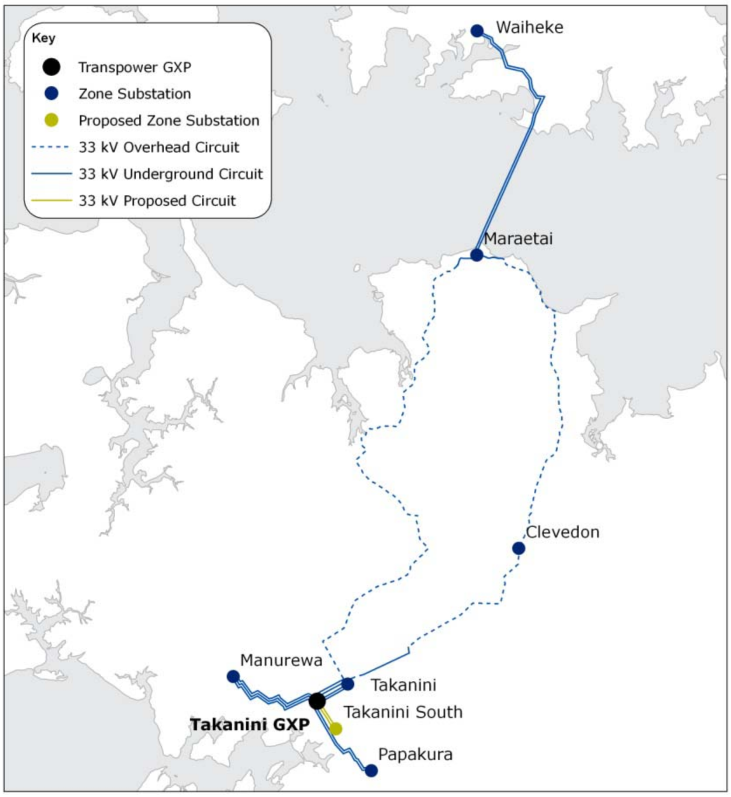


Figure 5-25 : Existing and proposed supply arrangement in the Takanini area

Six zone substations are supplied from Takanini GXP, namely, Takanini, Manurewa, Papakura, Clevedon, Maraetai and Waiheke.

Takanini is expected to experience moderate residential growth with a number of subdivisions under construction or planned. Higher density housing developments are expected to increase with a target of 2000 houses per annum. Development of the remainder of Wattle Downs (33ha undeveloped) is expected to continue along with open land surrounding the Super Clinic between Manukau and Manurewa. Growth at Maraetai is dominated by the Beachlands development at Spinnaker Bay where the release of 500 new residential full sections is well underway.

Clevedon substation supplies residential load in the Clevedon area. This substation was established in 2002 to improve the reliability and quality of supply to the area east of Clevedon. The single 33/11kV 5MVA transformer is supplied by a “tee” off the Takanini - Maraetai 33kV circuit. The 2011 winter peak demand was 3.5MVA and is projected to grow to about 4.4MVA towards the end of the planning period. Depending on the long term load growth, it may be necessary to upgrade the transformer to a 10MVA unit. Proposed plan changes to Clevedon Village will introduce a number of new residential zones around the village to provide for future growth for up to 600 new homes. This will impact on the available capacity of the Clevedon substation

Manurewa substation supplies a mixed commercial and residential load in the Manurewa area. There are three 33/11kV 20MVA transformers installed at this substation. The 2011 winter peak demand was 50.2MVA and the projected load by 2021 is about 57.0MVA. The short term capacity for the substation is 54.1MVA, limited by 33kV cables. The summer capacity is also limited to 31.8MVA again, by the rating of the 33kV cables. The substation load is therefore forecast to approach the limits of its short term capacity towards the end of the planning period and depending on growth, reinforcement may be required after 2018.

At the beginning of 2011 a new feeder was installed to the Takanini Fonterra site. This new feeder transfers about 4.7MVA load from Takanini substation onto Manurewa. It is also expected that 3500 new housing sites will become available over the next 10 years around the Manurewa town centre as part of nodal development plan.

According to Papakura District Council's "Long Term Council Community Plan", 10,000 more people are expected to be settled in the District within the next 10 years. As a result Takanini is expected to experience moderate residential growth with a number of subdivisions under construction or planned, especially near the old horse training track, the Papakura Camp and the extensive farming land west of Takanini.

Depending on load growth Takanini substation, may not be able to meet the supply requirements in the latter part of the planning period. It is proposed to establish a new Takanini South substation on a site close to the Addison subdivision in Porchester Road. This substation will provide backstop to Manurewa, Takanini and Papakura substations and cater for the potential load growth on the western side of Porchester Road along Great South Road and the railway line.

5.6.19.2 Projects Planned

a. Projects – Within the next five years

- Maraetai– New 11kV feeder to reinforce Maraetai # 9 feeder (FY13)

  Maraetai #9 feeder cannot be backstopped successfully using adjacent feeders in summer 2013. Installing a new 11kV feeder from Maraetai substation along Whitford-Maraetai Road can provide security to Maraetai #9 feeder.

  Alternatives considered include installing a new feeder from Otara substation, installing a new feeder from South Howick substation, or connecting into adjacent feeders. Of these, a new 11kV feeder from Maraetai was the most cost effective and practical solution.

- Maraetai–Reinforce Maraetai #2 feeder (FY13)

  Maraetai #2 feeder cannot be backstopped successfully using adjacent feeders after summer 2013. By reconfiguring Maraetai #7, security can be provided to Maraetai #2 feeder.

  The alternative of installing a new feeder from Maraetai substation is a more costly option.

- Waiheke–Rinforce Waiheke #5 feeder (FY14)

  Waiheke #2 feeder cannot be backstopped successfully using adjacent feeders after summer 2014. Reconfiguring Waiheke #3 feeder will provide the necessary security to Waiheke #5 feeder.

  This is the most cost effective option.

b. Projects – Within five to ten years

- Takanini– New Mill Road feeder (FY17)

  Takanini is expected to experience moderate residential growth with a number of subdivisions under construction or planned. To meet the demand in these areas a new Mill Road 11kV feeder from Takanini zone substation is required.

  Alternatives considered include installing a new feeder from Manurewa substation or from Papakura substation. Of these options new Mill Road feeder is the most cost effective solution.

5.7 Asset Relocation

As outlined in sections 32, 33 and 35 of the Electricity Act 1992, sections 33 and 34 of the Gas Act 1992, section 54 of the Government Roading Powers Act 1989 and sections 147A and 147B of the Telecommunications Act 2001, it is a requirement for Vector as owner and operator of network assets to relocate assets when requested by requiring authorities. Infrastructure projects can be initiated by other utilities (such as Transpower and Telecom) or roading authorities such as the NZTA and local councils. The process and funding of such relocation work is governed by the relevant Acts.

The timing of relocation projects is driven by the authority concerned and usually provides less advance notice or detailed scope compared with projects initiated from within Vector. Information about projects more than one year in advance is generally not available for all but the large multi-year projects. In this respect expenditure forecasts are based on continuation of the current level of relocation activity.

The relocations forecast is divided into two groups, namely the larger projects as described above and a second group comprising of the smaller projects such as pole relocations, minor network relocations, etc. The budget allocated to minor relocations has remained static over the last few years at $1.5 million per annum.

Following is a list of known large infrastructure projects greater than $1.0m that require relocation of Vector electricity network assets. Many of these projects also impact on Vector's gas and communications assets:

- NZTA plans to construct a motorway tunnel between Waterview and Avondale. Existing 11kV and LV cables that impinge on the work area will need to be relocated.
- NZTA is planning to widen the north-western motorway (SH16) from Waterview through to Westgate.
- Watercare proposes to install a new water main from Redoubt North Reservoir in Manukau to Market Road in Epsom (Hunua 4).
- Transpower, as a result of their NIGUP/NAaN projects, has requested that Vector relocates some if its assets to make way for their works. The NIGUP/NAaN project also requires relocation works to be carried out at four GXP's.
- Auckland Transport is planning to upgrade the following roads. Their works will require Vector to relocate some of its assets.
- Albany Highway
- AMETI (Auckland Manukau Eastern Transport Initiative)
- Dominion Road
- Glenfield Road
- Tiverton Road/Wolverton Street
- Wairau Road
- Whangaparaoa Road
- Transpower GXP conversion of 33kV switchgear from outdoor to indoor: Hepburn Road, Penrose, Henderson and Pakuranga

5.8 Undergrounding of Overhead Lines

Vector, through an agreement with its majority shareholder, the Auckland Energy Consumer Trust (AECT)[65], commenced the Overhead Improvement Programme (OIP) in 2001. Through this it aims to underground or make improvements for amenity purpose to the remaining overhead electricity lines across the urban areas of the former Auckland City, Manukau City, and Papakura District.

Through the agreement Vector commenced the programme investing a minimum of $10 million per year on undergrounding in this area. The minimum amount of undergrounding is inflation-adjusted each year by the producer's price index (PPI). The minimum investment targeted for the 2011/12 year is $13.2 million. Budgeted undergrounding expenditure for 2011/12 year is higher than the minimum investment targeted due to a shortfall of investment during 2010/11.

United Networks, when acquired by Vector in 2003, had embarked on an undergrounding programme in the areas of the former Rodney District, North Shore City, and Waitakere City. This programme was funded through dividends from shares in United Networks held through the Waitemata Electricity Trust for Rodney District Council, North Shore City Council, and Waitakere City Council. The United Networks Share Holders Society, as trustees of the Waitemata Electricity Trust, was responsible for administering payment for the undergrounding work.

With the councils divesting their United Networks shares through the sale of the company to Vector and then opting to use the proceeds of the sale of shares to fund other council activities, dividend income to the Waitemata Electricity Trust ceased. Vector continued with this programme until the available funds in the Waitemata Electricity Trust, approximately $11 million, had been invested through further undergrounding activity. Vector has not been able to justify further investment in the undergrounding of overhead lines across the areas of the former Rodney District, North Shore City, and Waitakere City since funding support ceased in 2005.

5.8.1.1 Criteria for Selecting the Area for OIP

Vector sets its priority for undergrounding based on the condition and performance of overhead lines. Priority is given to undergrounding areas where large investments would otherwise be needed to rebuild overhead lines.

Secondary drivers include:

a. The frequency of faults in the area (pole strikes, etc.);

b. The resulting benefit versus undergrounding costs;

c. The level of other council or utility works planned for the area; and

d. Other synergy opportunities that help to reduce overall costs and provide other benefits.

5.8.1.2 Projected OIP Expenditure

Vector's targeted investment in undergrounding for the 2011/12 year is $15.6 million. Projected expenditure for undergrounding over the next ten years will be targeted at the same (real) level but adjusted to reflect movements in PPI. The projected expenditure projection over the planning is shown in Table 5-31 below.

[65] This is a requirement of the Trust Deed.

	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Total Budget ($m)	$15.6	$13.2	$13.2	$13.2	$13.2	$13.2	$13.2	$13.2	$13.2	$13.2	$13.2

Table 5-31 : OIP improvement budget

5.9 Protection, Automation, Communication and Control

Vector’s electricity distribution network has to continually evolve and adapt to changing customer requirements and technological developments. The challenges ahead include the requirement to integrate distributed energy resources into the distribution network, to assure improved resilience and quality of supply and to provide customers with increased flexibility to control their appliances and electricity consumption patterns, while still retaining a safe, economically and technically efficient electricity network.

We foresee that the power system of the future will:

- Be made up of numerous automated transmission and distribution systems, all operating in a coordinated, efficient and reliable manner;
- Handle emergency conditions with ‘self-healing’ actions and will be responsive to energy-market and utility business-enterprise needs; and
- Serve millions of customers and have an intelligent communications infrastructure enabling the timely, secure and adaptable information flow needed to provide reliable and economic power to the evolving digital economy.

To successfully address the challenges such a future power system poses, electricity distribution businesses need to develop not only their power networks, but also the information and control networks supporting this. Future network applications are likely to lead to continuously increasing network-complexity, necessitating incremental deployment and integration of more sophisticated protection and control equipment, widespread use of sensors and IED and improved information and communication technologies.

Figure 5-26 and Figure 5-27 show the parallels between the power and information infrastructures that utilities have to manage.

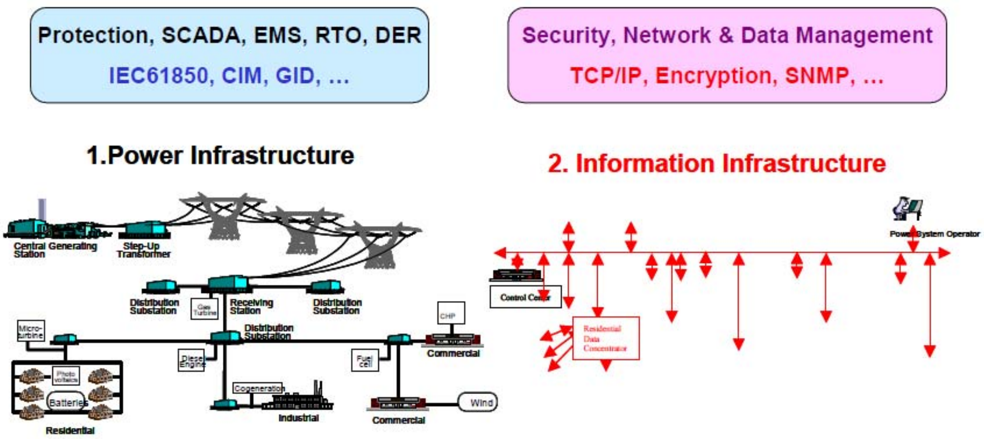


Figure 5-26 : Mirroring the power and information infrastructures at a utility

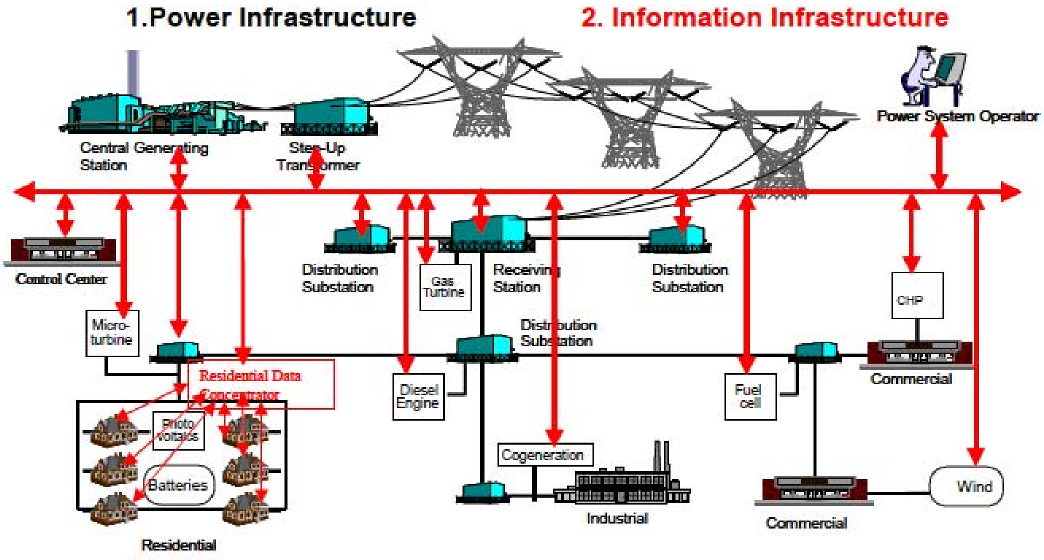


Figure 5-27 : Power system infrastructure with integrated information and communication systems

As the use and applications for "intelligent" control and information devices on electricity networks increase, the offering of equipment and solutions are increasing apace. This leads to a bewildering array of potential devices, standards, solutions and opportunities, some of which provide a high degree of flexibility and compatibility, but many of which rely on proprietary systems, effectively locking in the user.

Vector has decided to adopt, as far as practicable, a standard, internationally-recognised, open communications architecture, that would allow different devices and applications to integrate seamlessly and would allow Vector to choose from a wide range of present and future applications. Adoption of a standards based power system information infrastructure is considered vital to allow the required flexibility to ensure the ongoing, optimal development of our control systems. In Figure 5-28 the key standards adopted by Vector for its information and control systems are illustrated.

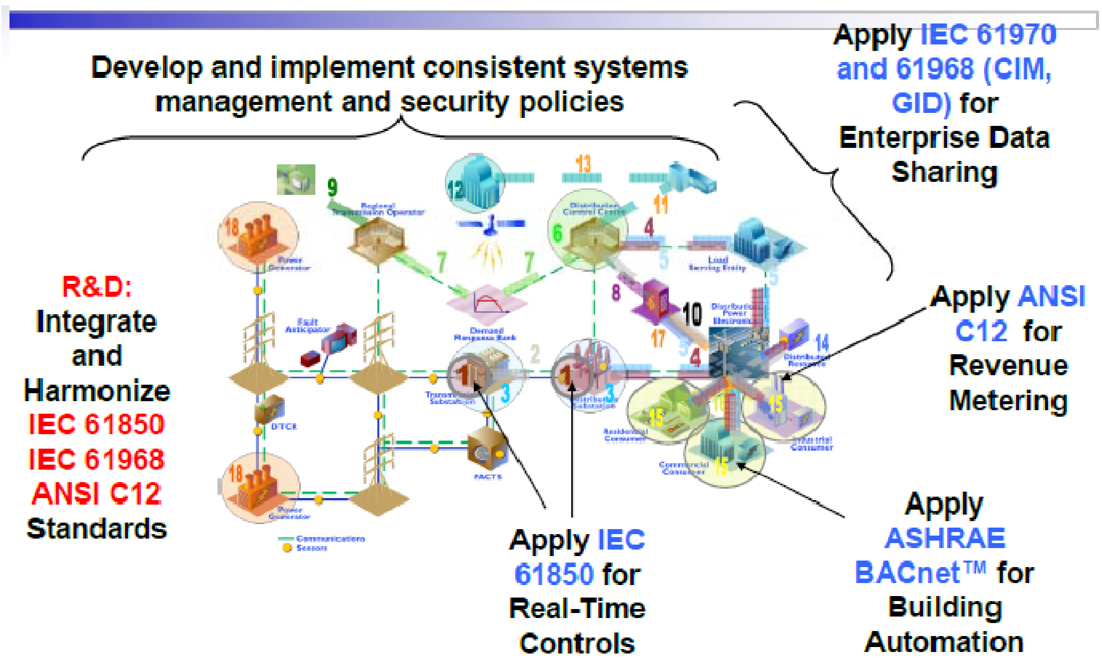


Figure 5-28 : Key standards for information and control systems

An approach that is independent of the architectural technology chosen is necessary to deal with the increased complexity of the power system and to facilitate systems interoperability and reduction in information integration costs.

The International Electrotechnical Commission (www.iec.ch) is the leading global organisation that prepares and publishes international standards for all electrical, electronic, and related technologies, primarily for the electric power industry. The IEC is spearheading a global initiative to support the new "smart" electric power network. IEC Technical Committee TC 57 (Power Systems Management and associated information exchange - http://tc57.iec.ch) has developed unique reference architecture for power system protection, automation, communications and control systems. Figure 5-29 shows the IEC TC57 reference architecture, which Vector has also adopted.

The reference architecture reflects the ultimate objectives for an information infrastructure that can meet all business needs, including network configuration requirements, quality of service requirements, security requirements, and data management and exchange requirements. It will enable integration of:

- Abstract modelling;
- Security management;
- Network and system management;
- Data management and exchange; and
- Integration and interoperability.

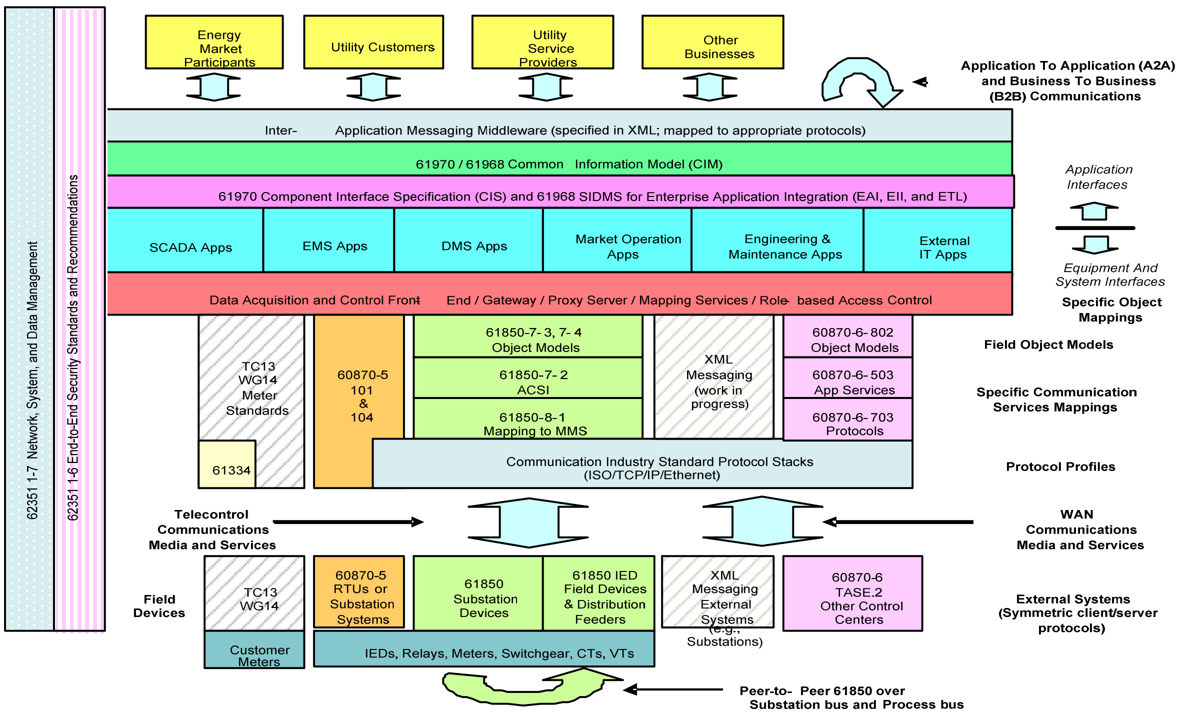


Figure 5-29 : IEC TC57 reference architecture

- Adopting this reference architecture facilitates:
  - Innovation (enabling advanced applications that will require a ubiquitous infrastructure);
  - Cost Efficiency –

  - Capital savings from standardised components that can be competitively procured;
  - Life cycle savings from lower maintenance costs due to standardisation;
  - Reduction in stranded assets from systems that can integrate;
  - Ability to incrementally build upon first steps; and then scale up massively;
  - Reduced development costs by building on components of the reference architecture systems engineering; and
- Resilience (achieved from structured approaches to systems management); and
- Increased security - consistently and adequately secure the energy industry.

5.9.1 Power System Protection

All of Vector's new and refurbished substations are equipped with multifunctional IEDs. Each IED combines protection, control, metering monitoring and automation functions within a single hardware platform. IED compliance to IEC 61850 is mandatory.

- Vector's older protection system is being phased out over time, with the main drivers for this being;
- Protection system obsolescence (non-compliance with system requirements);
- End of technical life or unit failure;
- Reduced maintenance cost (cost efficiency);
- Improving safety;
- Improving reliability;
- Standardising and simplifying maintenance practice; and
- Standardising protection installation designs.

At present over 50% of Vector's primary substation are equipped with IEC 61850 compliant IEDs.

5.9.1.1 Network Protection – Design Standards

The main functions of a network protection system are to rapidly detect network faults by monitoring various parameters (current, voltage etc) and selectively initiate fault isolation should an abnormal situation be observed. As a result the protection system minimises damage to the electricity system components (generators, overhead lines, power cables, power transformers, CBs etc) and loss of supply to customers.

- Protection systems take into account the following principles:
- Reliability - the ability of the protection to operate correctly;
- Speed - minimum operating time to clear a fault;
- Selectivity - disconnection of minimum network sections in order to isolate the fault; and
- Cost - maximum value from investments.

a. Maximum Fault Clearing Time

Maximum fault clearing time is defined as the time from fault initiation to the fault breaking device arc extinction. Main protection maximum fault clearing time is stipulated in Table 5-32.

Fault Location	System Voltage			
Primary Equipment	**11kV**	**22kV**	**33kV**	**110kV**
Switchgear and Power Transformer Faults	150ms	150ms	150ms	150ms
Line Faults	600ms	150ms	150ms	150ms

Table 5-32 : Maximum fault clearing time

The fault clearing time of the back-up protection shall not exceed the short-circuit thermal withstand capability of the primary equipment.

b. Protection Schemes

Vector's primary network equipment is protected to minimise damage during any type of faults. All new and refurbished substations are equipped with multifunctional IEDs. Each IED combines protection, control, metering monitoring, and automation functions within a single hardware platform. It also communicates with the substation computer or directly to SCADA central computers over the IP based communication network using industry standard communication protocols.

c. Line Protection

Table 5-33 sets out the protection schemes for protecting the various parts of the distribution network.

Line Type	System Voltage	Protection Scheme
Overhead Line	110k	Main - Longitudinal Differential protection (ANSI 87L) Back-up - Distance Protection (ANSI 27) - Breaker Failure (ANSI 50BF)
Overhead Line	33 / 22kV	Main - Longitudinal Differential protection (ANSI 87L) Back-up - Over-current and Earth Fault (50 /51)
Overhead Line	11kV	Main - Over-current and Earth Fault (50 /51) Back-up - Over-current and Earth Fault (50 /51)
Underground Cable	110kV	Main - Longitudinal Differential protection (ANSI 87L) - Thermal overload (ANSI 49) Back-up - Distance Protection (ANSI 27) - Breaker Failure (ANSI 50BF)
Underground Cable	33kV / 22kV	Main - Longitudinal Differential protection (ANSI 87L) - Thermal overload (ANSI 49) Back-up - Over-current and Earth Fault (50 /51-50N/51N)
Underground Cable	11kV	Main - Over-current and Earth Fault (50 /51) Back-up - Over-current and Earth Fault (50 /51)

Table 5-33 : Line protection schemes

Dedicated optical fibres are used for all communication assisted protection schemes eg. longitudinal differential protection scheme.

d. Auto Reclosing

Auto-reclosing is applied to overhead network but not to the underground cable or combined underground cable and overhead lines.

e. Busbar Protection

Table 5-34 sets out the protection schemes for protection busbars at zone substations and bulk supply substations.

System Voltage	Protection Scheme
110kV	Main - Low Impedance differential protection (ANSI 87BB) Back-up - Over-current-time and Earth Fault (ANSI 50/51-50N/51N)
33, 22 and 11kV GIS	Main - Arc detection (50AR) or Low Impedance differential protection (ANSI 87BB) Back-up - Over-current and Earth Fault (ANSI 50/51-50N/51N)
33, 22 and 11kV AIS – Metal-clad	Main - Arc detection (50AR) or Low Impedance differential protection (ANSI 87BB) Back-up - Over-current and Earth Fault (ANSI 50/51-50N/51N)
33, 22 and 11kV AIS	Main - Low Impedance differential protection (ANSI 87BB) Back-up - Over-current and Earth Fault (ANSI 50/51-50N/51N)

Table 5-34 : Busbar protection schemes

5.9.2 Control Centre Applications

5.9.2.1 SCADA Master Station

Siemens Spectrum Power TG master station has been deployed for monitoring and control of the electricity networks.

As with the rest of the Vector information system topology, SCADA solutions based on non-proprietary industry open standards are applied. This is a major driver for flexibility and cost efficiency. Vector has standardised on the Siemens SpectrumPower TG application since 2002. It has been recently upgraded to the latest release. Vector has a long term strategy for the complete migration of the Northern region real-time information to the Siemens Spectrum Power TG system, to allow us to operate one, efficient SCADA system and to standardise in our applications was accomplished. The migration process started in 2004 and the intended integration solution is shown in Figure 5-30.

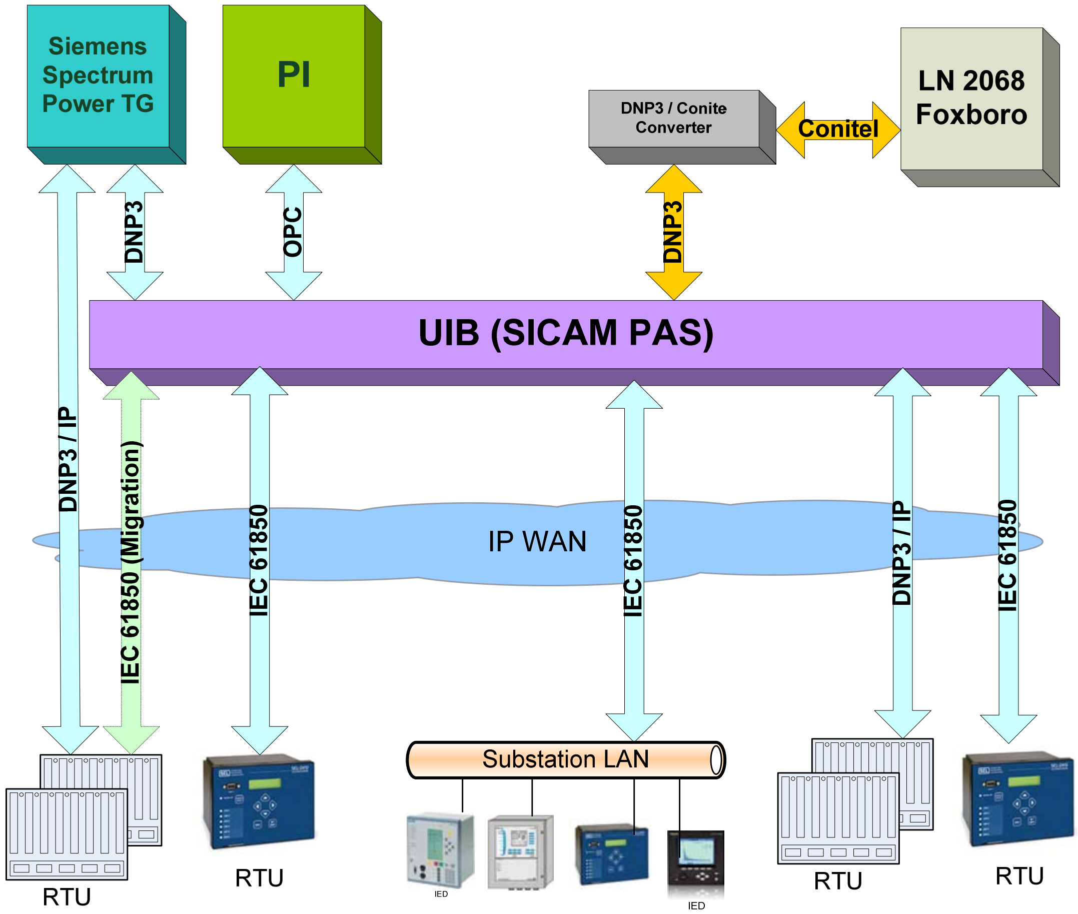


Figure 5-30 : The field information integration solution to the Control Centre applications

5.9.2.2 Future SCADA Spectrum Power TG Vision and Development

Siemens is a leader in the implementation of IEC 61850 based solutions, which is the standard adopted by Vector. Siemens has a number of sophisticated SCADA system products and it has laid out its vision and evolutionary path towards a unified platform compliant to the recommended standards (IEC 61850 and IEC61970 CIM), as shown in Figure 5-31, Figure 5-32 and Figure 5-33. This is aligned with Vector's SCADA and information system strategy.

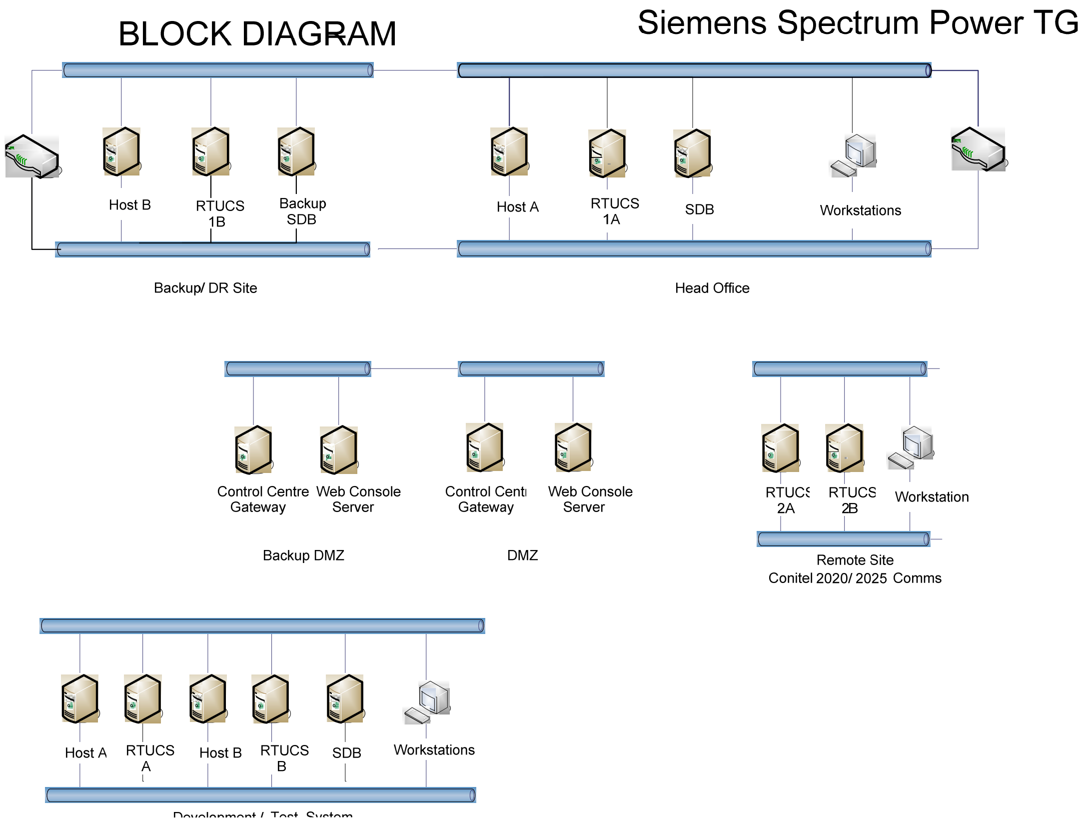


Figure 5-31 : Siemens Spectrum Power TG Master Station Application Architecture

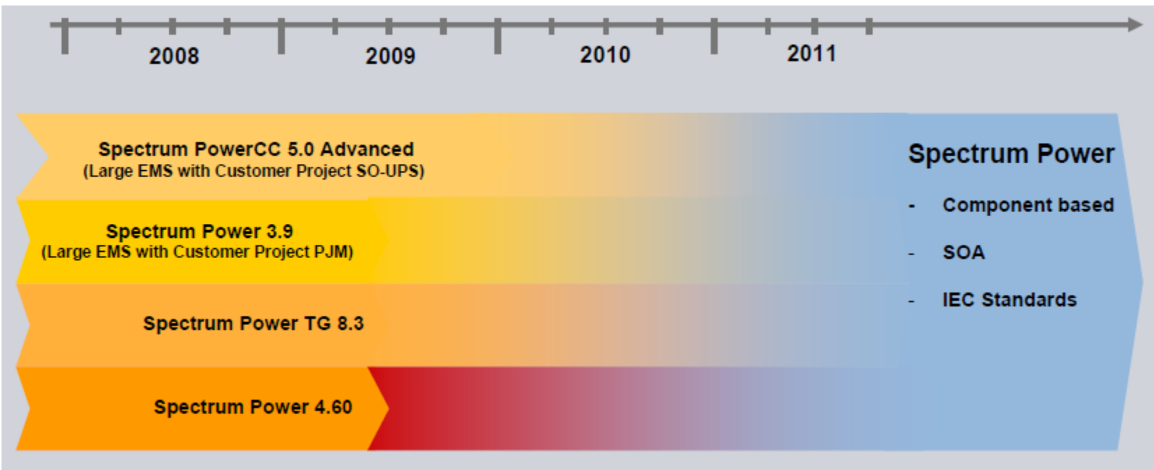


Figure 5-32 : Siemens SCADA Control Centre Applications Product Portfolio Evolution

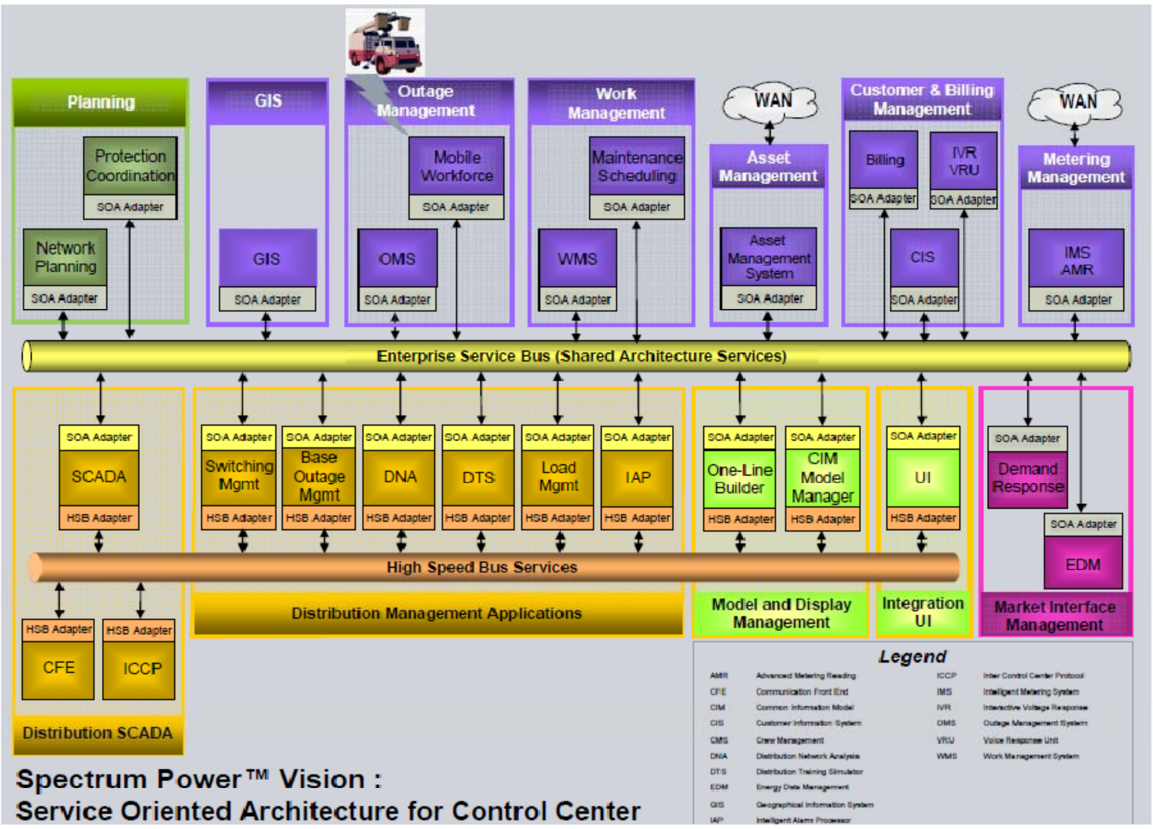


Figure 5-33 : Siemens Spectrum Power Control Centre Applications - Architecture Vision

5.9.2.3 Real-Time Interface to other Control Centres

Vector is planning to implement real-time data exchange with the Transpower SCADA system, via Vector's Siemens Spectrum Power TG Inter-control Centre Communications Protocol solution (ICCP per IEC60870-6 TASE.2 Standard).

Inter-utility real-time data exchange of real-time and historical power system information, including status and control data, measured values, scheduling data, energy accounting data and operator messages is becoming increasingly important and is a vital link in ensuring the maximum benefit from future smart grid operations. The open standard based secure communication links among the utility control centres are identified in Figure 5-37 (IEC 60870-6 TASE.2 Inter-control centre communications (ICCP)).

At present, Vector has very limited SCADA information of the Southern network sub-transmission lines connected to Transpower substations eg. no status indication and control capability of Vector's supply lines circuit breakers, circuit loading information, etc. From a network operational excellence perspective this is a significant deficiency.

The Northern region SCADA information of the sub-transmission lines connected to Transpower substations is provided via Vector's "legacy" protocol interface to the Transpower RTU at each site. As a planned part of Transpower's substation automation modernisation programme the support of the "legacy" protocol (Conitel 2020 / 2025) interface will no longer be supported and, if not addressed, would provide a similar deficiency in information about the Northern region interconnections as is experienced in the Southern region.

In addition to these above operational issues, Vector needs to protect its network against potential situations of excessive circulating current condition resulting in outages, should temporarily paralleling of Transpower GXPs occur inside the Vector network. This can be avoided if real-time voltage magnitude and phase angle of

Transpower supply busbars is available for load flow calculation, for which a SCADA interface with Transpower is required.

IEC 60870-6 TASE.2 (ICCP) is a global standard that is very widely used by many utilities for inter-control centre communications between SCADA and/or EMS (energy management system) systems (USA, Europe, Australia etc). It is supported by most vendors of SCADA and EMS systems. Transpower has evaluated a number of options to exchange data with the third parties, and has concluded that ICCP is the only solution that:

- Allows fast provisioning of new connections;
- Can be efficiently and effectively secured;
- Is standards-based and in widespread use;
- Allows bi-directional exchange of data & controls;
- Is simple architecture and scalability;
- Provides good native resilience;
- Is based on open standard and has multi-vendor support; and
- Provides low cost integration options.

The intended flow of inter-control information between utilities is illustrated in Figure 5-34.

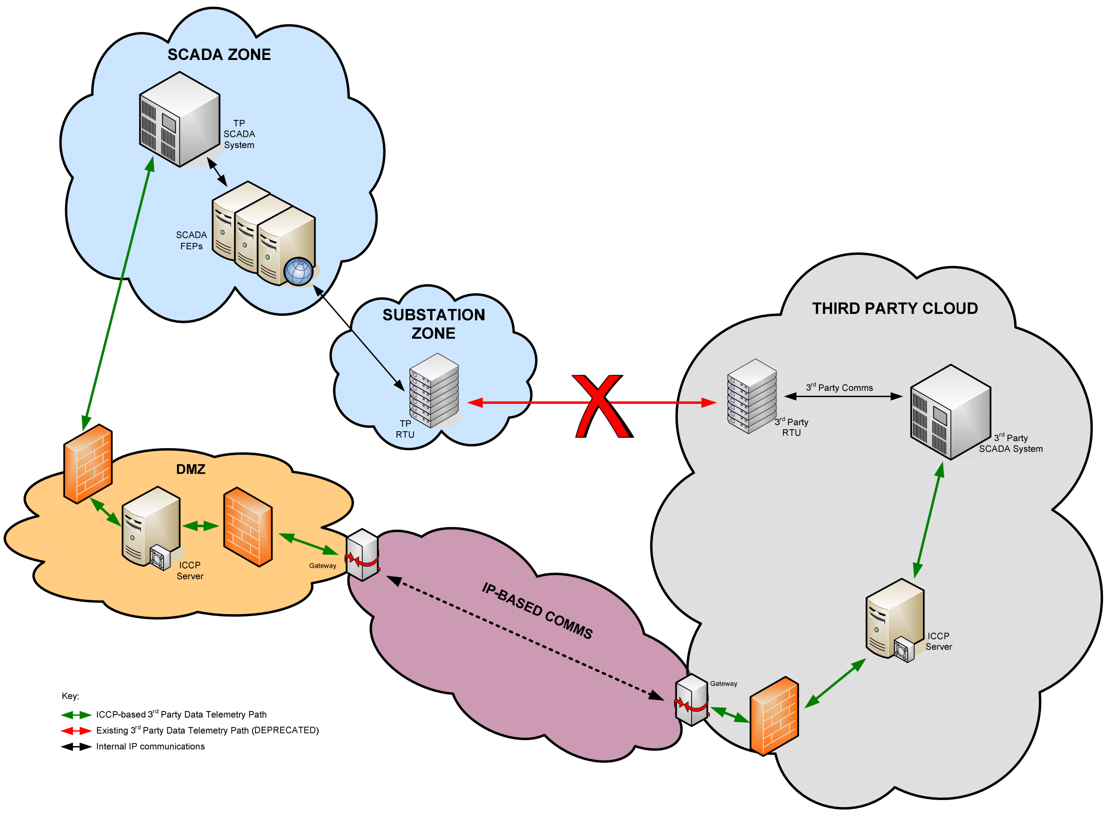


Figure 5-34 : Future Inter-control Centre Information exchange among NZ utilities

Vector completed a feasibility study to establish an ICCP link with Transpower in 2003.

Vector's Siemens Spectrum Power TG master station supports ICCP, as shown in Figure 5-34 (Control Centre Gateway). The Transpower SCADA master station is capable of secure ICCP information exchange with the third parties. ICCP is Transpower's preferred future proof option for data exchange with the third parties.

ICCP also provides a means of reaching beyond SCADA systems to other utility database systems such as historians (data collection and storage), outage and scheduling systems, to facilitate exchange of data for uses over and above than real-time power system control and supervision. This will provide possible business opportunities and challenges for sharing resources and competing for operating and power system management services.

The immediate benefits for Vector of an ICCP link to Transpower's SCADA master station include:

- Obtaining data originating from Transpower substations would no longer require any Vector equipment at the Transpower substations;
- Existing Vector SCADA communications circuits into Transpower substations would no longer be required;
- Vector's total communications requirements would be simplified;
- Lower lifetime costs for obtaining data from Transpower sites;
- Easier to make changes to data obtained from Transpower sites;
- ICCP is truly scalable with low incremental cost and expansion only limited by master station capacity and ICCP network bandwidth;
- Higher reliability communications by utilising Transpower's existing redundant network to site;
- Greater data integrity through lower risk of any Transpower site works inadvertently affecting Vector data transfers; and
- Complete flexibility for configuring controls and data acquisition.

5.9.2.4 Penrose to Hobson Tunnel Management System

The tunnel management system is used to monitor:

- Tunnel ventilation;
- Drainage sump level control;
- Status monitoring (temperature, levels);
- Alarm monitoring (fire);
- Visualisation & control (HMI functions); and
- Access control via airlocks.

The system consists of range programmable logical controllers (PLC) made by Siemens S7-200 and S7300 connected in an optical fibre ring. The PLCs are interfaced to a Citect SCADA application, which runs on a stand-alone desktop computer, via Ethernet / IP network.

The field installed PLCs are interfaced to Siemens Spectrum PowerTG SCADA master station

5.9.3 Network Automation at Vector

Power system automation schemes are being implemented at Vector to support reduced customer outages, increased network utilisation, cost efficiency and increased system reliability.

Vector's current substation automation system is based on IEC 61850 - *Communication networks and systems for power utility automation standards*. The substation LAN is based on a resilient optical ethernet and the connected IEDs are IEC 61850 standard compliant. Over 50% of Vector's primary substations are equipped with IEC 61850 compliant IEDs.

5.9.3.1 Control Centre Automation - Load Shifting Scheme Based on CIM / IEC 61850 Model

An automation scheme is being developed to transfer network load between adjacent substations under overloading or fault conditions. This is intended to increase asset utilisation and provide an opportunity for substantial cost efficiencies. The scheme, illustrated in Figure 5-35, is based on the information and communication standards adopted by Vector.

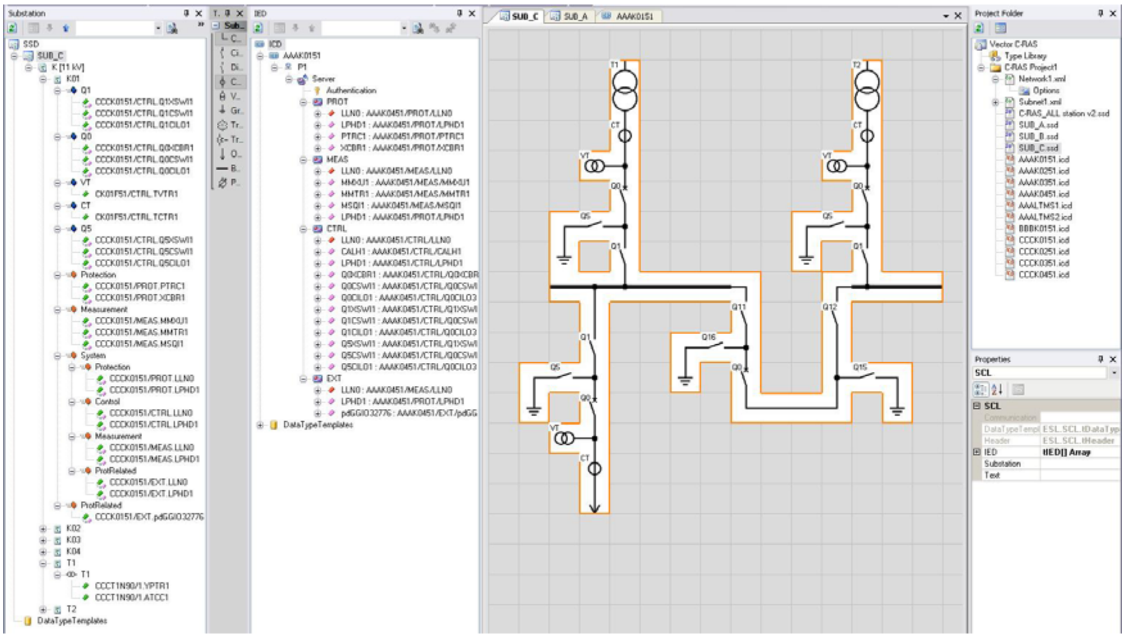


Figure 5-35 : Network automation scheme

5.9.3.2 Substation Automation

Substations constitute the electric power system nodes for all access and information retrieval. Substation automation describes the collection of infrastructure within a substation enabling the co-ordination of protection, automation, monitoring, metering and control functions, and utilising substation internal communications network infrastructure. Vector's substation automation system is based on resilient optical ethernet local area networks, running IEC 61850 compliant IEDs.

Substation automation is not just the automation of a substation. It is part of a major paradigm shift for all power system operations. It is the first step toward the creation of a highly reliable, self-healing power system that responds rapidly to real-time events with appropriate actions and supports the planning and asset management necessary for cost-effective operations.

A typical substation automation system, as applied on the Vector network, is illustrated in Figure 5-36.

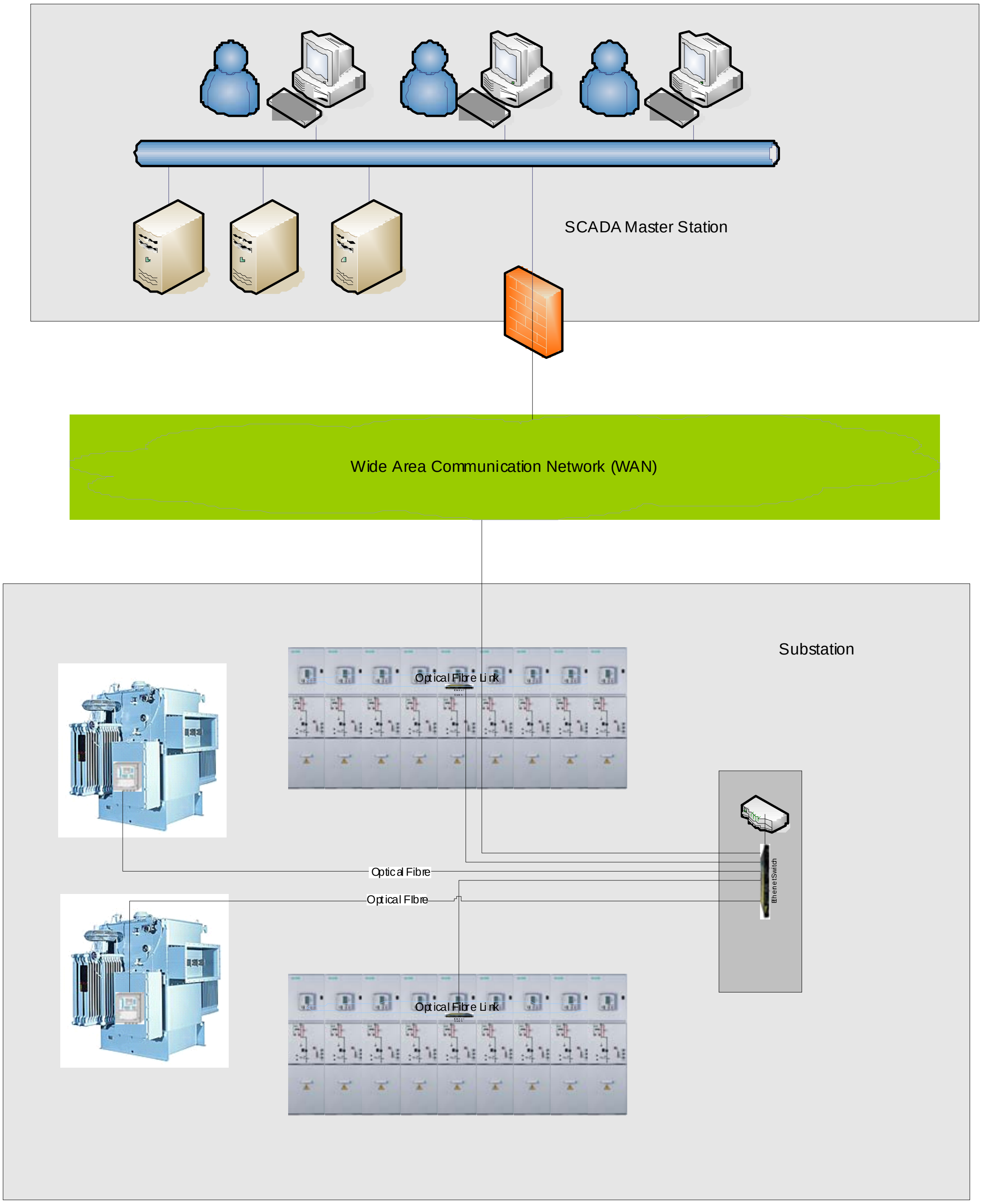


Figure 5-36 : Vector's typical substation automation system

The following automation schemes are being implemented:

- Centralised substation bus load-transfer schemes;
- Centralised substation overloading load shedding scheme; and
- Centralised substation under-frequency load shedding scheme.

The automation schemes are based on the IEC 61850 standard and peer-to-peer relay communication over the substation LAN. The algorithms for the schemes are centralised in the incoming IEDs. These schemes, illustrated in Figure 5-37, increase reliability, as all incoming IEDs have the same algorithm and execute the programme automation sequence and issue the control command concurrently.

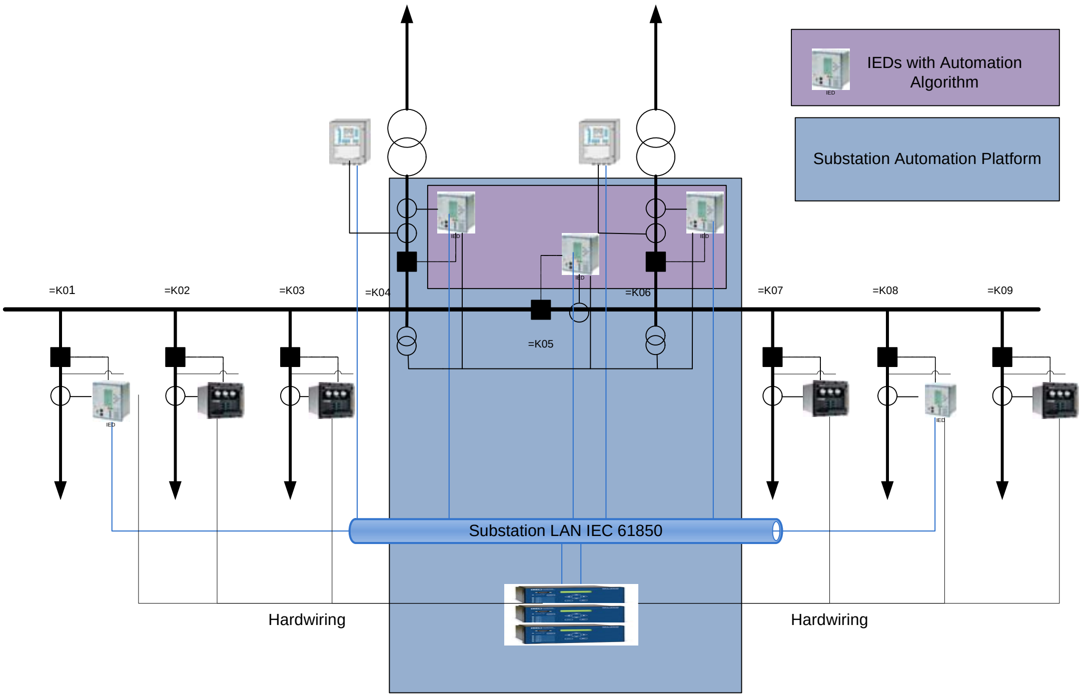


Figure 5-37 : Substation automation scheme

a. Centralised Substation Bus Load-Transfer Schemes

At the substations, a situation arises from time to time where fault current level can exceed the switchgear fault current ratings. This presents safety risks to people and equipment.

To reduce fault levels, and avoid switchgear replacement, the network has been split at substation busbars by opening bus-section circuit breakers. This, however, impacts on network reliability, as under incomer fault conditions switching is required to restore supply from the other side of the switchgear bus.

This situation is alleviated by a substation centralised automatic busbar load transfer scheme. The scheme is designed to automatically close the bus section circuit breaker upon loss of one of the incoming feeders.

b. Substation Centralised Overload Load Shedding Scheme

Owing to increased substation loading, a loss of a substation incoming feeder can result in overloading of the primary equipment (eg. power cables, power transformers) associated with the remaining incoming feeder(s). The equipment overloading can lead to accelerated asset ageing, equipment failure or loss of supply to large numbers of customers due to overload tripping.

A substation centralised automatic feeder load-shedding scheme has been designed and implemented in order to mitigate these consequences. The basic operation of the load-shedding scheme is to detect when one of the incomers has tripped, to continuously check loading conditions on the remaining incoming feeders and to shed as many outgoing feeder loads as required to prevent tripping of the remaining incomers.

This may result in a loss of some customer load, but the extent of outages will be far less than that which would result from further incomer trips while also protecting the assets.

c. Substation Centralised Automatic Under-Frequency Load Shedding Scheme

The frequency of a power system changes when the load-generation equilibrium is disturbed. If the unbalance is caused by a deficiency in generation capacity, the system frequency decays to a level value at which load-generation equilibrium is re-established. If equilibrium, however, cannot be established system collapse will occur, leading to widespread and possibly prolonged outages.

Vector is required to provide an Automatic Under frequency Load Shedding (AUFLS) scheme under the EGRs. The EGRs require electricity distribution utilities to provide 2x16% (of the total load at the time) blocks of customer demand which can be shed automatically via the AUFLS when the grid frequency drops to 47.8Hz and 47.5Hz respectively.

A substation centralised AUFLS scheme is realised through using the incoming feeder IEDs. When under-frequency conditions arise the IEDs initiate load shedding based on the predefined outgoing feeder priorities, by tripping feeders via the substation RTUs via peer-to-peer communication (using the IEC 61850 standard).

5.9.3.3 Distribution Feeder Automation

Feeder automation can be defined as schemes of equipment (automated switches, auto-reclosers etc) capable of acting without human intervention in order to minimise outages, restore supply or carry out other network/asset automation functions eg. substation off-loading. The feeder automation schemes are frequently interfaced to the network control centre for remote indication, control and data acquisition (SCADA functions).

Vector's existing feeder automation schemes enables SCADA functionalities, auto-reclosing, auto-sectionalising, feeder reconfiguration, fault detection and voltage control. Over 300, mostly overhead line pole mounted, switchgear (load-break switches, auto-reclosers and sectionalisers, RMU) have been deployed. GPRS/3G IP (Internet Protocol) centric third party communication network and DNP3 communication protocol have been used for SCADA master station and engineering applications. The standard Vector deployment is shown in Figure 5-38.

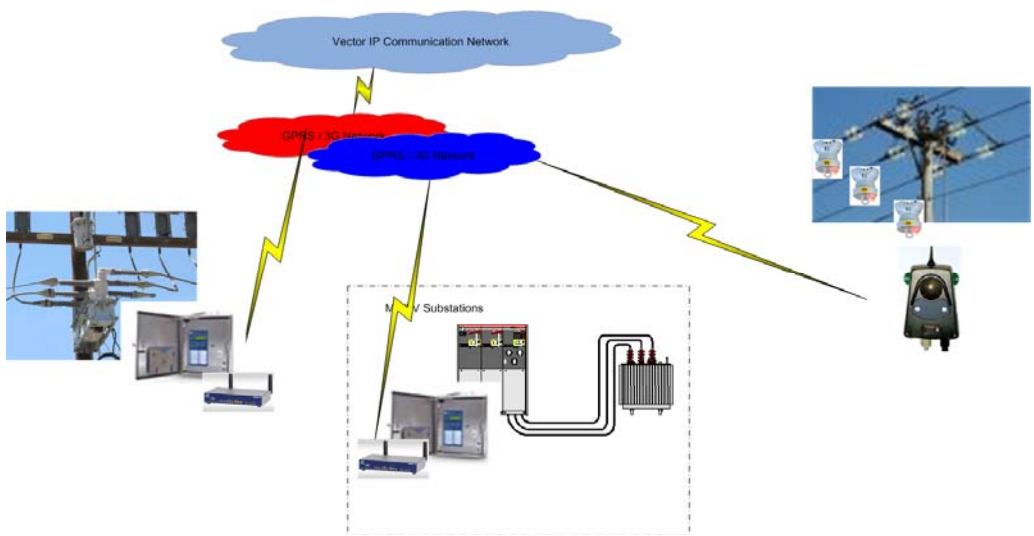


Figure 5-38 : Automation - Using GPRS/3G Communication System

5.9.3.4 MV/LV substation - Metering and Monitoring

In order to improve fault location, optimise asset management for the 11kV and LV networks, as well as to improve visibility of the LV network and power quality over the whole of the Vector distribution network, situation it is planned to roll-out MV/LV metering and monitoring equipment at selected sites over a 10 year period. (See also the discussion in Section 3.)

Vector has piloted a solution that includes optical current sensors that are interfaced to the control center via IEC 61850 and 3G communication networks. This is illustrated in Figure 5-39.

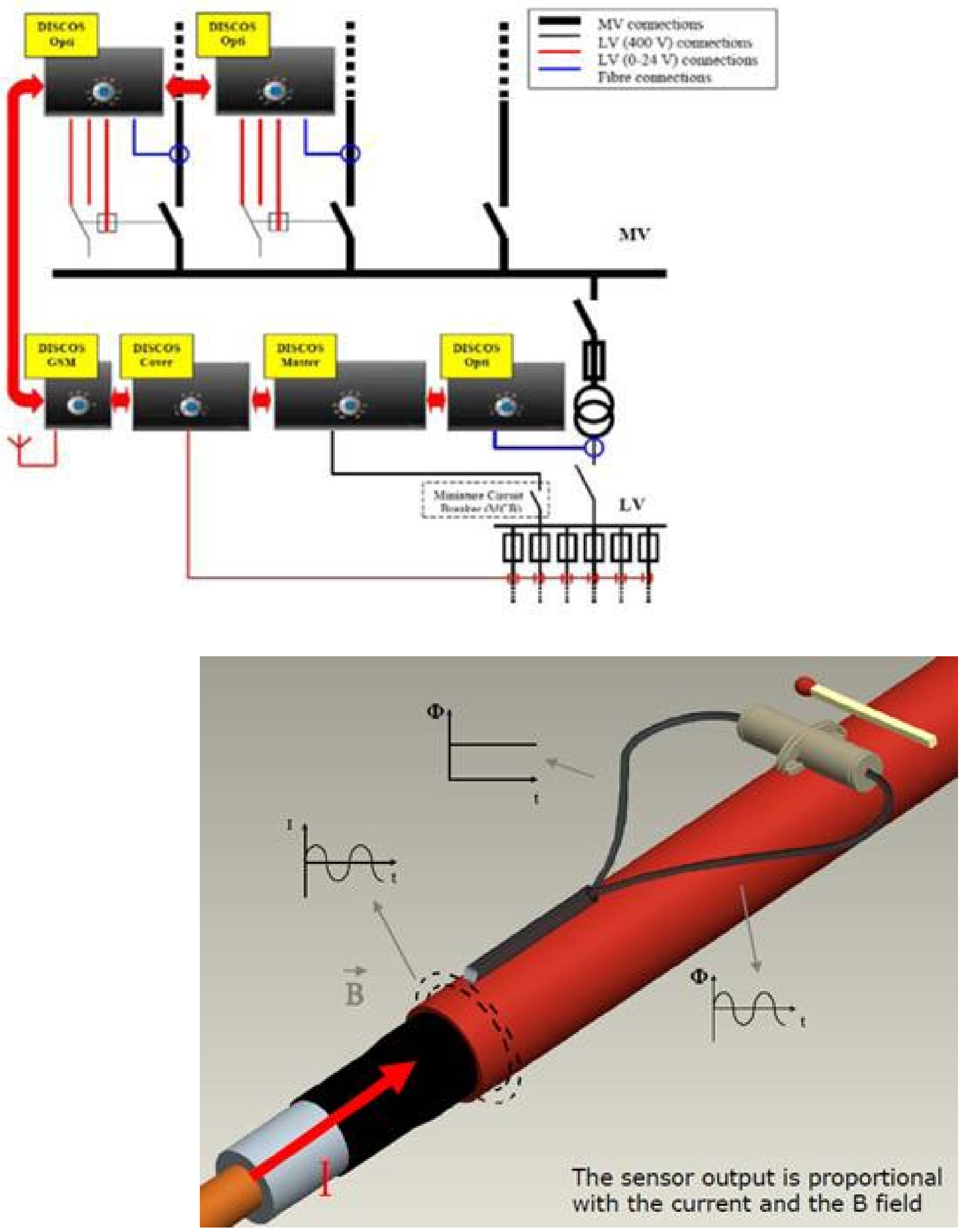


Figure 5-39 : Typical monitoring solution for a single transformer MV/LV distribution substation

5.9.3.5 Remote Terminal Units (RTU) Replacement

The RTUs used on the Vector network are microprocessor controlled electronic devices, which interface objects in the physical world (eg. switchgear, power transformers etc) to a distributed control system or SCADA system by transmitting telemetry data to the system and/or altering the state of connected objects based on control messages received from the system:

- Over time, a number of different RTUs have been installed in Vector's network many of which are nearing the end of their technical life or are obsolete;
- In the Southern region there are 30 Plessey GPT RTUs and Siemens PCC systems to be replaced in the coming years; and
- In the Northern region 23 Foxboro C225 RTUs and 3 Foxboro C50 RTUs are planned for replacement.

Vector has standardised on the open industry standards (the IEC defined www.iec.ch) for the distribution and substation automation technologies, the operational communication network (ethernet/TCP/IP) and communication protocols (IEC 61850) from the field to the SCADA master station applications.

Vector has been running an annual RTU replacement programme for a number of years, and is currently replacing approximately 10 RTUs per region per annum. The RTUs are replaced with fully compliant IEC 61850 solutions from SEL.

5.9.4 Technical Application Integration

Increased use of "intelligent" devices utilises ever-increasing volumes of automation and technical analysis applications to optimise planning, design, operations and maintenance activities. Robust and highly integrated communications and distributed computing infrastructures are required for this. This infrastructure needs to be interoperable and easily integrated across vendor equipment and across the utility business. To achieve the necessary level of interoperability and low cost integration of the complex application requires adoption of a suite of the industry standards.

The reference architecture (Figure 5-40) identified the key standards, IEC 61850 and IEC 61968/IEC61970 (CIM - Common Information Model, GID – Generic Interface Definition) that facilitate interoperability and standardised information exchange.

IEC 61970/61968 standardises:

- A shared device information (data) model:
    - CIM / XML; and
- A shared set of services:
    - The Generic Interface Definition (GID).

CIM is an abstract data model that is used to represent the major objects in an electric utility enterprise and facilitate the application integration. Figure 5-40 shows the integration architecture as defined in the IEC 61968-1 standard.

IEC 61968/IEC61970 (CIM/GID) standard-based solutions are to be used for Vector technical application integrations. The advantages of using CIM/GID based application integration are:

- Vector already has a large population of field installed devices supporting IEC 61850 standard and harmonisation of the IEC 61850 and the CIM model is under way;
- IEC 62351 standard is to address cyber security issues for CIM;

- Many of Vector's applications are being developed to be CIM Compliant (DIgSILENT Power Factory, Power Factory Station Ware, Siemens Power TG Master Station etc); and
- Lower integration cost.

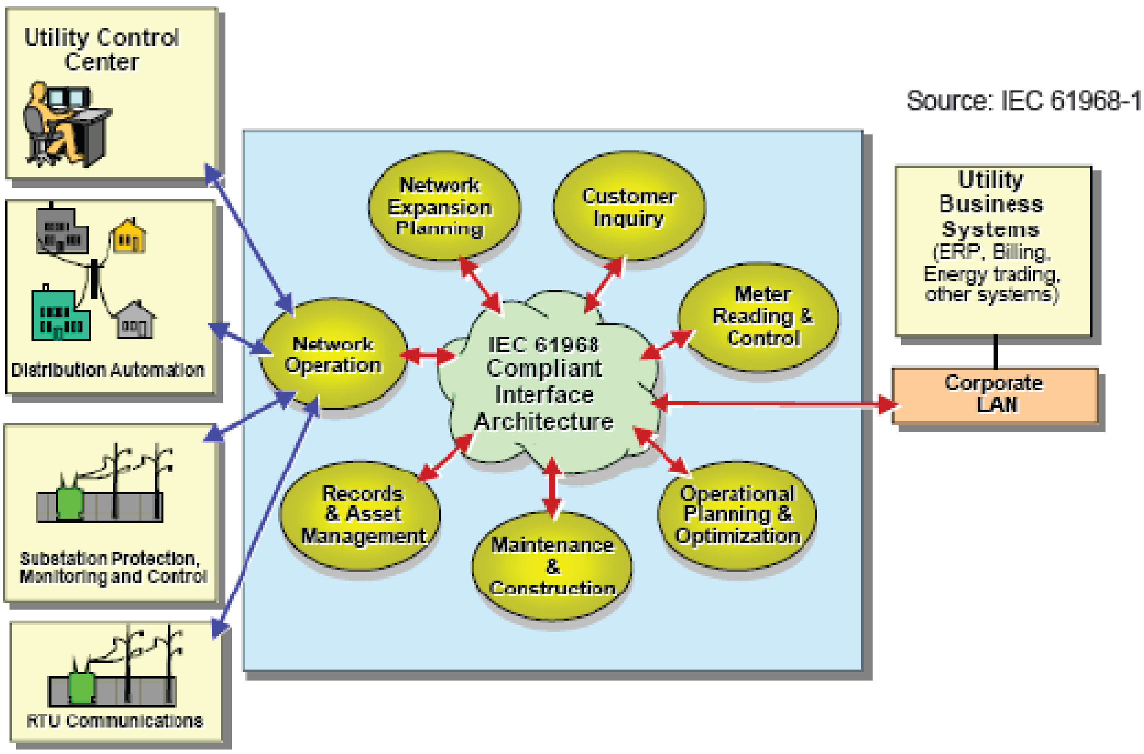


Figure 5-40 : Distribution management system with IEC 61968 compliant architecture

The diagram in Figure 5-41 shows the proposed application and integration of the Vector control systems.

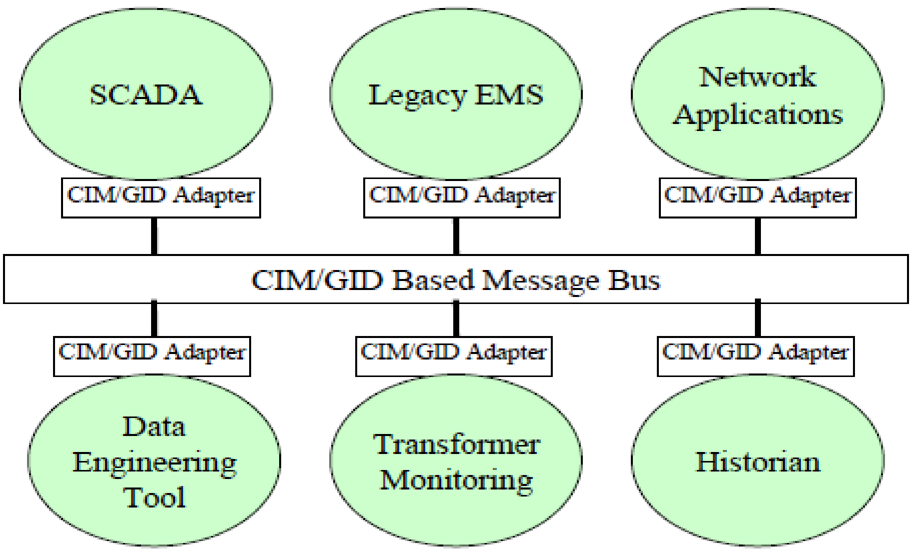
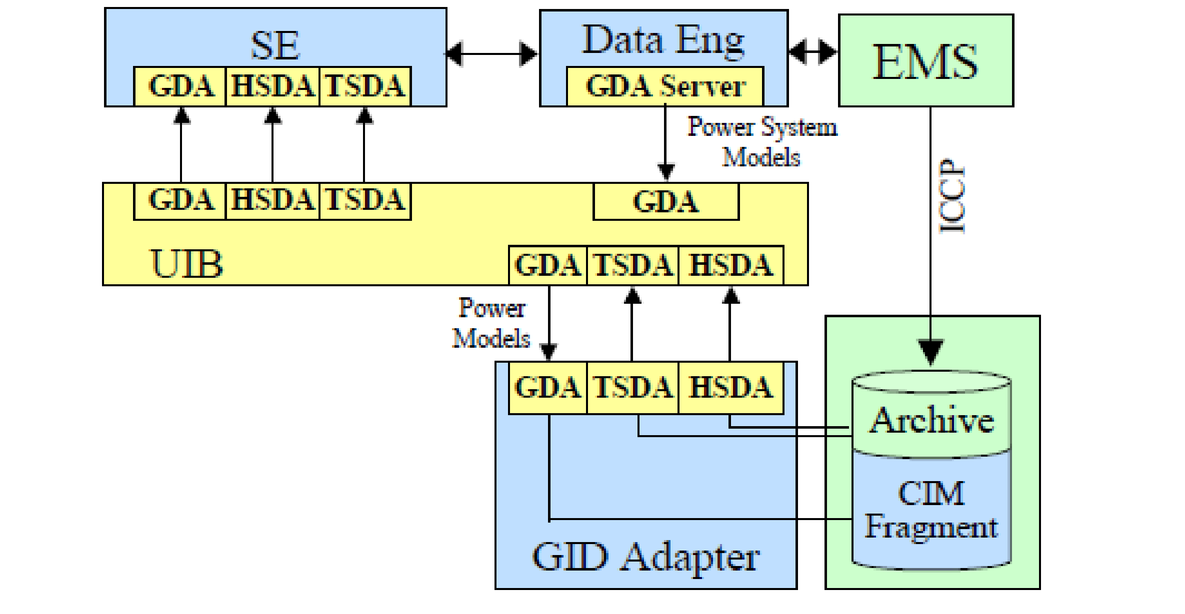


Figure 5-41 : Application integration scenario

5.9.4.1 Utility Integration Bus Topology (UIB)

The Utility Integration Bus (UIB) is a standards-based integration platform designed to significantly reduce the engineering effort required to integrate data in the utility environment. An approach to facilitate incremental upgrading of the Vector's control centre application integration is to use integration solution as shown in Figure 5-42.



API Name	Acronym	Description
Generic Data Access	GDA	Based on the Object Management Group (OMG) Data Access Facility (DAF) specification, GDA is used to access and modify model data in a model server and supports model change notifications.
Generic Eventing and Subscriptions	GES	Based on the OPC Alarm and Events (AE) specification, GES is used to publish and subscribe to XML messages using data in the context of a unified model.
High Speed Data Access	HSDA	Based on the OMG Data Access for Industrial Systems (DAIS) and the OLE for Process Control (OPC) Data Access (DA) specifications, HSDA is used for the exchange of real-time data in the context of a unified model.
Time Series Data Access	TSDA	Based on the OPC Historical Data Access (HDA) specification, TSDA is used to access time-based data from a historian in the context of a unified model.

Figure 5-42 : Specific GID interfaces used for application integration

A project to develop the standards based integration platform is currently underway.

5.9.5 Communication Systems

Deployment of Vector's modern operational wide area communication network (WAN) infrastructure, on the open standard based IP, began in 2002. The WAN consists of the optical fibre infrastructure, digital communication over Vector's copper pilot cables, Vector's owned digital microwave radio links and third party IP network including wireless GPRS/3G GSM standard based networks. The IP network facilitates cost effective migration and integration of the operational services from obsolete disparate proprietary solutions to the open standard based solution. Over 50% of Vector substations have been connected via IP network. Hundreds of field installed apparatuses (auto-reclosers, load breaker switches, ring main units) are connected via third party GPRS/3G wireless communication networks.

Vector's standard substation LAN and operational WAN is based on Ethernet and IP communication technology. The ethernet/IP based operational communication network carries a number of services:

- SCADA (telecontrol and telemetering);
- The telemetry service(s) have QoS assigned, so that performance is not unduly compromised by other traffic sharing the same network;
- Engineering access (remote equipment management, on-line equipment monitoring);
- Digital fault record retrieval;
- Substation telephony – (voice over IP);
- Substation security;
- Video imaging and streaming video over IP is a future application impacting security and health and safety;
- Network management;
- Management of the network devices, routers, switches, and in the future SNMP management of the IEDs is an essential service; and
- The substation telephone is an essential tool for technicians and engineers working on site.

Choosing the right communications technology is key to creating an intelligent platform that can continually monitor utility assets, operations and consumer demand. The deployment of ethernet and IP based communication systems has become pervasive for a wide range of applications. There has been a rapid development of "networking standards" frequently involving active industry user and supplier organisations.

With current technology it is possible to develop a large, peer, autonomous and scalable network. TCP/IP facilitates a logical, low cost and easy solution to manage systems based on heterogeneous technologies by providing a common communication protocol for disparate communication technologies eg. Vector uses copper (Cu) pilot cables, digital microwave radios, optical fibres, Vodafone GPRS/3G to carry its SCADA communication using TCP/IP protocol. A future network in which all the elements (smart meters, home appliances, home energy management platform, infrastructure devices, plug-in vehicles etc) support IP will allow utilities and consumers to enjoy the benefits of a competitive and innovative ecosystem built around open standards.

Teleprotection over IP, remote asset management, video surveillance are being planned.

Vector is committed to an open communications architecture based on industry standards. This has resulted in the adoption and deployment of ethernet and IP based communication technologies. TCP/IP facilitates a logical, low cost and easy solution to incorporate and manage heterogeneous technologies by providing a common communication protocol eg. Vector uses copper (Cu) pilot cables, digital microwave radios, optical fibres, Vodafone GPRS/3G to carry its SCADA communication using TCP/IP protocol. Vector's standard substation LAN and operational WAN are based on ethernet and IP communication technology, as illustrated in Figure 5-43 and Figure 5-44.

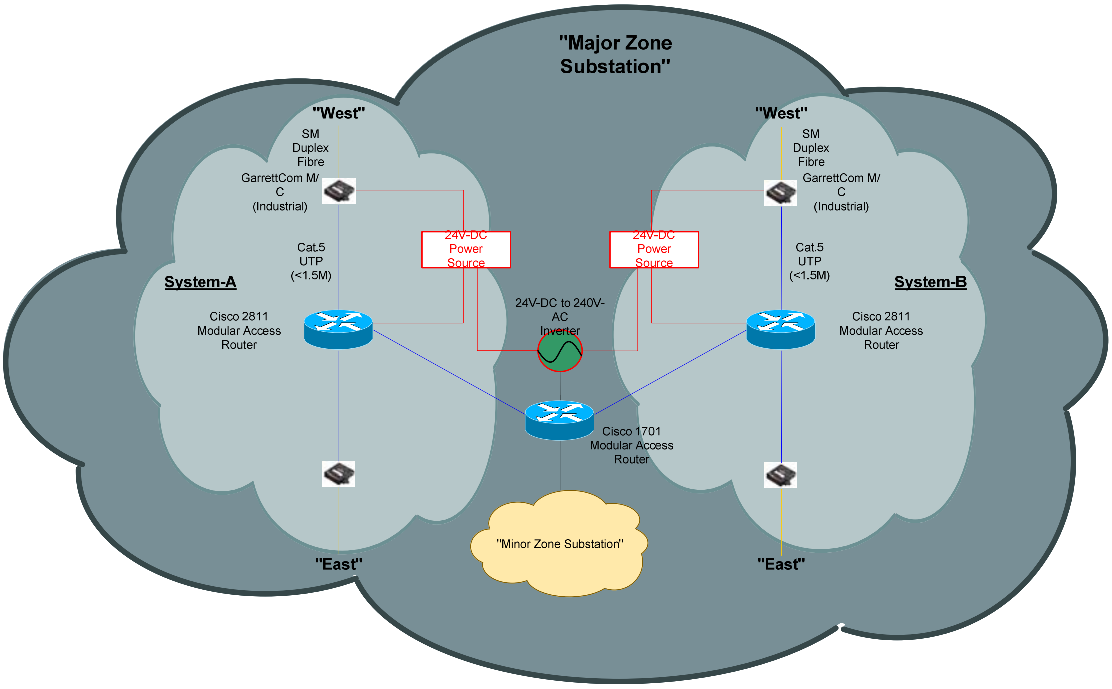


Figure 5-43 : Vector's IP WAN

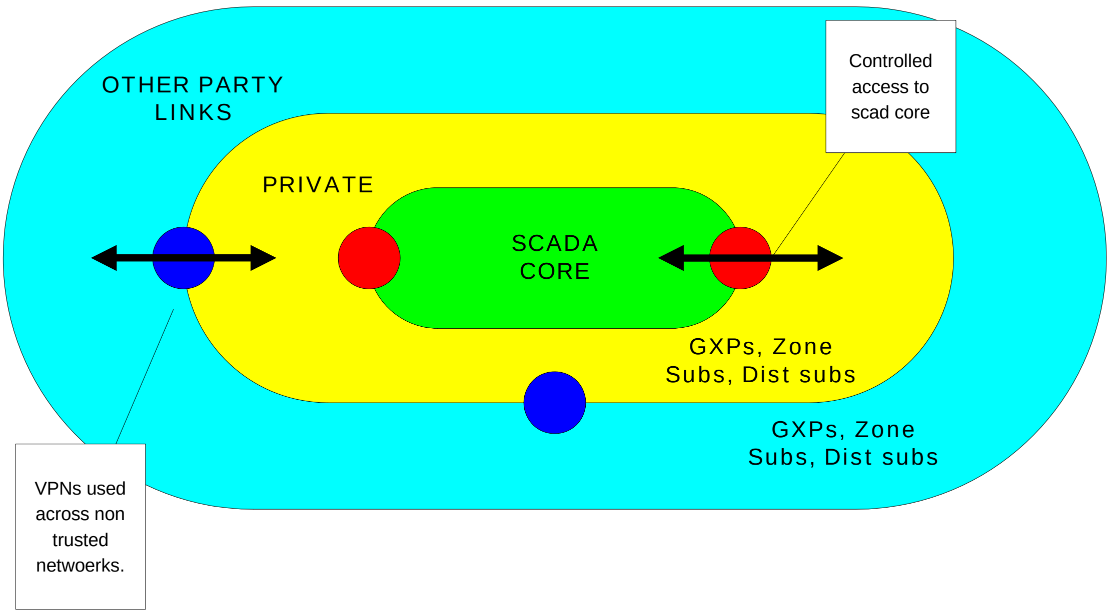


Figure 5-44 : Operation IP Communication Network - Private and Public Zones Boundary

Migration to an IP based network started in 2002. Vector will continue to introduce IP to its substations in conjunction with the network development or protection and control upgrade projects. Within the next five years it is planned that all zone substations will be connected via IP network. The substation communication network is provided by Vector Communication and other third parties, including Telecom, Vodafone and Transpower.

5.9.6 Cyber Security

The public electric power system is now characterized as one of several critical infrastructures, requiring rigorous application of security practices. Cyber security must address not only deliberate attacks, such as from disgruntled employees, industrial espionage, and terrorists, but also inadvertent compromises of the information infrastructure due to user errors, equipment failures, and natural disasters.

For Vector's real-time information and communications systems the cyber security strategy is focused on prevention, while also defining a response and recovery strategy in the event of a cyber attack. Cyber security risk assessment of Vector's real-time systems is applied to both Vector's power and information infrastructure.

The diagram in Figure 5-45 shows the security requirements, threats, counter-measures, and management at Vector.

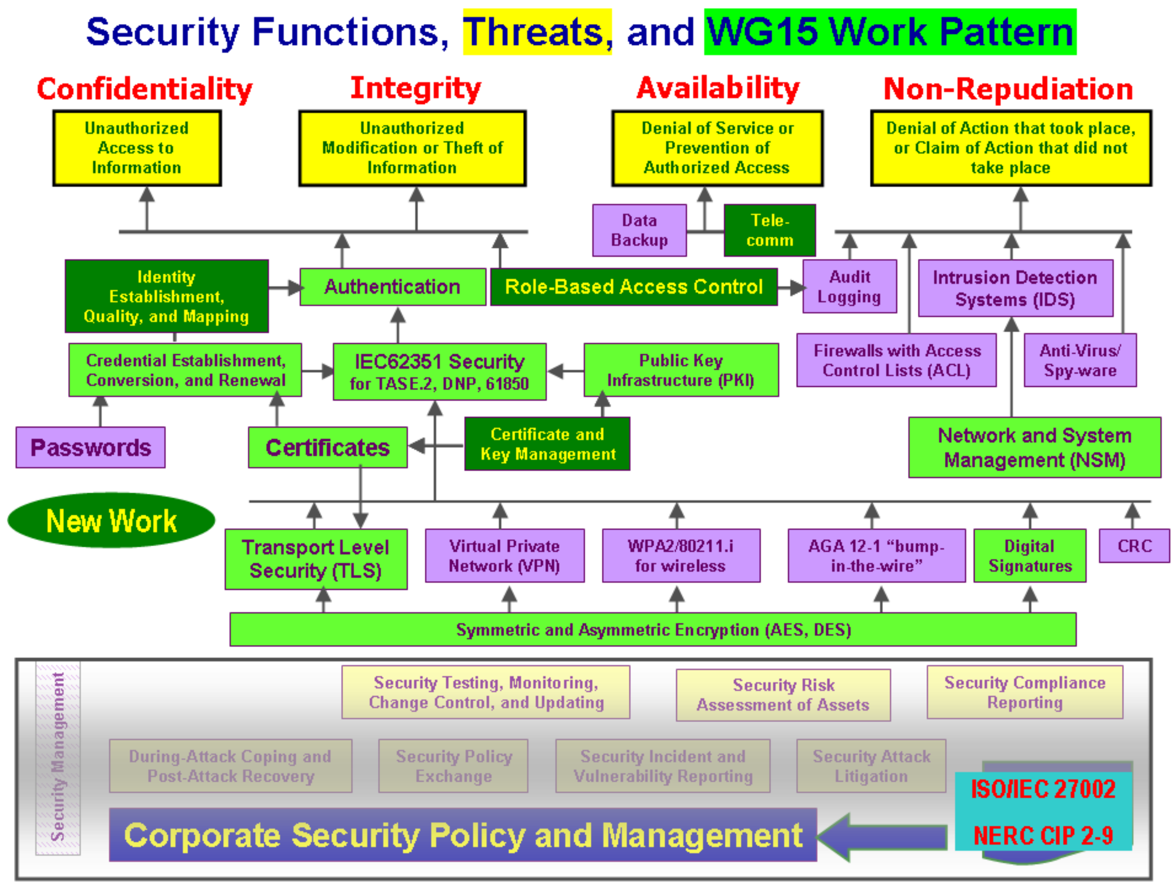


Figure 5-45 : Overall Security: Security requirements, threats, counter-measures, and management

Communication protocols are one of the most critical parts of power system operations, responsible for retrieving information from field equipment and, vice versa, for sending control commands. Vector is committed to IEC specified communication protocol for its real-time system and application interfaces (Figure 5-48). IEC TC57 has published a set of standards for information security for power system control operations (IEC 62351) to security IEC 60870-5, its derivative DNP, IEC 60870-6 (ICCP), IEC 61850, IEC 61968 and IEC 61970 communication protocols, as illustrated in Figure 5-46.

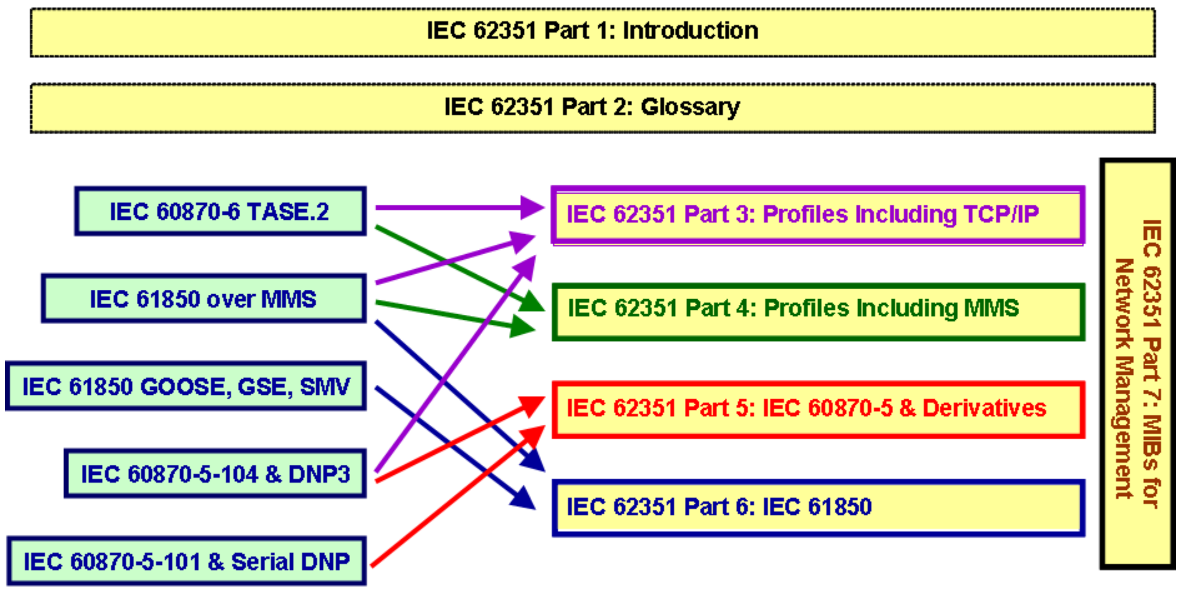


Figure 5-46 : Mapping of TC57 communication standards to IEC 62351 security standards

Vector is in the process of incorporating IEC 62351 standard protocol security enhancements within the communication protocols it uses for its protection, automation and control systems. New products, when they become available in the products and are practicable to be implemented, will adhere to this standard.

Following a detailed audit in 2009 into the cyber-security standards of Vector's SCADA network, several recommendations for improvement were made. In response, Vector's real-time systems information security policy and management have been enhanced within Vector's overall IT security policy and management. This has been developed in accordance to ISO/IEC 27002 standard and extended to incorporate real-time system specific requirements as defined by NERC CIP standards.

Other programmes are also underway to ensure the roles and responsibilities for the SCADA system, which lie across the business, are clearly allocated, and that adequate firewall protection and intrusion detection is provided for all parts of the system.

5.9.7 Substation Information Management

By using object-modelling technology, IEC61850 establishes a standardised self-describing object names structure for substation information. This is discussed below.

5.9.7.1 Digital Fault Recording Retrieval

Vector has implemented the automatic retrieval and archiving of power system digital fault recordings. The application enables timely analysis of substation and network events. It also contributes significantly to the reduction in time of post-fault investigations, problem identification and incident reporting. This is used to facilitate improved network and protection system performance.

5.9.7.2 Setting Management Modelling

Protection system modelling and settings is a vital part of network modelling and scenario simulations. Vector has implemented a protection setting management system (StationWare) from DIgSILENT that has an interface to the DIgSILENT network and protection tool, PowerFactory. Both products are planned to support IEC 61850 and CIM.

5.9.8 Time Synchronisation

Accurate and reliable time synchronisation is critical to ensure automatic control and system protection equipment operates correctly to allow optimal utilisation of network assets. When a system event occurs, it is important for later forensic analysis that all system events and data captured during the event are time stamped accurately so the root cause of the event can be determined. GPS time synchronisation plays a key role in Phasor Measurement Systems – a technique that permits the real-time visualisation of instantaneous power flows.

Time synchronisation of Vector's real-time systems is done using Network Standard Protocol (NTP). Fields installed IEDs are synchronised over an IP based wide area network to 1 ms resolution, using SNMP (Simple Network Time Protocol) according to IEC 61850 Standard.

Edition 2 of IEC 61850 Communication Network and Systems for Power Utility Automation Standards has adopted a precision sub-microseconds accuracy timing solution based on IEE1588v2 standard. In future, our new equipment will be compliant with this standard.

5.9.9 Energy and Power Quality Metering

Some businesses, such as those in manufacturing and service industries, have a high reliance on disturbance free power supply. One of the objectives of PQ monitoring is to identify disturbances that could adversely impact on customers' equipment with the objective of identifying solutions.

Vector's energy and PQ metering system consists of a number of intelligent web-enabled revenue class energy and PQ meters installed at GXPs and zone substations. The meters communicate to the metering central software over an ethernet-based, IP routed communication network. The meters are web enabled and the latest firmware version of the meters are compliant to the IEC 61850 standards (Vector's adopted information exchange standard).

The metering system provides Vector with essential information about the quantity, quality and reliability of the power delivered to Vector's customers and is currently used to:

- Improve asset utilisation by managing network peak demands;
- Provide PQ and load data for network management and planning purposes;
- Provide information to assist in the resolution of customer-related PQ issues; and
- Contribute to the power system stability by initiating instantaneous load shedding during under-frequency events.
- The following strategies have been implemented to monitor and report PQ problems identified on Vector's network:
- PQ monitoring equipment has been installed at selected GXPs and zone substations;

- An electronic mail system automatically sends a PQ disturbance report in real-time to customers;
- A web-based reporting system that makes real-time and historical PQ information available for diagnosis of customer PQ issues;
- Use of network modelling software and tools to predict the impact of PQ disturbances at customer premises; and
- Using portable PQ instruments to investigate PQ related complaints.

The information in the PQ reports provide details on any event that caused voltage and current transients or voltage sags and swells in the network. By drilling down into each report the daily maximum/average/minimum of voltage, current, frequency, power factor, voltage unbalance, voltage total harmonic distortion (THD) and current THD can be observed. The voltage sags captured by each monitor for the same period can also be viewed as a voltage sag magnitude duration chart.

Other PQ action at Vector includes:

- Installation of PQ monitoring instruments at new zone substations. This is to increase the number zone substations being monitored and gain increased knowledge of the quality of supply to customers;
- Benchmarking the quality of supply on the network and monitor changes over time;
- Offering support to customers by assisting with solutions to PQ problems; and
- Developing an automated link between network events such as faults and data captured on the PQ instrumentation.

5.10 Network Programme Summary

Table 5-35 summarises the project programme for development of the power network in the two network regions. It shows the current target completion dates for these projects, compared with that in the previous plan. If there is a difference the reasons for the change are described (advanced or delayed) in the following tables. Newly identified and completed projects are also highlighted.

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY11	Keeling Road	Reinforcement of Valley Road 11kV feeder	2011	Completed		
FY11	Westgate	Zone substation land purchase	2011	Completed		
FY13	Wiri West	Zone substation land purchase	FY12	Delayed	To allow for construction of Wiri West substation	
Complete	Hobson	Supply to Victoria park roadway tunnel	2011	Completed		
Complete	Liverpool	Stage One of 11kV supply to Medical School	2011	Completed		
Complete	Sylvia Park	Sylvia Park 11kV feeders to offload CARB 10 and 18	2011	Completed		
FY11	Browns Bay	Stapleford 11kV feeder	2011	Completed	To transfer load from Torbay to Browns Bay to defer the need for Glenvar substation	5.7.6.2
FY13	Newmarket South	Purchase of land for new zone substation	2011	Deferred due to viaduct rebuild project by NZTA	To allow for construction of Newmarket South substation and GXP	5.7.11.2
FY12	Orewa	Orewa zone substation - Weranui 11kV feeder	2012	Completed	To allow for new loads at Waiwera township and thermal area to be supplied - Hatfield and Waiwera feeders needed to be offloaded	5.7.5.2
Complete	Chevalier	Chevalier two 11kV new feeders	2012	Completed		
Complete	Chevalier	Install second 33/11kV transformer	2012	Completed		
FY12	Atkinson Rd	Upgrade of zone substation	2012	Completed		
FY12	Rosedale	Zone substation land purchase	2012	In progress	To allow for construction of Rosedale substation	5.7.6.2
FY12	Waimauku	Zone substation upgrade: install second transformer	2012	In progress	This substation is loaded over 80% of its capacity and needs a new transformer	5.7.6.2

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
Cancelled	Clendon	Reinforce Wiri South 11kV network	FY12	Cancelled		
FY13	Flatbush	Purchase of land for new zone substation	FY12	Delayed	To secure land to allow for supplying the new town centre according to draft Auckland plan	5.7.15.2
FY13	Customer B	Stage 1 upgrade of supply to customer B	FY12	Deferred	To upgrade the supply to a existing customer	
FY13	Mangere East	Upgrade Supply to Customer A	FY12	Deferred	To upgrade the supply to a existing customer	
FY12	Warkworth	New 11kV feeder to Warkworth South (use 33kV cable)	2012	In progress	Two main feeders supplying Woodcocks area are heavily loaded and cannot be backstopped- this project is to meet required service level	5.7.4.2
Cancelled	Hillsborough	Hillsborough auto load shifting scheme	2012	Not required		
Cancelled	Mt Albert	Auto load shifting scheme	2012	Not required		
FY20	St Heliers	Load shedding & auto shifting scheme	2012	Deferred due to revised load forecast	To avoid overloading and damaging assets under contingency conditions	
FY12	Helensville	Kaukapakapa/South Head 11kV reinforcement	2012	Completed		
Deleted	New Lynn	Totara Avenue 11kV feeder reinforcement	2012	Deleted after cable rating review		
Complete	Avondale	11kV reinforcement for Waterview tunnel south portal	2012	Completed		
FY13	Avondale	Avondale zone substation - establish 33kV switchboard	2012	Deferred as requested by customer	For Waterview tunnel construction supply	5.7.13.2
FY13	Maraetai	Reinforce 11kV feeder nine	FY12	Deferred	To reinforce Maraetai 9 feeder and provide additional backstop capacity to this feeder	5.7.19.2
FY13	Waterview	Waterview - South portal sub for 16MW TBM	2012	Deferred as requested by customer	For Waterview tunnel construction supply	
FY13	Waterview	Waterview - 11kV reinforcement - Yard 2-3-5-10-11-12	2012	Deferred as requested by customer	For Waterview tunnel construction supply	

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY12	Hobsonville	New 11kV feeder to offload Oreil feeder	2012	In progress	To offload Oriel feeder which is 90% loaded and is supplying Westgate shopping centre	5.6.9.2
Complete	Penrose, Westfield	Ontrack: power supply cabling	2012	Completed		
FY12	Penrose tunnel	Enhanced fire suppression for Transpower cables	2013		Required in the Tunnel Agreement	
FY13	HP Data Centre	To provide supply to the new HP data centre	New	New project	To provide supply to HP Data centre	5.6.10.6
Cancelled	Otara	New 11kV feeder	FY13	Cancelled		
FY13	Rosedale	Establish a zone substation in Rosedale	2013	Awaiting land purchase	To offload single transformer substation at East Coast Rd and increase backstop capacity at East Coast Rd, Bush Rd, McKinnon and Sunset Rd substations	5.6.6.2
Cancelled	Rosebank	Rosebank North zone substation - land purchase	2013	Not required, replaced with 11kV reinforcement project		
FY13	Various	Capacitor banks for Northern network	New	Replaces removed capacitor banks		
FY18	Highbury	Install second 33/11kV transformer	2013	Deferred to FY18	To increase N-1 capacity at Highbury substation	5.6.7.2
FY13	Te Atatu	Waterview tunnel SH 16 Te Atatu - nth portal ducts	2013		For Waterview tunnel north portal permanent supply	5.6.13.2
Deleted	Swanson	Birdwood feeder extension	2013	Deleted - bring forward Waitakere substation		
FY12	Mckinnon	Extend The Avenue feeder	2013	In progress	To provide backstop option to a spur line on The Avenue feeder to meet service levels	5.6.6.2
FY13	Sylvia Park	Sylvia Park 11kV new feeders to offload Westfield feeders	2013	Under construction	To offload feeders at Westfield which are loaded 80%-90% of their capacity	5.6.11.2
FY13	Rockfield	11kV feeders to off-load McNab feeders 16 and 29	2013	Under construction	To offload feeders at McNab which are loaded 80%-90% of their capacity	5.6.11.2

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY12	Quay	Replace 110/22kV transformer T3	2013	Project brought forward		
FY13	Newmarket	Newmarket: new 11kV feeder to supply Farmers redevelopment	2013		To supply new load due to commercial development in Broadway Newmarket	5.6.11.2
FY13	Flatbush	11kV feeder reinforcement to Flatbush area	FY13	No change	To supply new developments in Flatbush area	
FY14	Hillsborough	Install second 33kV cable and 33/11kV transformer	2014		To address forecast capacity issues at the single transformer substation at Hillsborough	5.6.14.2
Cancelled	Greenmount	New 11kV feeder to Armoy Drive	FY14	Cancelled		
FY14	Hobsonville	Reinforcement of the Clark Road 11kV feeder	2014	No change	To delay the need for Hobsonville East substation. This feeder will initially supply demand at Hobsonville development	5.6.9.2
Cancelled	Hans	11kV feeder to reinforce Savill Drive	FY14	Cancelled		
after FY22	Newton	Load shedding & auto shifting scheme	2014	Deferred due to revised load forecast	To avoid overloading and damaging assets under contingency conditions	
Cancelled	Takanini	11kV feeder to Porchester Road	FY14	Cancelled		
FY13	Hobsonville East	Zone substation land purchase	2014	In progress	To secure land so that when old Hobsonville airbase is developed additional capacity is required	5.6.9.2
FY14	Birkdale	New 33/11kV transformers	New	Load increase at substation	To decrease loading on existing 12.5 MVA transformers	5.6.7.2
FY14	Red Beach	Second 33/11kV transformer	2014	No change	To allow for load increase in Silverdale North and security of supply at Red Beach	5.6.5.2
FY14	Balmoral	Reinforcement of 11kV network for St Lukes supply	2014		To supply new load due to St Lukes shopping centre expansion	5.6.14.2
FY20	Te Papapa	11kV reinforcement	2014	Deferred due to revised load forecast	To meet load growth in Te Papapa industrial area	5.6.11.2

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY16	Westgate	Establish a new zone substation at Westgate	2014	Deferred due to slow load growth	To supply Massey North subdivision which has recently had the zoning changed	5.6.9.2
FY14	Belmont	New 11kV feeder (Ngataringa Bay)	2014	No change	To increase backstop capacity at Ngataringa Bay substation	5.6.7.2
Completed	Highbury	New 11kV feeder	2014	Completed	To ensure Highbury, Northcote and Balmain can be fully backstopped to meet required service levels	5.6.7.2
FY14	Hobson	Development of the airspace above Hobson substation in CBD	2014			
FY14	Hobson	Installation of a 110kV switchboard as part of new GXP	2014			
Delayed	Quay	22kV switchboard extension	2014	Subject to further study	Progressive roll-out of 22kV network in the CBD	
FY14	Liverpool	Replace the number three 110/22kV transformer	2014			
Delayed	Quay	Investigate 110kV GIS at Quay	2014	Subject to further study		
FY14	Mangere West	Extend 11kV feeder two	FY15	Project brought forward	To increase backstopping capacity to Mangere Went 10	5.6.17.2
after FY22	Remuera	Reinforce 11kV feeder no 12 from Remuera	2015	Deferred due to revised load forecast	To address forecast capacity issues in Remuera feeders	
FY19	Otara	11kV feeder to Chapel Road	FY15	Deferred	To increase backstop capacity to Otara feeders 2 and 7	5.6.1.6.2
FY17	Takanini South	Procurement of land for a zone substation	FY15	Deferred	To allow for construction of Wiri West substation	
FY15	Manurewa	Manurewa Super Clinic upgrade	FY15	No change	To upgrade the supply to a existing customer	
FY14	Greenhithe	33kV cable extension	New	Part of road widening works	Due to widening of Albany highway. This circuit was teed onto Albany GXP-James St substation overhead circuit. Once this circuit is underground the tee cannot be retained	5.6.6.2

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY15	Orewa	Savoy 11kV feeder reinforcement (spare two extension)	2015	No change	Savoy and Maire Rd do not comply with security criteria - This project will also to allow high density development along Orewa foreshore according to district plan	5.6.5.2
FY18	Sandspit	Establish zone substation	2015	Deferred due to increased backstopping Snells Beach	Snells Beach is a single transformer substation and is 80% loaded. This project is to meet required service levels	5.6.4.2
FY15	Wainui	Zone substation land purchase	2015	No change	According to long term plan for Silverdale area land needs to be secured to allow for construction of Wainui substation	5.6.5.2
FY15	Warkworth South	Establish zone substation	2015	No change	Load voltage problems on the existing long rural feeders - not enough backstopping capacity	5.6.4.2
Cancelled	Waterview	11kV new feeders along Waterview tunnel for permanent supply	2015	Not required as advised by customer		
FY15	Sandringham	Supply to south portal of Waterview roadway tunnel	2015		For Waterview tunnel south portal permanent supply	5.6.13.2
FY15	Atkinson Rd	New 11kV feeder (Kaurilands)	2015	No change	To decrease loading on existing 7.5MVA transformer at Waikaukau	5.6.8.2
FY15	Warkworth	New 11kV feeder (Matakana)	2015	No change	Matakana feeder has limited backstop capacity and load is over 70% loaded - This project is to split this feeder load in half to provide extra backstopping capacity	5.6.4.2
FY15	Te Atatu	Waterview tunnel supply, north portal	2015		For Waterview tunnel north portal permanent supply	
after FY22	Newton	11kV reinforcement to offload Newton feeders 9, 10 & 22	2015	Deferred due to revised load forecast	To address forecast capacity issues in Newton feeders	
FY15	Liverpool	Medical School 11kV reinforcement stage two	2015		To supply customer increasing their load	5.6.10.3
FY14	Hobson	Install a third 110/22kV transformer	2015			
FY16	Customer B	Customer B upgrade Stage 2	FY15	Deferred	To upgrade the supply to a existing customer	

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
Delayed	Quay	Designation and consenting process for the establishment of a 110kV substation plus detail design	2015	Subject to further study		
FY16	Glenvar	Establish zone substation and reinforce 33kV network	2016	No change	Torbay is single transformer substation loaded over 80% of its capacity. Backstop shortfall. This project to meet required service level	5.6.6.2
FY18	Mangere East	Rearrange 11kV feeders 13, 15 and 19	FY16	Deferred	To enhance backstop capacity at Mangere East 15	5.6.17.2
Cancelled	Rosebank North	Rosebank North zone substation - establish	2016	Not required, replaced with 11kV reinforcement proejct		
FY16	Warkworth	Backstop for Whangateau 11kV feeder Warkworth zone SS	2016	No change	During contingency events Tomarata feeder which is the main backstop to Whangateau experiences low voltage problems	5.6.4.2
FY16	Newmarket South	Establish a zone substation in Southern Newmarket	2016		To supply increasing load due to customer expansion in Broadway Newmarket	5.6.11.2
FY16	Liverpool	Telecom Mayoral Drive 22kV feeders	2016		To supply customer increasing their load	5.6.10.3
after FY22	Parnell	Parnell 11kV new feeder to offload NEWM 6 & 12	2016	Deferred due to revised load forecast	To address forecast capacity issues in Newmarket feeders	
Cancelled	Waiheke	11kV voltage regulator	F16			
FY16	Helensville	Establish new Rodney GXP for future power plant	2016	No change		
FY12	Spur Rd	Wade River 11kV feeder reinforcement	2016	Brought forward	Offload Spur Rd substation to as it is 75% loaded	5.6.5.2
FY16	Kumeu	Zone substation land purchase	2016	No change	To allow for construction of Kumeu substation post FY22	
FY16	Hobson	Extend the 22kV switchboard	2016		Progressive roll-out of 22kV network in the CBD	5.6.10.3
FY16	Chevalier	Extend ex Waterview tunnel construction feeder to offload Mt Albert	2016		To offload Mt Albert substation therefore defer project to upgrade the substation capacity	

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY16	Newmarket South	Investigation and concept design for Newmarket 110kV substation	2016			
FY16	Quay	Install a 110kV cable from Hobson 110kV switchboard to Quay, connect to second 60MVA transformer to create a 2nd "cable-Tx feeder"	2016			
Delayed	Quay	Quay: construction of civil and building facilities for 110kV switchboard	2016	Subject to further study		
Delayed	Quay	Installation of 110kV switchboard	2017	Subject to further study		
FY17	Waiwera	Zone substation land purchase	2017	No change	To allow for construction of Waiwera substation post FY22	
FY17	Quay	Ports of Auckland reinforcement	2017		To supply customer increasing their load	5.6.10.3
FY17	Kaukapakapa	Establish zone substation	2017	No change	To reinforce Helensville substation and provide 11kV backstop capacity	5.6.5.2
FY17	Te Atatu	Upgrade 33/11kV transformers	2017	No change	To increase N-1 capacity at Te Atatu substation	5.6.9.2
FY13	Brickworks	New 11kV feeder	2017	Part of substation redevelopment		
after FY22	Freemans Bay	22kV extension at Union St to offload FREE 13 & 15	2018	Deferred due to revised load forecast	To address forecast capacity issues in Freemans Bay feeders	
after FY22	St Johns	33kV reinforcement	2018	Deferred due to revised load forecast	To address forecast capacity issues in St Johns sub transmission circuits	
FY18	Ellerslie	Establish zone substation	2018		To meet forecast load growth associated with racecourse development and offload heavily loaded feeders supplying this area	5.6.11.2
FY15	Flatbush	Establish a zone substation in Flatbush	FY18	Project brought forward	To allow for supplying the new town centre according to draft Auckland plan	5.6.15.2

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY13	Brickworks	Second 33/11kV transformer	New	To coincide with station rebuild	To offload the single transformer substation which is currently loaded 80% of its capacity and allow for extra load from the land next to the substation	5.6.8.2
FY18	Coatesville	Second 33/11kV transformer	2018	No change	Current load forecast indicates shortfall on 11kV backstop capacity to this single transformer substation. This project is to meet required service level	5.6.6.2
FY18	Oratia	11kV feeder to Piha from Oratia zone substation	2018	No change	Piha feeder is heavily loaded and requires reinforcement	5.6.8.2
FY18	Takapuna	Install second transformer	2018	No change	To increase capacity at single transformer substation as the load is expected to grow due to intensification plans at Takapuna	5.6.7.2
FY18	Newmarket South	Obtain consents and designation for the 110kV substation	2018		To enable establish proposed Newmarket South 110kV substation	
after FY22	Avondale	Avondale area 11kV reinforcement to offload AVON 1, 9 & 13	2019		To address forecast capacity issues in Avondale feeders	
FY17	Takanini	11kV Mill Road feeder from Takanini zone substation	F19		To supply new load growth arising from Takanini and Papakura areas according to draft Auckland council plan	5.6.19.2
FY15	Waitakere	Establish zone substation	2019	Project brought forward	To offload Swanson substation and improve voltage levels at Bethells Rd feeder to meet required service levels	5.6.92
FY19	Hobsonville East	Establish zone substation	2019	No change	When old Hobsonville airbase is developed additional capacity is required	5.6.9.2
FY19	Waimauku	Install 33kV line	2019	No change		
FY19	Takapuna	New 11kV feeder (Taharoto)	2019	No change		
FY19	Takapuna	New 11kV feeder (Clifton)	2019	No change		
FY19	Takapuna	New 11kV feeder (Kitchener)	2019	No change		
Delayed	Quay	Install a second 110kV cable from Hobson	2019	Subject to further study		
FY20	Customer B	Customer B upgrade Stage 3	FY19	Deferred	To upgrade the supply to a existing customer	
FY19	Newmarket South	Construction of civil and building facilities for new 110kV substation	2019			

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY20	Lincoln	Zone substation land purchase	2020	No change	To secure land for Lincoln Rd new substation to allow for additional capacity in the area	5.6.9.2
FY17	Greenmount	Install NER at Greenmount	FY20	No change	To manage the fault levels under the designed limits	
FY20	Mt Albert	Sub-transmission reinforcement	2020		To enable retirement of existing supply due to age/condition	5.6.13.2
FY20	Hobson West	Designate site	2020			
FY20	Newmarket South	Long-term: cut and turn PEN-LIV 110kV cable to Newmarket south, install 110kV switchboard and two x 110/33kV transformers	2020			
after FY22	Hillsborough	11kV new feeder	2021	Deferred due to revised load forecast	To address forecast capacity issues in Hillsborough and Onehunga feeders	
FY21	Hobson & Quay	22kV feeders to Queens Wharf	2021		To supply customer increasing their load	5.6.10.3
FY21	Newmarket	11kV supply to ex Lion Breweries site	2021		To supply customer load at ex-Lion Breweries site	5.6.11.3
FY21	Woodford	Second 33/11kV transformer + 33kV reinforcement	2021	No change	To allow for increased N-1 capacity at this single transformer substation and additional load expected in the area	5.6.9.2
FY14	Keeling Road	Install second 33/11kV transformer and reinforce 33kV network	2021	Brought forward due to load transfers	To ensure security of supply to the largely business customers supplied from Keeling Rd and provide support to McLeod and Sabulite substations	5.6.8.2
FY21	Hobson West	Establish zone substation	2021			
FY21	Quay	Install a third 110/22kV Transformer	2021			
FY21	Victoria	Install 22kV switchboard	2021			
FY15	Quay	Extend 22kV switchboard stage 2	2021	Brought forward		
after FY22	Rockfield	11kV feeder reinforcement	After 2021		To address forecast capacity issues in Rockfield feeders	

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY16	Rosebank	11kV feeder reinforcement	After 2021	Brought forward due to revised load forecast	To increase 11kV backstopping at Rosebank North to meet required service levels	5.6.8.2
after FY22	St Johns	11kV reinforcement to Auckland University Tamaki campus	After 2021		To supply customer increasing their load	
after FY22	Glen Innes	11kV reinforcement to off-load feeders six and thirteen	After 2021		To address forecast capacity issues in Glen Innes feeders	
after FY22	Kingsland	11kV reinforcement	After 2021		To address forecast capacity issues in Kingsland feeders	
after FY22	White Swan	11kV reinforcement	After 2021		To address forecast capacity issues in White Swan feeders	
after FY22	Orakei	11kV reinforcement	After 2021		To address forecast capacity issues in Orakei feeders	
after FY22	Ellerslie	Install second 33kV cable and 33/11kV transformer	After 2021		To meet forecast load growth associated with racecourse development	
after FY22	Glen Innes	upgrade Glen Innes sub-transmission & transformer to 33kV	After 2021	Pending assets condition assessment		
after FY22	Onehunga	Upgrade Onehunga sub to 33kV	After 2021	Pending assets condition assessment		
after FY22	Tamaki, proposed	Establish Tamaki substation	After 2021	Customer driven	To meet load growth due to ACC's Tamaki development plan	
after FY22	Westfield	Upgrade Westfield substation to 33kV	After 2021	Pending assets condition assessment		
Complete	Liverpool	Liverpool substation - replace 110/22kV transformers	Complete			
Complete	Quay	Liverpool to Quay 110kV sub-transmission cables	Complete			
Cancelled	Greenmount	Install Auto Close device on 11kV bus	Deferred	Project brought forward	To manage the fault levels under the designed limits	

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY20	Wiri West	Establish zone substation	Deferred	Project brought forward	To supply increasing load around Roscommon Rd according to draft Auckland plan	5.6.18.2
Deferred	Takanini South	Establish zone substation	Deferred	Deferred beyond planning period		
FY22	Wainui	Establish zone substation	New	Previously deferred		
FY22	Albany	Establish zone substation	New	Previously deferred		
FY21	Kumeu	Establish zone substation	New	Previously deferred		
On-going	Hobson	Extend 22kV feeders to Tank Farm development	on going		To meet load growth due to redevelopment in Tank Farm	
On-going	Hobson, Liverpool, Quay, Victoria	Auckland CBD 11kV to 22kV load transfer	On-going			
On-going	Hobson, Liverpool, Quay, Victoria	Auckland CBD 22kV network extensions	On-going			
FY18	Mangere Central	Mangere Central Install 3rd transformer		New project	To allow for increased load due to draft Auckland plan	5.6.17.2
FY13	Maraetai	Maraetai Reinforce Maraetai feeder 2		New project	To reconfigure feeder 7 to provide additional backstop capacity to Maraetai feeder 2	5.6.19.2
FY14	Waiheke	Maraetai Reinforce Maraetai feeder 5		New project	To reconfigure feeder 3 to provide additional backstop capacity to Waiheke feeder 5	5.6.19.2
Cancelled	Mangere Central	Installation of 11kV feeder to Massey Road	Deferred	Cancelled		
Cancelled	Waiheke	11kV voltage regulator	F15	Cancelled		
FY16	Rockfield	NZ Technology Park supply	n/a	New project, customer driven	To supply Development of NZ technology park, load is estimated around 6MVA	5.6.11.2
FY21	Southdown	Southdown: establish 33kV cable circuits to GXP to be established by Transpower	n/a	New project, provisional	To relive heavily loaded 33kV bus at Penrose	5.6.11.2

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
FY13	Howick	Install NER at Howick	New	New project	To manage the fault levels under the designed limits	
FY13	Hillsborough	Substation Designation	New	New project		
FY13	Ellerslie	Substation Designation	New	New project		
Ongoing	Power System Protection	Replacement / Refurbishment based on asset condition / system adequacy with IEC 61850 compliant solutions			Operational Excellence	5.1
FY13	Network Automation	Control centralised automatic load shift scheme based on CIM / 61850 model – Proof of Concept			Cost Efficiency	5.1
FY20	Network Automation	MV/LV secondary substation automation –based on IEC 61850 and IP network communication			Cost Efficiency	5.1
As required	Network Automation	Centralised substation scheme · bus load-transfer schemes · overloading load shedding scheme · under-frequency load shedding scheme			Cost Efficiency	5.1
Ongoing	Network Automation	Substation Modernisation – RTU Replacement with IEC61850 based solution			Cost Efficiency Operational Excellence Future Proofing	5.1
FY13	Control Centre Applications	Interface To Transpower SCADA System via Inter-control Centre Communications Protocol (ICCP) per IEC60870-6 TASE.2 Standard			Cost Efficiency Operational Excellence Future Proofing	5.1
Ongoing	Communication Networks and Systems	Continue Deployment of IP based substation LAN / WAN solutions			Cost Efficiency Operational Excellence Future Proofing	5.1
FY20	Power System Protection	Replacement / Refurbishment based on asset condition / system adequacy with IEC 61850 compliant solutions			Operational Excellence	5.1

Implementation Date	Substation	Project Description	Implementation Date from Previous AMP	Comments	Project Justification	AMP Section
Ongoing	Network Automation	Substation Modernisation – RTU Replacement with IEC61850 based solution			Cost Efficiency	5.1

Table 5-35 : Project programme for network development

5.11 Project Expenditure Forecast

The expenditure and timing forecasts for the major projects included in Vector's development programme are listed in Table 5-36.

Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Airport - 33kV Reinforcement							$7.70m				
Airport - 33kV switchboard and third transformer				$2.00m	$4.80m						
Airport - Customer capacity upgrade											$4.10m
Albany - New Zone Substation											$6.00m
Atkinson Rd - New 11kV Fdr, redistribute Kaurilands Fdr			$0.04m	$0.46m							
Avondale - 11kV Reinforcement for Waterview	$0.45m										
Avondale - Avondale CB12 metering	$0.05m										
Avondale - Install 33kV SWBD	$0.10m	$1.30m									
Balmoral - 11kV Reinforcement St Lukes			$1.00m								
Belmont - 11kV Reinforcement		$1.00m									
Birkdale - Substation Reconstruction	$0.20m	$2.30m	$1.00m								
Brickworks - First 33/11kV transformer		$2.10m									
Brickworks - Second 33/11kV transformer					$2.10m						

Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Browns Bay - 11kV Reinforcement (stapleford)	$0.20m										
Chevalier - 11kV Reinforcement					$0.30m						
Chevalier - 11kV Reinforcement for Waterview	$0.35m										
Chevalier - 2nd transformer for Waterview	$0.40m										
Chevalier Ponsonby upgrade	$0.80m										
Coatesville - Second 33/11kV transformer						$0.05m	$0.65m				
Ellerslie - New Zone Substation					$0.40m	$4.10m	$4.10m				
Ellerslie - Substation designation		$0.10m									
Flatbush - 11kV Reinforcement		$0.30m	$0.30m	$0.30m	$0.30m						
Flatbush - New Zone Substation			$0.65m	$8.05m	$11.30m						
Flatbush - Zone Substation Land Purchase		$0.50m									
Glenvar - New Zone Substation				$0.36m	$1.64m	$4.80m					
Greenhithe - 33kV cable extension			$0.75m	$0.75m							
Greenhithe - Second 33/11kV transformer						$0.08m	$0.93m				
Helensville - Capacitor Bank (Kaukapakapa)	$0.10m										
Helensville - Rodney Power Station				$0.02m	$0.28m						
Henderson Valley - 11kV Voltage Regulator - Piha Fdr	$0.10m										
Highbury - 11kV Reinforcement	$2.30m	$0.32m									
Highbury - Install 2nd 33kV Power Transformer					$0.17m	$0.03m	$2.30m				
Hillsborough - Install 2nd 22kV Power Transformer & 2nd 22kV Cable	$0.20m	$2.30m	$2.30m								
Hobson - 22kV cabling in Halsey St for Waterfront development					$0.50m	$0.50m					
Hobson - 22kV cabling in Madden St for									$0.50m		

Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Waterfront development											
Hobson - 22kV ducts in Madden St for Waterfront development							$0.30m	$0.30m			
Hobson - 22kV extension in Halsey St for Waterfront development			$0.30m	$0.30m							
Hobson - 22kV feeder extension for the Tank Farm development	$1.20m	$0.90m									
Hobson - 22kV Reinforcement Queens Wharf									$0.67m	$0.67m	$0.67m
Hobson - 3rd 22kV new feeder to supply Waterfront development										$0.80m	$0.80m
Hobson - Extend 22kV switchboard					$0.60m						
Hobson - GXP Construction	$15.80m	$26.63m	$2.00m								
Hobson - Install 3rd 110kV Power Transformer		$0.11m	$1.39m								
Hobson West - 110kV switchboard & 2x 60MVA 110/22kV transformers											$15.00m
Hobson West - Civil works for 110kV Substation									$0.90m	$11.10m	
Hobson West - Designation & consenting							$0.01m	$0.09m	$0.10m		
Hobsonville - 11kV Reinforcement - Oreil Fdr	$1.60m										
Hobsonville - Clark Rd 11kV feeder extension		$0.10m	$1.40m								
Hobsonville East - Land purchase		$0.50m									
Hobsonville East - New Zone Substation						$0.15m	$1.85m	$2.50m			
Kaukapakapa - New Zone Substation				$0.15m	$1.85m	$2.00m					
Keeling Rd - 11kV Reinforcement	$0.10m										
Keeling Rd - Install 2nd 33kV Power Transformer & 33kV Reinforcement		$1.50m	$2.40m								
Kumeu - Land purchase				$0.04m	$0.46m						
Kumeu - New Zone Substation									$0.45m	$5.55m	

Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Lincoln - Land purchase								$0.08m	$0.93m		
Liverpool - 22kV Reinforcement Telecom Mayoral Dr				$0.40m	$0.40m						
Liverpool - 2nd 22kV tie to Quay			$0.15m	$1.85m							
Liverpool - Capacity upgrade for University Medical School			$0.90m	$0.90m							
Liverpool - Fire suppression in Penrose tunnel	$0.65m	$0.20m									
Liverpool - New 110/22kV transformer		$0.23m	$2.78m								
Liverpool - Protection upgrade at Penrose	$0.10m										
Mangere Central - Third 33/11kV transformer						$0.10m	$1.20m				
Mangere East - 11kV Reinforcement							$0.20m				
Mangere East - Customer capacity upgrade	$0.50m	$1.00m	$1.00m								
Mangere West - 11kV Reinforcement			$0.60m								
Manly - 11kV Reinforcement (Wade River)	$0.70m										
Manurewa - 11kV Reinforcement			$0.08m	$1.02m							
Maraetai - 11kV Reinforcement		$0.70m	$0.70m								
Maraetai - 11kV Reinforcement		$0.20m									
Matakana - Land purchase			$0.40m								
McKinnon - 11kV Reinforcement - Avenue Fdr	$0.50m										
Mt Albert - Subtransmission Reinforcement							$0.07m	$0.88m	$0.95m		
Newmarket - 11kV Reinforcement Broadway		$1.30m									
Newmarket - ex Lion Breweries site									$0.75m	$0.75m	$0.75m
Newmarket South - 110kV cable alterations								$0.75m	$9.25m		
Newmarket South - Civil works for 110kV Substation							$0.30m	$3.70m			

Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Newmarket South - Concept study for 110kV Substation					$0.20m						
Newmarket South - Designation & consenting			$0.20m								
Newmarket South - New Zone Substation		$0.08m	$0.40m	$3.86m	$3.86m						
Newmarket South - Zone Substation Land Purchase		$2.50m									
Northern - Various 11kV Capacitor Banks		$0.50m	$0.50m	$0.50m	$0.50m						
Oratia - 11kV Reinforcement						$0.15m	$1.85m				
Orewa - 11kV Reinforcement - Savoy Fdr			$0.04m	$0.46m							
Orewa - 11kV Reinforcement - Weranui Fdr	$1.00m										
Orewa - Third 33kV circuit											$6.00m
Otara - 11kV Reinforcement							$0.08m	$1.02m			
Quay - 110kV cable Hobson - Quay and Relocate T3A		$0.10m	$3.69m								
Quay - Customer capacity upgrade Ports of Auckland					$1.20m	$1.20m					
Quay - Extend 22kV switchboard					$0.12m	$1.60m					
Quay - Replace 3rd 110kV Power Transformer	$1.50m										
Quay - Second 110kV cable Hobson - Quay									$0.38m	$4.63m	
Red Beach - Install 2nd 33kV Power Transformer		$0.20m	$1.40m								
Rockfield - 11kV Reinforcement	$1.50m										
Rockfield - NZ Technology Park Supply					$0.56m						
Rosebank - 11kV Reinforcement			$0.16m	$1.94m	$2.10m						
Rosebank/Te Atatu - 11kV Reinforcement (ducts)		$0.30m	$0.30m								
Rosedale - Zone Substation Construction	$0.20m	$3.20m	$3.50m								

Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Rosedale - Zone Substation Land Purchase	$0.50m										
Sandspit - Zone Substation Construction					$0.15m	$1.85m	$4.50m				
Southdown - Establish 33kV circuits									$0.19m	$2.31m	
Spur Rd - Install 2nd 33kV Power Transformer						$0.08m	$0.93m				
St Helliers - Auto Load Shedding Scheme									$0.20m		
Sylvia Park - 11kV Reinforcement	$1.50m										
Takanini - 11kV Reinforcement					$0.08m	$0.93m					
Takanini South - Zone Substation Land Purchase					$0.04m	$0.46m					
Takapuna - 11kV Reinforcement - Clifton Fdr							$0.08m	$0.93m			
Takapuna - 11kV Reinforcement - Kitchener Fdr							$0.08m	$0.93m			
Takapuna - 11kV Reinforcement - Taharoto Fdr							$0.08m	$0.93m			
Takapuna - Install 2nd 33kV Power Transformer						$0.19m	$2.31m				
Te Atatu - 11kV Reinforcement	$0.20m										
Te Atatu - New 33/11kV transformers					$0.15m	$1.85m					
Te Atatu/Waterview - 33kV Reinforcement (ducts)		$0.50m	$0.50m								
Te Papapa - 11kV Reinforcement							$0.06m	$0.78m	$0.84m		
Various - Ducts: future-proofing ducts - Northern	$0.50m	$0.50m	$0.50m	$0.50m	$0.50m	$0.50m	$0.50m	$0.50m	$0.50m	$0.50m	$0.50m
Various - Ducts: future-proofing ducts - Southern	$1.00m	$0.50m	$0.50m	$1.00m	$1.00m	$1.00m	$1.00m	$1.00m	$1.00m	$1.00m	$1.00m
Various - Minor Fdr Reinforcements: Southern	$0.40m	$0.40m	$0.40m	$0.40m	$0.40m	$0.40m	$0.40m	$0.40m	$0.40m	$0.40m	$0.40m
Various CBD - 11kV to 22kV load transfer	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m
Various CBD - 22kV network extension	$1.50m	$2.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m	$1.50m

Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Victoria - Establish 22kV switchboard					$0.23m	$2.78m					
Waiheke - 11kV Reinforcement			$0.80m								
Waimauku - 11kV Reinforcement	$1.40m										
Waimauku - 33kV Reinforcement							$0.26m	$3.24m			
Waimauku - Install 2nd 33kV Power Transformer	$1.80m	$0.20m									
Wainui - Zone Substation Construction											$6.00m
Wainui - Zone Substation Land purchase			$0.03m	$0.37m							
Waitakere - Zone Substation Construction		$0.23m	$1.75m	$3.42m							
Waiwera - Zone Substation Land purchase					$0.02m	$0.28m					
Warkworth - 11kV Reinforcement - Matakana Fdr			$0.08m	$0.93m							
Warkworth - 11kV Reinforcement - Warkworth South Fdr	$1.50m	$0.20m									
Warkworth - 11kV Reinforcement - Whangateau Fdr				$0.08m	$0.93m						
Warkworth South - Zone Substation Construction				$0.08m	$0.93m	$3.00m					
Waterview - 11kV Reinforcement	$0.60m										
Waterview - New Substation South Portal		$0.50m									
Waterview - South Portal permanent supply			$0.40m	$0.40m							
Waterview - Zone Substation Construction North Portal permanent		$0.20m	$2.50m	$2.30m							
Wellsford - 11kV Voltage Regulator - Tomarata Fdr	$0.10m										
Westgate - Zone Substation Construction			$0.48m	$1.52m	$6.40m						
Wiri West - Zone Substation Construction								$0.59m	$7.22m		
Wiri West - Zone Substation Land Purchase		$0.50m									

Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Woodford - Install 2nd 33kV Power Transformer & 33kV Reinforcement								$0.15m	$1.85m	$3.20m	

Table 5-36 : Timing and estimated cost of major growth projects until 2022

5.12 Network Development Expenditure Forecast

In Table 5-37 the network development expenditure forecast is broken down into broad expenditure categories. Note that customer initiated projects relate to those projects that are significant enough to initiate network reinforcement to supply the demand requested. These projects have been separately identified from normal network reinforcements due to the uncertainty of timing and scope. The projects in the first five years reflect our best estimate based on information received from the customer (refer Section 5.3.2). Certainty around project timing reduces as we move away from the current year's budget.

Financial year ending	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Sub-transmission and zone substation reinforcements	$22.5m	$44.0m	$25.6m	$20.6m	$29.3m	$21.2m	$17.1m	$12.0m	$22.2m	$26.8m	$33.0m
Customer initiated network reinforcement	$3.6m	$5.7m	$6.6m	$6.3m	$7.5m	$1.7m	$8.0m	$0.3m	$1.9m	$2.2m	$6.3m
Distribution reinforcements	$17.1m	$8.5m	$9.1m	$10.4m	$10.7m	$8.2m	$9.6m	$9.5m	$5.9m	$4.9m	$4.9m
LV reinforcements	$0.9m	$2.0m	$2.0m	$2.0m	$2.0m	$2.0m	$2.0m	$2.0m	$2.0m	$2.0m	$0.9m
Relocations	$10.8m	$11.0m	$8.5m	$5.1m	$5.1m	$5.1m	$5.1m	$5.1m	$5.1m	$5.1m	$5.1m
OIP expenditure	$15.6m	$13.2m	$13.2m	$13.2m	$13.2m	$13.2m	$13.2m	$13.2m	$13.2m	$13.2m	$13.2m
Customer connections growth	$26.1m	$24.6m	$24.6m	$24.6m	$24.6m	$24.6m	$24.6m	$24.6m	$24.6m	$24.6m	$24.6m
Total	$96.5m	$109.0m	$89.6m	$82.3m	$92.4m	$75.9m	$79.6m	$66.6m	$75.0m	$78.8m	$88.0m

Table 5-37 : Expenditure on growth budget to FY22 broken down by major categories

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Electricity
Asset Management Plan
2012 – 2022

Asset Maintenance, Renewal and Refurbishment Planning – Section 6

[Disclosure AMP]

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6 Asset Maintenance, Renewal and Refurbishment Planning

6.1 Overview

This section covers Vector's life cycle asset maintenance, renewal and refurbishment plans, and the policies, criteria, assumptions, data and processes used to prepare these.

Vector's electricity distribution network is designed and built to deliver electricity to the service level set out in the Vector Electricity Network Security Standards[1], as reflected in the connection agreements with its customers[2]. In order to achieve the required level of service at optimum cost, the fixed assets have to be kept in good operating condition. This is achieved by way of renewing (replacing), refurbishing and maintaining assets (regular maintenance). Vector's long-term asset maintenance strategy is to achieve the optimal trade-off between capital expenditure (capex) and operational expenditure (opex), while maintaining a safe, efficient and reliable network. Achieving this requires a balance between effective maintenance and judicious asset renewal.

6.1.1 Vector's Maintenance and Refurbishment Approach

Vector has developed a comprehensive suite of asset maintenance standards that describe its approach to maintaining and refurbishing various asset categories. There are clearly significant differences required in the approach to different asset types, but as a broad rule the maintenance standards provide the following:

- The required asset inspection frequency;
- The routine and special maintenance activities required to be carried out during these inspections; and
- Condition testing that needs to be carried out and the required response to the test results.

In general, Vector's philosophy is to keep its assets in use for as long as they can be operated safely, technically and economically. The maintenance and refurbishment policies support this goal by intervening to ensure optimal performance.

In a small number of cases (such as pole fuses), assets that have low impact on the electricity network's integrity and performance are allowed to run to failure, as the cost of systematically identifying defects to avoid such failures far outweighs the benefits.

6.1.2 Vector's Asset Renewal Approach

Assets are only renewed when:

a. They are irreparably damaged;

b. The operational and/or maintenance costs over the remaining life of the asset will exceed that of replacement;

c. There is an imminent risk of asset-failure; and/or

d. Assets become obsolete and hence impossible or inefficient to operate and maintain.

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[1] The Electricity Network Security Standards are discussed in more detail in section 5 of the AMP.

[2] Security levels higher than that described in the standards may be available to consumers, in which case dedicated commercial arrangement will be entered into.

Asset renewal is therefore in general condition-based rather than age-based.

Optimisation of capital investment and maintenance costs is an important part of Vector's capital investment efficiency drive. This requires comprehensive evaluation of the condition, performance and risk associated with the assets, to provide a clear indication of the optimal time for assets' renewal. Often it may be more efficient to extend the life of asset to beyond normal predicted asset life, by servicing or refurbishing the assets.

Asset condition evaluation is based on:

- Vector's field service providers' (FSPs') surveys, observations, test and defect work schedules;[3] and
- Analysis of equipment test data, such as transformer oil tests, serving tests on cables (checking integrity of outer sheath) and online/offline partial discharge (PD) (test joints and switchgear).

The asset performance evaluation is based on asset fault records and reactive maintenance records.

Once an asset is identified for replacement, Vector's prioritisation methodology is applied to determine the ranking of replacement projects. This methodology is based on assessing the criteria giving rise to the need for replacement, the importance of the asset in question, the impact should the asset fail and the likelihood of such failure. Additional factors considered are the health and safety risk, risk to assets, risk to the company's reputation, potential financial impacts and potential effects on the environment. The final project prioritisation list (that incorporates scoring based on conditions and performance as well as risk assessment), along with budgetary estimates, forms the basis of the annual renewal budgets for each fiscal year.

It is essential to gain and maintain relevant information on the performance of assets in the field in order to undertake accurate assessments. The field data is currently collected and held by our FSPs. Historically, this data was generally not available in a user-friendly form (it existed mainly as paper-based records, for example). For this reason Vector commissioned a Systems Applications and Processes (SAP) based plant maintenance system during 2010. Following this, asset condition and replacement data is now being directly fed into Vector's databases, based on the activities of our FSPs. Vector has also converted substantial volumes of historical asset performance and replacement records into a database format, to allow these to be assessed together with future field-data. This process is ongoing.

The investigation data, field data and fault records collected and maintained in Vector's databases are increasingly being used to conduct asset condition/performance and risk assessments, informing our renewal programmes.

6.1.3 Enhanced Condition-Based Risk Management Framework

Vector is continually monitoring developments in asset maintenance. Based on our surveys and advice from experts, we have identified the substantial benefits that leading international utilities are achieving though adopting a formal condition-based risk management (CBRM) framework for the renewal and maintenance of their electricity network assets. As part of its ongoing improvement programme, Vector has therefore decided to adopt this approach for future prioritisation of its renewal and maintenance activities.

While elements of a CBRM approach has been in place at Vector for a long time, we have recently commenced the development of a formal CBRM framework. It is intended to:

[3] These surveys and tests are conducted in accordance with Vector's technical asset standards.

- Systematically collect and store information about the condition and performance of all major assets on the network and capture this information in an electronic database forming part of our SAP planned maintenance system. Besides information collected during scheduled inspection and maintenance activities, it will also include asset information collected during outages (and subsequent repairs) as well as ad hoc information collected during non-routine field visits.
- Implement a condition-assessment framework that will assign a condition-value to all assets, based on the information collected from the field, test results or other information obtained. In the case of assets for which condition cannot be easily observed (which includes the bulk of underground assets), condition assessments will be guided by asset performance data collected on the Vector network (failure and reliability data), known information about similar assets of similar age elsewhere on the network, other utility experience with similar assets in similar conditions and from periodic testing and inspection[4]. The condition-based information will form the basis for assessing the likelihood of the failure of relevant major network assets.
- Implement a criticality-assessment framework that will rate the importance of all assets in terms of the potential impact failure or mal-function of the asset would have on public and operator safety, on network reliability and on operational effectiveness. The criticality assessment will take into account factors such as asset location (geo-spatial analysis), network capacity impacted by failure of the asset and the likely nature and physical impact of the failure of an asset. The criticality information will form the basis for assessing the impact that the failure of an asset will have.

By combining the information about the likelihood and impact of an asset failure, the network-risk associated with the asset will be derived. Vector will maintain this asset risk information for all major assets on its network, using it for enhanced prioritization of asset replacement and non-routine maintenance work.

Collecting asset-related data in the manner described above will also allow Vector to in future accurately assess the health of individual assets on an ongoing basis. By combining the information per asset category or for all assets, the asset-health per category or for the network as a whole, could also be derived. These asset health figures will be continually updated, as more, or updated information from the field becomes available. By tracking this information over time and assessing this in conjunction with network reliability performance, the effectiveness of Vector's renewal and maintenance investment can be continually assessed and optimised.

Work on developing a more formal CBRM framework for Vector's electricity assets commenced during FY2011. It is intended to complete the development and commence with the full implementation of the CBRM framework by the end of (calendar year) 2012.

6.2 Maintenance Planning Processes, Policies and Criteria

This section presents the planning processes, policies and criteria for managing Vector's network assets. Vector's strategic focus drives the asset integrity strategies:

Operational excellence

- Maintain the existing assets in good and safe working order until new assets are built or until they are no longer required;
- Ensure the network operation is reliable;
- Ensure network investments and operating activities are efficient; and

[4] When assets are uncovered, whether due to a fault or due to proximity to other assets requiring attention, we use the opportunity to conduct condition inspections or tests.

- Strive for continual innovation and efficiency improvements on how assets are maintained and operated.

Customer service

- Ensure the safety of the public, our staff and our FSPs;
- Ensure assets are designed, operated and maintained to the required level of standard to provide the agreed level of service ; and
- Ensure an appropriate level of response to customer, concerns, requests and enquiries.

Cost efficiency

- Strive to achieve the optimal balance between capital and operational costs;
- Coordinate asset replacement and new asset creation programmes; and
- Apply innovative approaches to solutions, development and projects execution.

6.2.1 Asset Maintenance Standards and Schedules

Vector's asset maintenance standards are prepared by the Asset Investment (AI) group – in particular by the integrity teams forming part of the engineering group. Asset inspections and maintenance work is carried out by FSPs, under the direction of Vector's Service Delivery (SD) group.

Vector has developed maintenance standards for each major class of assets. The standards form a key part of Vector's schedule for planned maintenance. The purpose of these standards, in conjunction with the schedules of maintenance work, is to ensure assets operate safely and deliver their designed outcomes with regard to life and performance

As part of the asset maintenance standards, the frequency of inspection and reporting per asset category has also been defined. This forms the basis of Vector's asset maintenance schedule.

Vector's maintenance standards are kept on Vector's secure websites and are available to personnel engaged in maintenance activities, as well as for our FSPs. The FSPs must comply with the standards and inspection schedules for each class of assets.

The standards are updated on an "as-you-go basis", so any new findings or updates are incorporated in Vector's standards as soon as they are reviewed by the asset management team, and signed off. Vector's FSPs contribute to, and form an integral part of, this continual improvement process.

Progress against the maintenance schedules and the associated maintenance costs are monitored on a monthly basis. Defects identified during asset inspections are recorded in the contract defects database. FSPs recommend the priorities for the remedial works for defects, which are then reviewed by Vector prior to issuing orders for the work. Maintenance priorities are based on costs, risks and safety criteria.

In making decisions on repairing or replacing the assets Vector will consider recommendations submitted by the FSPs, as well as the factors discussed above. The long-term plans supported by trend analysis for an asset will also be taken into account when assessing whether it should be maintained or replaced.

Vector also undertakes clustering of the projects where they are part of the replacement programme or growth programme of works. If, for example, during inspection or maintenance work, it is found that a large number of defects occur within a specific geographic area where block replacement is planned within the next two years, consideration will be given to carry out the work together as a combined project. Likewise, if new assets are planned to be constructed in a specific area, replacement and/or maintenance work may be deferred for up to two years, if deemed safe. In coordinating such projects long-term savings are achieved due to the economy of scale of projects and potential reduction in establishment and re-establishment costs. Moreover, disruptions to customers and wider public are minimised.

Root cause analysis is normally undertaken as a result of faulty equipment. If this identifies systemic faults or performance issues with a particular type of asset, and if the risk exposure warrants it, a project will be initiated to carry out the appropriate remedial actions on a class of assets. The assets and maintenance standards are also amended to reflect the learning from such root cause analysis.

6.2.2 Maintenance Categories

Maintenance works at Vector are categorised in three main categories:

- *Preventive maintenance* is defined by Vector's standards and is work intended to avoid failures before they occur. The frequency of performing the preventative maintenance work (per asset group) is defined in the maintenance standards, flowing through into the field services providers' schedule;
- *Corrective maintenance* work is the work that flows from the preventative activities, site inspections, testing and observations by Vector's field services providers or any party that reports on potential issues relating to our network's conditions or performance; and
- *Reactive maintenance* work is undertaken following customers' complaints, accidents or any other work that is to rectify damage to the assets caused by unforeseen circumstances.

In addition, Vector also has categories for value added maintenance and for maintenance management services.

The maintenance categories are further explained below.

6.2.2.1 Reactive Maintenance

Reactive maintenance is considered to encapsulate all maintenance activities that relate to the repair and restoration of supply, and the safeguarding of life and property. It primarily involves:

- Safety response and repair or replacement of any part of the network components damaged due to environmental factors or third parties interference; and
- Remediation or isolation of unsafe network situations, including immediate vegetation threats, low clearance lines and non-compliant installations.

6.2.2.2 Preventative Maintenance

Preventive maintenance covers activities defined through the maintenance standards, and relates to the following:

- Provision of network patrols, inspection and condition detection tasks, sampling and maintenance service work; and
- The coordination of shutdowns and associated network switching and restoration, along with the capture and management of all defined data.

6.2.2.3 Corrective Maintenance

Corrective maintenance catches the follow up maintenance repair and component replacement requirements resulting from:

- Assets identified from planned inspections or service work to be in poor condition, requiring repair;
- Poor condition or unserviceable assets identified via one-off coordinated network inspections or identified through proximity capital works;
- Removal of graffiti, painting and repair of buildings and asset enclosures, removal of decommissioned assets, remediation of television interference complaints, one-off type inspection and condition detection tasks outside of planned maintenance standards; and
- Coordination of shutdowns and associated network switching and restoration, along with the capture and management of all defined data.

6.2.2.4 Value-Added Maintenance

Value-added maintenance activities describe third party directed requests such as the following:

- Issuing maps and site plans to indicate the location of network assets;
- Asset location services, including the marking out of assets, safe work practice site briefings, worksite observer, urgent safety checks, safety disconnections;
- Issuing close approach permits, high load permits, high load escorts; and
- Disconnection and reconnection associated with the property movement of customers and any concerns relating to non-compliance of electricity regulations.

6.2.3 Asset Maintenance and Field Services Provider Management Process

Vector has, through a competitive process, engaged two contractors to maintain its electricity and gas networks. Electrix Ltd is Vector's maintenance contractor for the Northern Region network and Northpower Ltd is Vector's maintenance contractor for the Southern Region network. The maintenance contracts drive the preventative, corrective and reactive maintenance works programmes, based on the requirements set by the Vector maintenance standards.

Both contractors are managed by Vector's SD group. The maintenance contract defines the responsibilities, obligations and key performance indicators (KPIs) to complete scheduled works. Vector's AI group works closely with the SD group to keep abreast of any issues with regards to the contractors' obligations and performance. The maintenance standards form part of the maintenance contract and contractors must comply with them when performing their duties.

Figure 6-1 below describes the flow of work and responsibilities in maintaining Vector's assets.

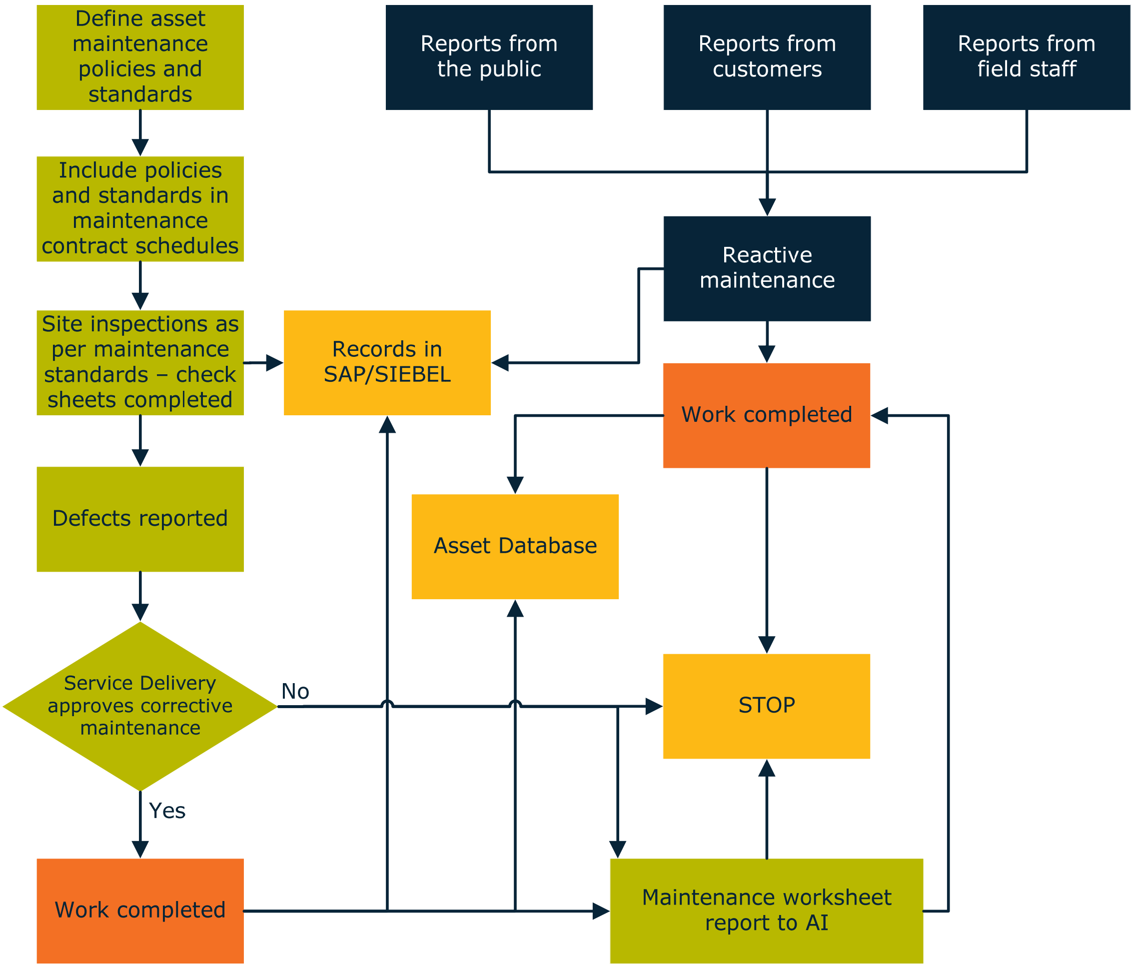


Figure 6-1 : Asset maintenance processes

6.2.4 Forecast Maintenance Budgets

In the Commerce Commission's Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010 (Input Methodologies) a far more segregated breakdown of maintenance expenditures (actual and forecast) is indicated than for previous AMPs.[5]

For Vector direct maintenance expenditure is a combination of the following internal cost elements:

- **Core maintenance:** Encapsulates all reactive, planned and corrective maintenance activities and services associated with the Northern and Southern network areas. It also includes servicing of the mobile generation units;
- **Value added maintenance:** Provides for customer or retailer recoverable activities, callouts to other utility assets, safety disconnection and following reconnections, voltage quality issues traced to customer assets, false callouts, line care services, provision of maps, network mark outs, safety stand-overs, high load permitting and escorts, and asset change over requests from Telecom;

[5] These expenditure category requirements would strictly speaking relate to a customised price-path (CPP) application only. A decision of whether Vector would apply for a CPP is still forthcoming. However, as it is clearly intended that the AMP would be an important supporting document for such an application, Vector has deemed it prudent to incorporate these expenditure categories requirements in the AMP as well.

- **Vegetation maintenance:** All reactive, planned and corrective actions associated with distribution assets including substation grounds management, notifications and recovery associated with vegetation management services;
- **Non-core maintenance:** Contains maintenance activities relating to exceptional and extreme network events, specialist contractor or extraordinary maintenance activities over and above that provisioned through core services. This also includes all reactive, planned and corrective work associated with the Penrose-Hobson tunnel and associated services;
- **Miscellaneous maintenance:** All reactive, planned and corrective activities and services related to the Lichfield network, check metering support and maintenance, road opening notice fees and building warrant of fitness fees associated with the Northern and Southern networks;
- **Inventory related costs:** Includes the warehousing, servicing and management of fault stock, project stock, strategic spares, facilities management of locks, scrap material and distribution transformer refurbishment activities; and
- **Maintenance recoveries:** Cost recovery associated with reactive third party damage activity and capex balancing entry due to the internal capitalisation of assets replaced as the result of faults.

The Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010[6] requires a breakdown in the following expenditure categories:

- **Fault and emergency maintenance opex**: Opex principally incurred in responding (by way of undertaking remedial work) to an unplanned instantaneous event that impairs the normal operation of network assets but does not include expenditure on work to prevent or mitigate the impact such an event would have should it occur;
- **Refurbishment and renewal maintenance opex:** Opex that is predominantly associated with the replacement, refurbishment or renewal of items that are asset components;
- **Routine and preventative maintenance opex:** Opex that is predominantly associated with planned work and
  - a. Includes:
    - o Fault rectification work that is undertaken at a time or date subsequent to any initial fault response and restoration activities;
    - o Routine inspection;
    - o Testing; and
    - o Vegetation management activities; and
  - b. Excludes expenditure on initial fault or emergency maintenance;
- **System management and operations opex:** Opex that is predominantly associated with the management and operation of the network including:
  - a. System operations;
  - b. System studies and planning;
  - c. Design;
  - d. Network record keeping; and
  - e. Standards and manuals.

[6] Ibid.

The Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010[7] also requires direct maintenance expenditure disaggregation into the following expenditure categories:

a. Assets owned by the Electricity Distribution Business (EDB) but installed at bulk supply points owned by others;

b. Sub-transmission network including power transformers;

c. Distribution network including distribution transformers;

d. Switchgear;

e. Low voltage distribution network; and

f. Supporting or secondary systems including:

    i. Ripple injection plant;

    ii. SCADA;

    iii. Communications equipment;

    iv. Metering systems;

    v. Power factor correction plant;

    vi. EBD-owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and

    vii. Other generation plant owned by the EDB; and

g. Other.

The direct maintenance opex forecast considers all network areas, Northern, Southern and Lichfield, and also combines each of the networks, the four required opex types: (i) Fault and Emergency Maintenance, (ii) Refurbishment and Renewal, (iii) Routine and Preventive, and (iv) System Management and Operations opex per defined asset category.

In Figure 6-2 to Figure 6-5 and Table 6-1 to Table 6-4 a disaggregated breakdown of forecast opex is provided in accordance with the input methodologies' requirements. A gradual (small) increase in opex is anticipated, to reflect the addition of new assets over time. Provision is also made for increased expenditure on distribution switchgear maintenance (refer to Section 6.3.21 for a discussion).

[7] Ibid.

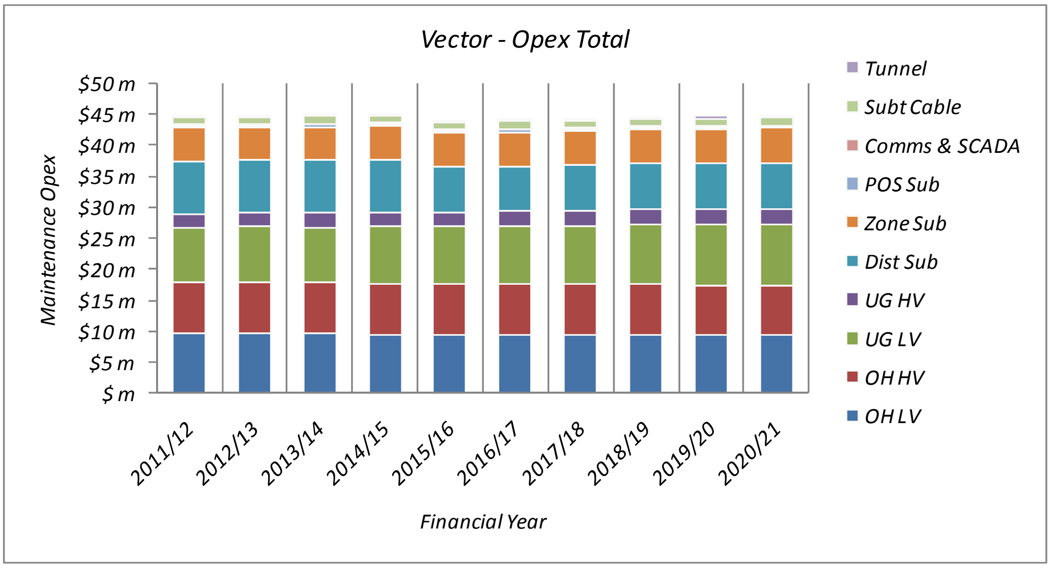


Figure 6-2 : Total disaggregated opex forecast

AMP Category	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
OH LV	$9.57 m	$9.55 m	$9.47 m	$9.39 m	$9.36 m	$9.33 m	$9.30 m	$9.27 m	$9.24 m	$9.21 m
OH HV	$8.31 m	$8.29 m	$8.23 m	$8.21 m	$8.19 m	$8.17 m	$8.15 m	$8.13 m	$8.12 m	$8.10 m
UG LV	$8.77 m	$8.89 m	$9.01 m	$9.14 m	$9.26 m	$9.39 m	$9.52 m	$9.64 m	$9.78 m	$9.91 m
UG HV	$2.20 m	$2.24 m	$2.27 m	$2.30 m	$2.33 m	$2.37 m	$2.40 m	$2.44 m	$2.47 m	$2.51 m
Dist Sub	$8.48 m	$8.45 m	$8.48 m	$8.51 m	$7.29 m	$7.32 m	$7.35 m	$7.38 m	$7.28 m	$7.31 m
Zone Sub	$5.42 m	$5.34 m	$5.37 m	$5.40 m	$5.43 m	$5.47 m	$5.50 m	$5.53 m	$5.56 m	$5.59 m
POS Sub	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m
Comms & SCADA	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m
Subt Cable	$1.14 m	$1.15 m	$1.17 m	$1.18 m	$1.19 m	$1.21 m	$1.22 m	$1.23 m	$1.25 m	$1.26 m
Tunnel	$0.33 m	$0.33 m	$0.23 m	$0.33 m	$0.23 m	$0.33 m	$0.23 m	$0.33 m	$0.33 m	$0.33 m
Total	$44.74 m	$44.77 m	$44.75 m	$44.98 m	$43.81 m	$44.10 m	$44.19 m	$44.48 m	$44.54 m	$44.74 m

AMP Opex Category	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Routine & Preventive	$19.70 m	$19.77 m	$19.73 m	$19.90 m	$19.86 m	$20.04 m	$20.01 m	$20.18 m	$20.25 m	$20.32 m
Refurbish & Renewal	$12.04 m	$11.94 m	$11.88 m	$11.87 m	$10.66 m	$10.71 m	$10.75 m	$10.79 m	$10.71 m	$10.75 m
Fault & Emergency	$13.00 m	$13.07 m	$13.14 m	$13.21 m	$13.28 m	$13.36 m	$13.43 m	$13.51 m	$13.59 m	$13.67 m
Total	$44.74 m	$44.77 m	$44.75 m	$44.98 m	$43.81 m	$44.10 m	$44.19 m	$44.48 m	$44.54 m	$44.74 m

Table 6-1 : Total disaggregated opex forecast

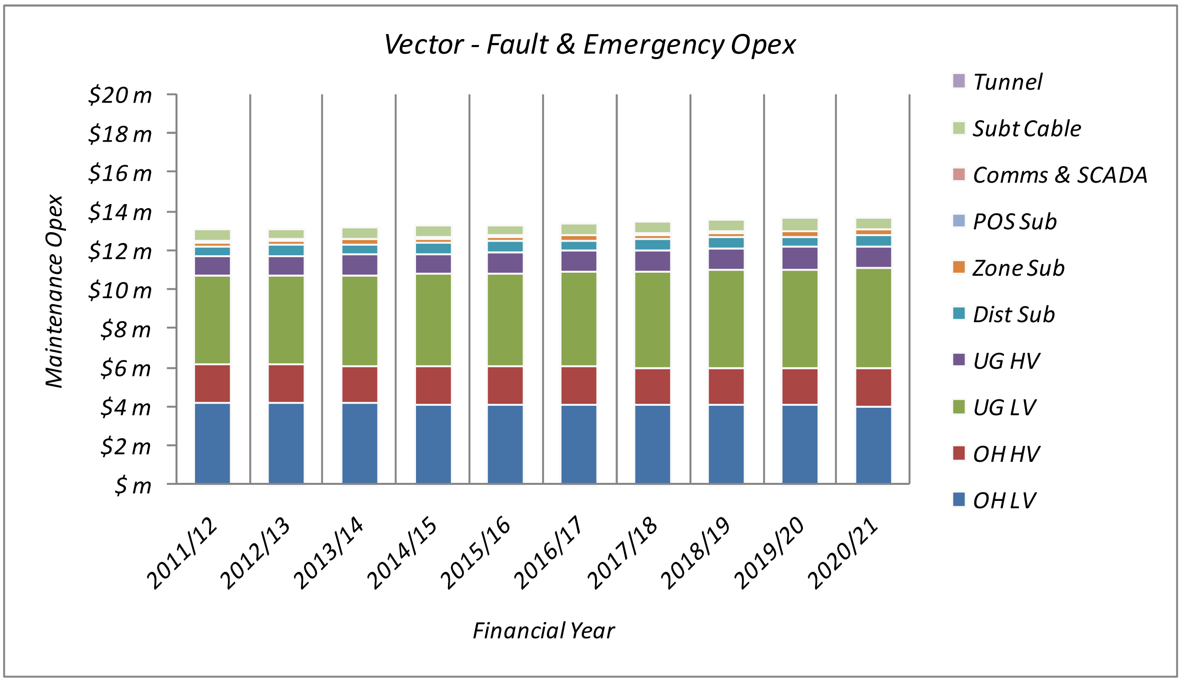


Figure 6-3 : Fault and emergency maintenance expenditure

AMP Category	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
OH LV	$4.15 m	$4.13 m	$4.11 m	$4.09 m	$4.08 m	$4.06 m	$4.04 m	$4.02 m	$4.00 m	$3.99 m
OH HV	$1.96 m	$1.95 m	$1.95 m	$1.94 m	$1.93 m	$1.93 m	$1.92 m	$1.91 m	$1.91 m	$1.90 m
UG LV	$4.52 m	$4.59 m	$4.65 m	$4.72 m	$4.79 m	$4.86 m	$4.93 m	$5.00 m	$5.07 m	$5.15 m
UG HV	$0.99 m	$1.01 m	$1.03 m	$1.04 m	$1.06 m	$1.08 m	$1.10 m	$1.12 m	$1.14 m	$1.16 m
Dist Sub	$0.54 m	$0.54 m	$0.55 m	$0.55 m	$0.55 m	$0.55 m	$0.56 m	$0.56 m	$0.56 m	$0.57 m
Zone Sub	$0.22 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m
POS Sub	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m
Comms & SCADA	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m
Subt Cable	$0.56 m	$0.56 m	$0.57 m	$0.58 m	$0.58 m	$0.59 m	$0.59 m	$0.60 m	$0.61 m	$0.61 m
Tunnel	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m
Total	$13.00 m	$13.07 m	$13.14 m	$13.21 m	$13.28 m	$13.36 m	$13.43 m	$13.51 m	$13.59 m	$13.67 m

Table 6-2 : Fault and emergency maintenance expenditure

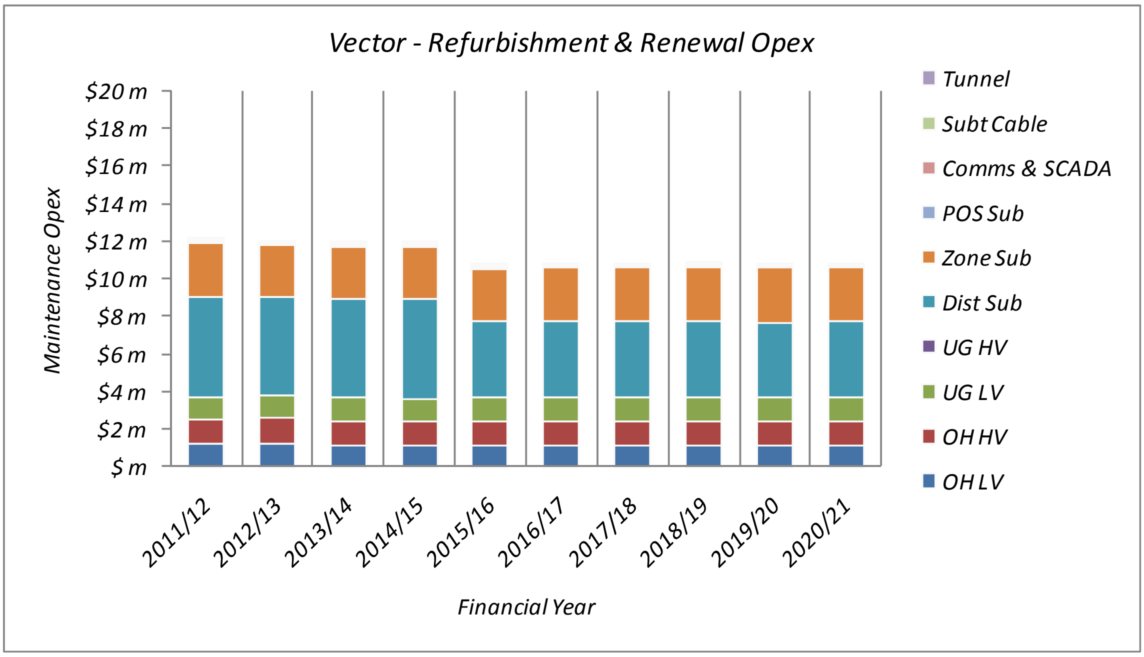


Figure 6-4 : Refurbishment and renewal maintenance expenditure

AMP Category	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
OH LV	$1.18 m	$1.18 m	$1.13 m	$1.08 m	$1.07 m	$1.07 m	$1.07 m	$1.07 m	$1.06 m	$1.06 m
OH HV	$1.34 m	$1.34 m	$1.29 m	$1.29 m	$1.28 m	$1.28 m	$1.28 m	$1.28 m	$1.27 m	$1.27 m
UG LV	$1.19 m	$1.20 m	$1.22 m	$1.24 m	$1.25 m	$1.27 m	$1.29 m	$1.30 m	$1.32 m	$1.34 m
UG HV	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m
Dist Sub	$5.29 m	$5.25 m	$5.27 m	$5.28 m	$4.05 m	$4.06 m	$4.08 m	$4.09 m	$3.98 m	$4.00 m
Zone Sub	$2.86 m	$2.78 m	$2.79 m	$2.80 m	$2.82 m	$2.83 m	$2.85 m	$2.86 m	$2.88 m	$2.89 m
POS Sub	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m
Comms & SCADA	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m
Subt Cable	$0.06 m	$0.06 m	$0.06 m	$0.07 m	$0.07 m	$0.07 m	$0.07 m	$0.07 m	$0.07 m	$0.07 m
Tunnel	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m
Total	$12.04 m	$11.94 m	$11.88 m	$11.87 m	$10.66 m	$10.71 m	$10.75 m	$10.79 m	$10.71 m	$10.75 m

Table 6-3 : Refurbishment and renewal maintenance expenditure

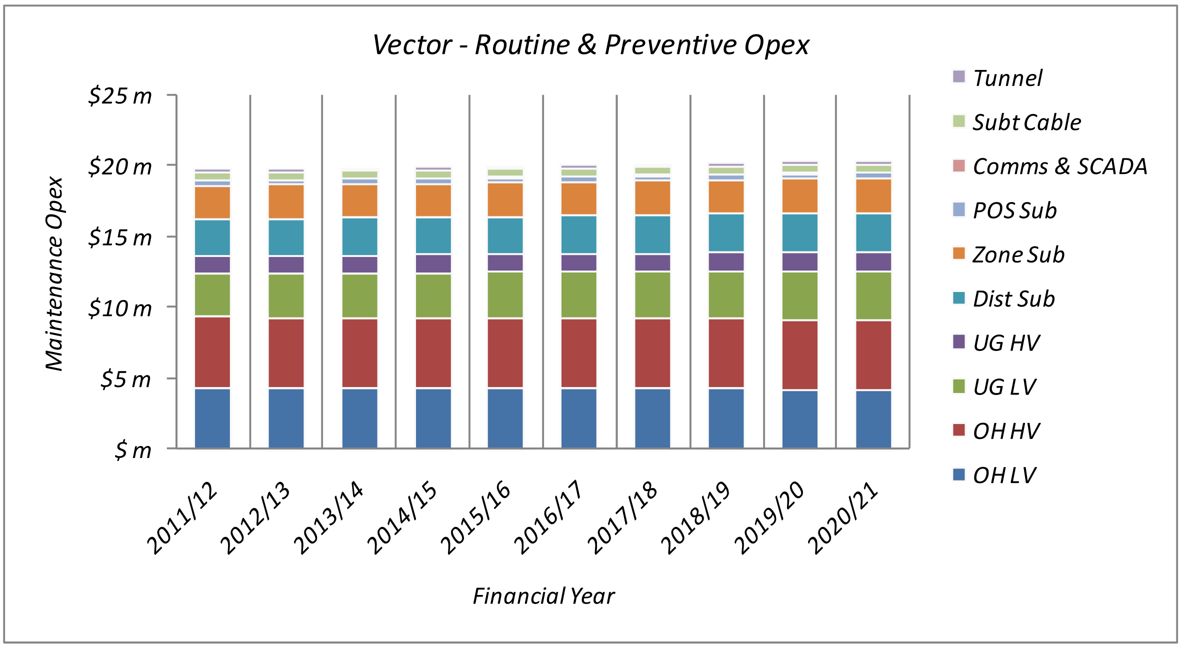


Figure 6-5 : Routine and preventive maintenance expenditure

AMP Category	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*2019/20*	2020/21
OH LV	$4.25 m	$4.24 m	$4.23 m	$4.22 m	$4.21 m	$4.20 m	$4.19 m	$4.19 m	$4.18 m	$4.17 m
OH HV	$5.01 m	$5.00 m	$4.99 m	$4.98 m	$4.97 m	$4.96 m	$4.95 m	$4.94 m	$4.93 m	$4.92 m
UG LV	$3.07 m	$3.10 m	$3.14 m	$3.18 m	$3.22 m	$3.26 m	$3.30 m	$3.34 m	$3.38 m	$3.42 m
UG HV	$1.21 m	$1.23 m	$1.24 m	$1.26 m	$1.27 m	$1.29 m	$1.30 m	$1.32 m	$1.33 m	$1.35 m
Dist Sub	$2.65 m	$2.66 m	$2.67 m	$2.68 m	$2.69 m	$2.70 m	$2.71 m	$2.72 m	$2.73 m	$2.75 m
Zone Sub	$2.33 m	$2.34 m	$2.36 m	$2.37 m	$2.38 m	$2.40 m	$2.42 m	$2.43 m	$2.44 m	$2.46 m
POS Sub	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m
Comms & SCADA	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m
Subt Cable	$0.52 m	$0.52 m	$0.53 m	$0.54 m	$0.54 m	$0.55 m	$0.56 m	$0.57 m	$0.57 m	$0.58 m
Tunnel	$0.29 m	$0.29 m	$0.19 m	$0.29 m	$0.19 m	$0.29 m	$0.19 m	$0.29 m	$0.29 m	$0.29 m
Total	$19.70 m	$19.77 m	$19.73 m	$19.90 m	$19.86 m	$20.04 m	$20.01 m	$20.18 m	$20.25 m	$20.32 m

Table 6-4 : Routine and preventive maintenance expenditure

Vector has a comprehensive preventive maintenance approach across its network asset base. The delivery of all of these maintenance activities in accordance with prescribed maintenance standards (see Table 6-4) is closely monitored and adjusted by SD, on a monthly basis, to ensure the agreed annual target volumes are complied with. Extensive monthly feedback is obtained on actual versus planned progress, KPI performance, causality and issues impacting progress or performance, new risks, action plans and focal points for the coming months. The overall effectiveness of the programme is evaluated by contract KPI performance and the roll up to Vector's corporate performance metrics, of which environmental compliance, public, employee and contractor safety and network SAIDI are the core measures.

6.3 Asset Inspection, Maintenance, Refurbishment and Renewal Programmes

In this section, the details of Vector's asset inspection, refurbishment and renewal programmes are discussed, broken down per major asset category.

6.3.1 Sub-Transmission Cable

The total Vector sub-transmission network consists of 579km of cables operating at 110kV, 33kV and 22kV with a book value of $254 million. A breakdown per cable type is provided in Table 6-5 below and the age profile per network is indicated in Figure 6-6 and Figure 6-7 below.

Cable Length	110kV	33kV	22kV	Total km
Southern	71 km	253 km	123 km	447 km
Northern	0 km	132 km	0 km	132 km
Total	71 km	385 km	123 km	579 km
Cable Value	**110kV**	**33kV**	**22kV**	**Total $m**
Southern	$52 m	$102 m	$42 m	$196 m
Northern	$0 m	$58 m	$0 m	$58 m
Total	$52 m	$160 m	$42 m	$254 m

Note: Quantities exclude pole riser lengths of 10 metres per 33 kV and 22kV overhead terminations.

Table 6-5 : Sub-Transmission Cable Population and Book Value

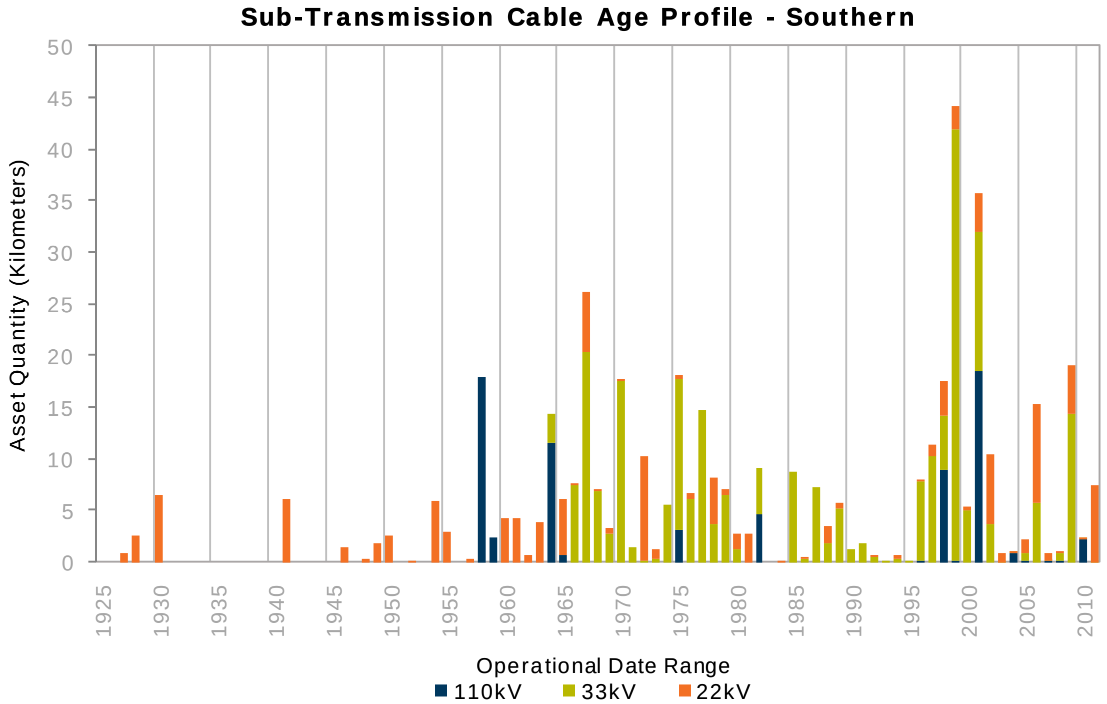


Figure 6-6 : Sub-Transmission Cable Age Profile - Southern

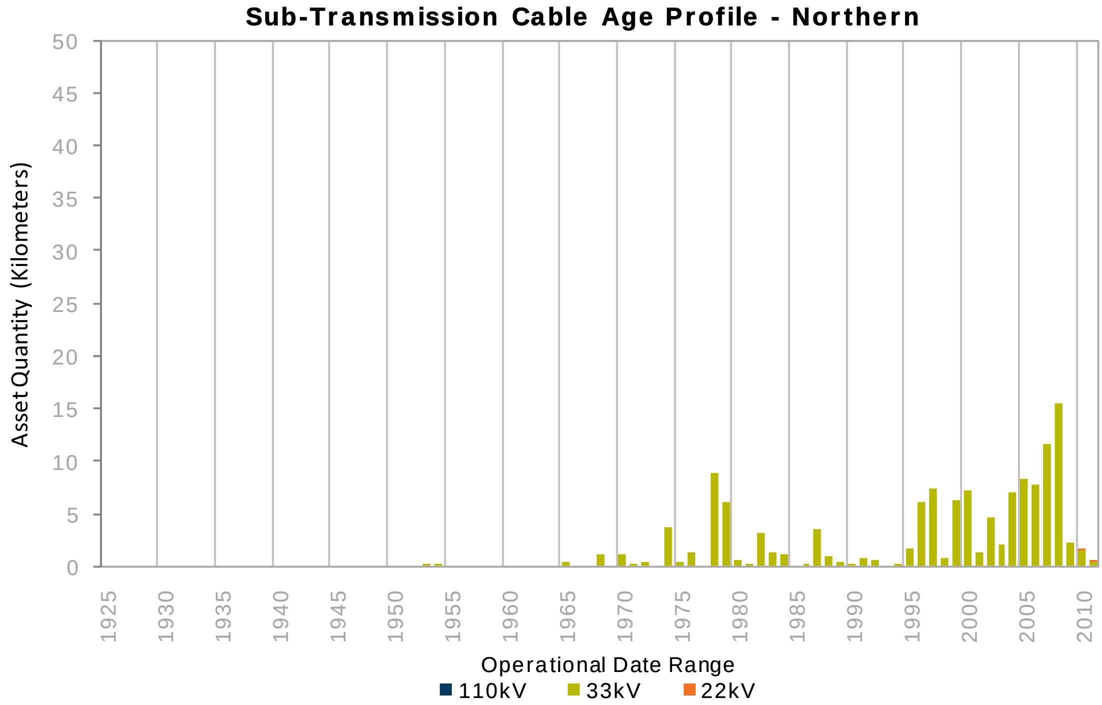


Figure 6-7 : Sub-Transmission Cable Age Profile - Northern

6.3.1.1 Asset Condition by Construction Type:

a. Paper Insulated Lead Cables (PILC)

There is approximately 78km of 22kV and 33kV PILC type cables installed on the Vector network between the early 1920's and late 1980's.

The cables are generally in good to very good condition and any failures are usually the result of old joints that fail or the result of 3rd party damage. A number of the older cables were laid on private property and when faults develop these are proving difficult to access due to concerns raised by the private land owners. These cables are likely to be replaced over the next ten years. Others will be replaced as their failure rate increases or ratings can no longer meet network requirements.

b. Fluid Filled Cables

There is approx 170km of 110kV, 33kV and 22kV fluid filled cable installed on the Vector network with all but 3km on the Southern network. These cables were installed between 1964 and 1990 and are generally in very good condition. All fluid filled cables have their fluid pressure closely monitored and alarmed via the SCADA system to promptly identify and minimise any fluid leaks. Cables subject to excessive fluid loss are scheduled for extra maintenance in order to locate and repair the leaks. Vector's experience is that the majority of leaks occur at joints due to thermo-mechanical movement within the cable or due to ground movement.

A systemic issue has been found with thermal-mechanical movement in the three core aluminium conductor joints on these cables and one cable in particular (Takanini - Maraetai 33kV) are likely to be replaced over the next five years due to its location and fault history. Other joints are X-rayed if they are exposed for any reason, including fluid leak repairs, and are remade if the movement is too severe.

Vector's contractor has a KPI to reduce the fluid loss below certain predetermined values. However, this is sometimes difficult to achieve due to load restraints in getting certain cables out of service. In such cases the leak is managed so the cable can be kept in service for as long as possible without compromising its integrity and risking electrical failure. Figure 6-8 below shows the sub-transmission cable fluid consumption over the past six years.

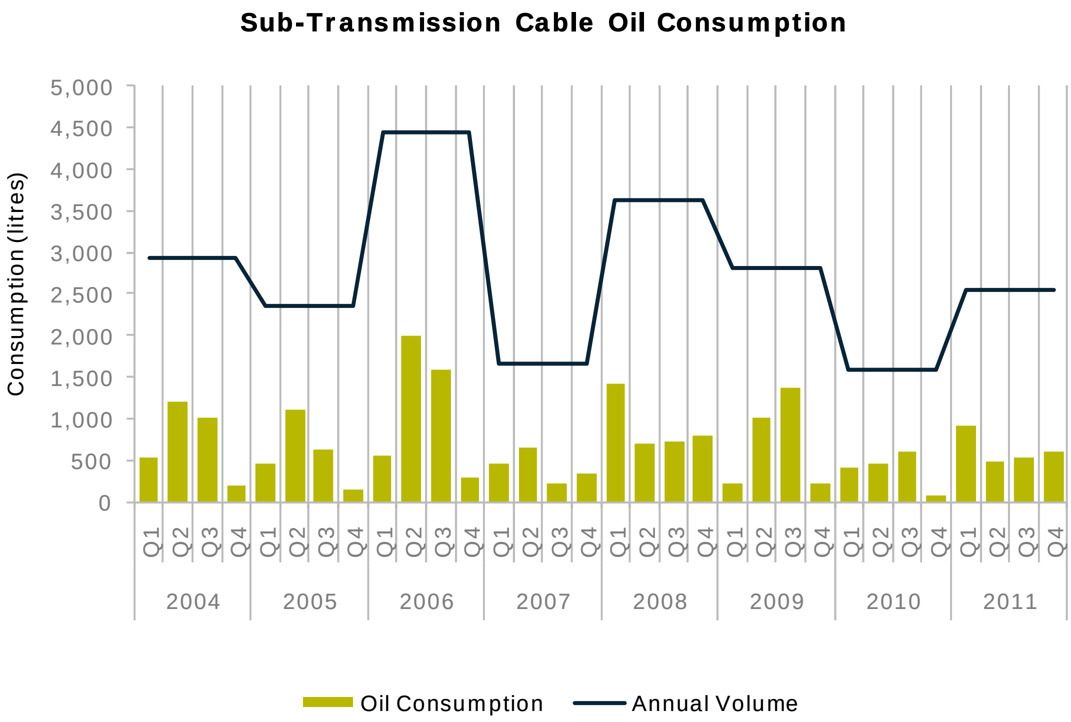


Figure 6-8 : Sub-transmission cable fluid consumption

c. XLPE Cables

There is approximately 310km of 110kV, 33kV and 22kV XLPE installed across Vector's networks. XLPE at sub-transmission level was only introduced onto the Southern network in 1996. As a consequence the problems experienced world-wide with water treeing in the earlier (1960's -70's) cables have been avoided. 181km of these cables are in very good condition. However, five 33kV circuits with possible incorrectly installed joints have caused problems over the past nine years (Risk AIAE3020). All joints on two of these circuits have been replaced. Due to their locations and the back fill material used the joints in the other circuits have not been replaced. Instead they are being closely monitored and tested and will be replaced should their condition deteriorate or fail.

The 128km of 33kV XLPE in the Northern network was installed from 1970 onwards. Due to the nature of the network there are many short sections inserted between sections of overhead lines. These short sections (often no more than one or two spans) cannot be tested economically and are only tested after fault repairs. The maintenance standard requiring serving tests every two years on sub-transmission cable is intended for long sections of continuous cable from the GXP to zone substation or from zone substation to zone substation. However, given the very low fault rate these cables are believed to be in good to very good condition.

d. Gas Pressurised Cables

There are now only four circuits of this gas pressurised cables left on the Southern network. Two of these circuits operate at 110kV and run for 10km each, providing backup to parts of the Auckland CBD. These two circuits are 1958 vintage and the joints, of which there are over 100, are now proving unreliable with a number of failures over the past four years due to pulled ferrules. A project was recently completed to provide an alternative 110kV supply circuit (Liverpool to Quay substation), to ensure Vector's service levels in the CBD can be met without relying on the gas pressurised cables. Final retirement of these cables is scheduled for February 2012 when the Orakei rail bridge is to be replaced and the cables have to be removed.

The other two gas-filled circuits operate at 22kV, are in good condition and will only be replaced when condition or rating dictate.

6.3.1.2 Maintenance and Testing

The maintenance and testing of sub-transmission cables is covered in Vector's network Standard ENS-0196. Selected circuits are subject to ongoing partial discharge testing, to gain an early indication of any problems. Other circuits are tested in accordance with the routine frequency specified in our standard.

In summary the ENS-0196 defines:

- Routine and preventive maintenance:
  - Weekly – Patrol of cable routes to detect any works or activities that could affect the security or rating of the cables; and
  - Schedule of specific maintenance required on the different cable types and their ancillaries
- Test procedures:
  - High voltage withstand and insulation tests for the various types of cable;
  - Cable serving test;
  - Oil cable pressure system and accessory testing;
  - Gas cable pressure system and accessory testing;
  - Cross-bonding current injection test; and
  - Cable Cover Protection Unit (CCPU or SVL) tests.

6.3.1.3 Replacement Programme

The following flow charts in Figure 6-9 to Figure 6-11 give a simplified version of the replacement criteria for each type of cable:

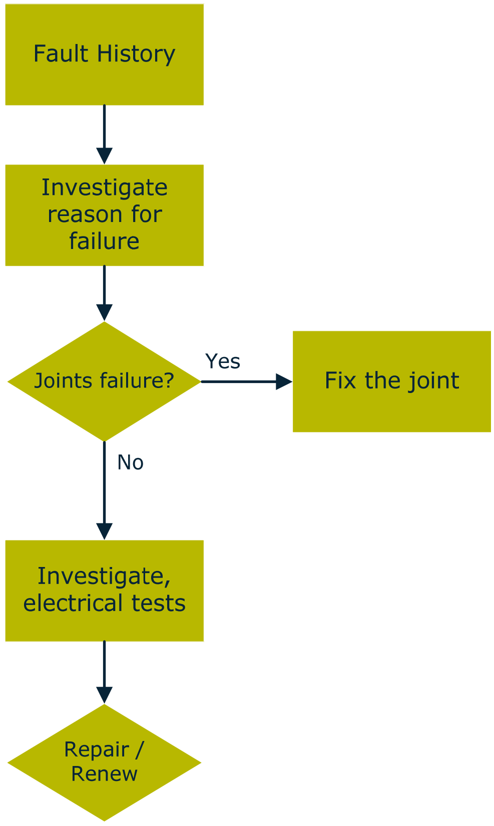


Figure 6-9 : Sub-transmission cables – PILC

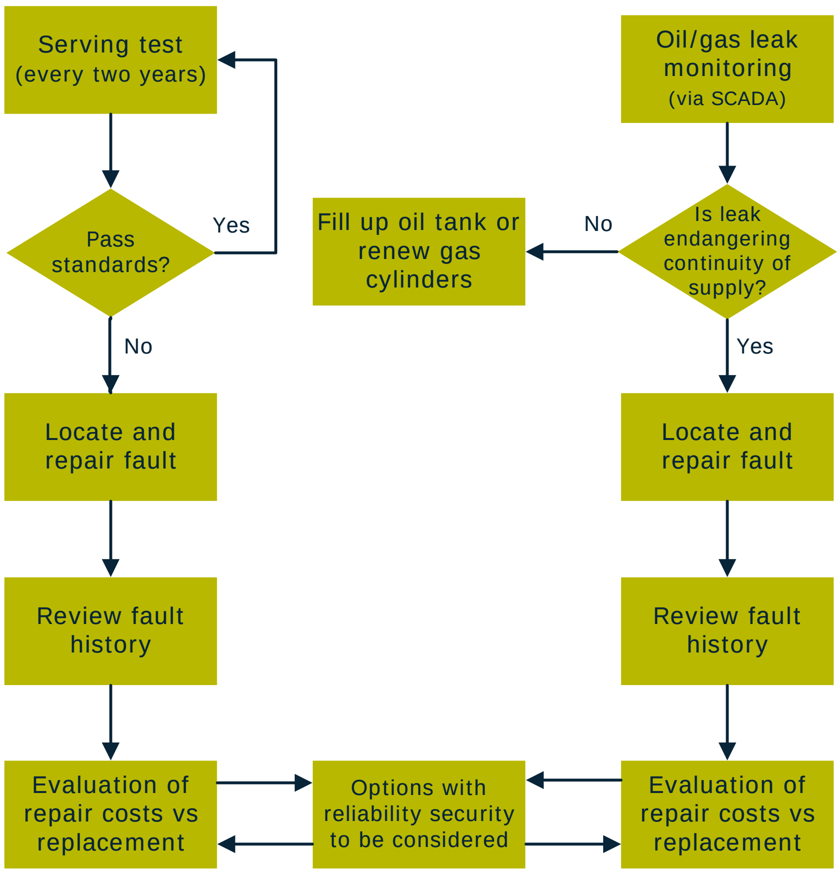


Figure 6-10 : Sub-transmission cables - oil/gas

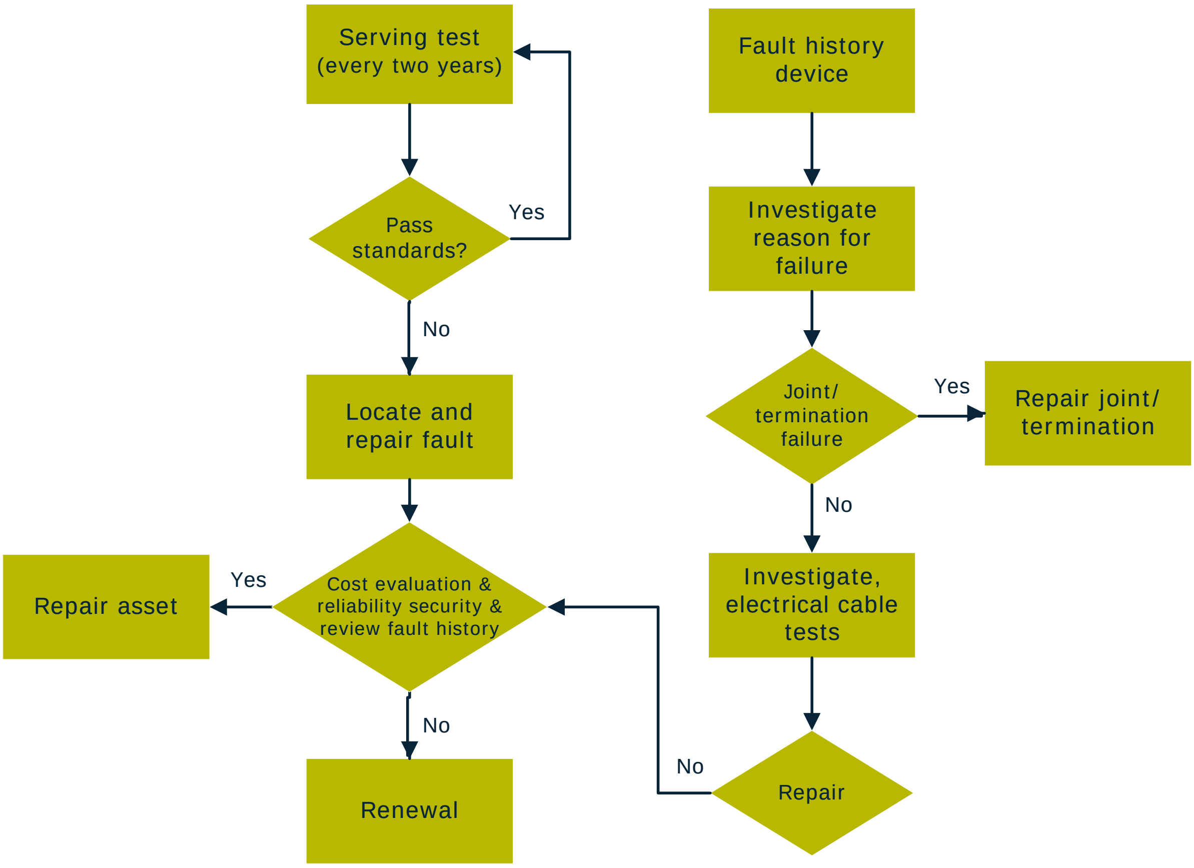


Figure 6-11 : Sub-transmission cables – XLPE

The timing for the replacement of sub-transmission cables is generally based on condition, performance, ratings and industry related failure information. However, it can also result from non-electrically related drivers such as relocation due to other infrastructure development by requiring authorities.

Maintenance history, fault repairs and associated costs to the networks (SAIDI/SAIFI impact) and analysis of risk profiles have identified several cables due for replacement. These circuits represent a significant investment, but keeping them in operation would pose an unacceptable level of risk to the network.[8] A summary of the planned sub-transmission cable replacement projects, taken from the 10 year Programme of Works sheet (subject to ongoing performance measurement), is given in Table 6-6 below.

Asset Description	Circuit Length	Replacement Year	Estimated Cost
Balmoral 22kV	2.0km	2012/13	$5.5 million
Maraetai (FF) 33kV	5.0km	2014/15	$6.0 million
Parnell 22kV	1.8km	2013/14	$4.0 million
Ponsonby 22kV	2.5km	2014/15	$5.0 million
Pt Chevalier 22kV	3.4km	2015/16	$6.0 million
Liverpool–Quay 22kV	2.0km	2016/17	$4.0 million

Table 6-6 : Planned sub-transmission cable replacement projects

[8] The requirement for replacing the old 22 kV sub-transmission cables was also identified by Siemens GmbH in an assessment carried out by them in 2009 on the robustness of asset management at Vector.

The requirement for replacing each of the sub-transmission cables (as described below) is based on analysis of the condition and fault data that is currently available. While the dataset is still incomplete, the analysis is further supported by the experience and observations of Vector's asset specialists. The priority order of replacement is based on indicative condition and failure rates, also taking into account budget requirements and contractor capacity. (The proposed order may change as the asset database is expanded.)

An annual provisional allowance of $5.0 million has been made in the 10-year CAPEX estimate between FY 2017 to 2020 for replacing older PILC cables, which are expected to be approaching the end of their useful life at that stage. More accurate costs estimates for this replacement work will be prepared closer to the time. This allowance is included in the 10 years work programme (Table 6-32).

6.3.1.4 Major Sub-Transmission Cable Replacement Projects

a. Balmoral 22kV circuits

These old PILC cables were installed in 1941. The cables have had an increasingly unacceptable fault history over the last 20 years. This problem was temporarily addressed by cutting and turning into Sandringham substation in early 2000 (reducing the extent of reliance on the circuit), but their underlying condition remains poor. The Sandringham feeders which were of the same batch are currently being replaced. In addition, the Balmoral circuits are also under rated for the proposed upgraded transformers at Balmoral substation. Civil works and cable procurement started in 2011/2012 with the total project to be completed in 2012/2013. The total project cost is estimated at $5.0 million. $2.4 million has been spent in 2011/12. The balance of the budget ($2.6 million) will be invested in 2012/13.

b. Maraetai 33kV Fluid-filled circuit

This circuit is the last remaining fluid-filled cable at Takanini, commissioned in the late 70's. Due to its location it is subject to continual faults on the overhead line to which it is joined. In addition, because of the peat ground it is buried in, the joints are subject to excessive movement which is problematic for a fluid filled cable. This has already resulted in faulted sections of cable being replaced with overhead line and the replacement and reinforcement of many of the joints. Further faults occur on an ongoing basis and the only economically feasible means of addressing this and to ensure the reliability of supply is to replace the cable.

c. Parnell 22kV circuit

Major sections of these old PILC circuits were laid in 1927. Over the years the cables have not performed very well, but sections of the circuits have over time been replaced (due to road realignment requirements, etc) and as a result the failure rate has dropped off. However, the remaining old sections of cable are now used well beyond their reasonable lives and, based on historical experience, could fail at any time and would be uneconomic to repair. These cables are also under rated for the proposed new transformers at Parnell.

d. Ponsonby 22kV circuits

These circuits consist of one GF (gas filled) 22kV cable installed in 1965 which is one of two remaining gas-filled cables left on the Auckland network. This type of cable technology has gradually been replaced because of the ongoing maintenance issues of leak location and prevention and this cable will need replacing. The other circuit comprises 2x PILC cables installed in 1949-50 and run in parallel. Both these cables are under rated for the existing and any future new transformers.

e. Pt Chevalier 22kV Number 2 circuit

This circuit comprises 2x PILC cables installed in 1930 and run in parallel. They have been the subject of many failures over the years and are now underrated for the new transformers proposed for this substation.

f. Liverpool-Quay 22kV circuit

This project will replace the last remaining gas-filled cable on our network. Given the ongoing 110kV and 22kV reinforcement in the CBD however, this cable may not need direct replacement and could simply be abandoned. A final decision will be made closer to the time.

6.3.2 Power Transformers

Vector owns 205 sub-transmission power transformers, including two at Lichfield which lies outside of Vector's main supply network. The transformers have been manufactured by some 16 manufacturers from around the world including ABB, ASEA, AEI, Alstom, BET, Brush, Bonar Long, Fuller, GEC, Hawker Siddeley, OEL, Pauwels, Tyree Power Construction, Wilsons and YET.

The power transformers have a book value of approx $84 million. There are 18 transformers with a primary voltage of 110kV, 149 at 33kV and 38 at 22kV ranging in rating from 5MVA to 75MVA. The majority of these transformers are fitted with on-load tap-changers. Table 6-7 shows the current number of, and value of, power transformers on the networks, categorised by supply side operating voltage.

Population	110kV	33kV	22kV	Total
Southern	15	74	38	127
Northern	3	75	0	78
Total	18	149	38	205

Book Value	110kV	33kV	22kV	Total
Southern	$11 m	$33 m	$15 m	$59 m
Northern	$2 m	$23 m	$0 m	$25 m
Total	$13 m	$56 m	$15 m	$84 m

Table 6-7 : Sub-Transmission Transformers - Population and Book Value

The age profile of the sub-transmission transformers is shown in Figure 6-12 and Figure 6-13.

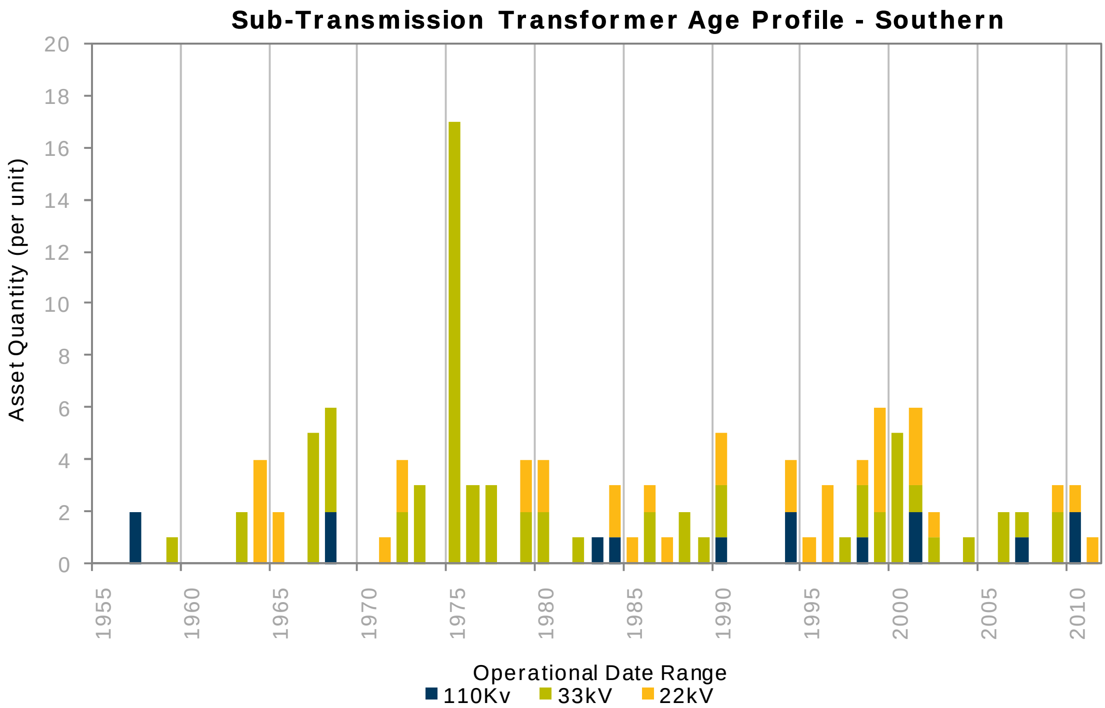


Figure 6-12 : Sub-Transmission Transformer Age Profile – Southern

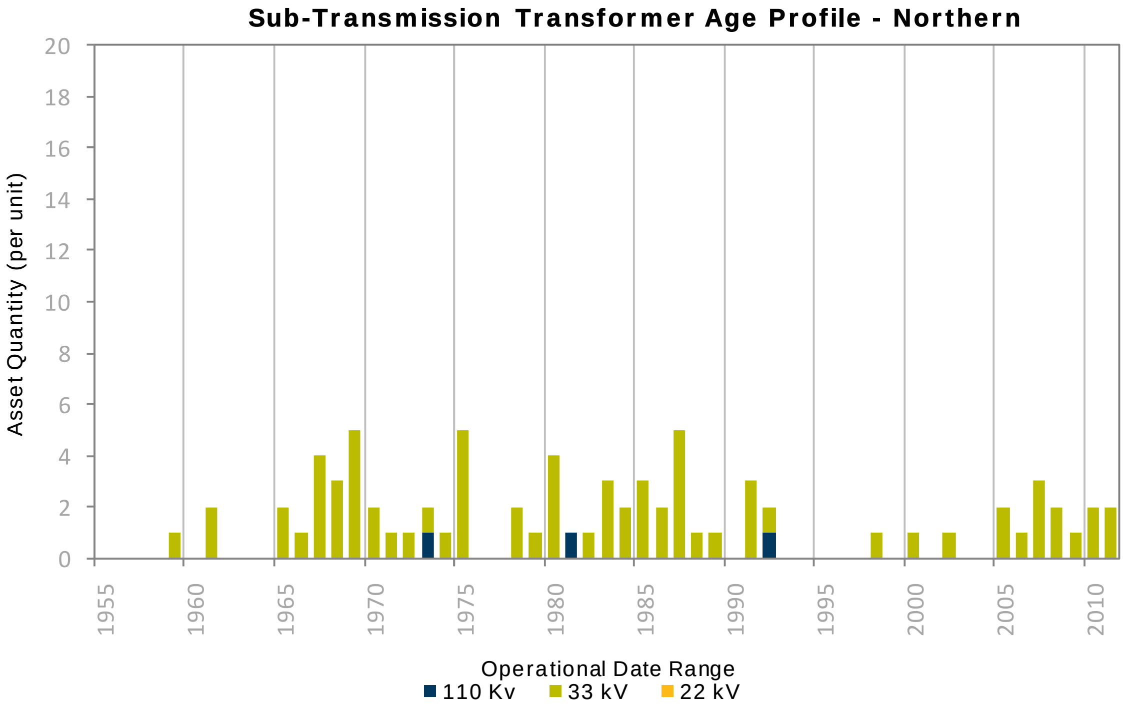


Figure 6-13 : Sub-Transmission Transformer Age Profile – Northern

The flow chart in Figure 6-14 is a simplified version of the condition assessment process.

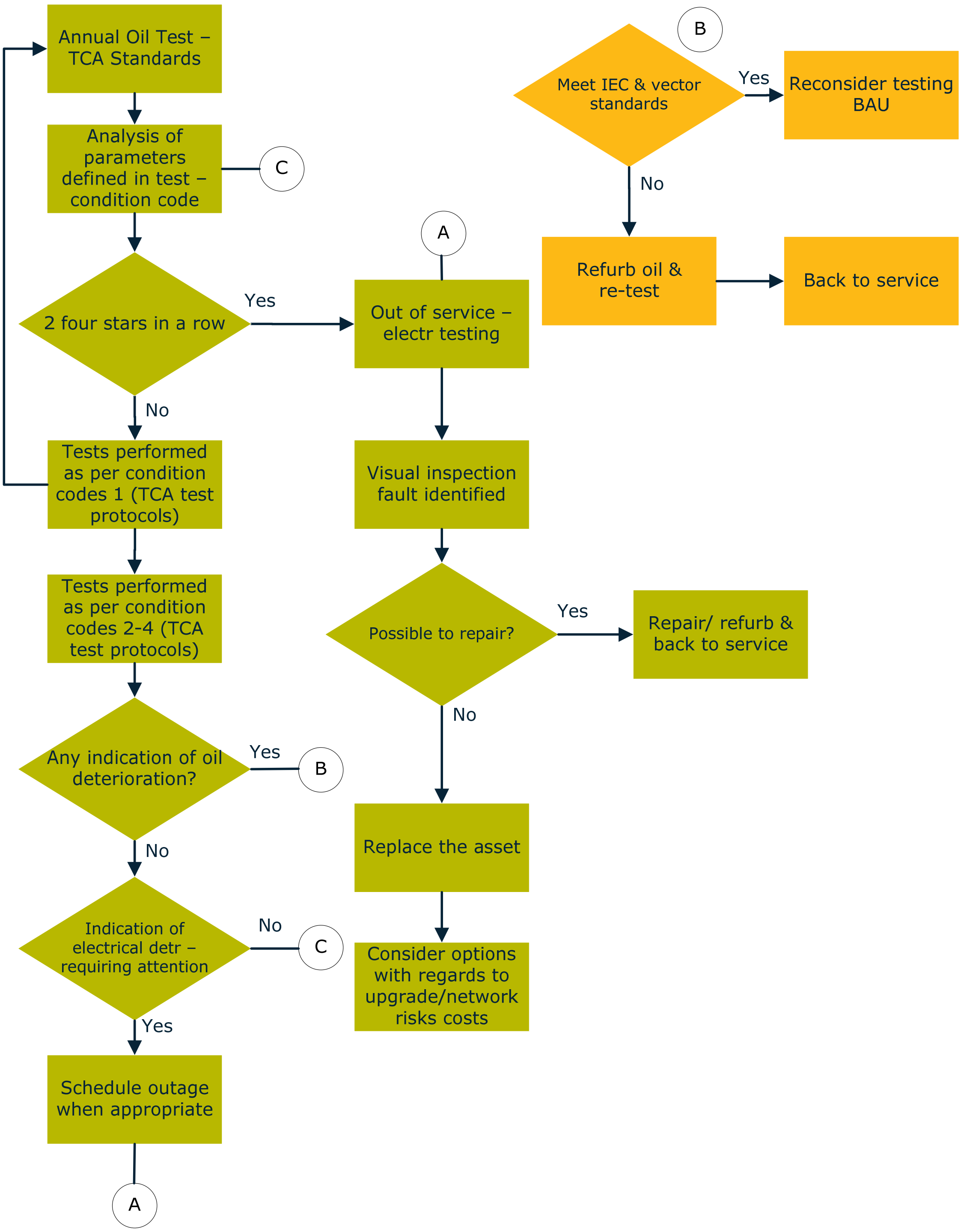


Figure 6-14 : Condition assessment process

The normal inspection and maintenance of power transformers is covered in Vector's Network Standard ENS-0193. All intrusive maintenance activity on transformers, including that on the on-load tap changer, is purely condition driven. If off-site refurbishment is deemed necessary this is performed in accordance with Vector's Network Transformer Refurbishment Standard ENS-0164.

In summary the ENS-0193 defines:

- Routine and preventive maintenance:

- **Annual:** Transformer oil condition sample, transformer condition assessment (TCA) provided by TjH2B covering breakdown voltage, neutralisation value, water content, interfacial tension, dielectric dissipation factor, dissolved gas analysis (DGA), furan analysis required every third year;
- **Annual:** Tap changer oil condition sample, tap changer activity signature analysis (TASA) provided by TjH2B covering breakdown voltage, neutralisation value, water content, interfacial tension, dielectric dissipation factor, DGA, furan analysis required every third year;
- **Annual:** Acoustic discharge inspection, thermal camera inspection and PD inspection; and
- **Bi-monthly:** Visual inspections encompassing tap change mechanism tank, main tank, conservator tank, bushings and insulators, buchholz and pressure relief devices, radiators, heat exchangers, ancillary coolant pumps and motors, instrument and marshalling cubicles, oil and winding temperature gauges, earthing installation, seismic and foundation mounts.

- Refurbish and renewal maintenance:
  - Further diagnostic or corrective maintenance service work is triggered on:
    - The oil analysis condition code together with TjH2B recommendations;
    - Identified thermal hotspots greater than ten degrees above surroundings;
    - Levels of acoustic discharge, significantly above background noise; and
    - Levels of PD, significantly above background noise.
  - Diagnostic testing may require:
    - Transformer winding resistance/impedance/insulation resistance/ratio testing, core insulation resistance testing, auxiliary wiring and CT insulation resistance testing, magnetising inrush current testing, bushing and winding insulation power factor and dielectric loss testing.
  - Maintenance servicing may require:
    - Internal tap changer inspection and service;
    - Desiccant replacement;
    - Bushing clean and re-grease; and
    - Bearing and lubricant service of fans, motors and coolant pumps.

6.3.2.1 Power Transformer Replacement Programme

Vector's transformer population is in good condition overall but there are a small number where DP (degree of polymerisation) tests indicate they are coming to the end of their technical life. These are monitored closely.

Based on recent testing results and past replacement history, the transformers in Table 6-8 have been identified for replacement in the 10 year programme of works.

Asset Description	No of Units	Replacement Year	Estimated Cost
Balmoral	2	2012/13	$4.4m
Onehunga	2	2013/14	$4.4m
Mt Albert	1	2014/15	$2.2m

Parnell	2	2015/16	$4.4m
Glen Innes	2	2016/17	$4.4m
Triangle Rd	2	2017/18	$4.0m
Waimauku	1	2018/19	$2.5m

Table 6-8 : Sub-Transmission Transformer replacement projects by year

The requirement for replacing these transformers is based on analysis of the condition and fault data that is currently available. While the dataset is still somewhat incomplete, this analysis is supported by the experience and observations of Vector's asset specialists. The priority order of replacement is based on indicative condition and failure rates, also taking into account budget requirements and contractor capacity. (The proposed order may change as the asset database is expanded.) As most of the units indicate a weakness in the winding insulation strength there is always a risk a close in fault may cause a complete loss of the transformer at any time and this has been figured into the replacement dates.

a. Balmoral

The existing units were manufactured in 1961 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. These units are only 12MVA and will be replaced with our standard 20MVA units to cope with expected future load growth.

b. Onehunga

The existing units were manufactured in 1964 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. These transformers are also extremely noisy, breaching current environmental regulations.

c. Mount Albert

The existing unit was manufactured in 1964 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. This transformer has also been the subject of noise complaints.

d. Parnell

One transformer failed in 2010 and has an old temporary replacement in its place. The other unit was manufactured in 1964 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. This transformer has also been the subject of noise complaints.

e. Glen Innes

The existing units were manufactured in 1958 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. These units are only 12MVA and will be replaced with our standard 20MVA units to cope with expected future load growth. While these units are the oldest in the replacement programme they were fully refurbished in the late 1990's to extend their operational life.

f. Triangle Rd

The existing units were manufactured in 1956 and 1961 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels.

g. Waimauku

The existing unit was manufactured in 1959 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. This transformer has also been the subject of noise complaints.

6.3.2.2 Operating Conditions

The engineering design life of a power transformer is 30 to 40 years. However, provided a unit is not subject to abnormal operating conditions (excess load and high winding temperatures), and is well maintained, this life can often be economically extended to at least 60 years.

The majority of Vector's power transformers are operating at the lower end of the permissible winding temperature range. Therefore, an extended operating life for most units can be expected. Transformer specifications have varied over the years from the very early versions of BS 171 (British Standard) to the latest AS 2374 (Australian Standard) which means different thermal and loading guides have been used. Vector's standard for operating temperatures has established three operating temperatures that should never be exceeded:

Top Oil Temperature	105 ^{o}C
Conductor Hot-spot Temp	125 ^{o}C
Metallic part temperature	135 ^{o}C

To take into account the different transformer designs and operating conditions, oil and winding temperature trips are assigned based on the year of manufacture, and knowledge of, and comfort with, the cooling systems.

A new condition ranking tool is being developed which will be used to rank the condition of all power transformers across the Network. This will take into account such factors as DP (degree of polymerisation), moisture in insulation, DGA's, oil leaks, age etc. and should be in place during the FY12.

6.3.3 Switchboards and Circuit Breakers

The Vector network comprises 110kV, 33kV, 22kV, 11kV and 6.6kV high voltage (HV) and medium voltage (MV) systems. Primary circuit breakers (CBs) and switchboards deployed to operate at these voltage levels are installed inside buildings or in outdoor yards enclosed by security fencing, or both. (This class of equipment does not include distribution switchgear.) All zone substation CBs and switchgear have protection relays to control their operation and are monitored by the Network Operations group (control centre) via SCADA systems.

New switchgear is supplied in compliance with Vector's Electricity Network Standard ENS-0005 for indoor switchboards up to and including 33kV, ENS-0106 for outdoor stand-alone CBs up to 33kV and ENS-0022 for indoor 110kV GIS switchboards. Vector's sub-transmission switchgear comprises oil, SF_6 and resin insulated equipment of varying age and manufacturer. The arc-quenching media used in this equipment include oil, SF_6 and vacuum. The majority of the switchgear is 11kV rated followed by 22kV, 33kV and 110kV. This dissemination generally corresponds to the network topology in that, with increasing system voltage, the fewer devices there are on the network. Table 6-9 shows the current number of and value of CBs on the networks categorised by operating voltage.

Population	110kV	33kV	22kV	11kV	Total
Southern	11	21	101	851	984
Northern	0	251	0	412	663
Total	11	272	101	1263	1647

Book Value	110kV	33kV	22kV	11kV	Total
Southern	$11 m	$0 m	$3 m	$15 m	$29 m
Northern	$0 m	$9 m	$0 m	$8 m	$17 m
Total	$11 m	$9 m	$3 m	$23 m	$46 m

Table 6-9 : Sub-Transmission Switchgear – Population and Book Value

The CBs on the Vector electricity network range from new to over 50 years of age. Further, the CBs consist of a mix of technologies corresponding to the relative age of the equipment. The oil type circuit breakers (OCB) are the oldest on the network followed by SF_6 and Vacuum type. Note that CB type as mentioned here refers to the arc quenching technology incorporated and not the insulation medium which can be compound, oil, solid, air or SF_6 gas.

Figure 6-15 and Figure 6-16 shows the age profile of CB's and switchboards in the Southern and Northern regions.

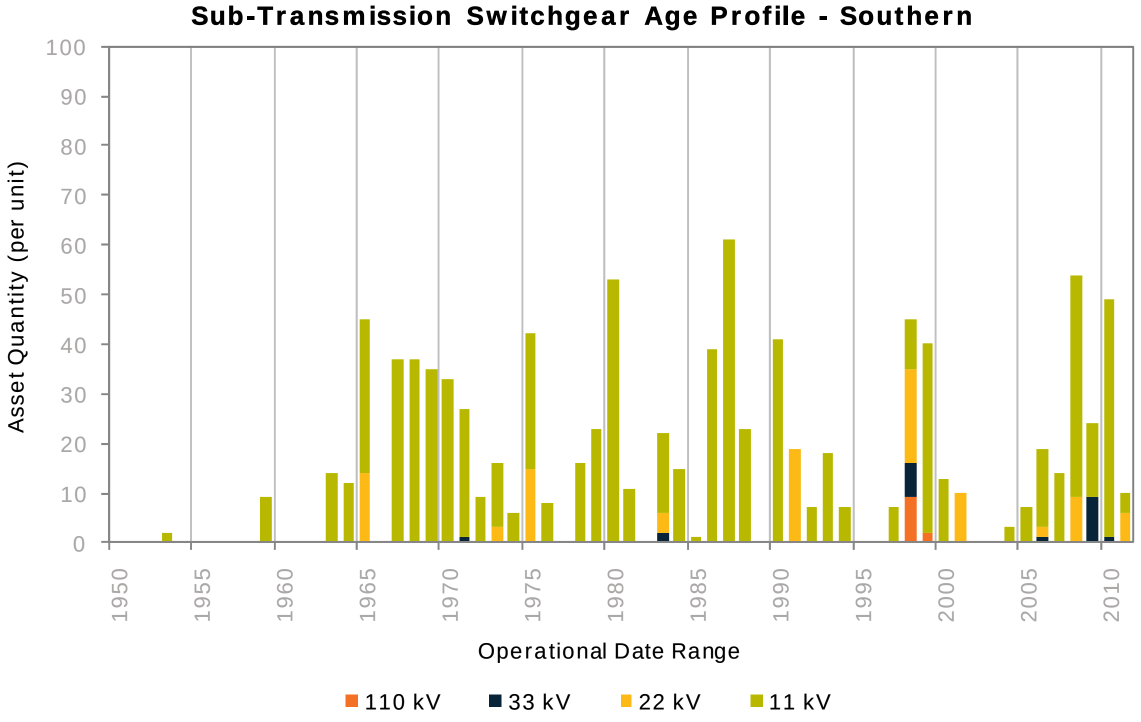


Figure 6-15: Sub-Transmission Switchgear Age Profile – Southern

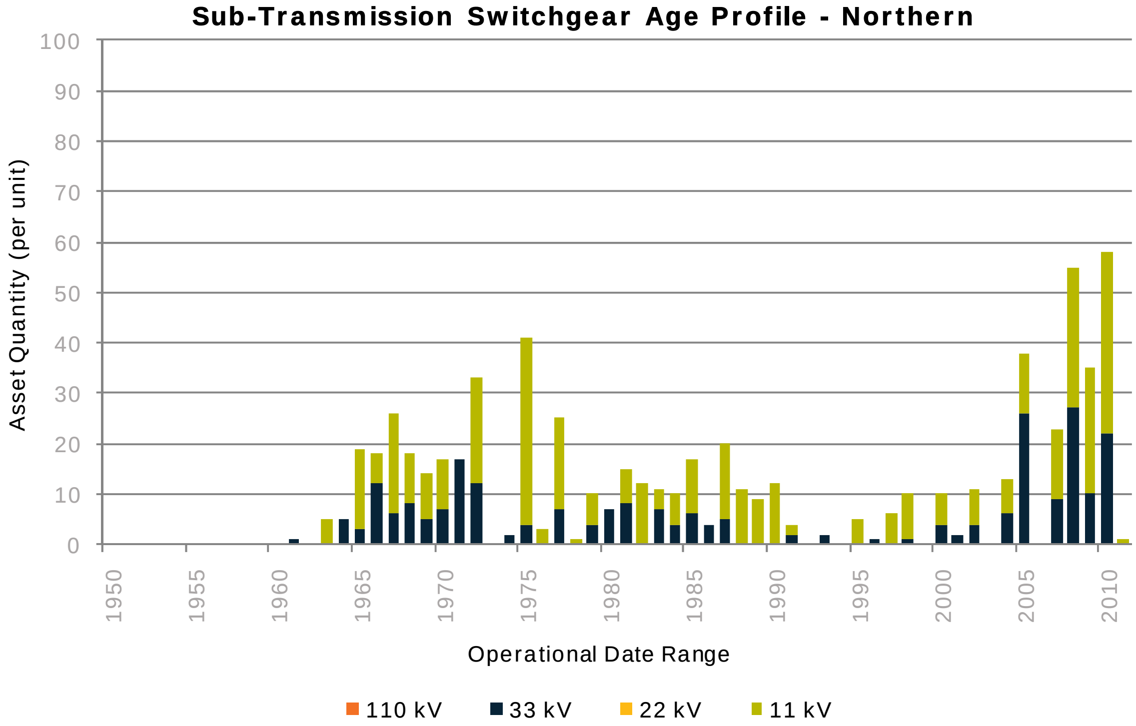


Figure 6-16 : Sub-Transmission Switchgear Age Profile – Northern

The number of CBs on the Vector network is increasing due to the establishment of new zone substations and extensions to existing stations to accommodate load growth, as well as reinforcement projects on the sub-transmission system. The vast majority of CBs are configured as indoor switchboards (consisting of multiple CBs connected to a common bus) the remainder are configured as follows:

- 154 outdoor 33 kV rated CBs and associated air break switches (ABS) and outdoor bus works at Vector zone substations;
- 37 outdoor 33kV rated CBs installed at Transpower GXPs (associated ABS and bus works are owned by Transpower);
- Nine bay 110 kV GIS switchboard at Auckland's Liverpool Substation; and
- Two outdoor 110 kV GIS CBs and associated air break switches (ABS) and outdoor bus works at the Litchfield substation (Fonterra Cheese Factory). Ownership (and responsibility for maintenance) of these two circuit breakers has been assigned to Transpower for the duration of the connection contract.

The oil type circuit breakers are the oldest in the network and constitute 75% of the asset followed by SF_6 at 13% and vacuum at 12%. Circuit breaker technology using vacuum or SF_6 interrupters and SF_6 gas insulated equipment is primarily technology of the last 20 years. Until this time, MOV (minimum oil volume) and bulk oil type circuit breakers dominated the market.

The ODV (optimised deprival value) life for indoor oil-filled equipment is 45 years and for SF_6 and vacuum equipment is 55 years. ODV life for outdoor ABS (air break switch) is 35 years and all outdoor circuit breakers are 40 years regardless of type. This matches reasonably well with Vector's operational experience for this class of equipment.

New equipment purchases must comply with Vector equipment standards ENS-0005 for 11kV to 33kV indoor switchboards, ENS-0106 for 33kV outdoor circuit breakers and ENS-0165 for outdoor air break switches. These equipment standards specify the latest in low maintenance equipment technology.

Depending on the condition of the zone substation building, construction costs to modify existing foundations and buildings can be considerable and need to be evaluated on a station by station basis.

6.3.3.1 Condition of the Assets

The SF_6 and Vacuum CBs are the newest in the networks (SF6 breakers are older than the vacuum breakers in the MV class as they were developed ahead of reliable vacuum interrupters). They are in good condition and pose little risk to the network due to modern manufacturing technologies, higher design specifications and compliance with the latest international equipment standards. Even a catastrophic failure in this class of equipment is often restricted to the immediate panel, minimising collateral damage.

The SF_6 CBs pose some environmental concern due to the gas they contain. However, the equipment is designed to be sealed for life and there are gas recovery techniques in the event the equipment requires service. Under normal operating conditions, experience shows only a catastrophic failure of the tank or seals would result in the expelling of gas – a very low probability event.

The oil type CBs are approaching the end of their useful design life and vary anywhere from 40 to 50 years of age. Underrating, failures, mal-operation and lack of spare parts continue to be of concern for this aged equipment. This class of equipment often poses a risk in the event of a catastrophic failure. When OCB's fail it can result in fire, explosion and irreparable collateral damage to adjoining or nearby apparatus.

To address these risks, Vector has embarked on a programme to replace the old oil-filled switchgear, as discussed in Section 6.3.3.3.

The oldest technology CBs and switchboards are showing signs of rust, leaking compound and oil, metal fatigue and age related operational concerns. Other apparatus have been shown to have high maintenance requirements or latent defects resulting in earlier than expected replacement and repair programmes.

More modern switchboards with air insulated bus bars and vacuum circuit breakers have proven to be less problematic, as expected with more modern manufacturing's techniques and higher equipment specifications. The metal clad portions, consisting of powder coated galvanised and stainless steel, are not expected to show the same signs of metal fatigue as apparatus that was produced even up to the late 1980's.

New switchboard installations and outdoor CBs of the last six years comply with Vector specifications ENS-0005, ENS-0106 and ENS-0022 and are of maintenance free design. End of life is therefore determined by lifetime fault interruption and normal load switching operations and not traditional time-based estimations. (IEC specification 6227-100 has both electrical and mechanical endurance classifications as part of the standard.) Vector equipment complying with this standard is classed M2 and E2 which equates to extended electrical and mechanical endurance. For primary switchgear the switching mechanism including the interrupter is rated for up to 10,000 mechanical operations and (depending on the manufacturer's interpretation of the standard) up to 100 full fault rated interruptions i.e. 100 operations at 25kA at three seconds.

Vector's numerical protection relays deployed on its switchboards complying to Vector specifications (ENS-0005, ENS-0106 and ENS-0022) are capable of recording fault interrupting data which can be can be used to determine when the switchgear is nearing the end of its operational design life. This information will be used in future asset replacement programmes for switchgear of this type.

6.3.3.2 Maintenance Programme

Asset maintenance criteria including inspection, testing and condition assessment is a requirement for each asset. Generic maintenance activities and cycles have been developed for each class of asset but could be applied differently depending on maintenance history and specific industry and manufacturer related information. Vector maintenance standards ENS-0049 and ENS-0188 outline maintenance and testing requirements and intervals for switchboard and circuit breakers. In general, preventative maintenance on Vector's switchgear assets consists of the following:

- All switchgear is visually inspected monthly/quarterly for leaks and general condition, depending on history and type i.e. some circuit breakers require more frequent inspection than others;
- Annual thermographic examination of substation equipment;
- Annual partial discharge testing and monitoring;
- 'Kelman' profile testing and non-invasive partial discharge location and monitoring is carried out on a two year cycle;
- Major maintenance on the switchgear, including inspection and testing of circuit breakers on an eight year cycle and testing of protection relays and systems on a two and four year cycle; and
- Condition assessments either on a scheduled basis or as a result of routine inspection or equipment fault operation.

Through this process of maintenance activities and testing, various CB types have been included in Vector's asset replacement programme. Assets such as indoor 11kV English Electric, Brush and Southwales switchboards and Outdoor 33kV Reyrolle, English Electric and Takaoka circuit breakers have been identified as the next priority replacements. Motorpol supplied 36PV25 (Crompton Greaves) outdoor 33kV CBs as identified in previous AMPs have now all been replaced.

As noted above, new equipment purchased under Vector specification ENS-0022, ENS-0005 and ENS-0106 for growth areas or replacement is maintenance free, fit for life design. Such equipment requires little maintenance activity outside of thermographic survey, PD monitoring and the occasional cleaning of the cabinetry. Existing stations, largely equipped with withdrawable OCB and vacuum circuit breakers (VCBs), will continue to be monitored and maintained on a regular basis.

In summary Vector's standards define:

- Routine and preventive maintenance
  - Annual - Switchboard and associated assets thermal camera inspection;
  - Two yearly - switchboard and associate assets PD assessment;
  - Two yearly - CB timing tests, perform as found/as serviced trip/close operation test, taking accurate time measurement of trip coil current and supply voltage or time measurement of trip coil voltage;
  - Four yearly - outdoor OCB maintenance service, general visual and mechanical inspection, clean external tank, clean bushings, perform as found /as left insulation resistance measurement, check heater operation, clean internal tank, perform as found/as left contact resistance measurements, clean contacts, contact travel and sync assessment, arc-control devices clean, isolating contacts clean and lubricate, trip/close mechanisms clean and lubricate, interlocks and indicators functional, control relays or contactors clean, insulating oil replacement, operational cycle checks;
  - Eight yearly - indoor OCB maintenance service, general visual and mechanical inspection, bushing clean, insulation resistance as found/as left testing, check heater function, internal tank clean, contact resistance as found/as left, clean contacts, arc-control devices clean, isolating contacts clean and lubricate, trip/close mechanisms clean and lubricate, interlocks and indicators

functional, control relays or contactors clean, insulating oil replacement, operational cycle checks;

    - Eight yearly - outdoor vacuum/SF6 CB maintenance service, general visual inspection, external tank clean, bushing clean, insulation resistance as found/as left testing, check heater function, internal tank clean, contact resistance as found/as left, clean contacts, arc-control devices clean, isolating contacts clean and lubricate, trip/close mechanisms clean and lubricate, interlocks and indicators functional, control relays or contactors clean, operational cycle checks;
    - 12 yearly - indoor vacuum/SF6 CB maintenance service; and
    - 16 yearly - switchboard maintenance service, general visual inspection, clean all cubicles, panels and cabinets, clean de-energised spouts and bushings, perform as found/as serviced insulation resistance measurements.
- Refurbish and renewal maintenance
    - Repair of identified defects are programmed for remediation at a convenient time based on operational importance;
    - Trip times measured must be within ten percent of previous test results, or satisfactory operation will occur at 70% of rated trip coil voltage. Trip times and spread must be within manufacturer's specified tolerance; and
    - Any pole contact resistance value must be within 25 percent of remaining pole contact resistance measurements.
- Further diagnostic or corrective maintenance service work is triggered on:
    - Identified thermal hotspots greater than ten degrees above surroundings;
    - Levels of acoustic discharge, significantly above background noise; and
    - Levels of PD, significantly above background noise.
- The prescribed maintenance service can be bought forward at any stage based on fault operations and fault magnitude.
- Fault and emergency maintenance
    - All identified defects that pose an unsafe condition for public and property, equipment operation, substation security, the environment or safety of personnel require immediate repair, replacement or isolation.

6.3.3.3 Refurbishment and Replacement Programme

The timing for the replacement or refurbishment is based on condition, performance, equipment versus network ratings and industry related information. The timing can also be the result of non-electrically related drivers such as site relocation or decommissioning, safety considerations, building code regulations (e.g. fire protection requirement, seismic compliance) and condition of the existing building (e.g. leaking roofs causing internal faults on the equipment).

To achieve the optimal replacement window requires a balance between risk (reliability and safety) and economic considerations (avoiding unnecessary or early replacement). This requires a fully-fledged switchboard and CB condition based management and replacement strategy, which Vector is continuing to develop and implement.

As noted previously, the continued use of old OCBs on the Vector network is giving rise to a potential safety risk. Some manufacturers (Reyrolle for example) have vacuum retrofit CBs available that can be installed to replace the OCBs. Such retrofits may not lower the incidence of sudden failure due to associated apparatus age and lifetime fatigue, but removing the oil will significantly reduce the collateral damage that can potentially be caused by catastrophic failure. Vector has recently adopted this approach, particularly where significant extensions to the existing switchboards has occurred e.g. Otara substation, which is undergoing a seven panel VCB extension to the existing Reyrolle LMT switchboard. All the OCBs will be replaced with new VCBs to remove the risk to the new apparatus as well as extend the life of the existing switchboard. Vector's VCB retrofit programme will continue with Carbine and Belmont substations slated for VCB retrofits this year followed by Pt. Chevalier which is also undergoing switchboard extension to address growth in its supply area.

Some apparatus is, however, of an age and design that makes retrofitting a non-viable option and these switchboards need to be replaced in their entirety. These switchboards and CBs have been identified and prioritised for replacement.

Due to the age of the existing infrastructure at some substations, the cost of switchboard asset replacement work is estimated to be about $5 million to $7.5 million per annum from now and well into the foreseeable future (estimate includes an allowance for unavoidable but necessary civil and small plant (lighting etc) works. This expenditure will result in the complete replacement (including switchboard, relays, ac/dc supplies, chargers and communications systems) of approximately two to three switchboards per annum.

The process diagram Figure 6-17 below illustrates the processes involved in evaluating switchboards and circuit breakers for replacement or refurbishment. Other criteria such as the technology, network growth, criticality and related factors are also used to assist in replacement prioritization.

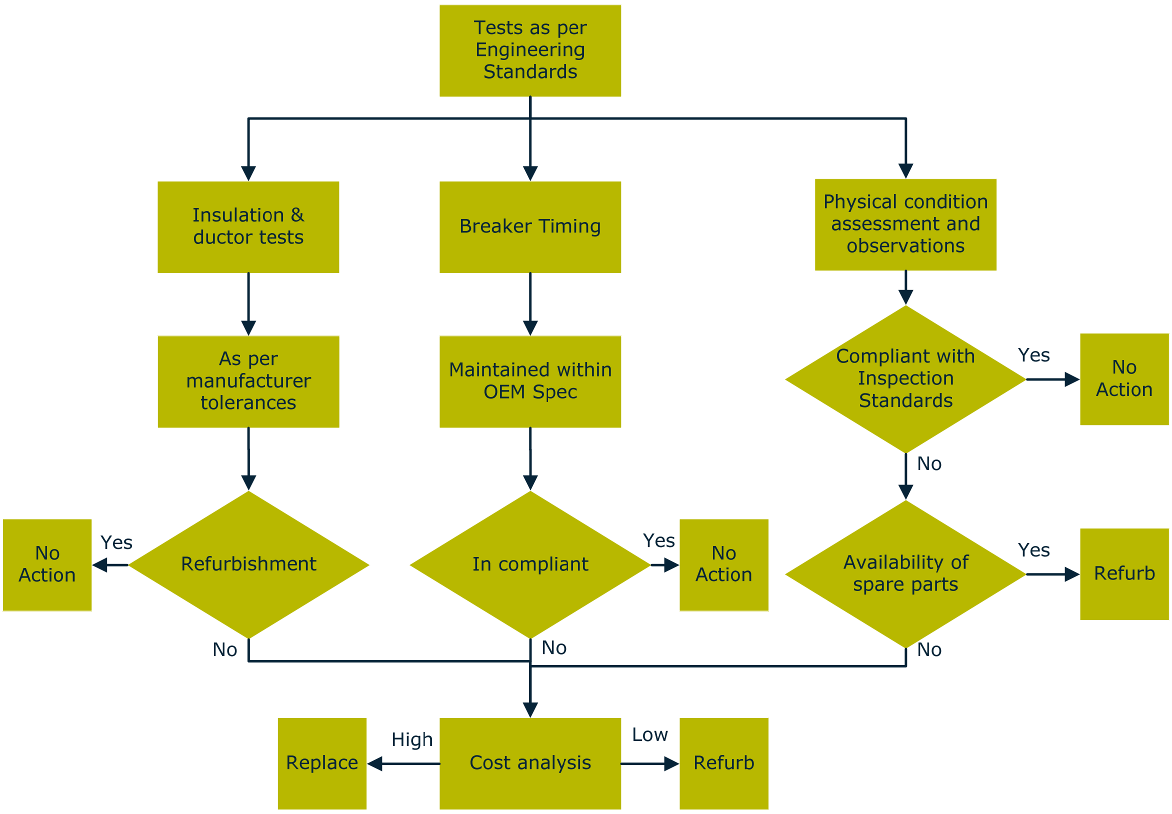


Figure 6-17 : Switchgear replacement decision process

Through the above process a priority programme of works has been established. Table 6-10 below is a summary of the switchboards and CBs identified for replacement in the 10-year programme of works.

Project Justification	Description	Year	Budget
The 11kV switchboard at Liverpool is one of the oldest (manufactured 1965) Brush type switchboards supplying the CBD. Many years ago it was upgraded to 11kV from 6.6 kV. This particular equipment has not been in production for over 20 years and there are limited spare parts for this double bus configured type of oil-filled apparatus. This switchboard has exhibited significant signs of Partial Discharge during annual surveys with visible rust, oil leaks and sign of past failures in the cable boxes indicating compromised mechanical and electrical systems. Failure of the switchboard would be likely to involve at least half the switchboard as past Vector experience has shown. This could have a significant impact on the CBD supply. Replacement is the most economic long-term solution considering the criticality to the CBD.	Liverpool - 11kV Indoor SWBD Replace - Stage I - 28 Panels (Scope and Design)	2010/11	$0.1 m
	Liverpool - 11kV Indoor SWBD Replace - Stage II -28 Panels (Procure Equipment)	2011/12	$3.5 m
	Liverpool - 11kV Indoor SWBD Replace - Stage III -28 Panels (Installation and Commissioning)	2012/13	$4.0 m
This is one of many Southwales C4 type oil switchboards on the Northern and Southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution. A seismic study of the building carried out in 2010 has been completed. Recommended works are minor to bring the building up to seismic standards.	Maraetai - 11kV Indoor SWBD Replace - 11 Panels	2012/13	$1.8 m
The 11kV switchboard at Onehunga is one of many Southwales C4 type oil switchboards on the Northern and Southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.	Onehunga - 11kV Indoor SWBD Replace - 12 Panels	2013/14	$1.5 m
This is one of many 11kV Brush type oil switchboards on the Northern and Southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports show signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.	Balmoral - 11kV Indoor SWBD Replace - 12 Panels	2013/14	$1.5 m
	Orakei - 11kV Indoor SWBD Replace – 16 Panels	2014/15	$2.1 m
	Manurewa - 11kV Indoor SWBD Replace - 13 Panels	2015/16	$2.1 m
Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit	Manurewa - 11kV Indoor SWBD Retrofit - 7 Panels	2015/16	$0.4 m

Project Justification	Description	Year	Budget
breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards.			
The AEI (1963) 22kV switchboard at Kingsland is the only one of its kind on the network. During scheduled maintenance 3 years ago, many internal bushing clamps had to be replaced due to breakage caused by fatigue. This particular equipment has not been in production for well over 35 years and there are no spare parts. Failed parts have to be remanufactured at considerable expense and downtime. Replacement is the only long-term solution considering the criticality to the CBD.	Kingsland - 22kV Indoor SWBD Replace - Stage I (Scope and Design)	2012/13	$0.1 m
	Kingsland - 22kV Indoor SWBD Replace - Stage II (Procure Equipment)	2013/14	$2.5 m
	Kingsland - 22kV Indoor SWBD Replace - Stage III (Installation, Commissioning and all civil works)	2014/15	$2.0 m
This SWBD is comprised of both Brush and Southwales OCB (50/50). Both types are on the scheduled replacement programme of works for reasons already mentioned	Drive - 11kV Indoor SWBD Replace - 13 Panels	2016/17	
This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports are showing signs of deteriorated condition due to long in service life. After Liverpool, this is the only other DOUBLE BUS configure Brush Switchboard and is unique on the network (LP is an earlier version)This equipment has not been in production for many years and replacement is the most economic long-term solution.	Hobson - 11kV Indoor SWBD - 21 Panels	2014/16	$7.0 m
This is one of many 11kV Brush type oil switchboards on the Northern and Southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.	Freemans - 11kV Indoor SWBD Replace - 13 Panels	2016/17	$1.5 m
	Mangere Central - 11kV Indoor SWBD Replace - 15 Panels	2017/18	$1.8 m
	Pakuranga - 11kV Indoor SWBD Replace - 13 Panels	2018/19	$1.8 m
	Sandringham - 11kV Indoor SWBD Replace - 18 Panels	2019/20	$2.0 m
Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards.	Avondale - 11kV Indoor SWBD Retrofit	2011/12	$0.6 m
	Carbine - 11kV Indoor SWBD Retrofit	2011/12	$0.6 m
	Otara - 11kV Indoor SWBD Retrofit	2011/12	$0.2 m
	Chevalier - 11kV Indoor SWBD Reyrolle Retrofit	2011/12	$0.6 m
	Hans - 11kV Indoor SWBD Retrofit - 10 Panels	2013/14	$0.5 m

Project Justification	Description	Year	Budget
	Greenmount - 11kV Indoor SWBD Retrofit - 2 Panels	2013/14	$0.1 m
	Hobson - 11kV Indoor SWBD Retrofit (15 Panels)	2014/15	$0.8 m
	Howick - 11kV Indoor SWBD Retrofit (13 Panels)	2015/16	$0.7 m
	Mount Albert - 11kV Indoor SWBD Retrofit (5 Panels)	2016/17	$0.3 m
	Manukau - 11kV Indoor SWBD Retrofit - 13 Panels	2016/17	$0.7 m
	Quay St - 11kV Indoor SWBD Retrofit - 9 Panels	2017/18	$0.5 m
	Rockfield - 11kV Indoor SWBD Retrofit - 12 Panels	2018/19	$0.6 m
	St Heliers - 11kV Indoor SWBD Retrofit - 13 Panels	2018/19	$0.7 m
	South Howick - 11kV Indoor SWBD Retrofit - 12 Panels	2019/20	$0.6 m
	Takanini - 11kV Indoor SWBD Retrofit - 10 Panels	2019/20	$0.6 m
	Te Papapa - 11kV Indoor SWBD Retrofit - 13 Panels	2020/21	$0.7 m
	Wiri - 11kV Indoor SWBD Retrofit - 15 Panels	2020/21	$0.8 m
Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards.	Highbury - 11kV Indoor SWBD Retrofit - 5 Panels	2011/12	$0.5 m
	Brickworks - 11kV Indoor SWBD Replace - 6 Panels (New Building required due to Seismic constraints)	2012/13	$3.0 m
	Henderson Valley - 11kV Indoor SWBD Retrofit - 10 Panels	2013/14	$0.5 m
	Birkdale - 11kV Indoor SWBD Retrofit - 11 Panels	2013/14	$3.0 m
	East Coast Rd - 11kV Indoor SWBD Retrofit - 7 Panels	2015/16	$0.4 m
	Hillcrest - 11kV Indoor SWBD Retrofit - 12 Panels	2014/15	$0.6 m
	Ngataringa Bay - 11kV Indoor SWBD Retrofit - 7 Panels	2016/17	$0.4 m
	Northcote - 11kV Indoor SWBD Retrofit - 5 Panels	2017/18	$0.3 m

Project Justification	Description	Year	Budget
	Orewa - 11kV Indoor SWBD Retrofit - 5 Panels	2017/18	$1.0 m
	Woodford - 11kV Indoor SWBD Retrofit - 6 Panels	2018/19	$0.3 m
Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards.	Sabulite - 11kV Indoor SWBD Replace - 11 Panels	2011/12	$2.2 m
This 11kV switchboard is one of many Southwales type oil switchboards on the Northern and Southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.	Riverhead - 11kV Indoor SWBD Replace - 12 Panels	2012/13	$1.3 m
	New Lynn - 11kV Indoor SWBD Replace - 11 Panels (New Building required due to Seismic constraints)	2013/14	$2.3 m
	Laingholm - 11kV Indoor SWBD Replace - 11 Panels	2015/16	$1.1 m
	Wairau Valley - 11kV Indoor SWBD Replace - 11 Panels	2016/17	$1.2 m
	Hobsonville - 11kV Indoor SWBD Replace - 11 Panels	2017/18	$1.2 m
	Swanson - 11kV Indoor SWBD Replace - 10 Panels	2019/20	$1.2 m
The 11kV English Electric is the last of its kind on the network. Several spare panels have been recovered from previous replacement works so there are adequate spare parts. This SWBD suffered a major internal fault a few years ago resulting in an exploded circuit breakers and damaged bus. This switch is mechanically compromised and has to be replaced.	Browns Bay - 11kV Indoor SWBD Replace - 10 Panels	2013/14	$1.8 m
This 11kV switchboard one of many Southwales type oil switchboards on the Northern and Southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.	Milford - 11kV Indoor SWBD Replace - 5 Panels	2011/12	$0.5 m
	Balmain - 11kV Indoor SWBD Replace - 5 Panels	2011/12	$1.0 m
	Torbay - 11kV Indoor SWBD Replace - 5 Panels	2019/20	$1.0 m

<table>
<tr><th>Project Justification</th><th>Description</th><th>Year</th><th>Budget</th></tr>
<tr><td rowspan="2">The 33kV outdoor Switchyard is being redevelopment as part of Transpower's North Auckland and Northland Grid Upgrade (NAaN) projects. This investment represents the design, construction and installation of new indoor 33kV switchboard and switch room building.</td><td>Wairau Valley - 33kV Indoor SWBD Install
(Building Construction , Equipment Purchase, Installation)</td><td>2011/12</td><td>$7.0 m</td></tr>
<tr><td>Wairau Valley - 33kV Indoor SWBD Install
(Commissioning and Finishing Works)</td><td>2012/13</td><td>$0.7 m</td></tr>
<tr><td rowspan="6">Continued programmed replacement of aged outdoor 33kV bulk Reyrolle and English Electric Circuit breakers. These breakers are slow to operate, rusting and require intensive maintenance after every fault operations. These breakers are uneconomic to maintain and are in aged and in deteriorated condition with no spare parts.</td><td>Wellsford - 33kV Outdoor CB Replace - 2 CBs</td><td>2013/14</td><td>$0.5 m</td></tr>
<tr><td>Belmont - 33kV Outdoor CB Replace - 2 CBs</td><td>2013/14</td><td>$0.5 m</td></tr>
<tr><td>Highbury - 33kV Outdoor CB Replace – 1 CB</td><td>2013/14</td><td>$0.3 m</td></tr>
<tr><td>Helensville - 33kV Outdoor CB Replace - 2 CBs</td><td>2014/15</td><td>$0.5 m</td></tr>
<tr><td>Balmain - 33kV Outdoor CB Replace – 1 CB</td><td>2014/15</td><td>$0.3 m</td></tr>
<tr><td>Waiake - 33kV Outdoor CB Replace – 1 CB</td><td>2016/17</td><td>$0.5 m</td></tr>
<tr><td>Programme initiation to replace outdoor 33kV bulk Takaoka. These breakers are the next most aged bulk oil breakers and are showing signs of age related deterioration. There are currently no spares. These breakers are becoming uneconomic to maintain.</td><td>Browns Bay - 33kV Outdoor CB Replace - 2 CBs</td><td>2018/19</td><td>$0.5 m</td></tr>
<tr><td>Programme initiation to replace outdoor 33kV bulk Nissin. These breakers the next most aged bulk oil breakers which are showing signs of age related deterioration. There are currently no spares. These breakers are becoming uneconomic to maintain.</td><td>Waikaukau - 33kV Outdoor CB Replace - 3 CBs</td><td>2017/18</td><td>$0.8 m</td></tr>
</table>

Table 6-10 : Scheduled switchgear replacement

Beyond this identified programme of works a provisional CAPEX allowance has been made for the financial years from 2017 to 2021, based on our expectation that other switchgear units on the network will demonstrate similar life-cycle performance to those currently being replaced, and units will therefore be reaching the end of their useful lives by then. The actual units to be replaced and the more accurate cost estimates for this will be determined closer to the time. This allowance is included in the ten years work programme sheet (Table 6-32).

Looking at the programme of works over the next ten year period in Figure 6-18 below, a trend appears. Vector is not unusual in the industry in that there exhibits a "Bow Wave" of asset replacement works. Significant growth in electrification of the 1950's and 1960's is now appearing as replacement works. Vector has engaged actively in asset replacement works of its switchboards and switchgear over the past six years and this investment activity has helped in easing the financial impact in the coming years to smooth out this bow wave of asset replacement. In Figure 6-18 below it can be seen that in year three of the next ten year programme of works investment in switchboard replacement will begin to trend downward indicating the trailing edge of a 20 – 25 year "Bow Wave."

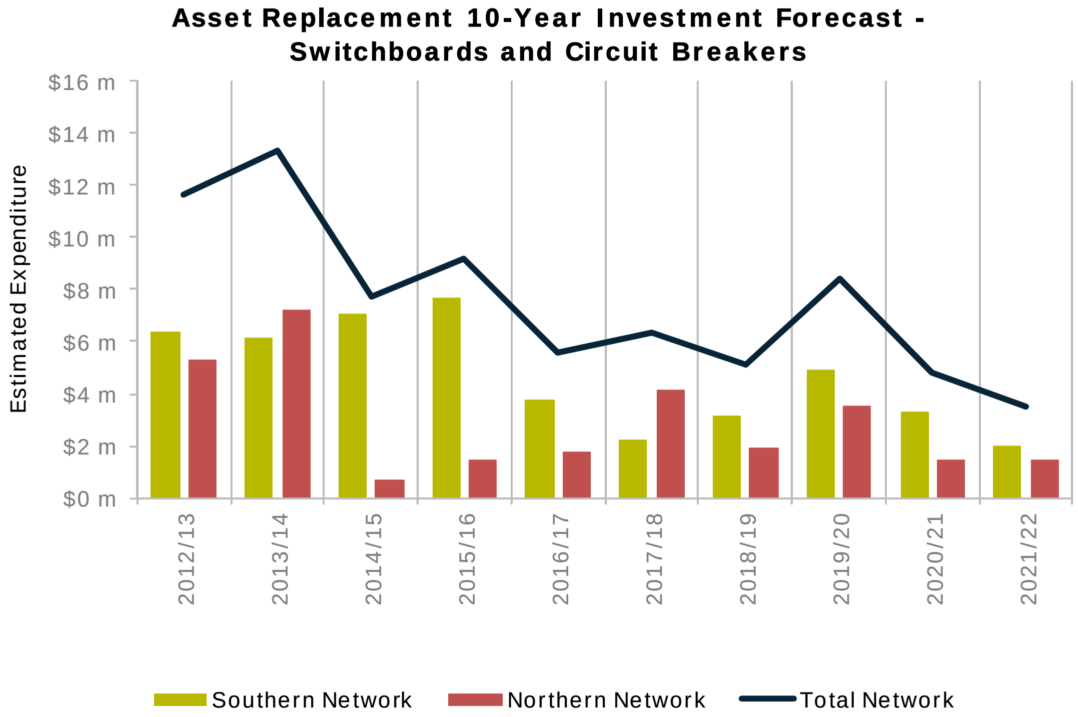


Figure 6-18 : 10-year Switchgear replacement annualised cost estimate

6.3.4 Zone Substation Buildings

Vector's primary substations are a result of two distinct design philosophies. Due to the more predominantly urban environment, substations located in the Southern region were built with the philosophy of containing as much of the primary apparatus as possible in enclosed buildings. The Northern region, initially developed largely in a rural environment, applied a more traditional approach, using outdoor switchyards for the sub-transmission apparatus with indoor control rooms and 11kV distribution switchboards.

Due to the differing design philosophies, the Northern region substations generally occupy twice the land area compared to a similarly configured urban substation. This in turn requires more maintenance (activities such as weed control, security fences, tree trimming and lawn mowing are more intensive).

For new construction, the trade-off between land and building and equipment needs to be considered, as well as the visual impact on surrounding land owners, and the security of supply. It is more costly to construct enclosed substation buildings although these costs need to be evaluated against reduced land requirements, reduced maintenance of the primary plant equipment and enhanced security of supply.

Vector's current network development philosophy for new substations is to enclose all station apparatus regardless of network region.

Newly constructed substations in the past few years have been of pre-cast concrete tilt up construction. These stations have been designed for ease of construction, low maintenance, safety of persons and adjoining properties, and compliance with the latest building and seismic requirements. These buildings are also designed to be in keeping with the local environment where they are located and are intended to be architecturally pleasing. For rural sites the design is less architecturally enhanced due to the reduced need to blend in with the urban environment facilitating some construction cost reductions.

Vector has also begun a process of evaluating the long-term requirements of the more rural aged substations with a view to converting the outdoor yards where it is economically viable to do so.

Vector redeveloped the Swanson zone substation in 2010 with a replacement of the outdoor 33kV infrastructure with a containerised indoor switchboard. The outdoor yard had reached the end of it design life, was exhibiting signs of significant deterioration of the bus works, insulators and outdoor breakers and was becoming a significant safety and supply risk. The container solution, albeit industrial in design, is in keeping with the existing station while at the same time improving the visual impact of the former outdoor apparatus. This project has also improved the security of supply for the area served by this station as well as significantly reducing the risk of injury to personnel and the public at this facility.

The remainder of Vector substations range from tin-clad wood frame buildings, to block or brick construction, wood frame as well as poured in situ reinforced concrete construction and other variants in various condition relating primarily to the age, materials and construction methodology.

Figure 6-19 : Swanson before redevelopment

Figure 6-20 : Swanson after redevelopment

Table 6-11 below shows the current number and book value of zone substations land and buildings on the Vector networks, including switching stations and a Vector owned GXP (Vector has one GXP located at Litchfield where supply is directly taken from Transpower at 110kV).

Network	Population	Book Value
Southern	56	$76 m
Northern	51	$33 m
Total	107	$109 m

Table 6-11 : Primary Substation land and buildings – Population and Book Value

The substation buildings range from new to 63 years old on the Southern region and from new to 54 years old on the Northern region. In all there are 107 in service zone substations and switching stations, with an additional four zone substations currently under construction.

Figure 6-21 and Figure 6-22 show the age profile of zone substation buildings in the Southern and Northern regions.

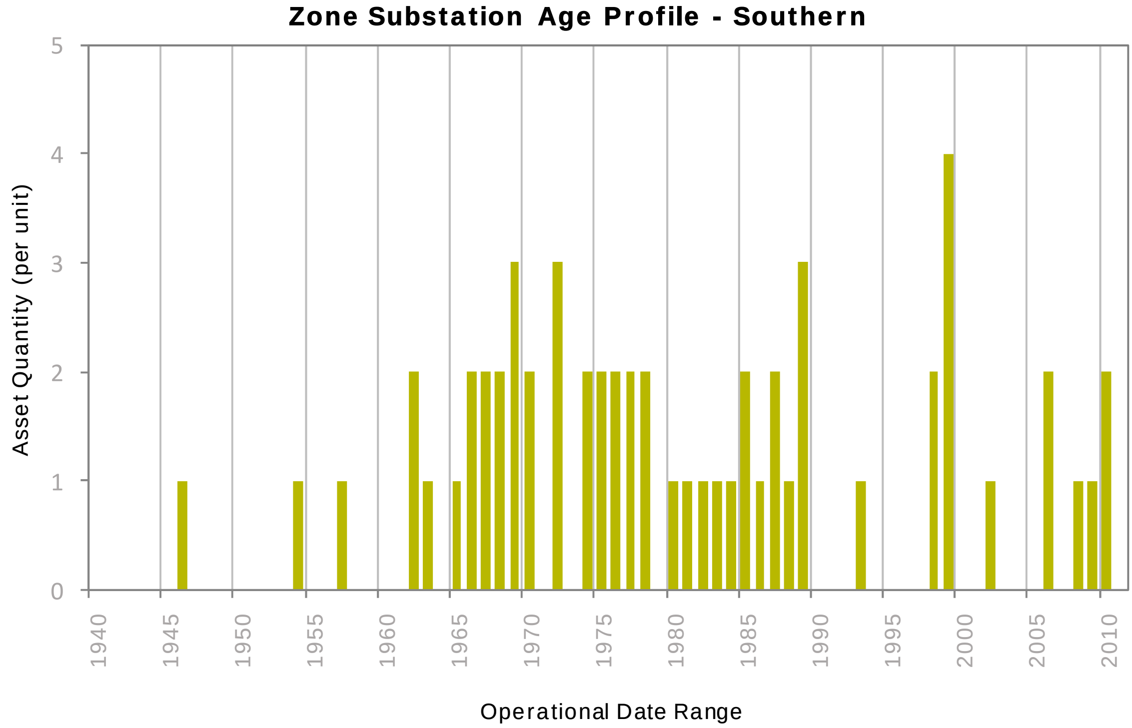


Figure 6-21 : Zone Substation Buildings Age Profile - Southern

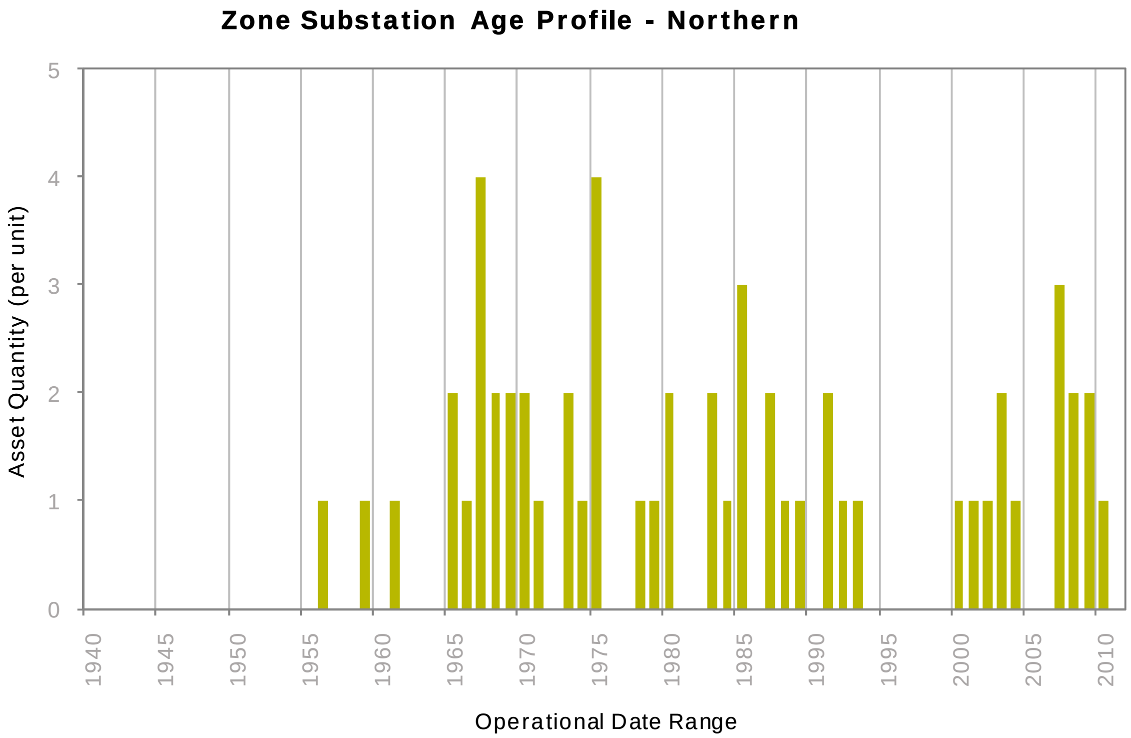


Figure 6-22 : Zone Substation Buildings Age Profile - Northern

The substation buildings vary in condition from very good to poor. The poorest, while structurally sound, are in need of upgrades due to deteriorating doors, window frames and roofs. Ongoing refurbishments of these buildings will be required.

6.3.4.1 Maintenance Programme

The substation building maintenance regime covers substation building structures, fire detection and protection, ventilation systems, environmental control fixtures, grounds, driveways, external lighting, fences, security systems, emergency lighting, and power supplies.

Maintenance intervals are specified in Vector standard ENS-0188 and maintenance activities defined in ENS-0189.

A summary of the standards is given below:

- Routine and preventive maintenance:
    - Three weekly – grounds inspection. Ensure perimeter security fencing and gates are free from damage, all locks and chains are sound, and site signage is adequate. Structural integrity and cleanliness of external walls, doors and windows, all drains and plumbing;
    - Three weekly - vegetation service. Site vegetation has adequate building clearance and security clearance, tree pruning where necessary, edges and lawns are mown and trimmed were required, any rubbish on site or vegetation trimmings are removed, any unintended plants, weeds or mould removed from driveways, equipment yards and buildings;
    - Monthly – building compliance assessment;
    - Two monthly – electrical assets visual inspection;
    - Two monthly – buildings services visual inspection and condition assessment. Ensure telephone and radio are operational, spill kits and first-aid kits are fully stocked, extinguishers compliant, rubbish is removed, structural integrity and cleanliness of internal walls, doors and windows, all drains and plumbing, and sump pumps and alarms are functioning as required. Test operation of substation lighting and emergency lighting, smoke detectors, intrusion alarms, electric fences and fire alarms. Test operation of radiant heaters, heat pumps and air conditioning systems where fitted, assess filter condition. Ensure all trench covers are secure, and trenches and cable ducts are sealed from water ingress. Restock any consumables;
    - Annual – alarm testing and compliance, ensure correct operation of all fire alarms, intrusion alarms and crisis alarms as required, clean and test all smoke heads; and
    - Annual – building warrant of fitness certification.
- Refurbish and renewal maintenance:
    - All defects that are not considered an imminent risk of asset failure, or a compromise in site security require repair or replacement before the next inspection is due.
- Fault and emergency maintenance:
    - All defects that are considered to pose an imminent risk of asset failure, or a compromise in site security require immediate repair or replacement.

6.3.4.2 Refurbishment Programme

A survey of all stations is intended to be carried out in the 2011/12 financial year. It is anticipated this will result in a refurbishment programme commencing in the 2012/13 financial year. The survey work will also include seismic evaluations of all zone substations. The evaluation process is indicated in the schematic in Figure 6-23.

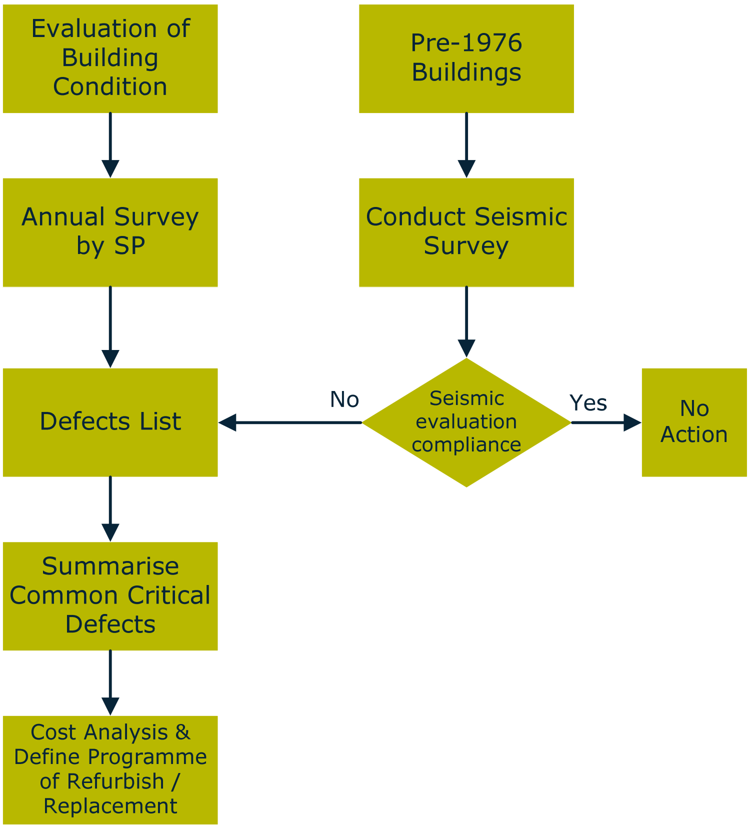


Figure 6-23 : Zone substation renewal process

6.3.4.3 Seismic Upgrades

The local authority has been empowered to enforce the seismic compliance rules of the Building Act 2004. Section 122 of the Building Act requires assessments be made of certain structures (single story houses etc are exempt) to verify their performance under earthquake conditions. Section 131 of the Building Act 2004 requires that local authorities develop a policy relating to dangerous and insanitary buildings within their areas of jurisdiction.

The Building Act defines a "Seismically Prone Building" as one that does not meet the requirements of 1/3 of the current Earthquake provisions in NZS1170. The New Zealand Society of Earthquake Engineering (NZSEE) has published a document "Assessment and Improvement of the Structural Performance of Buildings in Earthquakes dated June 2006." This document provides a means of determining the likely level of seismic compliance that a building may have. It takes into account many factors such as the importance of the building and its likely impacts of failure of the structure on the public.

The importance of seismic assessment and being prepared for this risk has been very graphically demonstrated following the recent major earthquakes in Christchurch. Vector is assimilating the findings and learning from these events and will take this into account in its review of the substation buildings.

A building is deemed to be "Earthquake Prone" if it fails to meet the requirements of 1/3 of the resistance required in the NZSEE document mentioned above. This is a legal requirement. There are assessment methods that can be used to rank buildings into likely (to exceed legal requirements) or unlikely (to exceed legal requirements). For example:

- Most buildings designed after 1976 will easily meet this legal requirement as they would have been designed to NZS4203 which included significant seismic design criteria;

- Similarly most light weight timber framed buildings, if they are single storey and lightly clad, will easily meet the legal requirements;
- Conversely unreinforced masonry buildings and lightly reinforced mass concrete buildings will be unlikely to meet the above legal requirements;
- The age of the building is important as it indicates not only the length of asset life left but also the likely design code they would have been designed to. Any buildings built earlier than the 1960s are unlikely to have an adequate seismic performance as only nominal attention was paid to earthquake design at that time.

It is reasonable and a simple task to rank buildings into likely or unlikely categories. The age and importance of the substation can be used to help categorise the buildings also.

The Building Act requires that all public utility buildings be seismically evaluated. Vector has engaged an experienced seismic and structural engineer to evaluate all pre 1976 constructed buildings. After the assessments have been made a more defined programme of works can be made. It is expected all pre-1976 buildings will have been assessed in the current financial year with a programme of remedial and major works identified in subsequent financial years.

At the time of writing, the stations listed in Table 6-12 below have been assessed with an estimate of seismic upgrade works made. Compliance with the provisions of the 2004 Building Act is ten years from when council have made their own determinations. Vector is identifying affected stations now in order that annualised budgets can be established. The following table depicts the stations that are identified thus far. The review process is not completed as yet therefore it is assumed that more stations may be subject to reinforcement or renewal.

Vector Substations	Final Report	Summary of Works Required	Estimated Cost for Seismic Compliance
Avondale	Complete	Replace or strengthen the cavity brick panels to the Switch Room Building. Add roof bracing to the underside of the purlins. Replace or strengthen the brick panels to the Transformer Bay Building. Strengthen the concrete pilasters to the walls of old part of the Transformer Bays. A detailed analysis of the wind loads and seismic loads on this will be carried out.	$740,000
Balmain	In Progress		
Balmoral	In Progress		
Belmont	In Progress		
Birkdale	In Progress		
Brickworks	Complete	This building will be demolished and a new switch room built meeting the future expected needs.	$1,200,000
Browns Bay	In Progress		
Carbine		A detailed analysis of the seismic loads on this structure has been carried out to determine what level of seismic acceleration this structure can provide. This analysis predicts this structure can easily resist the 1/3 NZS 1170 Seismic provision. This building meets the required standard for seismic resistance for old buildings of the Building Act.	$0
Greenmount	In Progress		
Hans	In Progress		

Vector Substations	Final Report	Summary of Works Required	Estimated Cost for Seismic Compliance
Helensville	Complete	No remedial work is required to make this building comply with the seismic provisions of the Building Act	$0
Henderson Valley	In Progress		
Hobson	In Progress		
Kingsland (Est. 1946)	Complete	The insitu concrete strength of the walls and sub floor structure will be determined by taking core samples at strategic positions. The results of the core samples will then be used in a detailed seismic assessment to determine the likely level of performance of this structure	$15,000
Kingsland (Est. 1962)	Complete	Vector is considering replacing or strengthening the cavity brick wall cladding to the Switch House Building. There are several alternatives which can be used. Alternative 1 is to remove the exterior brick layer, drill and place masonry anchors and into the inner brick layer add mesh reinforcing and gunite (sprayed concrete) the exterior surface of the bricks. This will form a structural panel which will resist seismic loads. There may be moisture problems with this method. This work can be done without affecting the operation of the electrical function of this building. Alternative 2 is to remove both layers of brick and the capping sill and replace these with light weight timber framed construction with fire resistant cladding and lining. This alternative would require the shut-down of the electrical function of this building.	$180,000
Laingholm	In Progress		
Liverpool -1 (Est. 1964)	Complete	A detailed analysis of the seismic loads on this structure will be carried out to determine the likely lateral movement of this structure with respect to the allowable movement of the electrical plant within the structure. A geotechnical assessment will be made on the stability of the large retaining walls along the eastern and southern boundaries. Unreinforced cavity brick and concrete block walls will be either strengthened or replaced with light weight fire rated walls. The unreinforced concrete block panels in the western boundary wall will be removed and the concrete framing structure around the panels demolished. The ceiling to the roof of the building will be checked for the suitability of the 12mm thick asbestos fire resistant coating. If it is found that this asbestos is a health risk it will be removed and a new fire rated ceiling system installed. This may require strengthening of the portal frames.	$1,100,000
Manurewa	In Progress		
Maraetai	Complete	A detailed inspection of the structure of these buildings will be undertaken by a chartered engineer to determine what, if any, remedial works should be undertaken. Strengthening of the roof trusses is required in the existing 11kV switch room to resist earthquake and uplift forces from wind.	$50,000
McNab	In Progress		
Milford	In Progress		$1,200,000

Vector Substations	Final Report	Summary of Works Required	Estimated Cost for Seismic Compliance
New Lynn		This building will be demolished and a new switch room will be built to meet the future expected needs of Vector.	New Building with provision for 2 XFMR bays as per template design $ 1.2 M (no equipment).
Onehunga	In Progress		
Orakei	In Progress		
Otara	In Progress		
Pakuranga	Complete	The double skin brick panels in the Switch Room are required to be either: a) removed and replaced with light weight timber framed panels that are adequately fire rated, or b) strengthened by adding a reinforced concrete “gunite” inner lining to the panels to provide the requisite shear strength. This is the recommended solution as it causes less inconvenience to the internal lay out and running of the switch gear). The unreinforced concrete block walls between the transformers and the cooling plant will be strengthened by adding a reinforced concrete “gunite” lining to the wall to provide the requisite shear strength.	$370,000
Parnell	Complete	No remedial work is required to make this building comply with the Seismic Provisions of the Building Act.	$0
Pt Chevalier	Complete	No remedial work is required to make this building comply with the Seismic Provisions of the Building Act.	$0
Quay St	In Progress		
Riverhead	In Progress		
Sabulite	Complete	This building will be demolished and a new switch room will be built meeting the future expected needs.	New Building with provision for 2 XFMR bays as per template design $ 1.2 M (no equipment).
Swanson	Complete	Additional bracing should be provided to each of the long walls. This can be achieved by either adding bracing panels or by providing some sort of strap bracing fixed to the internal timber framing.	$15,000
The Drive	In Progress		
Triangle Rd	Complete	A detailed inspection of the knee braces and wall braces of this structure and their connections will be undertaken by a chartered engineer to determine what, if any, remedial works should be undertaken. A detailed assessment of the fire resistance of the internal linings of this structure will also be undertaken. Fire resistance and protection systems will be added to the roof trusses, knee braces and RSC columns. The windows along the side walls will be removed and timber infill framing and appropriate cladding installed.	$260,000

Vector Substations	Final Report	Summary of Works Required	Estimated Cost for Seismic Compliance
Victoria	In Progress		
Westfield	Complete	Thorburn Consultants have assessed the design and condition of the Westfield Substation at 39% NBS. This result gives the building a "C" grade (moderate risk) from the initial evaluation criteria. Under the evaluation criteria set out by the NZSEE, Thorburn's assessment has assumed the building to be considered as a category 3 public utilities building rather than a category 4 post Disaster building	
		Total Estimated Investment Required	$5,130,000

Table 6-12 : Zone substations seismic compliance survey

Vector continues to engage with local authorities on the building and seismic compliance requirements for existing zone substations. An annual budget of $1 million dollars for each network (Northern and Southern) has been allotted for the duration of the ten year programme to accommodate building reinforcement works. Some buildings cannot be economically seismically reinforced (eg. Brickworks, Sabulite Rd, New Lynn) and will have to rebuilt. These stations are identified in the current 10 years programme of works.

Vector also has an ongoing programme of oil containment for power transformers to ensure compliance with environmental regulations. This programme has been under way since 2005. By 2012 all substations are expected to have effective oil containment measures in place.

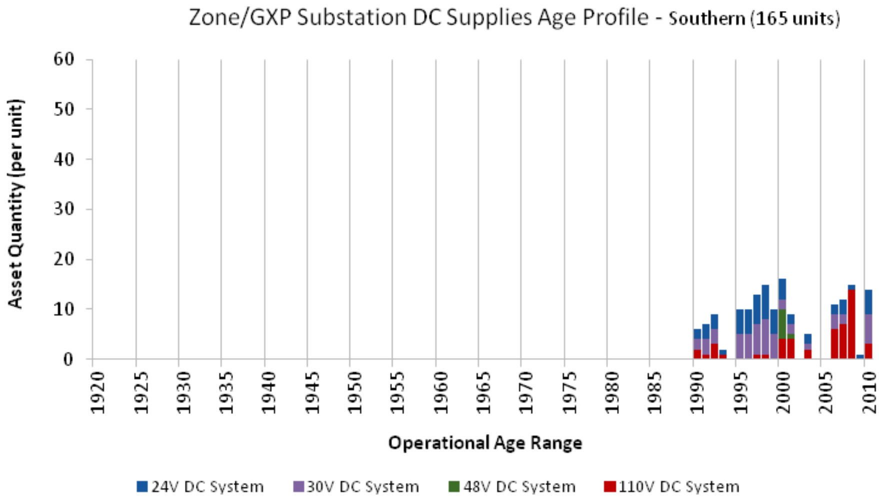
6.3.5 Zone Substation DC Supply and Auxiliaries

Substation direct current (DC) auxiliary power systems provide supply to the substations' protection, automation, communication, control and metering systems, including power supply to the primary equipment motor driven mechanisms. Vector's standard DC auxiliary systems consist of a dual string of batteries, a battery charger, a number of dc/dc converters and a battery monitoring system. The major substations are equipped with a redundant dc auxiliary system.

Vector faces a number of issues in relation to its DC supplies and auxiliaries at substations:

- In general the Southern network asset condition is considered to be average, while on the Northern network it is fair to poor;
- There are many substations with a mix of 110V/30V/24V supplies. This complicates effective maintenance;
- Many DC charger supplies are reaching the end of their life;
- Some output capacitors are drying out, causing excessive output voltage ripple. This reduces asset life;
- Many older chargers are not temperature compensated; and
- Many older chargers have insufficient output capacity to supply the substation without battery banks, and take too long to bring banks back up to full capacity (again reducing asset life).

An age profile is provided in Figure 6-24 below.



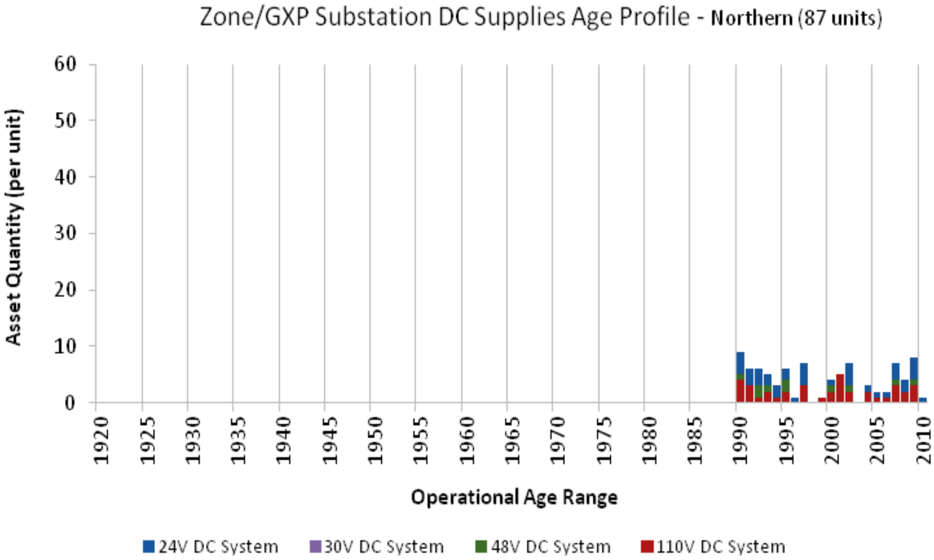


Figure 6-24 : Zone substation DC supplies – age profile

Maintenance for the valve regulated lead acid (VRLA) batteries is based on the recommendations of IEEE–1188 (IEEE Recommended Practice for Maintenance, Testing and Replacement of VRLA Batteries for Stationary Applications). Battery monitoring is an essential process for security of supply, ensuring 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.

Vector is implementing online battery monitoring in its substations. The intention is to in future progressively reduce the requirement for onsite maintenance and inspections.

The following display, in Figure 6-25, is an example of remote on-line monitoring capabilities of a recently installed DC auxiliary system in a distribution substation.

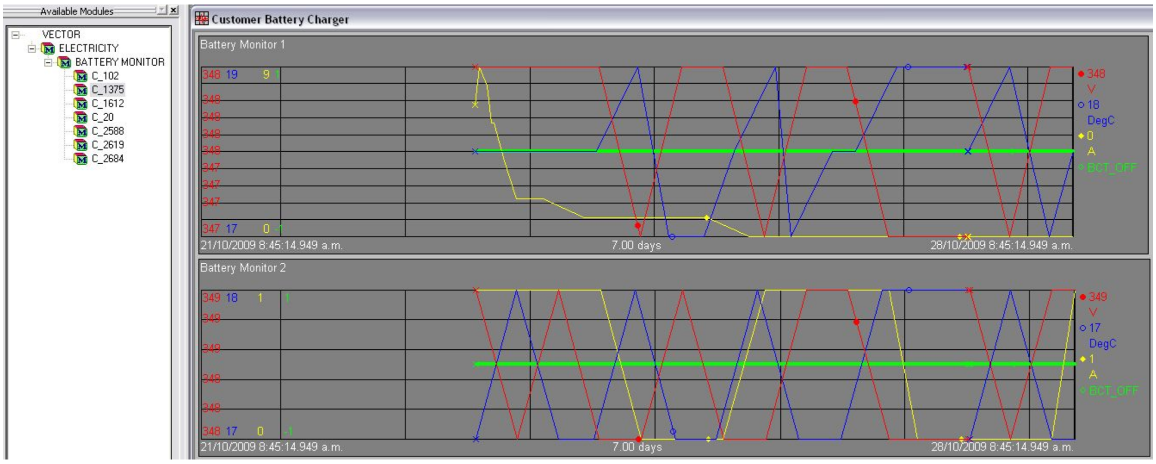


Figure 6-25 : Station batteries remote on-line monitoring

To address the issues listed above that Vector faces with its DC and auxiliary supplies, a systematic replacement programme has begun.

6.3.6 Power System Protection

All of Vector's primary switchgear and power transformers are equipped with comprehensive electrical protection systems – applying suites of protective relays. The age of installed relays is generally known and, in the absence of accurate performance data, is currently the most reliable indicator to serve as a basis for replacement. As per CIGRE and generally accepted industry practice, the useful life-span for protection relays is generally estimated to be in the following ranges:

- Numerical: 15-20 years;
- Static: 20-25 years; or
- Electromechanical: 32 years.

Vector's protection relay asset consists of 2,644 main protection relays. The age and technology distribution is given in Figure 6-26 and Figure 6-27.

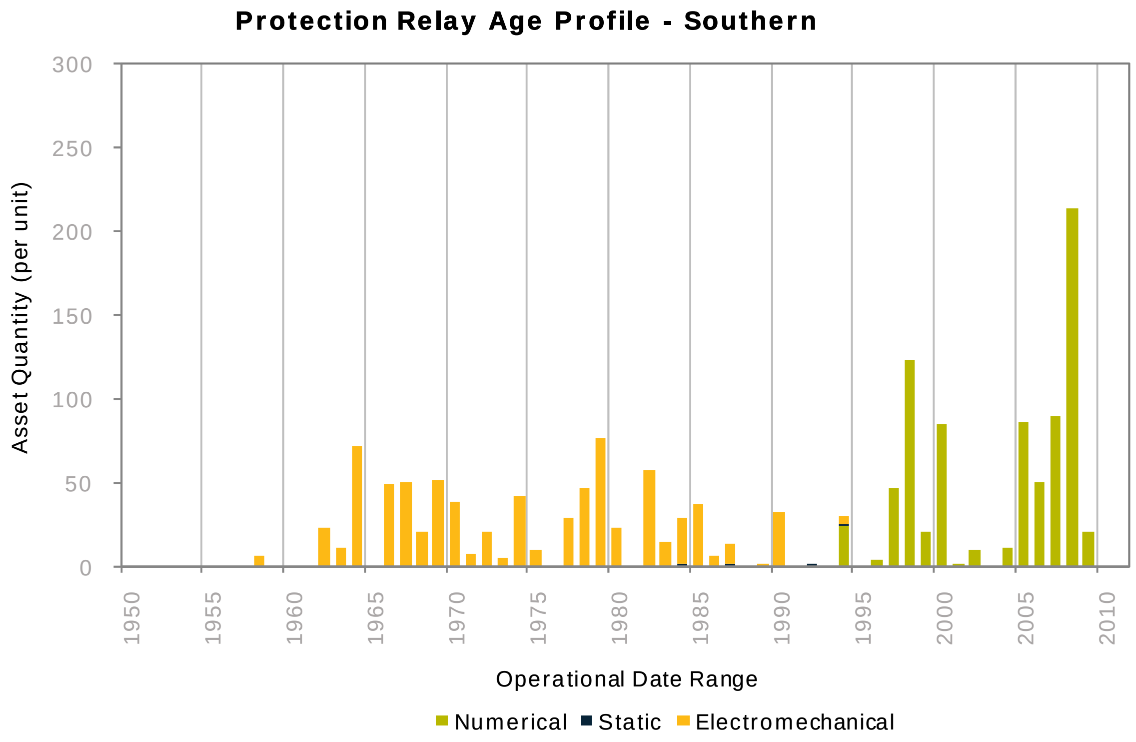


Figure 6-26 : Protection relay age profile – Southern

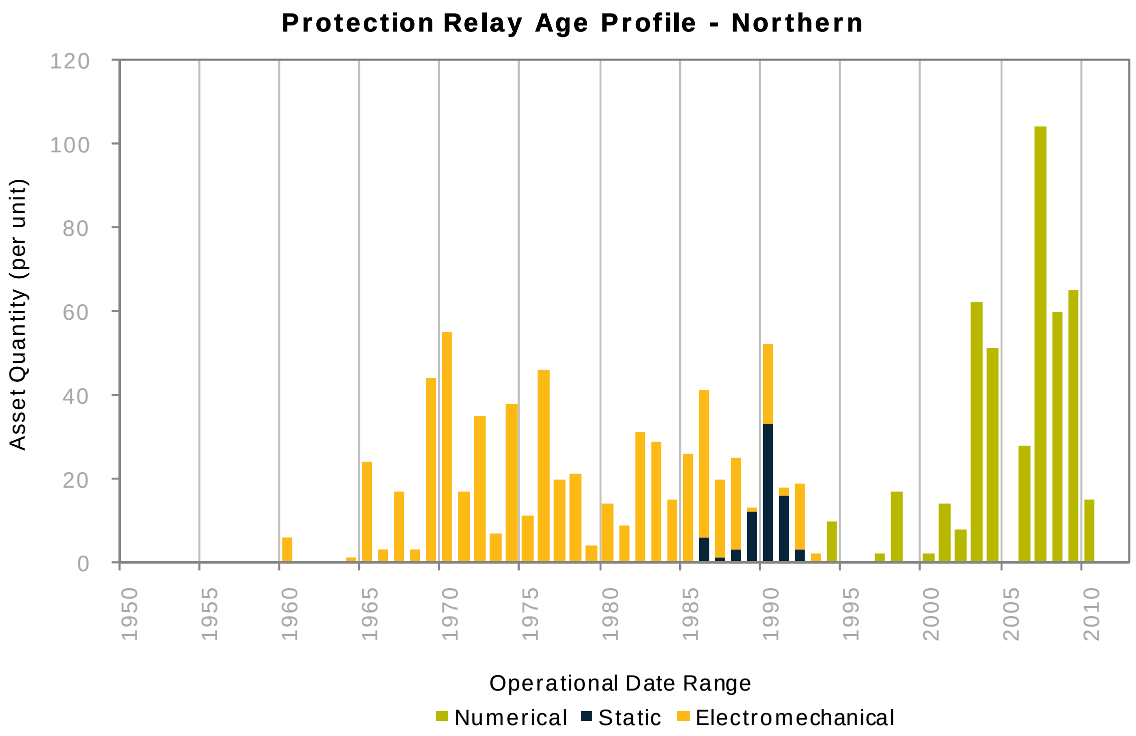


Figure 6-27 : Protection relay age profile – Northern

Vector's financial system (SAP) does not at present explicitly record the value of protection relays. This is included with the value of the switchgear it protects. Based on the cost of recently installed projects, the protection asset book value is estimated to be around $51 million.

Vector is not aware of any systemic problem with its current population of protection relays and the assets are generally in good condition.

6.3.6.1 Maintenance Programme

All protection maintenance is time-based at present. Maintenance frequencies vary depending on the generation of technology. For protection installed at the grid interface, the maintenance frequency is stipulated by the Electricity Governance Rules.

Maintenance of numerical relays (self-monitoring) is on an eight-yearly basis. Non self-monitoring relays require four-yearly maintenance. For analogue relays the period is six years, or two years at the grid interface. A summary of Vector's maintenance requirements is given in Table 6-13. If the next (eight-yearly) testing occurs after the relay has been in service for ten years the battery will be replaced.

<table>
<tr><th></th><th>Numerical Self Monitoring</th><th>Digital Non-Self Monitoring</th><th>Analogue (electro-mechanical or non-numerical electronic)</th><th>Measuring / Trip Circuit</th><th>AUFLS</th><th>IED Battery Replace-ment</th></tr>
<tr><td>Grid Interface</td><td>10</td><td>4</td><td>2</td><td>4</td><td>4</td><td>8*</td></tr>
<tr><td>Other Stations</td><td>10</td><td>4</td><td>6</td><td>4/6/10**</td><td>4</td><td>8*</td></tr>
<tr><td>Trf. Mech. Protn.</td><td colspan="5">**</td><td>-</td></tr>
<tr><td>Transformer IED</td><td colspan="5">**</td><td>8*</td></tr>
<tr><td>Transformer Voltage Regulating Relay, OTI and WTI</td><td colspan="5">**</td><td></td></tr>
</table>

	Required by Electricity Industry Participation Code
*	Refer to note 2.
**	Align with associated protection relay (e.g. buchholz) maintenance interval.

Notes:

1. Differential protection between the grid and a connected asset to be treated as a single protection function and be tested both ends.
2. Replace 8-yearly. Battery life is estimated to be ten years.
3. Periodic testing of RTU is not required. The RTU's on-board battery shall be replaced when the battery fail alarm is activated.
4. Where CBM test results replace periodic testing, the periodic test interval start date shall be reset to the date of acceptance of CBM results.
5. Calibration and operation of measurement transducers shall be tested when protection tests are carried out. Correct reflection of measured values within specified limits shall be tested locally and remotely (SCADA). Cable pressure alarm transducers and temperature transducers shall be tested 2-yearly.

Table 6-13 : Protection relay maintenance frequencies

6.3.6.2 Replacement Programme

The basic aim of the protection equipment replacement strategy is to ensure the managed replacement of installed protection assets is carried out in order to maximise the overall benefit of the exercise to Vector and its customers. In order to achieve this, the replacement strategy must strike a balance between cost implications and avoiding the risk of asset failures or malfunction. The replacement strategy also needs to consider lifecycle management factors and ensure full protection Vector's switchgear and transformers are maintained at all times.

The key principle of the strategy is that any protection device which cannot be kept to an overall level of adequacy through routine maintenance should be replaced, given protection is a network-critical function.

For this reason the replacement strategy is pre-emptive in its approach. It is also considered essential for the protection system to be systematically upgraded in order to align with modern practices, allowing substantial benefits offered by modern protection devices to be captured. Finally, the protection system must be sustainable in terms of available skills, spares and support.

The main drivers for protection replacement are:

- Protection system inadequacy (non-compliance with system requirements);
- End of technical life;
- Reduced maintenance cost (cost efficiency);
- Improving safety;
- Improving reliability;
- Standardising and simplifying maintenance practice; and
- Standardising protection installation designs.

The above drivers are balanced against the cost of replacement and practical/operational considerations, and some compromise is therefore necessary.

6.3.7 System Control and Data Acquisition - SCADA

The Vector SCADA system is made up of the following components:

- SCADA master stations

  Vector operates two SCADA master stations to monitor and control its electricity network. A Foxboro LN2068 system is used for the Northern region and Siemens Spectrum Power TG is used for the Southern region. A project at the final stage to complete migration of Northern region SCADA to the Power TG system and to retire the ageing LN2068 system. This is to ensure consistency across the networks and to make design, commissioning and maintenance activities more efficient.

- Remote telemetry units (RTU)

  Over time a number of different RTUs have been installed in Vector's network, many of which are nearing the end of their technical life or are obsolete. Vector has been running an annual RTU replacement programme for a number of years which is currently replacing approximately ten RTUs per region per annum. RTUs are replaced with a standard interface to both master stations.

  In the Southern region there are 30 Plessey GPT RTUs and Siemens PCC systems to be replaced.

  In the Northern region 23 Foxboro C225 RTUs and three Foxboro C50 RTUs are planned for replacement.

- Communication system

  Vector is committed to an open communications architecture based on industry standards. This has resulted in the adoption and deployment of ethernet and internet protocol (IP) based communication technology.

  Vector's communications network 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 (Cu) wire telephone type pilot cables and third party radio communication systems.

  In the next five years it is planned to decommission the legacy systems (NOKIA PHD and Siemens OTN) and migrate the operations services.

6.3.8 Load Control Systems

Vector's load control system consists of audio control frequency ripple control plants, pilot wire system and cycle control plant that can manage or control:

- Residential hot water cylinders and space heating (load shedding);
- Street lighting;
- Meter switch for tariff control;
- Time shift load to improve network asset utilisation;
- Time shift load to defer reinforcement of network assets; and
- GXP demand to reduce charges from Transpower (not currently applied).

An overview of Vector's load control systems (pilot and ripple based), with their associated age profiles, is given in Table 6-14 and Table 6-15.

It is recognised emerging technologies, notably smart meters and/or intelligent home energy control devices, are likely to supersede existing load control systems in the near to medium-term future. While Vector's intention is to maintain these to an acceptable economic standard during the transitional phase the configuration of the Northern area street lighting and hot water pilot systems is such that a control signal is generated at each zone substation that then operates all lights or hot water loads along the feeders radiating from that substation. A fault in the pilots will affect all connected streetlighting or hot water load after that fault. This can result in a very large area of roadlighting being inoperable. In conjunction with the Auckland Council Transport it is planned to improve the situation by splitting the road lighting into smaller areas by using photo electric cells that are dedicated to just that area thereby removing the need to rely on a signal that originates from a zone substation. Drawings of the pilot system have not been updated for many years. To reduce hotwater load outages it is planned to begin preparing new drawings showing the locations of relays, pilot routes and the areas served by each pilot.

Network Area	Site	Type	Age (Years)	Protocol	Injection Bus (kV)
Takapuna					
(Albany GXP)	Torbay	Pilot Wire	>50	Pilot Wire	11
	Waiake	Pilot Wire	>50	Pilot Wire	11
	James St	Pilot Wire	>50	Pilot Wire	11
	Wairau Valley	Pilot Wire	>50	Pilot Wire	11
	Bush Rd	Pilot Wire	>50	Pilot Wire	11
	Helensville	Pilot Wire	>50	Pilot Wire	11
	Manly	Pilot Wire	>50	Pilot Wire	11

Network Area	Site	Type	Age (Years)	Protocol	Injection Bus (kV)
	Belmont	Pilot Wire	>50	Pilot Wire	11
	Ngataringa Bay	Pilot Wire	>50	Pilot Wire	11
	Hauraki	Pilot Wire	>50	Pilot Wire	11
	Highbury	Pilot Wire	>50	Pilot Wire	11
	Balmain	Pilot Wire	>50	Pilot Wire	11
	Birkdale	Pilot Wire	>50	Pilot Wire	11
	Northcote	Pilot Wire	>50	Pilot Wire	11
	Hillcrest	Pilot Wire	>50	Pilot Wire	11
	Browns Bay	Pilot Wire	>50	Pilot Wire	11
	Sunset Rd	Pilot Wire	>50	Pilot Wire	11
	East Coast Rd	Pilot Wire	>50	Pilot Wire	11
	Forest Hill	Pilot Wire	>50	Pilot Wire	11
	Milford	Pilot Wire	>50	Pilot Wire	11
	Orewa	Pilot Wire	>50	Pilot Wire	11
(Henderson GSP)	Woodford Ave	Pilot Wire	>50	Pilot Wire	11
	Te Atatu	Pilot Wire	>50	Pilot Wire	11
	Triangle Rd	Pilot Wire	>50	Pilot Wire	11
	Hobsonville	Pilot Wire	>50	Pilot Wire	11
	Swanson	Pilot Wire	>50	Pilot Wire	11
	Riverhead	Pilot Wire	>50	Pilot Wire	11
	Simpson Rd	Pilot Wire	>50	Pilot Wire	11
(Hepburn GSP)	Henderson Valley	Pilot Wire	>50	Pilot Wire	11
	McLeod Rd	Pilot Wire	>50	Pilot Wire	11
	Laingholm	Pilot Wire	>50	Pilot Wire	11
	Brickworks	Pilot Wire	>50	Pilot Wire	11
	Atkinson Rd	Pilot Wire	>50	Pilot Wire	11
	Sabulite Rd	Pilot Wire	>50	Pilot Wire	11
	New Lynn	Pilot Wire	>50	Pilot Wire	11

Table 6-14 : Asset age profile - Northern region – pilot wire system

Network	Type	Year of Manufacture	Population
Northern	Rotary	1961	2
Northern	Rotary	1965	5
Northern	Rotary	1967	1
Northern	Rotary	1976	1
Northern	Cyclo	1983	2
Southern	Static	1990	3
Southern	Static	1992	1
Southern	Static	1993	2
Southern	Static	1994	2
Southern	Static	1995	5
Southern	Static	1996	1

Network	Type	Year of Manufacture	Population
Southern	Static	1997	1
Southern	Static	1999	1
Southern	Static	2002	1
Southern	Static	2005	1
Southern	Static	2006	1
Total (units)			**30**

Table 6-15 : Ripple load control population

6.3.9 Sub-transmission and Distribution Overhead network

The overhead line system consists of 26 km of 110 kV line, 369 km of 33 kV line, 3 km of 22 kV (linked to the adjacent Counties Power network), 3904 km of 11 kV line and 4265 km of 400 V line.

Around 115,000 poles support the overhead distribution network of which 7% are wood and the remainder concrete. There are also steel towers and telescopic steel poles in the Northern region primarily supporting 110 and 33 kV circuits.

New Vector poles are concrete, with the exception of a very small number where specific conditions (such as requirements for resource consent, or to access difficult locations) dictate otherwise. For these exceptions, Copper Chromium Arsenic (CCA) treated softwood or steel poles are used. Older wood poles are either hardwood or creosote treated softwoods.

Historical asset information obtained from the Vector GIS for the Southern region, in particular age information, is deficient due to historical legacy issues.[9] Through Vector's ongoing surveys, inspection and test programmes as per ENS-0188, this data is being corrected over time.

The number of poles in each area is summarised in Table 6-16 below.

Population	Concrete	Wooden	Total
Southern	44361	5929	50290
Northern	61707	2529	64236
Total	106068	8458	114526

Table 6-16 : OH Structures – Population by Material Type

The age profiles of the wooden and concrete poles on the Vector network are presented in Figure 6-28 and Figure 6-29.

[9] This includes the fact that for the ODV valuation methodology prescribed by the Commerce Commission, poles are not separately recorded.

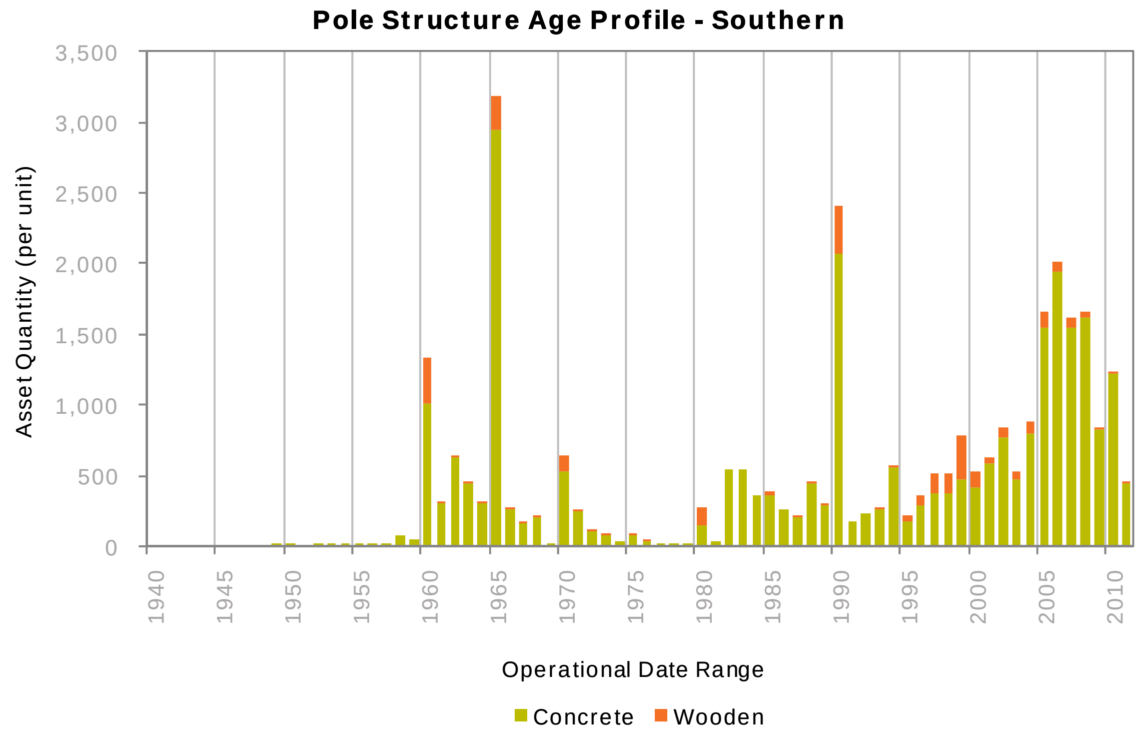


Figure 6-28 : Pole Structure Age Profile – Southern

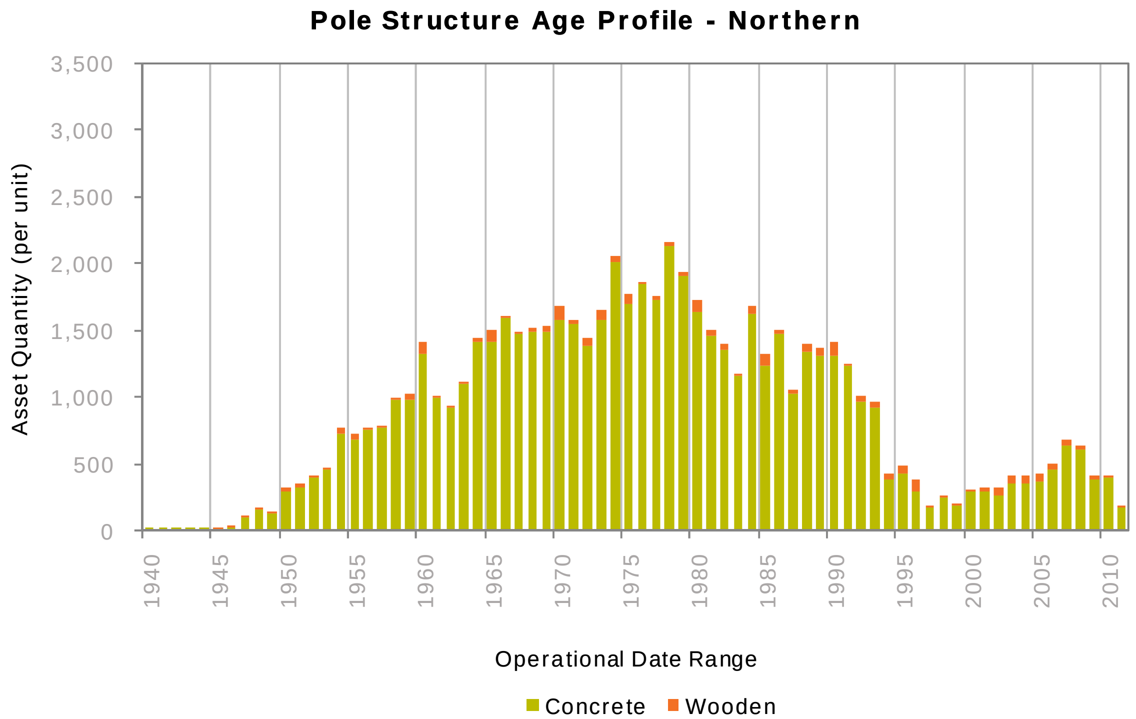


Figure 6-29 : Pole Structure Age Profile – Northern

There are 103 steel towers in the Northern region. These were originally installed by the State Hydro Electricity Department and although most are more than 80 years old, they are in good condition following extensive reconditioning works over the past few years.

Due to legacy/historical data issues, detailed replacement cost profiles cannot be prepared at this stage. Following Vector's current programme to update historical asset performance information this situation is expected to improve.[10]

The figures used above apply to 'dressed' installed poles. The value of a single pole has been assessed by sampling a number of work packs, rejecting the obvious outliers, and taking the mean of the remaining values as the value of a single pole.

Some number 1 vierendeel poles have failed through corrosion of the steel reinforcing at the steel strand spacer block interface near the base of the pole. This is not easily detected through visual inspection and as a consequence whenever a number 1 pole will experience a load change caused by work on that pole, it is to be replaced. Work is underway on an external bracing system that will reinstate the lost strength at the spacer block interface. If successful this will remove the need to replace many of these poles.

Ground inspections of the 110 kV circuits have identified 3 hardwood poles as requiring replacement because of strength considerations.

6.3.9.1 Inspection and Test Programme

Poles and towers are visually inspected on an annual basis, as per Vector standard *ENS-0187*, and their serviceability with regard to their assessed loading is tested every give years, as per the Line Design Handbook HB C(b) and AS/NZS 4676.

Wood poles are also ultrasound tested to obtain a measure of the condition of the timber and to determine the strengths of the poles. Any pole not meeting serviceability requirements is programmed for replacement *(ENS-0057)*. There is no equivalent test programme for concrete or steel poles.

A summary of the standards is given as follows:

- Routine and preventive maintenance:
  - Annual – ground based visual inspection of each pole and tower, conductors, insulators, binders and associated steel work, conductor and staywire preforms, crossarms, crossarm straps and braces, transformer platforms, bolts, connectors, fault passage indicators, stays and anchors, surge arrestors, pole mounted transformers, pole mounted capacitors, gas and ABSs, reclosers, sectionalisers, low voltage (LV) fuses, high voltage (HV) fuses, cable risers and other steel works;
  - Five yearly – wooden pole strength versus load assessment, ground based visual inspection, ultrasonic strength assessment, calculation of remaining pole strength, including site reinstatement;
  - Ten yearly – concrete pole strength versus load assessment; and
  - Ten yearly – wooden pole strength versus load assessment.
- Refurbish and renewal maintenance:
  - Any identified defect that renders a potentially unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable, remediation timeframes are based on likelihood of failure creating the unsafe situation.
- Fault and emergency maintenance:
  - Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

[10] Recognising, however, that records for some of the older assets will remain unavailable.

6.3.9.2 Maintenance and Refurbishment Programmes

The remaining life of a pole is difficult to predict accurately, because it is dependent upon several factors. These include the pole material and construction procedures at the time, natural environment, public exposure, access and the load that is being supported.

Good quality data is required for accurate life prediction. Such data is now being collected under the Multi Utility Service (MUSA) agreement with our FSPs, enacted in November 2009. Given the inspection frequency in the preventative maintenance regime, it is expected that over a three-year period sufficient high-quality data will obtained for accurate future renewal predictions.

Until the end of 2012, predicted pole replacement expenditure is based on a combination of the available asset records and an assumption the performance of poles will be largely similar to that observed over the last five years. Following an improvement in Vector's pole inspection standard (ENS-0057) implemented in 2010 a moderate reduction in future replacement needs is predicted.

Poles identified as problematic during the annual inspection or test programme may be repaired on site or replaced depending upon their condition. Poles inspected that require attention are tagged according to their as-found condition, in accordance with Vector inspection and replacement Electricity Standard ENS-0057:

- Blue Tag

  Overhead line structures found to be at risk of failing to support normal or design loads, and where engineering cannot be performed on site at the time of finding the suspect structure, shall be fitted with a blue tag. A full inspection and engineering shall be completed within ten working days of the structure being believed to be in a suspect condition.

- Red Tag

  Overhead line structures found to be at risk of failure under normal loads, or with the risk of injury to any person or damage to any property, must be marked with a red tag and repaired or replaced not later than three months after the discovery of the risk of failure.

- Yellow Tag

  Overhead line structures found to be incapable of supporting design loads must be marked with a yellow tag and repaired or replaced within 12 months of identification.

6.3.10 Overhead Conductors

Conductor types and sizes on the Vector network vary across the overhead network and are predominantly copper (Cu), all aluminium conductors (AAC) or aluminium conductor steel reinforced (ACSR) conductors. A smaller quantity of all aluminium alloy conductor (AAAC) are being utilised for new line construction.

Low voltage aerial bundle conductors (LVABC) and covered conductor thick (CCT) for 11kV lines are used in areas susceptible to tree damage.

There is a small section of high voltage aerial bundle conductor (HVABC) which was installed about 15 years ago. Although the material proved to be effective for improving reliability it was not continued, due to high installation costs. Table 6-17 below shows the amount of overhead conductor in kilometres by operating voltage and region, as well as the associated current book-value.

Population	110kV	33kV	22kV	11kV	LV
Southern	0 km	41 km	3 km	916 km	2031 km
Northern	26 km	328 km	0 km	2988 km	2235 km
Total	26 km	369 km	3 km	3904 km	4266 km

Book Value	110kV	33kV	22kV	11kV	LV
Southern	$0 m	$3 m	$0 m	$32 m	$46 m
Northern	$2 m	$16 m	$0 m	$51 m	$28 m
Total	$2 m	$19 m	$0 m	$83 m	$74 m

Table 6-17 : Conductor - Population and Book Value

Figure 6-30 and Figure *6-31* show the age profiles for all conductor voltages by region.

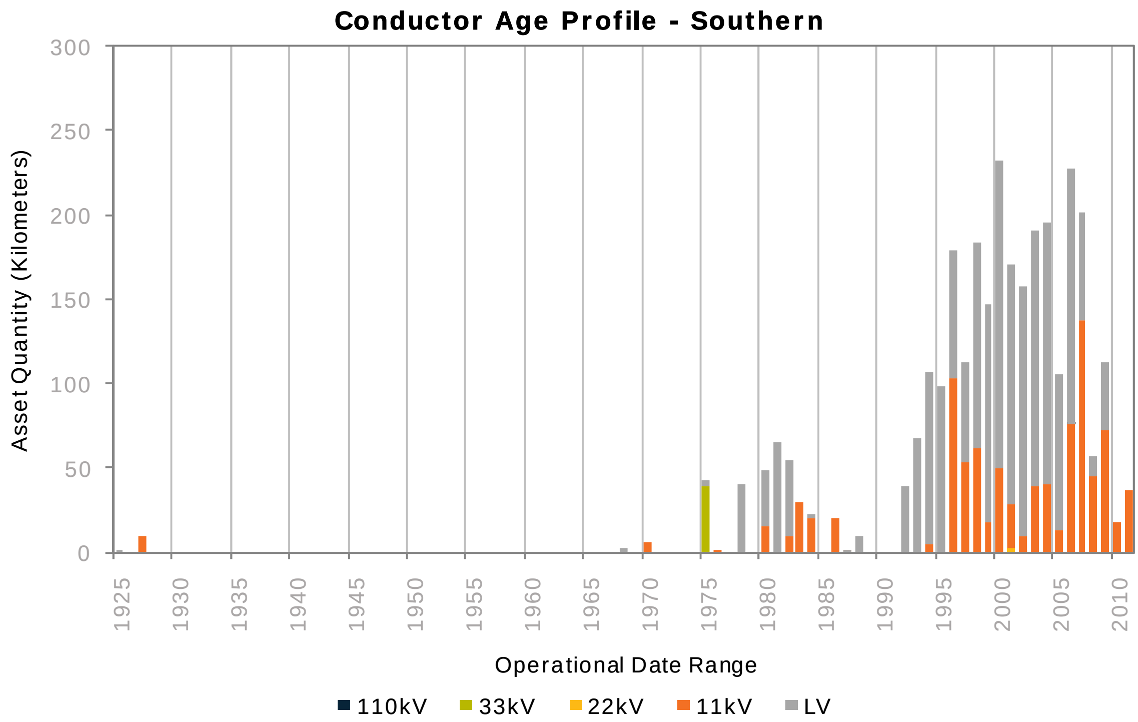


Figure 6-30 : Conductor Age Profile - Southern

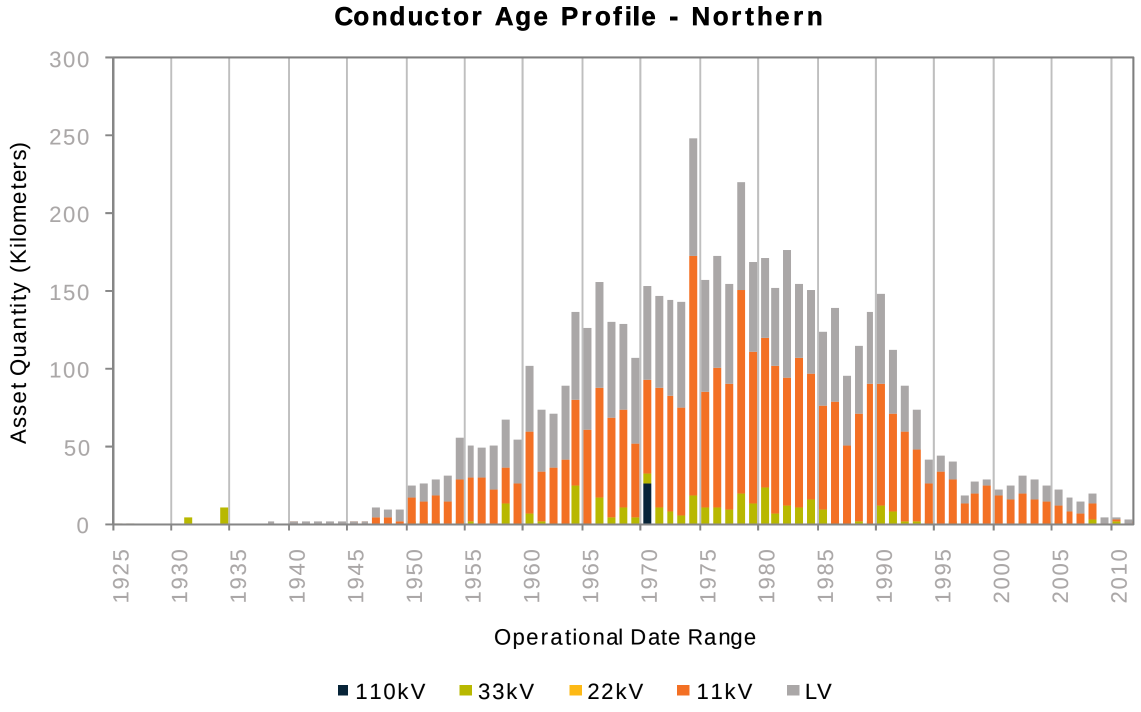


Figure 6-31 *: Conductor Age Profile – Northern*

The condition of most aluminium conductors and most copper conductors is good. However, there are areas reticulated with small sized copper conductors which have reached the end of their life. These are replaced when identified. There may be conductor corrosion issues associated with the clamps used on both the single and the double circuit 110 kV lines. Further investigation will be carried out during 2012 once the new switchboard at Wairau Rd is commissioned, to confirm this.

6.3.10.1 Inspection and Test Programmes

Conductors are inspected during the annual visual line patrol of the overhead network, in accordance with Vector standard *ENS-0187*.

There is no test programme for conductors.

A summary of the standard with regard to conductors is given as follows:

- Routine and preventive maintenance:
  - Annual – All Conductors are inspected as follows:
    - Ground clearances and conductor spacings visually assessed for adequate clearances;
    - Adequate clearance from vegetation;
    - Spans checked for balanced sags;
    - Conductors free from broken strands, corrosion and clash burn marks;
    - CCT high voltage conductors free from insulation;
    - Damage; and
    - Joints in conductors are visually secure and not showing signs of overheating.

- Refurbish and renewal maintenance:

  Any identified defect that renders a potentially unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable. Remediation timeframes are based on likelihood of failure creating the unsafe situation.

- Fault and emergency maintenance:

  Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

6.3.10.2 Maintenance and Refurbishment Programme

The remaining life of a conductor is difficult to predict because it is dependent upon several factors. These are the conductor material, natural environment, public exposure, access, mechanical loads, electrical loads and number and magnitude of downstream electrical faults.

Good data quality is required for acceptably accurate life prediction. Such data is now being collected under the MUSA agreements with our FSPs, enacted in November 2009. Given the inspection frequency in the preventative maintenance regime, it is expected that over a three-year period sufficient high-quality data will be obtained for more accurate future renewal predictions.

Until the end of 2012, predicted conductor replacement expenditure is based on a combination of the available asset records and an assumption the performance of poles will be largely similar to that observed over the last five years.

Conductors are not refurbished but recovered conductors in good condition may be reused. Conductors are repaired or replaced when they fail, in line with industry practice.

6.3.11 Overhead Switches

Overhead switches include MV air break switches (ABS), isolating links, SF_6 switches and reclosers and sectionalisers. These devices are installed to enhance network operation, allow remote switching (in some instances), reduce the impact of faults and the extent of outages and enhance reliability performance.

Table 6-18 shows the population and book value of overhead switches on the Vector network.

Population	Air Break	Recloser	Gas Break	Sectionaliser
Southern	378	27	191	13
Northern	662	100	227	31
Total	1040	127	418	44

Book Value	Air Break	Recloser	Gas Break	Sectionaliser
Southern	$1 m	$2 m	$3 m	$0 m
Northern	$6 m	$3 m	$4 m	$1 m
Total	$7 m	$5 m	$7 m	$2 m

Table 6-18 : OH Switchgear - Population and Book Value

Age profiles for 11 kV and 33 kV ABS and enclosed overhead switches installed in the Northern and Southern networks suffer from insufficient data. For legacy reasons, historical records are not completely accurate. In more recent times the installation of new enclosed switches has been triggered by Vector's standard ENS-0055 which is to replace ABSs with an enclosed switch when the opportunity arises, rather than at the end of their life. This has meant the age profiles are artificially skewed and do not necessarily represent assets at the end of their useful lives. The average age of removed ABSs has been between 20 and 25 years but, as noted, this cannot be used as a reasonable proxy for the expected end of life age for an ABS, or of average age of the assets.

The age profiles in Figure 6-32 and Figure *6-33* below clearly show the transition to enclosed switches in more recent times.

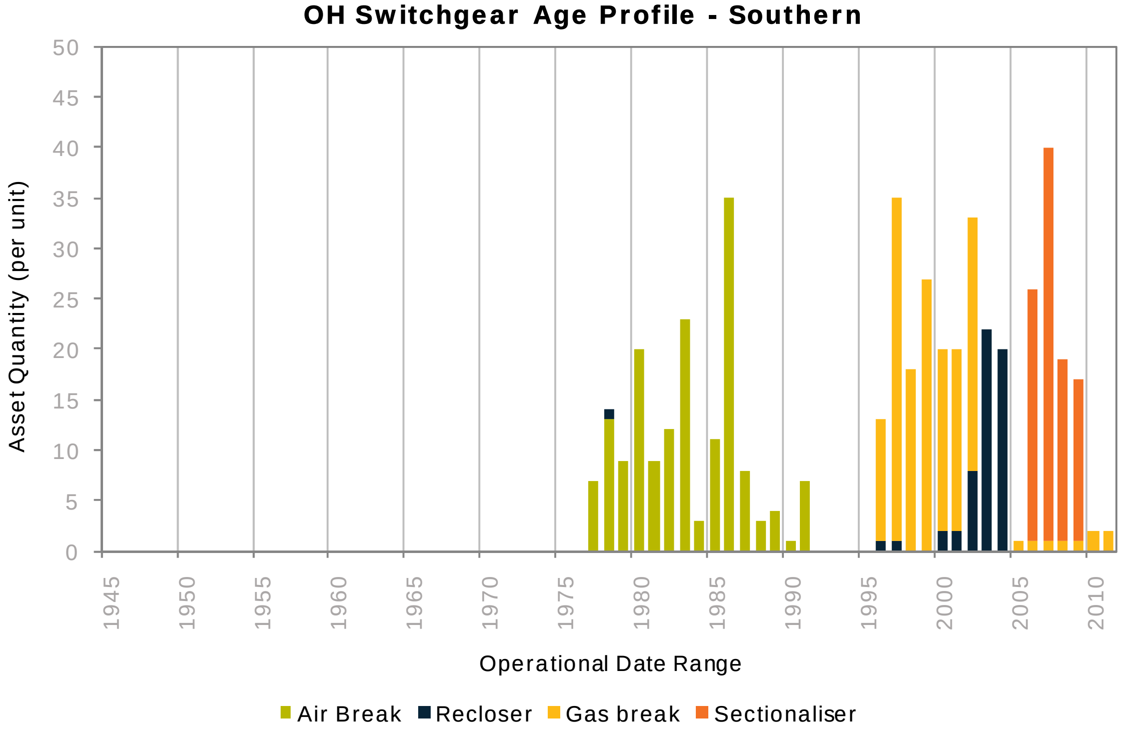


Figure 6-32 : OH Switchgear Age Profile – Southern

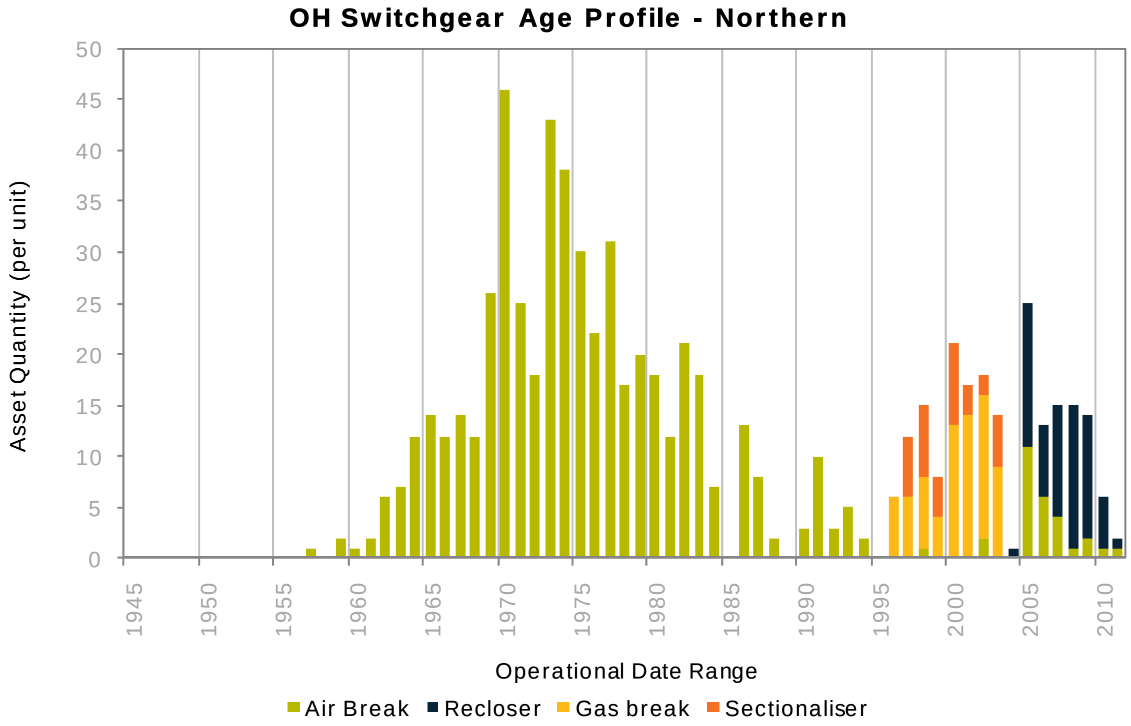


Figure 6-33 *: OH Switchgear Age Profile - Northern*

6.3.11.1 Condition of the Asset

Most of the ABSs are more than 20 years old and are in good to fair condition. The vast majority of the SF_6 switches are less than eight years old and are in excellent condition.

The reclosers are a mixture of older oil-filled units and the newer vacuum or SF_6 insulated equipment. The older oil-filled reclosers are in good condition and the SF_6 and vacuum reclosers and sectionalisers are in excellent condition.

Vector is not experiencing any systemic problems with its overhead switches.

6.3.11.2 Inspection and Test Programme

Overhead switches are visually inspected during the annual line inspections, in accordance with Vector standard *ENS187*.

A summary of ENS187 with regard to overhead switches is given as follows:

- Routine and preventive maintenance:
  - Switch mechanism visually complete and aligned;
  - Support framework secure, undamaged and free from corrosion;
  - Electrical connections (including earthing) visually secure, undamaged and free from overheating;
  - Control boxes visually secure; and
  - Gas indicators where fitted showing adequate levels of gas.
- Refurbish and renewal maintenance:
  - Any identified defect that renders a potentially unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable. Remediation timeframes are based on likelihood of failure creating the unsafe situation.

- Fault and emergency maintenance:
    - Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

ABSs are operationally tested every three years (to Vector standard ENS-0055). Enclosed switches are operationally tested every nine years. The remote control functions of switches fitted with this option are tested annually (to Vector standard ENS-0055).

A summary of ENS-0055 is given as follows:

- Routine and preventive maintenance:
    - Three yearly - MV ABS maintenance service, functional operation testing, bucket based visual inspection, contacts cleaned, dressed and lubricated, operating mechanisms bearings and pivots lubricated, contacts adjusted for correct alignment and operation;
    - Three yearly - thermal camera inspection;
    - Five yearly - earth system visual inspection and remote earth testing of overall earthing system resistance, each earth bank resistance, and step and touch voltage measurement. Marginally non-compliant sites require step and touch voltage retesting using off-frequency injection current; and
    - Nine yearly - MV Gas break switch bucket based visual inspection, adequate operating pressure;
- Refurbish and renewal maintenance:
    - Non-compliant earthing locations may require additional electrodes, asphalt patching, gradient rings, equipotential grids, fenced or non-conductive enclosures or wider network solutions such as neutral earthing resistors;
    - An identified MV ABS defect that meets the operating constraint criteria will require switch replacement if still essential, modern replacement being an enclosed SF6 switch;
    - An identified Gas break switch defect that meets the operating constraint criteria, specifically loss of pressure, will require switch removal and return to the manufacture for repair assessment and acceptance testing;
    - Connectors with identified thermal hotspots greater than 15 degrees above surroundings are replaced;
    - Switch contacts with identified thermal hotspots greater than 15 degrees above surroundings will require switch replacement if still essential, modern replacement being an enclosed SF6 switch;
    - Minor mechanical defects such as operating handles require repair; and
    - MV wedge connectors are required on all switch installations, the associated upgrade shall be programmed within six months.
- Fault and Emergency Repair:
    - All identified defects that pose an unsafe condition for public and property require immediate repair, replacement or isolation.

6.3.11.3 Maintenance, Refurbishment and Replacement Programme

ABSs are maintained when tested. The gas switches are fully enclosed and do not require maintenance. They are expected to have a life of about 40 years.

ABSs are replaced by an enclosed switch if they have to be removed from the pole because of a defect. They are not refurbished. Faulty gas switches are returned to the supplier.

There is no proactive replacement programme for ABSs. However, when cluster overhead replacement and pole replacements occur, any associated ABSs are replaced with gas switches. Gas switches are also installed when system reliability issues call for a remotely operable switch.

The remaining life of an ABS is difficult to predict because it is dependent upon several factors. Typically these are the natural environment, public access, electrical loads and number and magnitude of downstream electrical faults experienced over the life of the asset.

While condition data is being collected during routine inspections, as noted above, many ABSs will be replaced before the end of their life. Consequently, predicted replacement expenditure is based on the assumption the current base replacement rates will increase over the next ten years, to allow for additional switches installed to improve reliability.

6.3.12 Crossarms

The crossarms on the Vector network are mostly hardwood (99%) and their condition ranges from poor to good. Vector also has a small number of steel crossarms that are in good condition.

Vector has limited information on the age profiles and book values of the crossarms on the network. This is partly as a result of the manner in which assets were categorised under ODV valuations, where pole-top structures are not separately identified.

6.3.12.1 Systemic Issues

Crossarms installed in the 1990s were durability class 3 and are regarded as having a life of about 20 years. This is unlike the older crossarms which were more durable and were regarded as being capable of up to 40 years service. Only durability class 1 crossarms (longer life) are now installed on the network.

6.3.12.2 Inspection and Test Programme

Crossarms are inspected during the annual overhead line patrols, as specified in Vector standard ENS-0187. There is no specific test programme for crossarms.

A summary of ENS-0187 with regard to crossarms is given as follows:

- Routine and preventive maintenance:

  All crossarms shall be inspected as follows:

  - Hardwood crossarms and transformer platforms free from rot, significant cracks or splits, deformation, and signs of burning;
  - All 1.3m (4’6”) low voltage arms shall be identified;
  - Steel crossarms are free from obvious rust and general deformation;
  - Concrete crossarms are free from cracking and loss of concrete;
  - Laminated pine crossarms are free from signs of de-lamination;
  - Fibre glass arms are free from signs of de-lamination or failure of the outer epoxy coating; and
  - Double arms are constructed with spacer pipes, internally nutted bolts or eyebolts, or spacer blocks.

- Refurbishment and renewal maintenance:
  - Any identified defect that renders a potentially unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable. Remediation timeframes are based on the likelihood of failure creating an unsafe situation.
- Fault and emergency maintenance:
  - Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

6.3.12.3 Maintenance, Refurbishment and Replacement Programme

The remaining life of a crossarm is difficult to predict because it is dependent upon several factors other than age. These are typically the timber species used, pre-installation seasoning, natural environment, and the load being supported.

Good data collection is required to enable sufficiently accurate life prediction to take place. Such data is now being collected under the MUSA agreements with our FSPs, enacted in November 2009. Given the inspection frequency in the preventative maintenance regime, it is expected over a three-year period sufficient high-quality data will be obtained for accurate future renewal predictions.

Until then, predicted expenditure is based on the assumption crossarms will continue to be replaced at present rates.

Defective crossarms found during the annual line patrols are replaced. Crossarms are not refurbished.

6.3.13 Overhead Network - General

Various components of the overhead network are separately discussed below. In this section some general issues regarding the overhead network, with assets that do not fit with specific categories, are noted.

All overhead structures and supported equipment are visually inspected every 12 months.

Maintenance of the overhead network is a mix of reactive (based on faults) response and condition monitoring that drive preventative maintenance programmes. With the exception of gas switches and vacuum reclosers, which are returned to the supplier for refurbishment, damaged overhead equipment is not refurbished or salvaged as it is not cost effective to do so.

Assets requiring replacement are identified during the annual overhead inspection or one of the more detailed equipment inspections. Overhead distribution components are operated to failure, but in the past, when the number of identified replacements in near proximity exceeds a certain level, cluster replacement/reconstruction programmes were initiated.[11]

6.3.13.1 Connectors

To overcome copper/aluminium connection corrosion issues arising from the use of copper tails in aluminium connectors, a welded bimetal transition connection has been developed. This will be used in future instead of the current type of connectors (Ampacts). It is anticipated that this will offer far superior performance, at a much reduced cost.

[11] This is to achieve cost efficiencies by avoiding the need to repeatedly return to an area to repair faults, with the associated additional set-up costs (and inconvenience to customers).

Predicted connector replacement expenditure is based on the assumption the replacement rate will continue at present rates. This assumption will be tested as more data from routine maintenance inspections become available.

6.3.13.2 Conductor Insulator Ties

Early preformed conductor ties used a rubber cushioning packer that has a tendency to perish and cause TV interference. These are being replaced in an organic manner.

6.3.13.3 Insulators

Kidney type insulators are prone to failure and are a common source of TV interference. The use of kidney insulators has been superseded by ceramic and glass disc and polymer strain insulators.

6.3.13.4 Pole Transformer King-Bolts

It has been found that crossarm king-bolts have been rusting in the section of the bolt where it is encased by the crossarm. While this affects all king-bolts it is not a major safety issue for conductor crossarms as there will in most cases be secondary supports such as conductors and straps that will act to prevent the arm falling to the ground. Pole transformer king-bolt deterioration is a much more serious issue, as these are under a much heavier load and the failure of the bolt will lead to the transformer falling from the pole.

Replacement of transformer hanger arm king-bolts requires almost as much effort as replacing the hanger arm. A more efficient solution has been devised, by using a retro-fit clamping support that allows the transformer arm to be supported without having to rely on the king bolt. A programme is underway to install them on all overhead transformers.

6.3.13.5 Live Unused Spurs

Due to concern for the safety of the general public and Vector's assets, a survey is to be undertaken to identify any existing unused live overhead HV spurs and to either dismantle or isolate them from the network. .

6.3.13.6 110 kV Conductor Corrosion

The single and double circuit 110 kV lines may require maintenance to replace sections of corroded conductor, and further measures to prevent on-going corrosion. Corrosion sites have been detected at the insulator clamps, but the extent of this is still to be determined.

6.3.14 Distribution Cables and Accessories

Older 400V cables on the Vector network are paper-insulated and lead-sheathed while the newer 400V cables are either PVC or XLPE insulated. The 6.6 kV rated and the older 11 kV cables are PILC or paper insulated aluminium sheath (PIAS) construction, with the more recent 11 kV and the 22 kV cables having XLPE insulation.

Table 6-19 below shows the breakdown of distribution cables by voltage class, network and book value.

Population	22kV	11kV	LV	Total
Southern	28 km	1993 km	3010 km	5031 km
Northern	0 km	1196 km	1818 km	3014 km
Total	27 km	3189 km	4828 km	8045km

Book Value	22kV	11kV	LV	Total
Southern	$14 m	$279 m	$182 m	$475 m
Northern	$0 m	$142 m	$73 m	$215 m
Total	$14 m	$421 m	$255 m	$690 m

Note: Quantities exclude pole riser lengths of 8m per LV termination, 9m per 11 kV and 22 kV termination, and 10m per 33 kV terminations

Table 6-19 : Distribution cables - population and book value

Age profiles and book values for the distribution cables, per category and broken down per network, are given in Figure 6-34 and Figure 6-35.

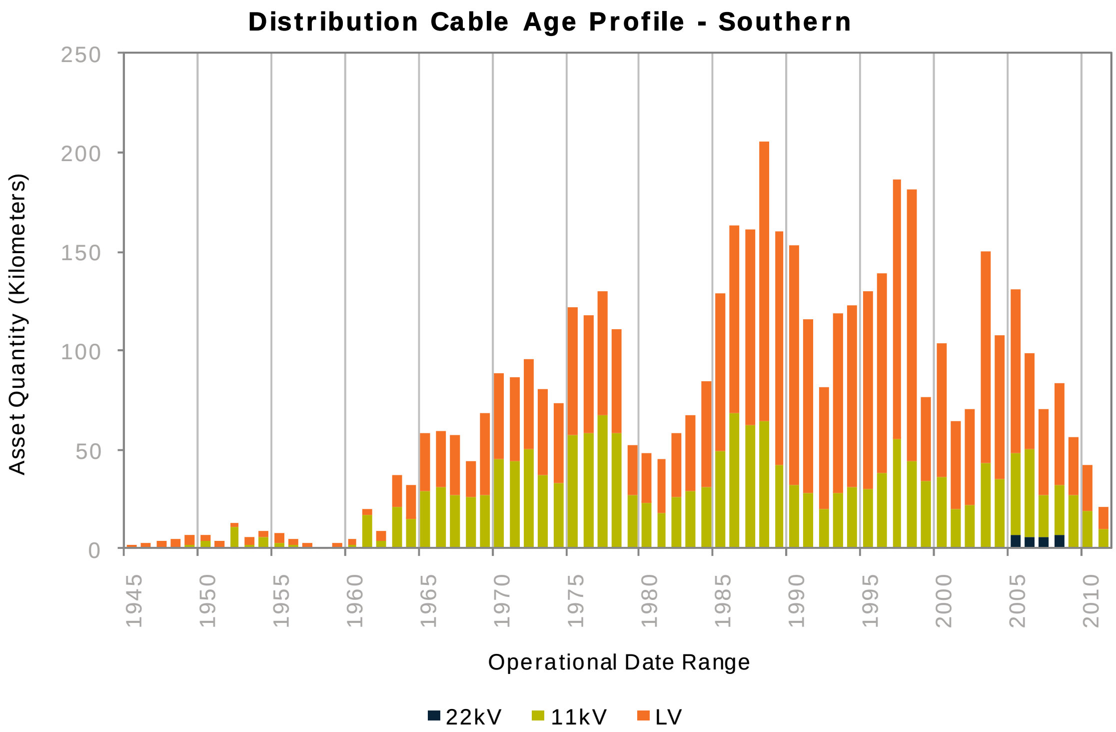


Figure 6-34 : Distribution cable age profile – Southern

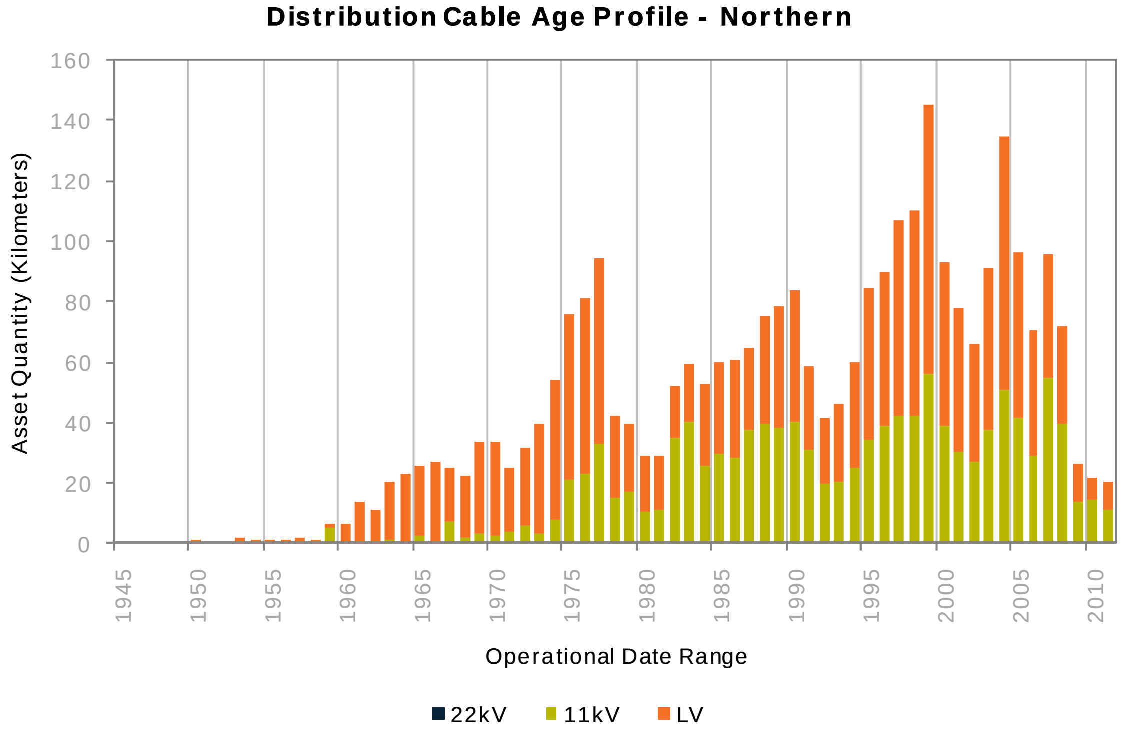


Figure 6-35 : Distribution cable age profile – Northern

6.3.14.1 Asset Condition

In the past, some 6.6 kV rated PILC cables were determined to be able to be energised at 11 kV and in most cases have successfully operated at this voltage for many years. However, some of these are now becoming more prone to failure. The associated issues are further discussed below.

The 11 kV rated PILC cables are generally operating satisfactorily.

The XLPE insulated cables are in good condition, with the exception of the early natural polyethylene ('poly') cables noted below.

Systemic issues:

- **22 kV cables:** These cables are still very new, with the first having been installed in 2005. As would be expected, to date there have been no known issues. Life expectancy of these cables is 60 years but this is dependent upon factors such as the electrical load, the installation conditions and the number and magnitude of any downstream faults;
- **11 kV cables:** In the early 1970s natural polyethylene insulated 11 kV cable was installed on the Northern network. This type of cable has a high fault incidence and Vector's current practice is to repair the cable when it faults to restore supply, followed by corrective works to replace the cable in a programmed manner. Past experience has shown that once faulted, subsequent faults soon follow;
- **6.6 kV cables:** In the past some cables have been upgraded to 11 kV operation, which is now creating issues.[12] Some of the issues are due to failure of the joints

[12] It should be noted that this earlier decision, in spite of the difficulties now experienced, has allowed Vector to continue operating the existing 6.6kV cables for several years after the network distribution voltage was increased. By deferring the earlier investment to replace the cables, the overall economic benefit has been substantial.

(workmanship and insulation only designed for 6.6 kV) and others due to insufficient cable insulation. The replacement priority for these cable sections has been defined.

The issues are compounded by the fact historical records of the cables are not always correct, with some cables indicated as being rated for 11 kV where this later proves not to be the case. The full extent of the issue is not known as confirmation of the actual voltage rating of an operating cable requires it be opened up and the insulating papers counted to confirm suitability for operation at 11 kV. Cables are treated on a case by case basis as faults occur.

- **400V cables:** Faulted breech joints on to the streetlight pilot cables occur frequently. As proactive location and replacement of these joints is not practical, they will continue to be replaced as they fail; and
- **Earthing cables:** An ongoing issue with earthing cables for pole-mounted equipment is conductor theft for the scrap value of the copper. Copper plated steel earthing cables are now installed to combat this.

6.3.14.2 Inspection and Test Programme

In practice only the terminations of underground cables are able to be inspected. Pole mounted cable terminations are inspected annually during the overhead network condition assessment, in accordance with Vector standard ENS-0187.

Outdoor terminations in zone substations are similarly inspected annually as per the Vector standard ENS-0191.

There is no regular testing of distribution power cables. Techniques such as PD mapping claim to be able to predict the health of cables. However, Vector's experience thus far is inconclusive and the technology requires further development. Long-term continuous monitoring of PD levels show promise but is currently impractical given the large number of cables involved.

The life of an underground cable is difficult to predict because it is dependent upon several factors. These are the cable construction, natural environment, public access, the electrical loads and the quantity and severity of downstream faults that the cable has experienced. In general, the best indicator of remaining life is the incidence of failures.

Underground cables are replaced when the failure rate becomes unacceptable. The benchmark level of unacceptability is more than one fault per annum. At present Vector is targeting cables exhibiting the most frequent faults and exceeding this level.

There are sections of cable that have been identified as exhibiting a high number of faults (generally ten or more faults over the past ten years). The future replacement programme for these 11 kV cables has been defined in the ten year programme of works. Vector anticipates replacing three cable sections per year for the next ten years as end-of-life failures become apparent.

Northern poly cable replacements have been historically included in the replacement programmes and it has been assumed this will continue at a constant rate. This rate has been falling as the population of cables of this type has diminished.

Maintenance of the underground cable network is limited to work identified during the visual inspections of cable terminations and exposed earthing cables. Power cables are operated to failure, after which sections are repaired, or replaced as indicated by previous fault history.

6.3.15 Earthing Systems

All installations with conductive equipment have their own dedicated earthing systems.

In general these consist of earth banks of driven pins connected by bare copper conductor.

6.3.15.1 Inspection and Test Programme

The earthing systems are normally visually inspected for integrity on an annual basis, but with increasing theft of the copper earth cables, the inspection frequency has been increased in some areas. Earth resistance and step and touch potentials where applicable are measured every five years in accordance with Vector standards ENS-0068 and ENS-0076.

A summary of ENS-0068 is given as follows:

- Routine and preventive maintenance:
- Five yearly - earth system visual inspection and remote earth testing of overall earthing system resistance, each earth bank resistance, and step and touch voltage measurement. Marginally non-compliant sites require step and touch voltage retesting using high current off-frequency injection; Refurbishment and renewal maintenance:
  - Non-compliant earthing locations may require additional electrodes, asphalt patching, gradient rings, equipotential grids, fenced or non-conductive enclosures or wider network solutions such as neutral earthing resistors;
- Fault and emergency maintenance:
  - All identified defects that pose an unsafe condition for public and property require immediate repair, replacement or isolation.

A summary of ENS-0076 is given as follows:

- Routine and preventive maintenance:
  - Annual – temporary earthing equipment, general visual inspection of leads and clamps, earthing lead contact resistance measurement;
  - Annual – earth system visual inspection, physical assessment of above ground earth conductors and connections and tags; and
  - Five yearly - earth system visual inspection and testing, bonding resistance measurements between primary assets, control cabinets and support structures to reference earth bar/grid, remote earth testing of overall earthing system resistance and independent main earth resistance testing if accessible, and step and touch voltage measurement using off-frequency heavy current injection.

6.3.15.2 Maintenance, Refurbishment and Replacement Programme

Earthing cables are only maintained if they are visibly unsound, missing, undersized or test results fall outside the limits given in Vector's distribution earthing maintenance standard.

Predicted future expenditure is based on the assumption the replacement/refurbishment rate will continue at the present rate.

6.3.16 HV Pole Mounted Cable Terminations

Terminations are the connection points between underground cables and the overhead network and include all 11 kV, 22 kV and 33 kV pole terminations. There are different types of these terminations in service.

Table 6-20 below shows the breakdown by voltage class, network and value of HV pole terminations on the networks.

Population	33kV	22kV	11kV	Total
Southern	15	2	2622	2639
Northern	175	0	5391	5566
Total	190	0	8013	8205

Book Value	33kV	22kV	11kV	Total
Southern	$0 m	$0 m	$7 m	$7 m
Northern	$2 m	$0 m	$10 m	$12 m
Total	$2 m	$0 m	$17 m	$19 m

Table 6-20 : Riser cable terminations - population and book value

Figure 6-36 and Figure *6-37* provide the age profiles and book values of cable terminations for each region, at the different voltage levels.

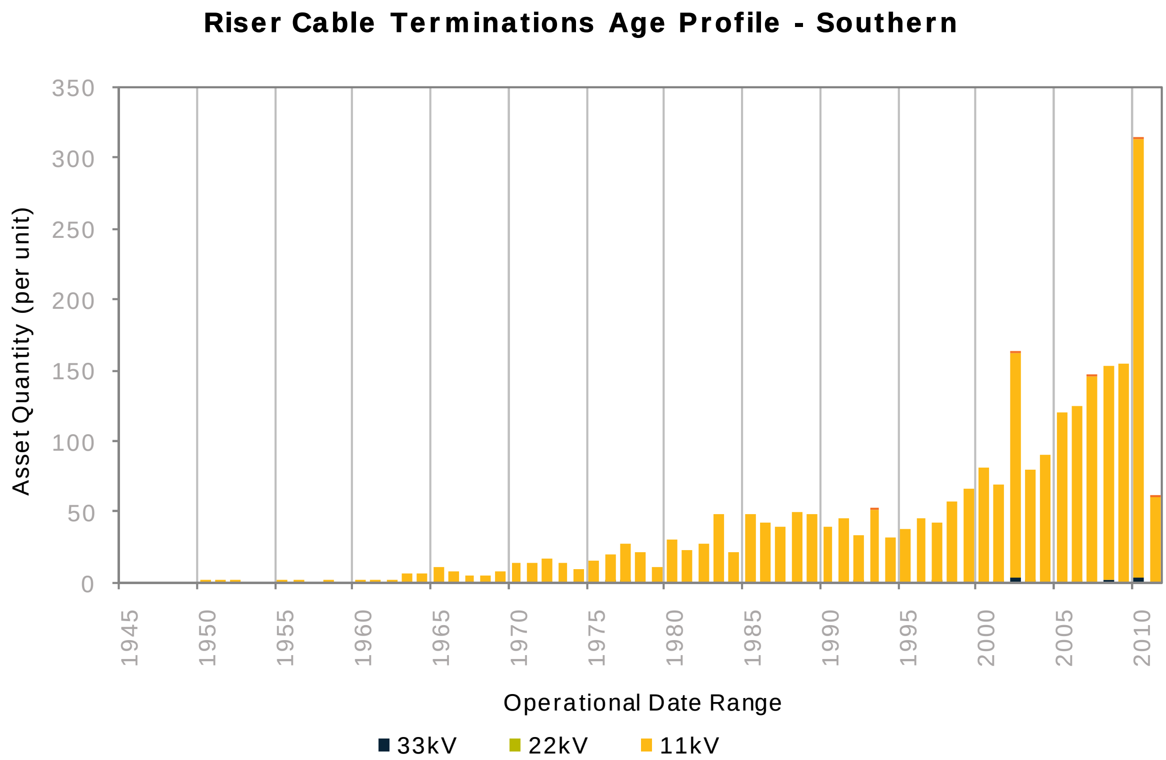


Figure 6-36 : Riser cable terminations age profile – Southern

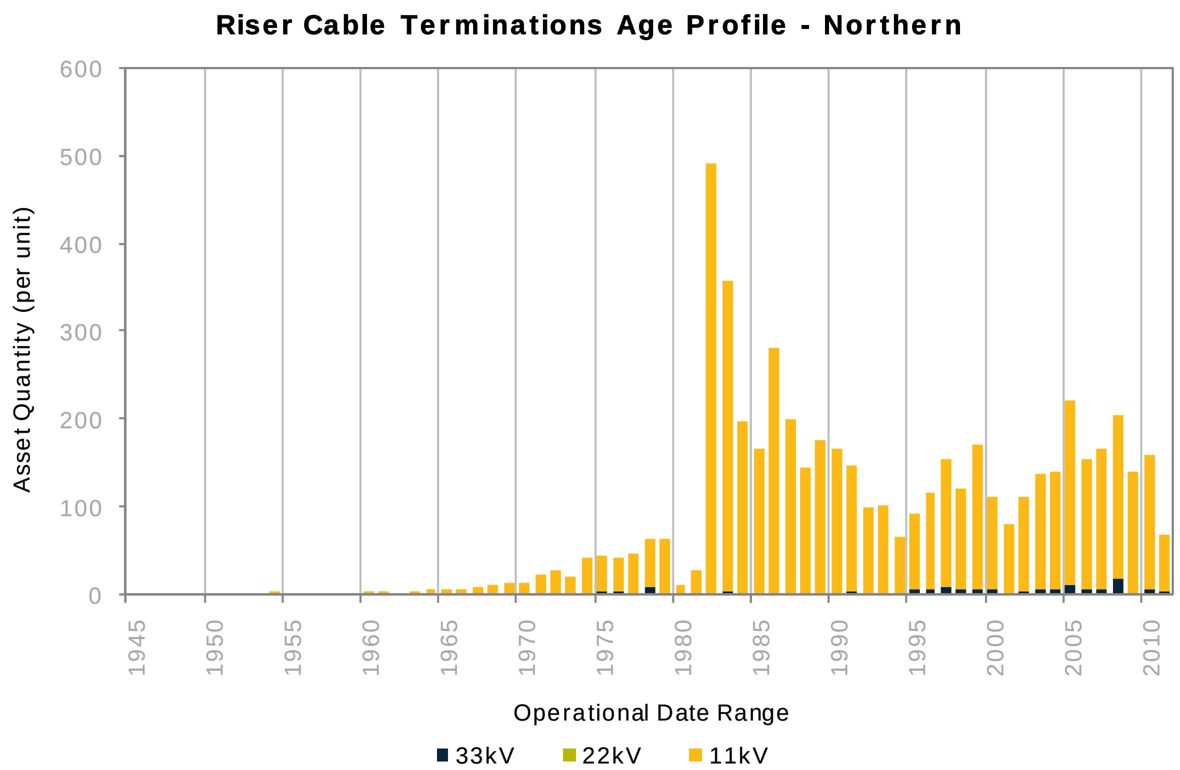


Figure 6-37 : Riser cable terminations age profile – Northern

6.3.16.1 Systemic Issues

Outdoor 3M cable pole terminations installed about 15 years ago are failing. The problem appears to be caused by poor sealing around the lugs, allowing water to enter the termination. Vector has pole mounted cable terminations where the connection between the underground cable and the overhead reticulation jumper is by two lugs bolted together at a standoff insulator. At some installations a steel nut has been placed between the two lugs, resulting in a high resistance connection between the underground cable and the jumper. Vector's overhead network condition assessment ENS-0187 standard specifically targets the identification of 3M terminations and of interposing nut/washer terminations, to target their replacement.

Several years ago some PILC cable manufactured with an HDPE sheath was installed. After a short time it was found that Raychem terminations on this cable leaked compound. The vast majority of these terminations were replaced by a pressure resistant termination and any remaining leaking terminations are replaced when found.

Older terminations were contained in a cast iron enclosure. This changed to cast aluminium and finally to hot shrink or cold applied alternatives. Because of safety concerns regarding the cast metal terminations, they are being progressively removed from the Vector network.

Inspection and Test Programme

Inspection of pole mounted cable terminations is included in Vector's annual overhead network condition assessment ENS-0187 standard. There is no regular testing of cable terminations. A summary of ENS-0187 is given as follows:

- Routine and preventive maintenance:

  Annual inspection

    - All cable risers, terminations and their protection covers shall be inspected as follows:
    - Terminations and supports secure, undamaged and free from corrosion, no visible leaks of insulating compound or oil;
    - All HV cable pole terminations shall be visually inspected to confirm a nut and/or washer has not been inserted between the two cable lugs on the standoff insulators/arresters;
    - Electrical connections including earthing secure, undamaged and not showing signs of overheating;
    - The locations of all HV 3 core 3M cable terminations shall be noted;
    - LV XPLE cables shall be visually inspected to confirm that ultra violet protection shrink tube has been installed over the XPLE insulation of the cores above the break-out udder;
    - Cable covers or pipe not damaged; and
    - Cables securely attached to the pole.
- Refurbishment and renewal maintenance:
    - Any identified defect that renders an unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable. Remediation timeframes are based on likelihood of failure creating the unsafe situation.
- Fault and emergency maintenance:
    - Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

6.3.17 Pillars and Pits

Pillars and pits provide the point for a customer cable to connect to Vector's reticulation network. They contain the fuses that isolate the service cable from the network distribution cable and which prevents major potential damage to the service cable following a fault in the consumer installation.

For loads up to 100 Amp, an underground pit has largely superseded the above ground pillar for new work, although there are still some applications where a pillar will be preferred. Pits are manufactured from polyethylene, as are most of the newer pillars. Earlier pillars have made use of concrete pipe, steel and aluminium.

The older aluminium pillars are generally adequate for their purpose although many have suffered knocks and minor vehicle impact.

Installation of pits began about ten years ago and comprehensive inspections to date have not shown up any significant maintenance issues.

Table 6-21 provides a summary of the total pillars and pits in use on the Vector network. This includes service and link pillars, service pits (Total Underground Distribution System (TUDS)) and underground network link boxes.

Network	Population	Book Value
Southern	82960	$59 m
Northern	25750	$26 m
Total	108710	$85 m

Table 6-21 : LV pit and pillar - population and book value

Figure 6-38 and Figure *6-39* show the pillar and pit age profiles and book values for each region.

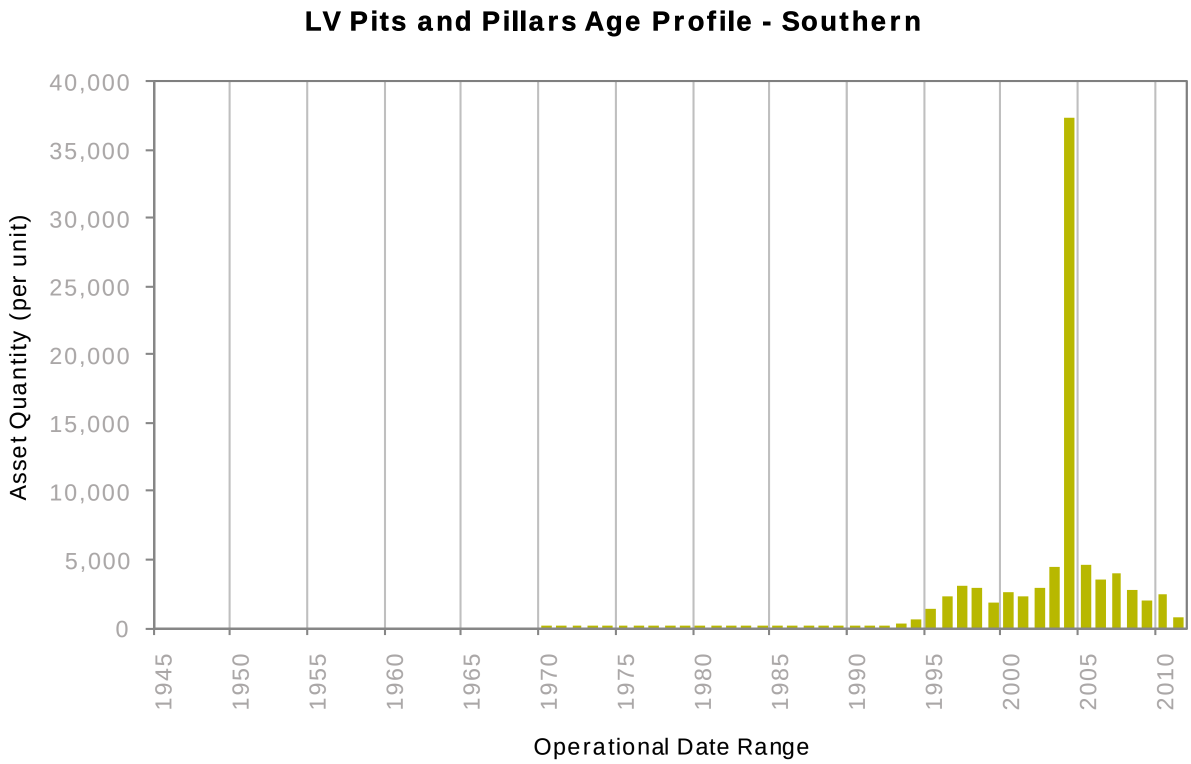


Figure 6-38 : LV pits and pillars age profile - Southern

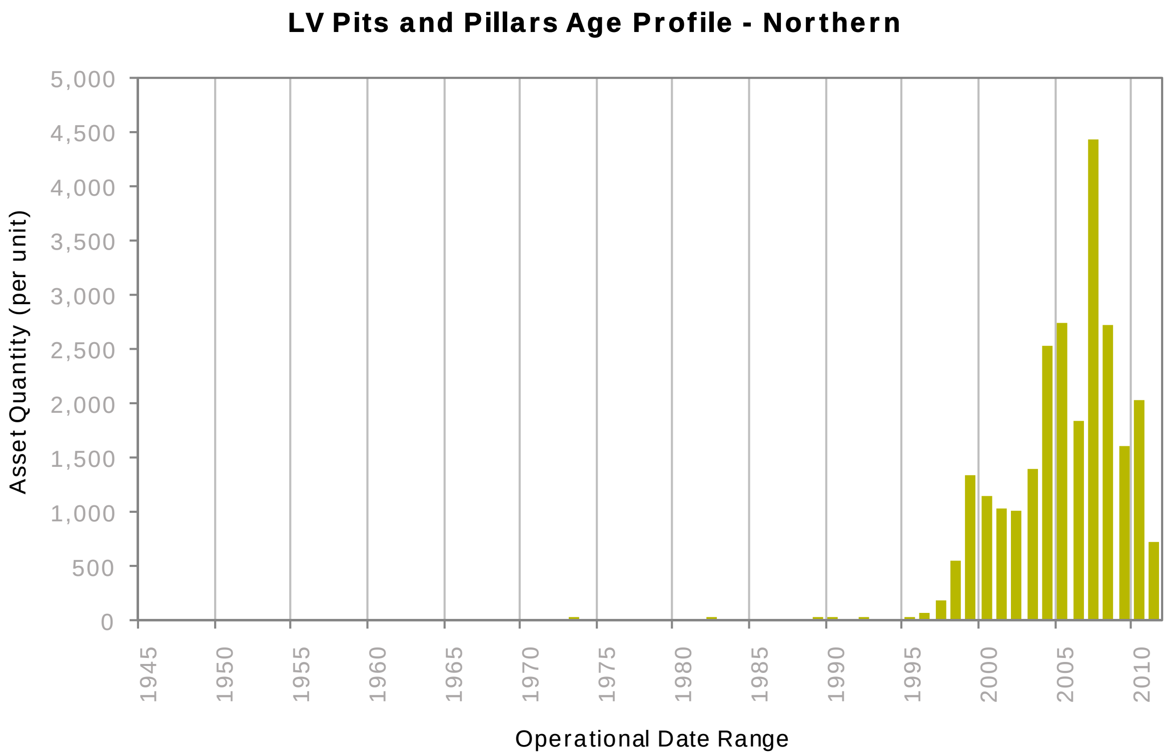


Figure 6-39 *: LV pits and pillars age profile - Northern*

6.3.17.1 Asset Condition

The condition of customer pits and pillars range from very poor to new condition. The age and range of installation condition is such that it is difficult to determine any primary cause for deterioration. Unsound units are identified through proactive inspection and maintenance programmes and are replaced accordingly.

Mushroom pillars that are found in the Northern region and are being replaced with a polyethylene pillar for safety reasons. Underground low voltage network link boxes used in the Auckland CBD are generally in poor condition and require replacement. Also many of the pavement lids and their supporting surrounds have been damaged. Off the shelf like for like replacements are not available for this equipment. Where possible the boxes are to be removed and the cables jointed through. Where underground network boxes are still required, a new smaller box will be installed.

6.3.17.2 Inspection and Test Programme

Pillars, TUDS and underground network boxes are inspected at three-yearly intervals as specified in Vector standard ENS-0175.

Loop impedance is measured when service pillars and pits are first installed, but there is no regular testing of these components of the distribution system.

A summary of ENS-0175 is given as follows:

- Routine and Preventive Maintenance:
  - Three yearly – visual inspections, encompasses the following asset, pillars, pits, link boxes, network boxes and fuse boxes. External inspection to ensure safe operation and emergency assessment of vegetation ingress, build up around assets, burial of assets, vandalism. Internal inspection covering loose or poor connections, water ingress, heating effects;
- Refurbishment and Renewal Maintenance:
  - Vegetation that cannot be easily removed or trimmed may require the relocation of the affected pit or pillar;
  - Buried or low seated pillars are uncovered and raised. In some cases they may require relocation;
  - Assets on private property that exhibit identified defects and require repair or replacement are relocated to the road reserve;
  - A pillar due for relocation or replacement will be assessed for suitable pit replacement depending on number of circuits and required capacity for; and
  - Minor repairs on site include removal of vegetation, replacement of lid screws, new connectors, corrosion treatments, repainting.
- Fault and Emergency Maintenance:
  - Hazardous defects identified resulting in potential unsafe situations for public or property, are repaired, replaced or isolated immediately.

6.3.17.3 Maintenance, Refurbishment and Renewal Programme

The remaining life of a pillar or pit is difficult to predict because it is dependent upon a number of factors. These are the pillar construction, natural environment, public exposure, access and the electrical loads supplied by the pillar.

Data now being collected under the MUSA agreements with our FSPs, enacted in November 2009, will in future allow a more accurate assessment of replacement programmes. Given the frequency of the preventative maintenance regime, exhaustive data will be available by late 2012. In the interim, predicted replacement expenditure is based on the assumption that replacement rate will continue at present rates.

Pillars are normally operated until they fail the inspection criteria, which are generally based on whether the condition of the pillar is creating a hazard.

Where practicable, pillars are repaired on site following faults or reports of damage or the results of the inspection programme. Otherwise a new pillar or pit or network box is installed.

Pillars with a high likelihood of future repeat damage by vehicles are replaced with pits. Older pillars are targeted for planned replacement as repair becomes impractical or uneconomic, or where they present an unacceptable safety risk.

Full replacement of the remaining identified mushroom pillars, is planned for FY12. Should ongoing network asset surveys identify additional mushroom pillars these will be replaced in FY13.

Replacement of underground network boxes has been included as a separate budget item. At present, there is no history of such replacement, and a small provisional sum only is allowed over the next five years.

6.3.18 Distribution Transformers

Distribution transformers convert distribution voltage levels (typically 22kV and 11kV) to customer voltage levels (typically 400V three phase or 230V single phase). The units are generally constructed with an off-load tap changer, which enables the LV output to be raised or lowered depending on system requirements.

For the majority of distribution transformers currently in service, the windings, insulated with paper insulation, are contained in a tank of mineral insulating oil. For a very small number of transformers, the windings are contained in a tank of synthetic organic ester. These transformers are used in situations where fire safety or protection of the environment (where other containment measures are not practical) are primary considerations.

New transformers are supplied in compliance with Vector's standard ENS-0093. Vector's distribution transformers are generally 11kV/415V and rated between 15kVA and 1,000kVA. All the transformers in that range are three phase. The three phase transformer windings are connected delta/star in accordance with the vector group reference Dyn11. There are also a small number of single phase transformers rated at 1.5kVA, 5kVA, 7.5kVA, 10kVA, 15kVA and 30kVA.

Transformers are either ground or pole mounted. Ground mounted transformers are either stand-alone, enclosed in metal or fibreglass canopies, installed in open enclosures or installed in a building. They can be further categorised into industrial, cubicle or package types. The majority of 11kV ground mounted transformers are connected to the MV and LV networks by cable lugs and bolted connections to the transformer bushing flags.

All cubicle style transformers that are installed as part of overhead improvement projects are connected to the HV cables by dead-break screened plug-in cable connectors. The connection to the LV cables is through cable lugs and bolted connections to the transformer bushing flag.

Pole mounted transformers are installed on single or double poles. The transformers are connected to the HV and LV networks by cable lugs and bolted connections to the transformer bushing flags.

In the development of the 22kV underground distribution networks in the Auckland CBD and Highbrook Business Park, 22kV/415V ground mounted transformers are being installed. Transformers for these two networks are three phase and are rated between

300kVA and 1,000kVA. The transformer windings are connected delta/zigzag in accordance with vector group reference Dzn2. The transformers are connected to the HV cables by dead-break screened plug-in cable connectors. The connection to the LV cables is by cable lugs and bolted connections to the transformer bushing flag.

Transformers installed on the network are presently supplied by either ABB or ETEL.

The ODV life for transformers that are 15kVA or less is 45 years and for all other transformers is 55 years. The design life, however, is typically 25 to 40 years based on loading, and if a transformer is well maintained this life can be extended to 60 years or more.

The age profiles and book values of Vector's distribution transformers on each network are shown in Table 6-22, Figure 6-40 and Figure *6-41*.

Network	Population	Book Value
Southern	8243	$85 m
Northern	12455	$81 m
TOTAL	20698	$166 m

Table 6-22 : Distribution transformer - population and book value

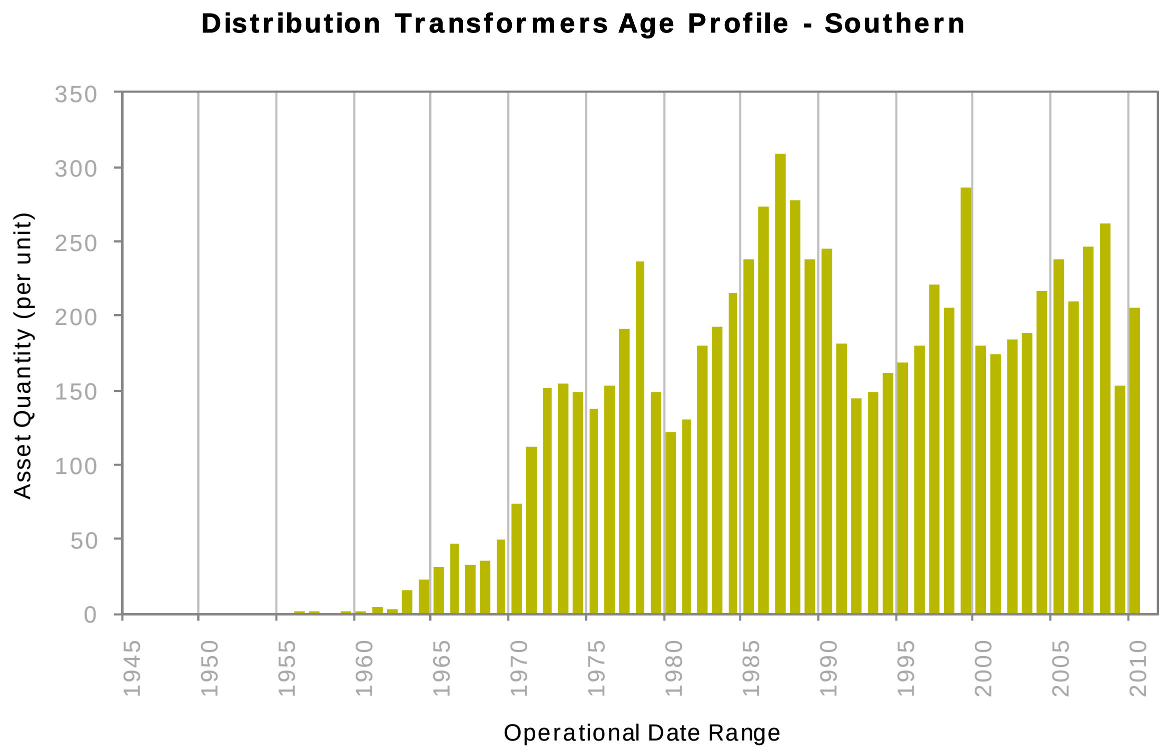


Figure 6-40 : MV transformers age profile – Southern

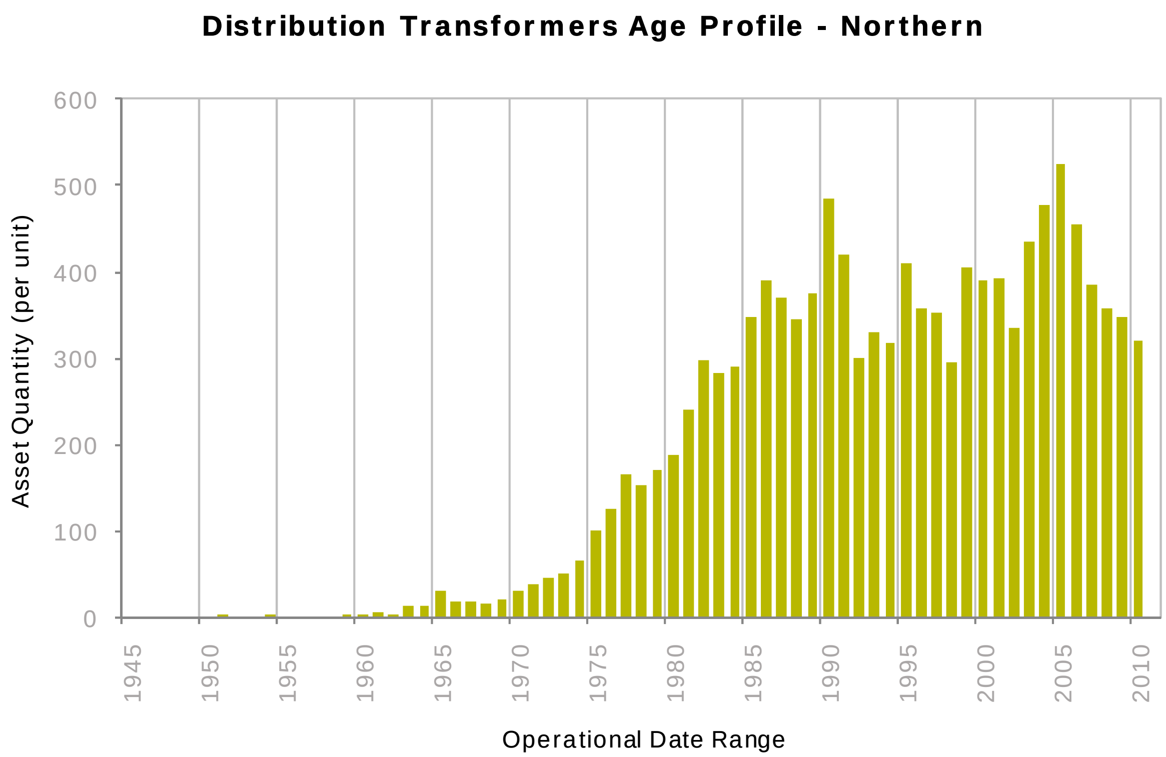


Figure 6-41 *: MV transformers age profile - Northern*

6.3.18.1 Asset Condition

In general the condition of the distribution transformers is good. Since 2001 many of those that were in poor condition have been replaced as part of renewal programmes which have been implemented across the network.

A systemic issue with corrosion and oil leakage leading to premature asset replacement has, however, been identified with some types of units:

- Some transformers installed between 1998 and 2001 have been identified as prematurely rusting. This is estimated to be about 2% of the population; and
- Ground mounted transformers about 25 years old have increased risk of excessive rust or oil leaks. This is estimated to be about 5% of the population; and
- A greater number of mini substations installed on the Northern network have corrosion issues compared to those on the Southern network. The reason is thought to be the manufacturer's inadequate preparation of the steel surface prior to painting and the subsequent inferior painting coating system.

These transformers are being systematically replaced in accordance with Vector's current renewal process.

6.3.18.2 Inspection and Test Programme

Visual inspection of distribution transformers is carried out in accordance with Vector Standard ENS-0188. The frequency of inspection is presently five-yearly for pole mounted transformers and four-yearly for ground mounted transformers.

Electrical testing is not carried out on distribution transformers unless there is a specifically identified issue that needs to be investigated and resolved.

Testing of the insulating oil in a customer transformer for the presence of polychlorinated biphenyls (PCB) is carried out on request from customers and customers' insurance companies. All the test results to date have shown less than 50 parts per million of PCB in the oil. This result means that the oil is classed as a non-PCB liquid.

Thermal imagining and testing for partial discharge (PD) is presently carried out on only ground mounted transformers as part of the transformer inspection programme.

6.3.18.3 Maintenance, Refurbishment and Renewal Programme

Maintenance on distribution transformers is on a time-based inspection regime carried out in accordance with Vector Standard ENS-0051. Onsite repairs are generally minor and include such items as oil top up, replacement of holding down bolts, repair of minor oil leaks, minor rust treatment and paint repairs. Where it is uneconomical or impractical to complete onsite maintenance, or the transformer poses a safety or reliability risk before the next inspection cycle, the transformer is replaced and, where economic, refurbished and returned to stock.

In general, Vector's approach is to assess the condition of distribution transformers and proactively replace these based on the assessment (or where a change in capacity is required).

Transformers removed from service that are still in salvageable condition are assessed and refurbished if the assessment criteria to refurbish are met. The assessment also includes consideration of Vector's stock requirements at the time. The assessment criteria are detailed in Vector Standard ENS-0170. It is expected a transformer will attain another 25 to 30 years of service after refurbishment. Transformers that do not meet the assessment criteria for refurbishment are scrapped.

6.3.19 Auto Transformers and Phase Shifting Transformers

An auto transformer is an electrical transformer with only one winding. A portion of the winding is common to both the primary and secondary circuits. The winding has at least three electrical connection points called taps. The voltage source and the load are each connected to two taps. One tap at the end of the winding is a common connection to both circuits (source and load). Each tap corresponds to a different source or load voltage.

A phase shifting transformer is a transformer that creates an output voltage with an altered phase angle compared to the input voltage, but with the same amplitude.

There are two ground mounted auto transformers and one phase shifting transformer on Vector's network. All are installed on the Southern network. One auto transformer is 11kV/6.6kV and the other is 22kV/11kV. Both were manufactured by ABB. The 11kV/6.6kV 750kVA auto transformer is used at MOTAT in Western Springs as a connection between Vector's 11kV network and MOTAT's 6.6kV network that supplies the rectifiers for their trams. Its capacity is 750kVA.

The 22kV/11kV 1.5MVA auto transformer is used as a backup supply from Counties Power to the Vector network.

The economic life for auto transformers and the phase shifting transformer is 55 years. An age profile of Vector's auto transformers and the phase shifting transformer is shown in Table 6-23 below.

Network	Year of Manufacture	Population
Southern	1997	1
Southern	2001	1
Southern	2006	1
Total (units)		**3**

Table 6-23 : Auto transformer and phase shifting transformer population

The condition of the auto transformers is very good.

The 5MVA 11kV/11kV phase shifting transformer was manufactured in 2006. It is installed in the Southern region and is used as a connection point between the Southern and Northern distribution networks. Its condition is very good.

6.3.19.1 Inspection and Test Programme

Inspection of the auto transformers and phase shifting transformer is carried out in accordance with Vector Standard ENS-0188. The frequency of inspection is the same as that for ground mounted distribution transformers; currently four-yearly.

Electrical testing is not carried out on the auto transformers and phase shifting transformers, unless there is an issue with a transformer which needs to be investigated and resolved.

Thermal imaging and PD and acoustic discharge testing is presently carried out as part of the inspection programme.

Transformer Condition Analysis (TCA) on oil samples from the 22kV/11kV auto transformer is presently carried out. It is planned that this test for the phase shifting transformer be added to the activities carried out by the service provider.

6.3.19.2 Maintenance, Refurbishment and Renewal Programme

Preventative maintenance of the auto transformers and phase shifting transformer is on a time-based inspection regime and is carried out in accordance with Vector standard ENS-0051. Onsite maintenance is generally minor and includes such items as oil top up, minor rust treatment and paint repairs.

The 11kV/6.6kV auto transformer was refurbished in 2011 prior to being installed at MOTAT. Due to the relatively young age of the 22kV/11kV auto transformer and the phase shifting transformer, their good condition and economic life, there is currently no refurbishment programme for these units.

There is no replacement programme for the auto transformers or the phase shifting transformer.

6.3.20 Voltage Regulators

A voltage regulator is a device that automatically produces a regulated output voltage from a varying input voltage. The regulators on Vector's network are step-voltage regulators and a tap changer in the regulator is used to achieve the regulation.

Voltage regulators are installed at four sites on the Southern network and three sites on the Northern network. All the voltage regulators installed on the network have been supplied by Siemens.

The ODV life for regulators is 55 years. The age profile and book value of Vector's voltage regulators on each network is shown below in Table 6-24.

Network	Year of Manufacture	Population	Book Value
Southern	1997	4	$0.27m
Northern	2001	2	$0.07m
Northern	2007	1	$0.17m
TOTAL (units)		**7**	**$0.51m**

Table 6-24 : Voltage regulator population and book value

The mechanical condition of the regulators on the Southern network is poor as both sites are located close to the coastline, resulting in increasing corrosion on the regulator tanks and controller boxes. The electrical condition, however, is good.

The mechanical condition of the single phase regulators on the Northern network is fair. There is some corrosion on the regulator tanks and the controller boxes. The electrical condition of all the regulators is good.

As noted, corrosion of the regulator tanks and the controller boxes is occurring on all the voltage regulators. All the single phase regulators will need to be removed from service and refurbished. The work will be carried out under corrective maintenance.

6.3.20.1 Inspection and Test Programme

Inspection of voltage regulators is carried out in accordance with Vector standard ENS-0188. The frequency of inspection is four-yearly.

Electrical testing is not carried out on voltage regulators unless there is a specific issue that needs to be investigated and resolved.

Thermal imaging is presently carried out on ground mounted voltage regulators as part of the inspection programme.

Transformer Condition Analysis (TCA) on oil samples from the voltage regulators is not presently carried out. It is planned that this test be added to the activities carried out by the service provider.

6.3.20.2 Maintenance, Refurbishment and Renewal Programme

Preventative maintenance of voltage regulators is on a time-based inspection regime and is carried out in accordance with Vector Standard ENS-0061. Onsite maintenance is generally minor and includes such items as oil top up, minor rust treatment and paint repairs.

Presently there is no refurbishment programme for voltage regulators as they are relatively new (1997 being the oldest installation).

Again, as the voltage regulators are quite new, it is expected that the existing installations will be on the network for some time (20 or more years) and as such there are no planned replacement programmes.

6.3.21 Ground Mounted Distribution Switchgear

Ground mounted distribution switchgear operates at 22kV and 11kV and is installed in buildings or enclosures on road reserves and private property. It excludes the switchgear in the zone substations. Ring main units, isolators, composite units and circuit breakers (CBs) are used to connect underground cables. Fused switches and CBs are used to protect distribution transformers. Switches may be operated manually or by a motorised mechanism.

New switchgear is supplied in compliance with Vector Standard ENS-0090 or ENS-0103.

Vector's distribution switchgear comprises oil, SF_6 and resin insulated equipment of varying ages and manufacturers. The arc-quenching mediums used in the equipment are air, oil, SF_6 and vacuum. The majority of the switchgear is rated at 11kV with small quantities of 24kV units. 24kV rated SF switchgear is installed on the 22kV distribution networks in the Auckland CBD and Highbrook Business Park. Definitions of the various categories of switchgear on the network are detailed in Table 6-25 below, while the manufacturers and models of the types used are detailed in Table 6-26.

Switchgear Type	Description
Oil-filled	Primary insulation and arc-quenching mediums are oil.
Solid Insulation	Primary insulation medium is resin and arc-quenching medium is air.
Disconnect Units	As per solid insulation, but without live switching capability.
Sulphur Hexafluoride (SF_6)	Primary insulation medium is SF_6 and arc-quenching medium is SF_6 or vacuum.

Table 6-25 : Distribution switchgear categories

Switchgear Type	Manufacturer	Series – Switchgear
Oil-filled	Andelect	Series 1 SD – SDAF, SDAF3, SD, SD2, SD3
	ASTEC	Series 1 SD – SDAF, SDAF3, SD, SD2, SD3
	ABB	Series 1 SD – SDAF, SDAF3, SD, SD2, SD3
	ABB	Series 2ASD – SDAF, SDAF3, SD, SD2, SD3
	ABB	Series 2BSD – SDAF, SDAF3, SD, SD2, SD3
	Long & Crawford	GF3, ETV2, J2, J4, T4GF3, ALD2P
	Lucy Co	FRMU (Mk 1A)
	Statter	
Solid Insulation	Holec	Magnefix, Hazemeyer
Disconnect Units	Frank Wilde Ltd	FTCE
Sulphur Hexafluoride (SF_6)	ABB	SafeLink, SafePlus (24kV)
	Schneider	Ringmaster, RM6, FBX-E
	Ormazabal	GA

Table 6-26 : Switchgear type, manufacturer and model

Vector has decided to terminate the installation of oil-filled switchgear. In future all distribution switchgear installed on the network will be switchgear that has a primary insulation medium of SF_6 and an arc-quenching medium of SF_6 or vacuum. A contract for the supply of Schneider FBX-E 24kV SF6 switchgear has been agreed. Installation of the switchgear is expected to commence in December 2011.

GIS records indicate there are 9,627 distribution switch units on Vector's network. (Note that a unit is defined as a maintainable tank i.e. an ETV2, J4 and SDAF are each one tank, as is an SDAF3, GF3 and T4GF3. For solid insulation type switchgear, a cabinet containing multiple cable units and a fuse unit is defined as a maintainable tank.) The ODV life for switchgear is 40 years. Table 6-27 provides a summary of the number of switchgear units on the network, as well as their book value.

Population	**22kV**	**11kV**	**6.6kV**	**Total**
Southern	184	7552	125	7861
Northern	0	1766	0	1766
Total	184	9318	125	9627
Book Value	**22kV**	**11kV**	**6.6kV**	**Total**
Southern	$2 m	$48 m	$1 m	$51 m
Northern	$0 m	$19 m	$0 m	$19 m
Total	$2 m	$67 m	$1 m	$70 m

Network	**Population**	**Book Value**
Southern	7411	
Northern	1685	
Total	9096	

Table 6-27 : Distribution switchgear population and book value

An age profile of Vector's ground mounted distribution switchgear on each network is shown below in Figure 6-42 and Figure 6-43.

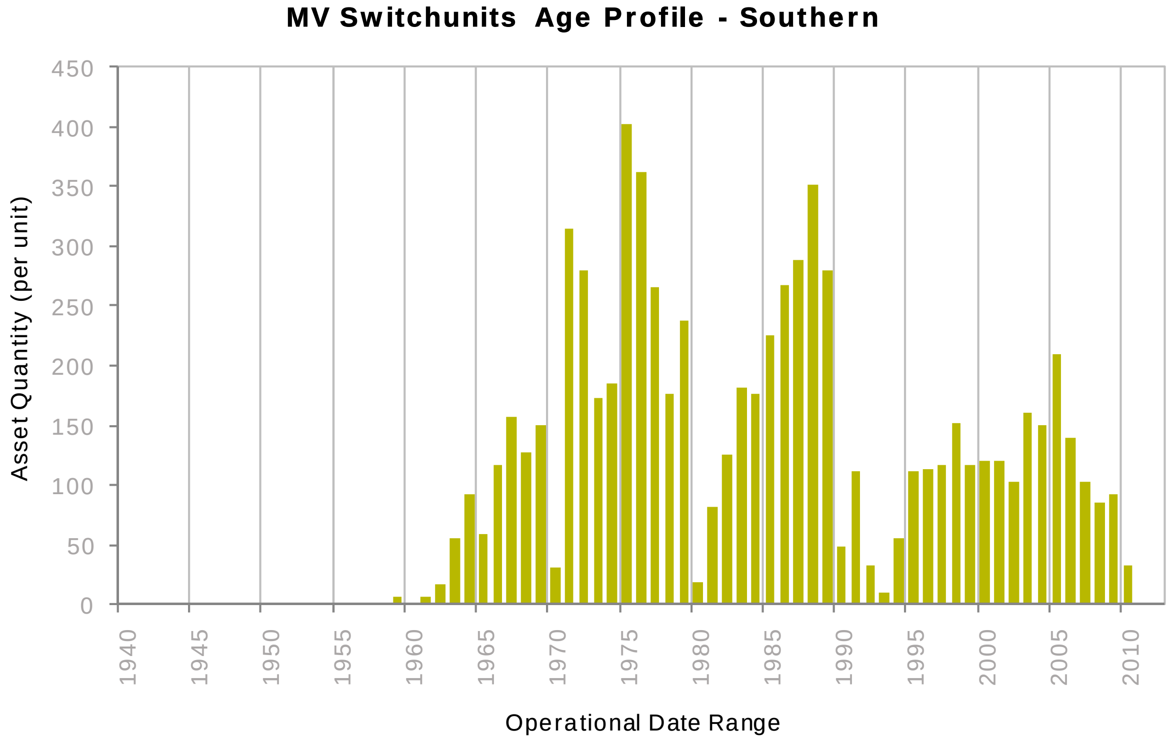


Figure 6-42 : MV switch unit's age profile - Southern

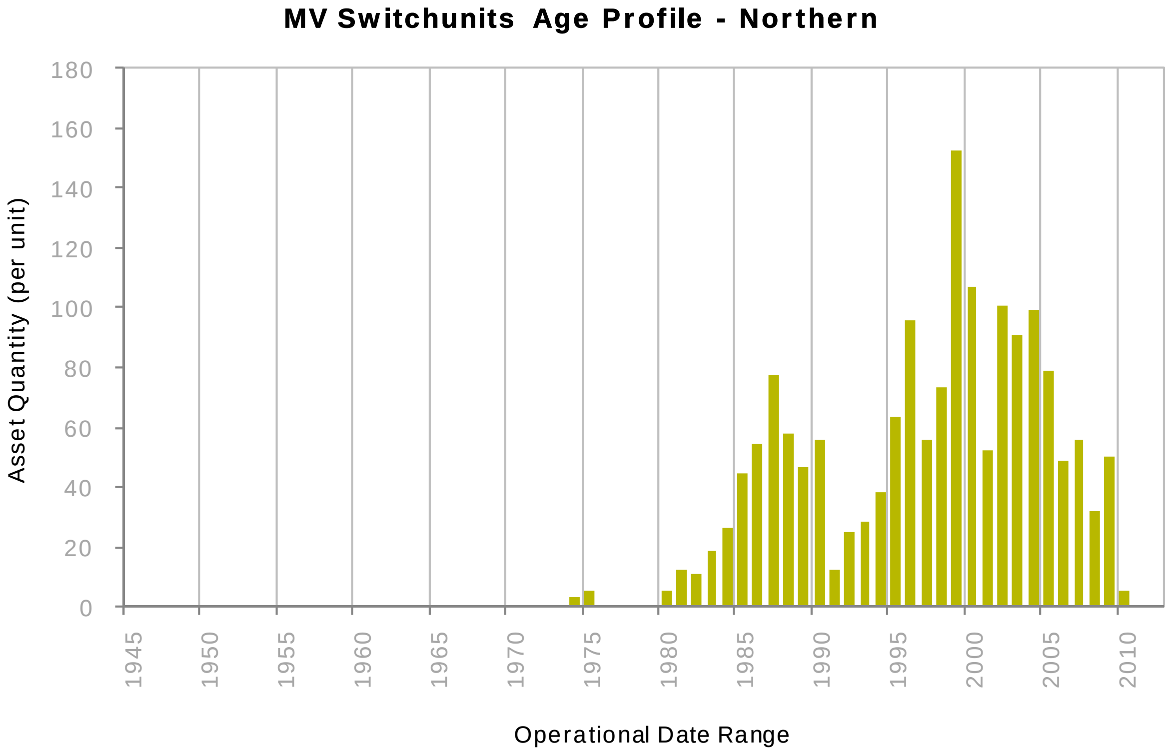


Figure 6-43 : MV switch unit's age profile – Northern

6.3.21.1 Asset Condition

In general the condition of switchgear is good although there are oil-filled SD units whose mechanical condition, due to corrosion, is poor. Many of those units have been replaced. Additionally, other replacements have been driven by transformer replacement through either being physically attached to a transformer requiring replacement or, where there is synergy opportunity to replace the switchgear, during other work. Other general causes for replacement are minor oil leaks and, to an even lesser degree, vehicle damage.

Systemic issues leading to premature replacement (or parts) of the assets include the following:

- Corrosion of the base of SD oil-filled switchgear, particularly where the switchgear contacts the precast concrete foundation, is the main reason for switchgear replacement. The issue has been investigated and a solution found. It is planned, as part of the four yearly switchgear inspection, to begin spraying the concrete with a sealant which prevents the chemical reaction between the switchgear and the concrete taking place.
- There are considerable numbers of SD fused switches installed on pre-cast concrete pads where movement of the ground under the pad has caused the switchgear to lean to varying degrees. Excessive lean may result in the rear clip of an HV fuse holder in a fused switch not being fully immersed in insulating oil and hence an increased risk of a flashover in the switch. The risk is identified as AIAE3003 on the Asset Investment Engineering risk register.
- There is no indication of the oil level in Andelect Series 1 SD switchgear. A low oil level in a switch unit due to oil leaks could result in an explosion in the unit. The risk is identified as AIAE3042 on the Asset Investment Engineering risk register.

Techniques for non-invasive measurement of the oil level in switch units are presently being investigated.

A survey of oil-filled switches on the network has been completed. Results from the survey will be used to determine prioritised remedial and replacement programmes for the SD oil-filled switchgear.

6.3.21.2 Inspection and Test Programme

Inspection of distribution switchgear is carried out in accordance with Vector Standard ENS-0188. The frequency of inspection is four-yearly.

Thermal imaging and testing for PD is also carried out as part of the inspection programme.

Electrical testing is not carried out on distribution switchgear unless there is a specific issue with a switch unit which needs to be investigated and resolved. However, for oil-filled switchgear that has had an internal inspection and maintenance carried out, a live tank oil sample (LTOS) is taken from a switch unit during the scheduled inspection and analysed. The procedure is carried out in accordance with Vector Standard ENS-0052. The results determine when maintenance needs to be carried out on the internals of the unit or when further oil samples should be taken and analysed.

Testing of the automation of automated switchgear is not currently carried out. It is planned to add this test to the activities carried out by the service provider.

6.3.21.3 Maintenance, Refurbishment and Renewal Programme

Preventative maintenance of distribution switchgear is on a time-based inspection regime and is carried out in accordance with Vector Standard ENS-0052.

Onsite repairs are generally minor and include such items as rust treatment, patching of holes, paint repair, oil top up, and replacement of mounting bolts. Where it is uneconomical to complete onsite maintenance or the switch unit poses a safety or reliability risk before the next inspection cycle, the switchgear is replaced.

Prior to September 2009, oil-filled switchgear that was removed from service was transported to the company that refurbished Vector's switchgear for assessment and refurbishment or scrapping. This procedure was stopped at the end of September 2009 but it is planned to reintroduce it as oil-filled switchgear is required for fault situations during the transition from the installation of oil-filled to SF_6 switchgear.

In addition to replacement of switchgear due to corrosion, leaks or the results of LTOS tests, it is intended to implement a replacement strategy for cast resin and oil-filled switchgear based on a switchgear replacement strategy prepared in 2007. The strategy is based only on the age of the switch units except for the Andelect Series 1 SD switch units. Andelect Series 1 SD switch units have a history of failure and unreliability due to a poor design that cannot be economically rectified.

Approximately 100 Andelect Series 1 SD oil-filled units that are older than 25 years have been identified as top priority for replacement.

A further 720 Andelect oil-filled units are between 20 and 24 years old and 150 Long and Crawford oil-filled units that are older than 40 years have been identified as high priority replacement items.

Moderate priority replacements include approximately 680 Andelect oil-filled units that are less than 20 years old and 1200 Long and Crawford units that are between 30 and 39 years old. All the units will be left in service until their condition warrants replacement.

6.3.22 Distribution Equipment Enclosures

Distribution equipment enclosures are used to accommodate Vector's ground mounted distribution equipment. There are many types of enclosures. They are defined as follows:

- Building - a free-standing concrete or concrete block structure with a roof or room housing Vector's distribution equipment;
- Open enclosure - a rectangular structure, without a roof, made of fibre panels, timber, metal, wire mesh or concrete block housing Vector's distribution equipment; and
- Enclosure - a structure, with a roof, made of metal or fibreglass housing Vector's distribution equipment.

The population breakdown for distribution equipment enclosures is given in Table 6-28. An age profile of Vector's equipment enclosures on each network is shown in Figure 6-44 and Figure *6-45*.

Network	Population	Book Value
Southern	6866	$43 m
Northern	8218	$17 m
Total	15084	$60 m

Table 6-28 : Distribution Substation - population and book value

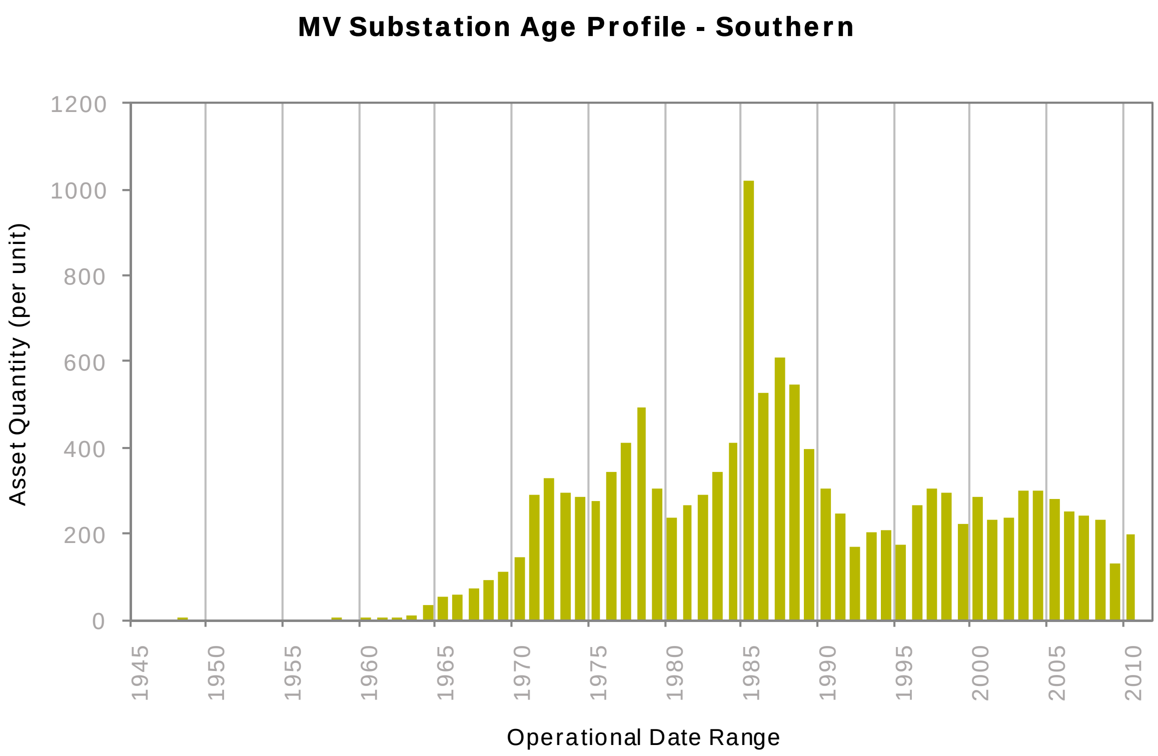


Figure 6-44 : MV substation age profile – Southern

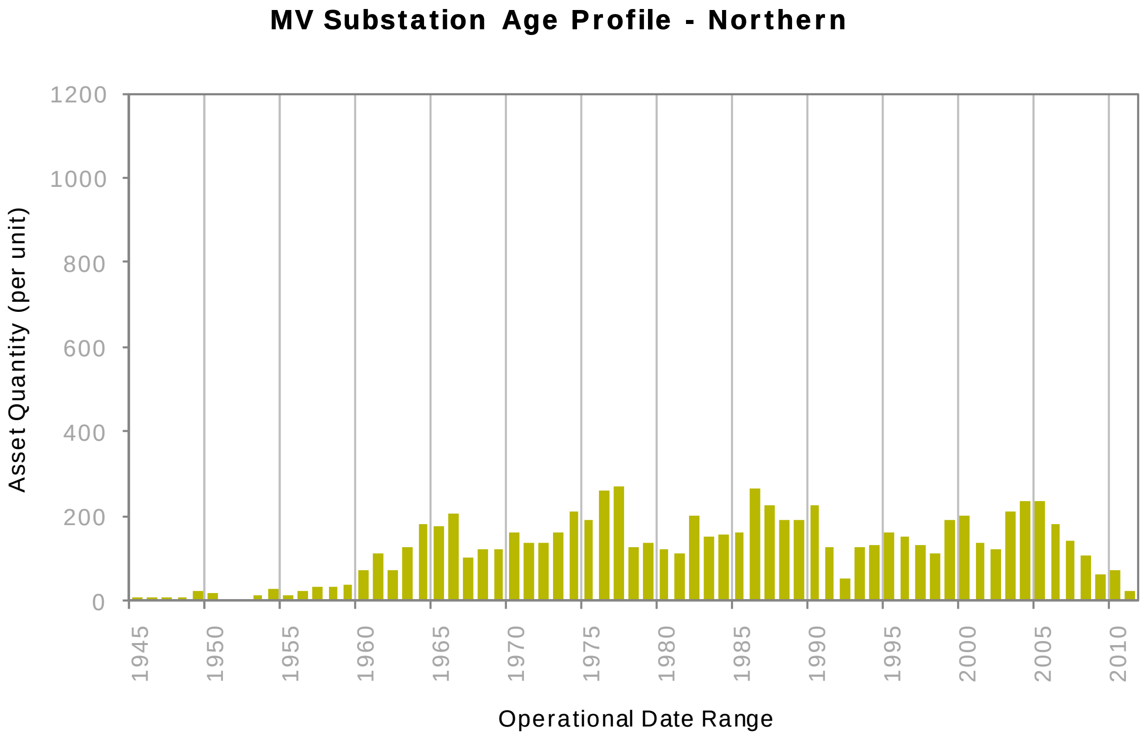


Figure 6-45 : MV substation age profile – Northern

In general the condition of the majority of distribution equipment enclosures is good. There are no systemic issues.

6.3.22.1 Inspection and Test Programme

The frequency of inspection of distribution equipment enclosures is carried out in accordance with Vector Standard ENS-0188. The frequency of inspection is four-yearly.

There is no test programme for the enclosures.

6.3.22.2 Maintenance, Refurbishment and Renewal Programme

Preventative maintenance of distribution equipment enclosures is on a time-based inspection regime and is carried out in accordance with Vector Standard ENS-0053. Repairs are generally minor.

There is no refurbishment or replacement programme currently under consideration.

6.3.23 Low Voltage Switchboards and Frames

An LV switchboard consists of a number of fuses or circuit breakers (CBs) mounted on a panel. The fuses and CBs are connected to cables which supply power and lighting circuits in the building in which the switchboard is located. The LV supply to the switchboard is either single phase or three phases.

An LV frame consists of a number of fuses and solid links mounted on three phase bus bars supported on a frame. There are two types of fusing installed on LV frames - JW type and DIN type. The frame is supplied from the 415V terminals of a distribution transformer via cables connected to the transformer terminals and the solid links on the frame. The fuses are connected to cables which supply customers.

A network standard for the supply of LV frames (ENS-0113) is presently in consultation form.

LV frames are presently supplied by Reticulation Development Ltd, Hamer Ltd, EMF Industrial Ltd and ETEL.

The data in GIS is incomplete and all the ages and book values of the LV switchboards and frames are presently unknown. (As noted before, this is a recurring problem on the LV network assets, which is intended to be addressed as part of a general review of the LV network.)

6.3.23.1 Asset Condition

LV switchboards are generally in good condition.

LV frames of both types are generally in good condition.

On both types of LV frame there have been incidents (overheating and fires).

There have also been operational issues and incidents with JW type LV frames and resultant from those incidents no work is permitted to be carried out on solid links on JW LV frames unless the frame is de-energised in accordance with the design intention. That work includes the tightening and loosening of the solid link securing bolts.

6.3.23.2 Inspection and Test Programme

LV switchboards and frames are visually inspected as per Vector Standards.

Thermal imaging is carried out on LV frames every four years.

6.3.23.3 Maintenance, Refurbishment and Renewal Programme

There are no specific maintenance standards or programmes for LV switchboards or frames. The units are generally replaced when they fail.

However, LV frames which are equipped with JW type fusing and solid links are replaced with frames equipped with DIN type fusing when the distribution transformer associated with the LV frame is replaced.

To address the operational constraint identified in Section 6.3.23.1 “Asset condition” above, a frame replacement programme is planned to be carried out over the next ten years.

6.3.24 Power Factor Correction Equipment

In the Southern region there is 153MVAr of capacitor banks installed in 25 zone substations. These capacitor banks are connected to the 11kV switchboards at zone substations and are rated at 3MVAr each. Up to three banks are connected to a zone substation. In the Northern area there are 58 pole mounted 11kV capacitor banks each rated at 750kVAr.

The 11kV capacitors in both regions were installed during 1998/99. About 25% of the original 78 pole mounted banks have been removed because of failure/corrosion/overhead improvement projects/3rd party incidents etc.. The zone substation 11kV capacitors are in good condition but associated equipment such as enclosures are showing signs of deterioration. The capacitors are housed in weatherproof enclosures. Many of these enclosures are located outdoors, are manufactured from painted mild steel and are rusting. Failures have been caused by water entering the outdoor enclosures. The mounting of the CTs in the enclosures has been causing damage to the potting compound. New CTs and a redesigned mounting system are required. The capacitors at Liverpool have suffered from a reactor fault and require major reconstruction.

6.3.24.1 Inspection and Test Programme

11kV pole mounted capacitors are inspected annually as part of the overhead inspection programme.

11kV and 33kV zone substation capacitors are visually inspected every two months. (Vector Standard ENS-0192).

6.3.24.2 Maintenance, Refurbishment and Renewal Programme

11kV pole mounted capacitors are maintained by cleaning the devices, checking connections and replacing the batteries in the controllers of the switched units at eight yearly intervals. The capacitance of the cans is measured during an eight-yearly maintenance cycle (Vector Standard ENS-0048). Components from removed capacitor banks in good condition are recovered and used to maintain the existing banks. Studies are being carried out to determine whether we need to replace these banks and possibly add more in line with Transpower's new requirement for our network to operate with a high power factor.11kV zone substation capacitors are inspected every two years, bushings and filters are cleaned and connections checked. The capacitance of the cans is measured, secondary injection performed on the protection relays, the CBs ductored and insulation resistance measured during a four yearly testing cycle (Vector Standard ENS-0192). The zone substation 11 kV capacitors are to be maintained in an operational state.

6.3.25 11 kV Energy and Power Quality Metering System

6.3.25.1 Asset Description

There are 65 combined energy and PQ meters installed at Transpower grid exit point (GXP) substations and in Vector's distribution network, primarily at zone substation level (refer Table 6-29 below for breakdown). There are four portable PQ meters. The meters communicate via IP network to the metering enterprise applications.

At GXP level, the meters are deployed to provide check metering function to Transpower's revenue metering installations. The meters are connected to check the metering instrument transformers owned by Transpower. The meters also receive pulse streams from Transpower's metering system and provide comparisons between the two systems.

At the control centre level metering ION Enterprise software is deployed for monitoring of real-time power conditions, analyse PQ and reliability, and respond quickly to alarms to avoid critical situations.

The meters are also configured to detect under-frequency event in the network and initiate load shedding.

Based on the cost of the recently installed projects, the Energy and Power Quality Metering System is estimated to be worth $2 million.

6.3.25.2 Age Profile

These assets have an expected technical life of 15 years. A breakdown of asset ages is provided in Table 6-29.

Network	Type	Year of Manufacturer	Population
Northern	ION 7650	2010	3
Northern	ION 7650	2007	4
Northern	ION 7650	2008	1
Northern	ION 7650	2007	4
Northern	ION 765000	2011	2
Southern	ION 7330	2003	3
Southern	ION 7330	2009	4
Southern	ION 7500	2002	9
Southern	ION 7550	2007	1
Southern	ION 7600	2002	10
Southern	ION 7650	2006	3
Southern	ION 7650	2007	1
Southern	ION 7650	2008	1
Southern	ION 7650	2010	2
Southern	ION 7650	2011	3
Southern	ION 7700	1999	5
Southern	ION 7700	2001	3
Southern	ION 7700	2002	2
Southern	ION 7700	2003	2
Southern	ION 7700	2006	1
Southern	VIP	2002	1
Total (units)			**65**

Table 6-29 : Combined energy and power quality meters

6.3.25.3 Condition of the Asset

The metering assets are in good condition.

6.3.25.4 Maintenance Programme

New meter firmware releases are evaluated for relevance to Vector's meter population and upgrades initiated if required.

The meters and metering system configuration is outsourced and is normally performed remotely. The ten-year cost estimate for maintaining the metering systems is presented in Table 6-30.

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
$0.10m	$0.11m	$0.12m	$0.13m	$0.14m	$0.15m	$0.16m	$0.17m	$0.18m	$0.19m	$0.20m

Table 6-30 : Vector's Network – metering system maintenance costs 2010 to 2020 ($million)

6.3.25.5 Replacement/Refurbishment/Expansion Programme

Vector keeps spare meters in case of meter failures. Based on the performance and failure rate Vector will consider planned replacement of the older generation of the meters from 2015.

Over the next five years it is currently planned to installed 41 new PQ meters at zone substation level and complete installation of PQ meters at GXP Albany, Henderson, Hepburn, Wellsford and future 110 kV Wairau GXP.

Vector's ION Enterprise Energy Management System is currently planned to be upgraded to version 6.0 and additional capabilities in analysing databases of PQ and energy measurements are also currently planned to be implemented over the next three years.

6.3.26 Other Diverse Assets

6.3.26.1 Mobile Generator Connection Unit (MCGU)

Vector owns two MGCUs purchased in 2006 with an estimated book value of $600,000. The units are used to provide voltage support to the network and to avoid outages at distribution substations during maintenance works.

The MGCUs are mounted in self-contained 20-foot containers on skids for rapid deployment. The MGCUs units provide an interface between the 11 kV network and multiple or single 415V diesel generators. Each unit has the capacity to inject up to 2.5MVA into the 11 kV network connecting to either overhead lines or underground cable networks.

Each MGCU comprises a 2.5MVA transformer, high and low voltage CBs, protection control, monitoring and auxiliary supply. The units are shown schematically below in Figure 6-46.

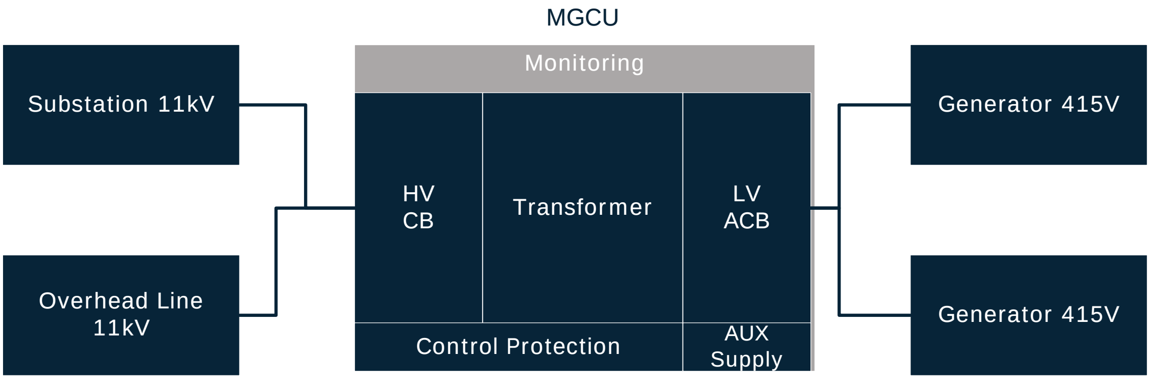


Figure 6-46 : Mobile generator connection diagram

The units are stored at and maintained by NZ Generator Hire.

6.3.26.2 Tunnels

Vector has a number of cable tunnels in its Southern network.

By far the largest single Vector asset is the 9200 metre by three metre diameter tunnel which extends from a shaft in Transpower's Penrose switchyard to the Hobson shaft at Vector's Hobson substation yard. There are access/egress points at the Newmarket shaft at the back of the ex-Vector (now Westfield) site in Nuffield Street and at the Liverpool substation, consisting of three shafts that extend into the basement of the Liverpool substation. The tunnel has a design life of 100-plus years and its present book value is $96.5 million.

The tunnel is primarily a conduit for HV power cables currently operating at voltages of 22 kV, 33 kV and 110 kV. The tunnel has been designed with the capacity to accommodate more circuits than presently installed. All work and maintenance within the tunnel is governed by Vector Standard EOS-018.

The other significant tunnels are:

- Swanson Street Tunnel - approximately 350 metre in length from the Hobson Substation east up Swanson Street;
- Victoria Street;
- North Western Motorway crossing Kingsland; and
- May Road to South Western Motorway crossing.

6.3.27 Cable Ducts

Cables can be directly buried or installed in ducts. When cables are directly buried they have to be installed in a safe manner which allows heat to be dissipated to the surrounding soil as well as buried deep enough to minimise the risk of accidental excavation damage and the effect of solar gain on the ground causing temperature rise and de-rating.

Cable ducts offer the benefit of providing added protection to cables, allowing more flexibility around installation and also simplifying future replacement. Ducts are also installed for future-proofing purposes; making use of construction opportunities and synergies as they arise[13].

However, cable ducts act as insulation to the cable which de-rates them. Often it has also been found that spare ducts have been crushed and are not usable.

Historically, Vector only installed ducts at road crossings, across bridges abutments, railway crossings or when new roads were laid (where a moratorium on later excavation is imposed). As time went on, ducts started to be installed as standard practice when opportunities arose, largely due to the low incremental cost of the materials.

A recent review of the cost of duct installation indicates they may not be as cost effective as they used to be. A review of the spare ducts policy (including the circumstances when spare ducts are to be installed and how these ducts are managed) will be carried out in the next 12 months.

6.4 Spares Policy and Procurement Strategy

Vector's strategic spares guideline EEA-0034 outlines the strategy and policy for the handling and purchase of strategic spares for the purposes of maintaining the electricity supply in the event of a major equipment failure or contingency event. Specifically, strategic spares refer to equipment and or parts that need to be held in store for ready deployment and cannot be obtained in reasonable time due to long delivery periods or obsolescence.

Vector's asset specialists are responsible for determining what items should be held as strategic stock and for re-ordering apparatus when stock levels are less than optimal. When new equipment is purchased for the first time (e.g. a new type of switchboard) an

[13] For example, working alongside other utility providers when they construct new footpaths or roads.

initial stock of manufacturer recommended spare parts is also purchased as part of Vector's strategy.

In practice it is impossible to carry spares for all network equipment. In addition, parts for some aged apparatus are no longer available as the OEM manufacturer no longer exists. Where possible, critical parts are recovered from other assets as reinforcement and replacement projects are undertaken.

In some instances, other market manufacturers have been approached to remanufacture critical parts (such as contacts on early model tap changers).

Lack of spares for key equipment could present a risk to the business, which is especially the case on older, discontinued equipment. This is taken into account in prioritising the equipment replacement programmes. (Other mitigation plans have also been drawn up, where appropriate.)

6.5 Adopting New Technologies

Vector has a team of asset specialists that approve and review all network fittings and apparatus to be used on the networks. An important function of this work is to look to the market and evaluate new, improved and emerging technologies. Important examples of how this has occurred in practice are discussed below.

6.5.1 Sub-Transmission Systems

6.5.1.1 Circuit Breakers and Switchboards

Vector was the first New Zealand network operator to adopt fixed pattern technology for its MV indoor zone substation switchboards. Specifically, new switchboards must comply with Vector equipment specification ENS-0005 and to IEC 62271. This specification was chosen due to its high level of operator safety and long periods between maintenance activities. Coupled with modern relaying and control systems, the modern zone substation has little need for operator intervention over its design life. This life is primarily based on life-time fault operations rather than traditional time-based parameters.

In addition, equipment complying with these specifications is also rated to contain faults and contains no oil or other combustible products. This makes equipment complying to these specifications some of the safest in the world today.

6.5.1.2 Power Transformers

The basic transformer construction materials and methodology has changed little over the past 100 years (notwithstanding significant improvements in insulating oils and manufacturing techniques). However, there have been developments in control monitoring and tap changing technologies.

Vector is currently evaluating the long-term cost-benefit of advancements in technologies such as vacuum tap changers, on-line PD and key gas monitoring technologies. Vacuum tap changers are a continuation from VCB technology developed over the past 20 years.

The newest technologies available today use SF_6 gas in place of mineral insulating oil. This technology, however, is very expensive and specialised and has thus far been regulated to the HV VHV (220 kV and above) levels and is not likely to be economic for electricity distribution networks for many years.

For Vector, traditional oil-filled transformers with Kraft paper insulation will likely continue to be the norm in the foreseeable future.

6.5.1.3 MV Cables

The sub-transmission system of Vector's networks comprises of a mixture of cable technologies. These technologies consist of fluid-filled, PILC, gas pressurised and XLPE cable technologies. Cable construction is also wide ranging from single phase, three phase, steel wire armoured (SWA), submarine and others.

XLPE cables are the preferred construction type worldwide and Vector has taken up this technology as its standard. Vector's current standard is for the installation of XLPE cable up to and including its maximum system voltage of 110 kV.

Changes in joint and termination technologies have advanced over the past 20 years and Vector has adopted some of these available technologies. After product evaluation, Vector has adopted mechanical sheer bolt fault-rated connector technology as well as 'cable plug' connecting systems for all of its MV switchgear apparatus complying with Vector Standard ENS-0005.

6.5.1.4 Protection and Control

Vector has adopted the IEC 61850 protocol. This protocol provides guidance on the series of standards applying to substation automation equipment and systems with an explanation of their structural elements, configurations and basic functions. Vector has selected protection relays, SCADA and control systems complying with this standard. Vector makes extensive use of the functionality offered by new relay systems to not only enhance network protection schemes, but also for monitoring and metering purposes.

Further, Vector is gradually converting its Cu pilot wire system to fibre optics, enabling greater functionality between stations and taking full advantage of the protection and control systems.

6.5.2 Distribution Systems

6.5.2.1 Transformers

Technology in distribution transformers has been unchanged over the past ten years. However, developments in insulating materials have progressed to address environmental concerns around oil-filled apparatus. Vector has explored the technology available for use in environmentally sensitive locations where the effects of fire, smoke and possible run-off into watercourses is an issue.

For these situations, Vector has adopted a synthetic ester (MIDEL 7131) instead of mineral oil as the insulating fluid. MIDEL 7131 is environmentally friendly, fully biodegradable and non-toxic.

6.5.2.2 Oil-Filled Switchgear

Vector has decided to terminate the installation of oil-filled switchgear. A contract has been agreed for the supply of switchgear that has a primary insulation medium of SF_6 and an arc-quenching medium of SF_6 or vacuum, in line with Vector's specification for MV switchgear for use on its sub-transmission networks.

6.5.2.3 Partial Discharge

PD measurement in cables and other distribution apparatus can give an indication of the health of the equipment. To date, results have been mixed and it is not possible to say categorically that any equipment with PD above a certain level will fail. The science around PD monitoring and reacting to this is still developing. It may become a useful tool for the prediction of imminent asset failure or faulty equipment in the future.

6.6 Renewal Expenditure Forecasts

All asset replacement projects and programmed replacement works have been identified for the review period as outlined in the preceding sections.

To ensure a consistent ranking of project priorities, a prioritisation matrix has been developed that is applied to each identified project. (This applies to the whole capital programme, not just the network integrity-related works). The matrix, in as far as it applies to renewal works, is described in Table 6-31.

Rank	Security & Capacity	Customer Connections	Network Reliability & Asset Performance	Brand & Reputation	Legal Compliance	Health, Safety & Environment	Financial Performance	Operational Performance Improvement
1. Vital investments	Mitigate capacity breach leading to asset damage. Mitigate capacity breach to widespread or critical areas.	Mitigate capacity breach to critical customer.	Reactive replacement of critical assets.	Avoid potentially serious reputation damage.	Avoid serious breach of technical regulations. Avoid serious breach of HSE or environmental legislation.	Mitigate imminent serious HSE or environmental threats.	Mitigate extreme and very high risks	Mitigate critical cyber security breach.
2. Critical investments	Mitigate security breach to widespread or critical areas. Mitigate capacity breach.	Satisfy contractual obligations (critical customers). New connections and capacity increase (critical customers).	Replacement of severely deteriorated assets with high risk and high consequence of failure. Reactive replacement of assets required for network operation.		Regulatory compliance (including Industry Participation Code, environmental, HSE, etc). Asset relocation as required by statute.	Mitigate anticipated serious environmental or HSE threats.	Mitigate high impact direct risks.	Overhead improvement programmes (AECT obligation). Mitigate serious cyber security breach.
3. Essential investments	Mitigate security breach in the general network areas (except for remote rural areas).	Customer capacity and security requests.	Replacement of rapidly deteriorating assets or assets at the end of technical life with increased risk of failure. High consequence of failure. Medium term mitigation against natural disasters. Reliability improvements (to widespread or critical areas).		Regulatory improvement. Mitigate breach of technical regulations (voltage, etc) in localised areas. DG connections.	Medium term safety & environmental improvement.	Assets costing more to maintain and operate than to replace.	Technology trials. Enhance operational efficiency.

Rank	Security & Capacity	Customer Connections	Network Reliability & Asset Performance	Brand & Reputation	Legal Compliance	Health, Safety & Environment	Financial Performance	Operational Performance Improvement
4. Beneficial investments	Mitigate security of supply breach in remote rural areas.	Customer funded projects.	Asset condition deteriorating gradually with increased risk of failure. Steady state asset replacement programmes. Reliability improvements.			Long term safety & environmental improvement.	Safeguard future options. Discretionary initiatives that are NPV>0.	Asset relocation requested by consumers and land owners. Enhance supply quality.

Table 6-31: Priority matrix for network integrity (renewal and replacement) projects

Based on the renewal requirements described in this section of the AMP, and after applying the prioritisation criteria, the proposed network integrity (asset renewal or replacement) capex programme for the next ten years is presented in Table 6-32.

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Protection & Control	Airport - Protection System - TMS Replace	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Airport - Substation Auxiliary Systems Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Avondale - 11kV Indoor SWBD Retrofit - 13 Panels	$0.6m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Avondale - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Avondale - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.7m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Avondale - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Avondale - Substation Auxiliary Systems Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Avondale - Protection System Replace / Upgrade	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Protection & Control	Bairds - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Balmoral - 11kV Indoor SWBD Replace - 12 Panels	$0.0m	$0.1m	$1.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Balmoral - 22kV Power Transformer Replace	$0.0m	$4.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Balmoral - 22kV Subt Cable Replace	$0.0m	$5.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Balmoral - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Balmoral - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m	$0.0m	$0.0m
Protection & Control	Balmoral - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Balmoral - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Carbine - 11kV Indoor SWBD Retrofit - 22 Panels	$0.6m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Chevalier - 11kV Indoor SWBD Retrofit - 11 Panels	$0.6m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Chevalier - 22kV Subt Cable Replace	$0.0m	$0.0m	$0.0m	$0.0m	$6.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Clevedon - Protection System - TMS Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Drive - 11kV Indoor SWBD Replace - 13 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Drive - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Drive - Seismic Rebuild	$0.0m	$1.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Drive - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Drive - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	East Tamaki - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	East Tamaki - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Freemans Bay - 11kV indoor	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

Investment Programme	Project	Yr 0 FY12	Yr 1 FY13	Yr 2 FY14	Yr 3 FY15	Yr 4 FY16	Yr 5 FY17	Yr 6 FY18	Yr 7 FY19	Yr 8 FY20	Yr 9 FY21	Yr 10 FY22
	SWBD Replace - 13 Panels											
Protection & Control	Freemans Bay - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Freemans Bay - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Freemans Bay - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Glen Innes - 22kV Power Transformer Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$4.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Glen Innes - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Glen Innes - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Glen Innes - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Glen Innes - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Greenmount - 11kV Indoor SWBD Retrofit - 2 Panels	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Greenmount - Protection System - TMS Replace	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Greenmount - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Greenmount - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Hans - 11kV Indoor SWBD Retrofit - 10 Panels	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hans - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hans - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hans - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hans - Protection System Replace / Upgrade	$0.0m	$0.1m	$0.7m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hobson - Power System Protection - 22kV Switchgear Busbar Protection	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

Investment Programme	Project	Yr 0 FY12	Yr 1 FY13	Yr 2 FY14	Yr 3 FY15	Yr 4 FY16	Yr 5 FY17	Yr 6 FY18	Yr 7 FY19	Yr 8 FY20	Yr 9 FY21	Yr 10 FY22
Protection & Control	Hobson - Protection System - TMS Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hobson - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hobson - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Hobson - 11kV Indoor SWBD - 21 Panels	$0.0m	$0.0m	$0.2m	$2.3m	$4.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Hobson - 11kV Indoor SWBD Retrofit - 15 Panels	$0.0m	$0.0m	$0.0m	$0.8m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Howick - 11kV Indoor SWBD Retrofit - 13 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.7m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Howick - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Howick - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Howick - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Howick - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.8m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Kingsland - 22kV Indoor SWBD Replace - Stage I	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Kingsland - 22kV Indoor SWBD Replace - Stage II	$0.0m	$0.2m	$2.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Kingsland - 22kV Indoor SWBD Replace - Stage III	$0.0m	$0.0m	$0.2m	$1.8m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Kingsland - Protection System - TMS Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Kingsland - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Kingsland - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Kingsland - Substation Auxiliary Systems Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Liverpool - 11kV Indoor SWBD Replace - Stage I	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Liverpool - 11kV Indoor SWBD Replace - Stage II	$3.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Asset Replacements	Liverpool - 11kV Indoor SWBD Replace - Stage III	$0.0m	$4.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Liverpool - 22kV Subt Cable Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$4.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Liverpool - Protection System - Line Differential Protection Upgrade - 110kV Liverpool Penrose	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Liverpool - Protection System Upgrade / Replace	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.0m
Asset Safety & Compliance	Liverpool - Seismic Strengthening	$0.0m	$1.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Liverpool - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Mangere Central - 11kV Indoor SWBD Replace - 15 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.8m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Mangere Central - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Mangere Central - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m
Protection & Control	Mangere Central - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Mangere Central - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Mangere West - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Mangere West - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m
Protection & Control	Mangere West - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.8m
Asset Replacements	Manukau - 11kV Indoor SWBD Retrofit - 13 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.7m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Manukau - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Manukau - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Manukau - Substation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m

Investment Programme	Project	Yr 0 FY12	Yr 1 FY13	Yr 2 FY14	Yr 3 FY15	Yr 4 FY16	Yr 5 FY17	Yr 6 FY18	Yr 7 FY19	Yr 8 FY20	Yr 9 FY21	Yr 10 FY22
	Auxiliary Systems Replace											
Protection & Control	Manukau - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m
Asset Replacements	Manurewa - 11kV Indoor SWBD Replace - 13 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$2.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Manurewa - 11kV Indoor SWBD Retrofit - 7 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Manurewa - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Manurewa - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Manurewa - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Manurewa - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Maraetai - 11kV Indoor SWBD Replace - 11 Panels	$0.0m	$1.8m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Maraetai - 33kV Subt Cable Replace	$0.0m	$0.2m	$2.8m	$3.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Maraetai - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Maraetai - Protection System - Line Protection Upgrade- 33kV Takanini - Maraetai	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Maraetai - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Maraetai - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Maraetai - Substation Auxiliary Systems Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Asset Replacements	Mt Albert - 11kV Indoor SWBD Retrofit - 5 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Mt Albert - 22kV Power Transformer Replace - T1	$0.0m	$0.0m	$0.2m	$2.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Mt Albert - 22kV Subt Cable	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
	Replace											
Protection & Control	Mt Albert - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Mt Albert - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Mt Albert - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Mt Albert - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Mt Albert - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Mt Wellington - Protection System - TMS Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Mt Wellington - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Newton - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Newton - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Newton - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Newton - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Onehunga - 11kV Indoor SWBD Replace - 12 Panels	$0.0m	$0.1m	$1.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Onehunga - 22kV Power Transformer Replace	$0.0m	$0.3m	$4.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Onehunga - 22kV Subt Cable Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Onehunga - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Onehunga - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Onehunga - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Onehunga - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Protection & Control	Onehunga - Protection System Replace / Upgrade	$0.0m	$0.1m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Orakei - 11kV Indoor SWBD Replace - 16 Panels	$0.0m	$0.0m	$0.2m	$1.9m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Orakei - Protection System - Line Protection Upgrade-33kV Incoming Feeders	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Orakei - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Orakei - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Otara - 11kV Indoor SWBD Retrofit - 13 Panels	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Otara - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Pacific Steel - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Pakuranga - 11kV Indoor SWBD Replace - 13 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.8m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Pakuranga - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Pakuranga - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Papakura - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Parnell - 22kV Power Transformer Replace - T1 & T2	$0.0m	$0.0m	$0.0m	$0.3m	$4.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Parnell - 22kV Subt Cable Replace	$0.0m	$0.3m	$3.7m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Ponsonby - 22kV Subt Cable Replace	$0.0m	$0.0m	$0.4m	$4.6m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Quay - 11kV Indoor SWBD Retrofit - 9 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Quay - Foundation Assessment & Seismic	$0.0m	$0.0m	$2.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

Investment Programme	Project	Yr 0 FY12	Yr 1 FY13	Yr 2 FY14	Yr 3 FY15	Yr 4 FY16	Yr 5 FY17	Yr 6 FY18	Yr 7 FY19	Yr 8 FY20	Yr 9 FY21	Yr 10 FY22
	Reinforcement											
Asset Safety & Compliance	Remuera - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Remuera - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Rockfield - 11kV Indoor SWBD Retrofit - 12 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m	$0.0m	$0.0m
Protection & Control	Rockfield - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Rockfield - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Rockfield - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Rockfield - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Rosebank - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Sandringham - 11kV Indoor SWBD Replace - 18 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$2.0m	$0.0m	$0.0m
Protection & Control	Sandringham - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Asset Safety & Compliance	Sandringham - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Sandringham - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Sandringham - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m
Asset Replacements	South Howick - 11kV Indoor SWBD Retrofit - 12 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m	$0.0m
Protection & Control	South Howick - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	South Howick - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	South Howick - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	South Howick - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Asset Replacements	St Heliers - 11kV Indoor SWBD Retrofit - 13 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.7m	$0.0m	$0.0m	$0.0m
Protection & Control	St Heliers - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	St Heliers - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	St Heliers - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	St Heliers - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	St Heliers - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	St Johns - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Takanini - 11kV Indoor SWBD Retrofit - 10 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m	$0.0m
Protection & Control	Takanini - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Takanini - Protection System - Line Protection Upgrade- 33kV Incoming Feeders	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.7m	$0.0m	$0.0m
Asset Safety & Compliance	Takanini - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Takanini - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Takanini - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Asset Replacements	Te Papapa - 11kV Indoor SWBD Retrofit - 13 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.7m	$0.0m
Protection & Control	Te Papapa - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m
Asset Safety & Compliance	Te Papapa - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.7m	$0.0m	$0.0m	$0.0m
Protection & Control	Te Papapa - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Te Papapa - Substation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
	Auxiliary Systems Replace											
Protection & Control	Te Papapa - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m
Asset Replacements	Various - CB & SWBD Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$2.0m	$2.0m	$2.0m
Protection & Control	Various - Communication System	$0.0m	$0.2m	$0.2m	$0.2m	$3.0m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m
Protection & Control	Various - Communication Systems	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Various - Control Centre Applications	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Various - Control Centre Applications	$0.0m	$0.2m	$0.2m	$0.2m	$3.0m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m
Protection & Control	Various - DC Auxiliary System Replacement	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Various - Distribution Automation	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Various - Distribution Automation - MV/LV substation automation	$0.0m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m
Asset Preventive Programmes	Various - Earthing Upgrades	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m
Asset Preventive Programmes	Various - GM Pillar and Pit Replace	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m
Asset Preventive Programmes	Various - GM Switchgear Replace	$1.1m	$1.1m	$1.1m	$1.1m	$1.1m	$1.1m	$1.1m	$1.1m	$1.1m	$1.1m	$1.1m
Asset Preventive Programmes	Various - GM Transformer Replace	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m
Asset Safety & Compliance	Various - LV Frame Replace	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m
Asset Preventive Programmes	Various - OH Conductor Replace	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m
Asset Preventive Programmes	Various - OH Riser Replace	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m
Asset Preventive Programmes	Various - OH Structure Replace	$6.7m	$6.7m	$6.7m	$6.7m	$6.7m	$6.7m	$6.7m	$6.7m	$6.7m	$6.7m	$6.7m
Asset Preventive Programmes	Various - OH Switchgear Replace	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m
Asset Preventive Programmes	Various - OH Transformer Replace	$0.7m	$0.7m	$0.7m	$0.7m	$0.7m	$0.7m	$0.7m	$0.7m	$0.7m	$0.7m	$0.7m
Protection & Control	Various - Power Quality	$0.0m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Protection & Control	Various - Power System Protection Replacement / Upgrade	$1.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Various - Power Transformer Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$2.0m	$2.5m	$4.0m	$5.0m	$6.0m
Asset Performance	Various - Reliability Improvements	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m
Asset Strategic Spares	Various - Strategic Spares	$0.2m	$0.2m	$0.2m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m
Protection & Control	Various - Substation Automation	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Preventive Programmes	Various - Subt Cable Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$5.0m	$5.0m	$5.0m	$5.0m	$5.0m
Asset Preventive Programmes	Various - UG Cable Replace	$1.6m	$1.6m	$1.6m	$1.6m	$1.6m	$1.6m	$1.6m	$1.6m	$1.6m	$1.6m	$1.6m
Asset Safety & Compliance	Various - Zone Substation Oil Containment	$0.8m	$0.8m	$0.5m	$0.5m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m
Protection & Control	Various - Power Quality Monitors	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Victoria - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Waiheke - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Waiheke - Protection System - Protection Relay Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.7m	$0.0m	$0.0m	$0.0m
Protection & Control	Waiheke - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Waiheke - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	White Swan - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Wiri - 11kV Indoor SWBD Retrofit - 15 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.8m	$0.0m
Protection & Control	Wiri - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m
Asset Safety & Compliance	Wiri - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Wiri - Substation Automation -	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
	RTU Replace and Automation Schemes											
Protection & Control	Wiri - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m
Protection & Control	Wiri - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m
Asset Replacements	Balmain - 11kV Indoor SWBD Replace - 5 Panels	$1.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Balmain - 33kV Outdoor CB Replace - 1 CB	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Balmain - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Belmont - 11kV Indoor SWBD Retrofit - 9 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Belmont - 33kV Outdoor CB Replace - 2 CBs	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Belmont - Protection System - TMS Replace	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Belmont - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Belmont - Substation Automation - RTU Replace and Automation Schemes	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Belmont - Substation Auxiliary Systems Replace	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Belmont - Protection System Replace / Upgrade	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Birkdale - 11kV Indoor SWBD Retrofit - 11 Panels	$0.0m	$0.2m	$2.8m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Birkdale - Protection System - TMS Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Birkdale - Seismic Rebuild	$0.0m	$0.8m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Birkdale - Substation Automation	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Birkdale - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Birkdale - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Brickworks - 11kV Indoor	$0.0m	$3.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

Investment Programme	Project	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
		FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
	SWBD Replace - 6 Panels											
Protection & Control	Brickworks - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Brickworks - Seismic Rebuild	$0.0m	$1.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Brickworks - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Brickworks - Substation Auxiliary Systems Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Brickworks - Protection System Replace / Upgrade	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Browns Bay - 11kV Indoor SWBD Replace - 10 Panels	$0.0m	$0.1m	$1.7m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Browns Bay - 33kV Outdoor CB Replace - 2 CBs	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m
Protection & Control	Browns Bay - Protection System - TMS Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Browns Bay - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Browns Bay - Substation Automation - RTU Replace and Automation Schemes	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Browns Bay - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Browns Bay - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	East Coast Rd - 11kV Indoor SWBD Retrofit - 7 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	East Coast Rd - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	East Coast Rd - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	East Coast Rd - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	East Coast Rd - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	East Coast Rd - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

Investment Programme	Project	Yr 0 FY12	Yr 1 FY13	Yr 2 FY14	Yr 3 FY15	Yr 4 FY16	Yr 5 FY17	Yr 6 FY18	Yr 7 FY19	Yr 8 FY20	Yr 9 FY21	Yr 10 FY22
Asset Replacements	Helensville - 33kV Outdoor CB Replace - 2 CBs	$0.0m	$0.0m	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Helensville - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Helensville - Substation Automation	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Helensville - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Helensville - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Henderson Valley - 11kV Indoor SWBD Retrofit - 10 Panels	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Henderson Valley - Protection System - TMS Replace	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Henderson Valley - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Henderson Valley - Substation Automation	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Henderson Valley - Substation Auxiliary Systems Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Henderson Valley - Protection System Replace / Upgrade	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Highbury - 11kV Indoor SWBD Retrofit - 5 Panels	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Highbury - 33kV Outdoor CB Replace - 1 CB	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Hillcrest - 11kV Indoor SWBD Retrofit - 12 Panels	$0.0m	$0.0m	$0.0m	$0.6m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hillcrest - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hillcrest - Substation Automation	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hillcrest - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hillcrest -Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Hobsonville - 11kV Indoor SWBD Replace - 11 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.2m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Protection & Control	Hobsonville - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hobsonville - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hobsonville - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Hobsonville - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	James St - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Asset Replacements	Laingholm - 11kV Indoor SWBD Replace - 11 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$1.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Laingholm - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Laingholm - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Laingholm - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Laingholm - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Laingholm - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Manly - Seismic Strengthening & Flood Assessment	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Asset Replacements	Milford - 11kV Indoor SWBD Replace - 5 Panels	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Milford - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m
Asset Replacements	New Lynn - 11kV Indoor SWBD Replace - 11 Panels	$0.0m	$0.2m	$2.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	New Lynn - Protection System - TMS Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	New Lynn - Seismic Strengthening	$0.0m	$0.0m	$1.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	New Lynn - Substation Automation	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	New Lynn - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	New Lynn - Protection System	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
	Replace / Upgrade											
Asset Safety & Compliance	Ngataringa - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Asset Replacements	Ngataringa Bay - 11kV Indoor SWBD Retrofit - 7 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Ngataringa Bay - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Ngataringa Bay - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Ngataringa Bay - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Ngataringa Bay - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Northcote - 11kV Indoor SWBD Retrofit - 5 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Northcote - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Northcote - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Northcote - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Northcote - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Northcote - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Orewa - 11kV Indoor SWBD Replace - 5 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Orewa - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Orewa - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Orewa - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Orewa - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Riverhead - 11kV Indoor SWBD Replace - 12 Panels	$0.0m	$1.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Riverhead - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Protection & Control	Riverhead - Protection System Replace / Upgrade	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Riverhead - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Riverhead - Substation Automation	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Riverhead - Substation Auxiliary Systems Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Sabulite Rd - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Sabulite Rd - 11kV Indoor SWBD Replace - 11 Panels	$2.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Sabulite Rd - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Sabulite Rd - Substation Automation	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Sabulite Rd - Substation Auxiliary Systems Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Sabulite Rd - Protection System Replace / Upgrade	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Spur Rd - Seismic Rebuild	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Sunset Rd - Protection System - TMS Replace	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Swanson - 11kV Indoor SWBD Replace - 10 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.2m	$0.0m	$0.0m
Protection & Control	Swanson - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Asset Safety & Compliance	Swanson - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Swanson - Substation Automation	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Swanson - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Swanson - Protection System Replace / Upgrade	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Takapuna - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Protection & Control	Takapuna - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Takapuna - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Takapuna - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Torbay - 11kV Indoor SWBD Replace - 5 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.0m	$0.0m	$0.0m
Protection & Control	Torbay - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Torbay - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Torbay - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Protection & Control	Torbay - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m
Asset Replacements	Triangle Rd - 33kV Power Transformer Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$4.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Triangle Rd - Seismic Strengthening	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Triangle Rd - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Triangle Rd - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Triangle Rd - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Triangle Rd - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Various - CB & SWBD Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$2.0m	$1.5m	$1.5m	$1.5m	$1.5m
Protection & Control	Various - Communication System	$0.0m	$0.0m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m
Protection & Control	Various - Communication Systems	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Various - DC Auxiliary System Replacement	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Various - Distribution Automation	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Various - Distribution Automation - MV/LV	$0.0m	$0.0m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
	substation automation											
Asset Preventive Programmes	Various - Earthing Upgrades	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m
Asset Preventive Programmes	Various - GM Pillar and Pit Replace	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m
Asset Preventive Programmes	Various - GM Switchgear Replace	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m
Asset Preventive Programmes	Various - GM Transformer Replace	$1.5m	$1.5m	$1.5m	$1.5m	$1.5m	$1.5m	$1.5m	$1.5m	$1.5m	$1.5m	$1.5m
Asset Preventive Programmes	Various - OH Conductor Replace	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m
Asset Preventive Programmes	Various - OH Riser Replace	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m
Asset Preventive Programmes	Various - OH Structure Replace	$5.4m	$5.4m	$5.4m	$5.4m	$5.4m	$5.4m	$5.4m	$5.4m	$5.4m	$5.4m	$5.4m
Asset Preventive Programmes	Various - OH Switchgear Replace	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m
Asset Preventive Programmes	Various - OH Transformer Replace	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m	$0.6m
Protection & Control	Various - Power Quality	$0.0m	$0.0m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m	$0.2m
Protection & Control	Various - Power Quality	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Various - Power System Protection Replacement / Upgrade	$1.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Performance	Various - Reliability Improvements	$0.5m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m	$0.8m
Asset Strategic Spares	Various - Strategic Spares	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m	$0.1m
Protection & Control	Various - Substation Automation	$0.0m	$0.0m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m
Protection & Control	Various - Substation Automation	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Preventive Programmes	Various - UG Cable Replace	$2.6m	$2.6m	$2.6m	$2.6m	$2.6m	$2.6m	$2.6m	$2.6m	$2.6m	$2.6m	$2.6m
Asset Safety & Compliance	Various - Zone Substation Oil Containment	$1.0m	$1.0m	$1.0m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m	$0.3m
Asset Replacements	Waiake - 33kV Outdoor CB Replace - 1 CB	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Waiake - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Protection & Control	Waiake - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Waiake - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Waiake - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Waikaukau Rd- 33kV Outdoor CB Replace - 3 CBs	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.8m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Waimauku - 33kV Power Transformer Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$2.5m	$0.0m	$0.0m	$0.0m
Protection & Control	Waimauku - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Waimauku - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Waimauku - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Waimauku - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Wairau Valley - 11kV Indoor SWBD Replace - 11 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$1.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Wairau Valley - 33kV Indoor SWBD Install	$7.0m	$0.7m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Wairau Valley - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Wairau Valley - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Wairau Valley - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Wairau Valley - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Warkworth - Seismic Strengthening	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Wellsford - 33kV Outdoor CB Replace - 2 CBs	$0.0m	$0.5m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Wellsford - Protection System - TMS Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Safety & Compliance	Wellsford - Seismic Rebuild	$0.4m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Wellsford - Substation	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m

		Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Investment Programme	**Project**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
	Automation											
Protection & Control	Wellsford - Substation Auxiliary Systems Replace	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Protection & Control	Wellsford - Protection System Replace / Upgrade	$0.0m	$0.2m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m
Asset Replacements	Woodford Ave - 11kV Indoor SWBD Retrofit - 6 Panels	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m
Protection & Control	Woodford Ave - Protection System - TMS Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Woodford Ave - Substation Automation	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Woodford Ave - Substation Auxiliary Systems Replace	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.1m	$0.0m	$0.0m	$0.0m
Protection & Control	Woodford Ave - Protection System Replace / Upgrade	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$0.3m	$0.0m	$0.0m	$0.0m

Table 6-32: 10 years programme of renewal works

Vector®

Electricity Asset Management Plan 2012 – 2022

Systems and Data – Section 7

[Disclosure AMP]

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7 Systems, Processes and Data

7.1 Asset Information Management Background

This section describes the information systems and associated business processes Vector maintains and operates to manage its asset data.

Vector's day-to-day operation involves specialists and teams within the organisation and its field service providers (FSPs) undertaking a wide variety of business functions such as financial forecasting, network planning, project management, asset valuation, maintenance management, asset inspection and condition monitoring.

These business functions are supported by data, systems and business processes. The following diagram (Figure 7-1) illustrates the relationships between business teams, functions, information systems and data: many functions are dependent on the same systems or indeed the same source data.

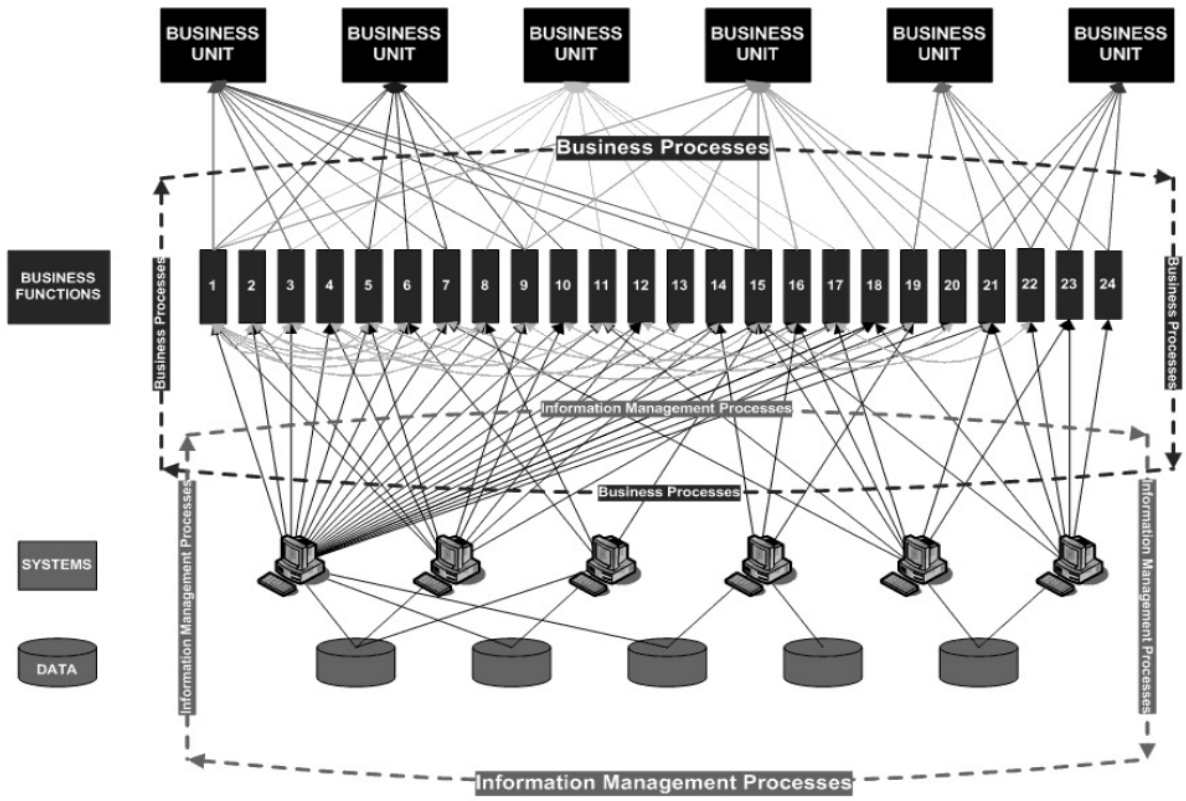


Figure 7-1 : Information Management Framework

To establish effective management of data, systems and processes, Vector has created a Corporate Data Catalogue (CDC), which holds a reference definition of data sets, master systems, and ownership. In addition, the CDC provides a current assessment of each data set in terms of quality, security, sensitivity and criticality, and the basis for identifying fitness for purpose of data: whether "good enough" or "perfect" is required. The CDC includes all data sets managed by Vector and held in its corporate systems, including those required to support asset management.

Note that Vector's FSPs employ their own information systems to manage activities related to their function, such as works management, resource scheduling and mobile data capture. The data sets held in these systems are managed by Vector's FSPs on Vector's behalf, in line with requirements set out in Vector's standards, business rules and the MUSA contractual arrangements.

7.2 Asset Information Systems

Vector's asset data is held by a dozen or more primary or enterprise systems which are described in section 7.3, built around Vector's corporate Enterprise Resource Planning (ERP) System. By establishing the ALIS in its ERP System Vector has adopted an enterprise asset management approach, in which electricity assets are managed through their entire lifecycle.

The enterprise systems are supplemented by a number of standalone databases, typically PC-based tools with no programmatic data feeds to or from enterprise systems. In addition, Vector manages a highly developed real-time data system (SCADA), the design, operation and future direction of which is described in Sections 5 and 6.

Each asset information system has a specific purpose, and is the master repository, providing the ultimate, sole source of truth for a specific data set, as summarised in Table 7-1.

ERP	Event Mgt	Geospatial	Billing	Other Enterprise System	Real-Time System	Standalone System	SPs' Systems

Asset Information Systems	Financial information	Technical attributes	Transactional history	Location	Connectivity	Customer service
Fixed Asset Register (FAR)	★	✓				
Asset Valuation Register	★	✓				
Asset Lifecycle Information System (ALIS)	★	★	★	✓		✓
Materials Management System (MMS)	★	✓	★			
Project Management Information Systems (PMIS)	★		★	✓		✓
Geographic Information System (GIS)		✓		★	★	✓
Landbase				★		
Engineering Drawing System (EDS)		★		✓	✓	
Power Systems Model (PSM)		★			✓	✓
Protection Settings Database (PSD)		★				
Cable Capacity Calculator (CCC)		★				
Real-Time Data Historian			★		✓	✓
Customer Management System (CMS)	★		★	✓		★
Outage Records			★	★	✓	✓
Billing System	★		★	★	✓	✓
SCADA		✓	✓		★	★

Master (source data) repository	★
Secondary reference	✓

Table 7-1 : Vector's asset information systems

Figure 7-2 illustrates the current organisation of Vector's asset information systems. Overlapping blocks indicate where systems are integrated, notably within the ERP System as a whole and between the Asset Lifecycle Information System (ALIS) and Geographic Information System (GIS). In addition, the Real-Time Data Historian is interfaced to SCADA. A number of one- and two-way data exchanges also exist between several of the enterprise systems and between the ALIS and the FSPs' Works Management Systems.

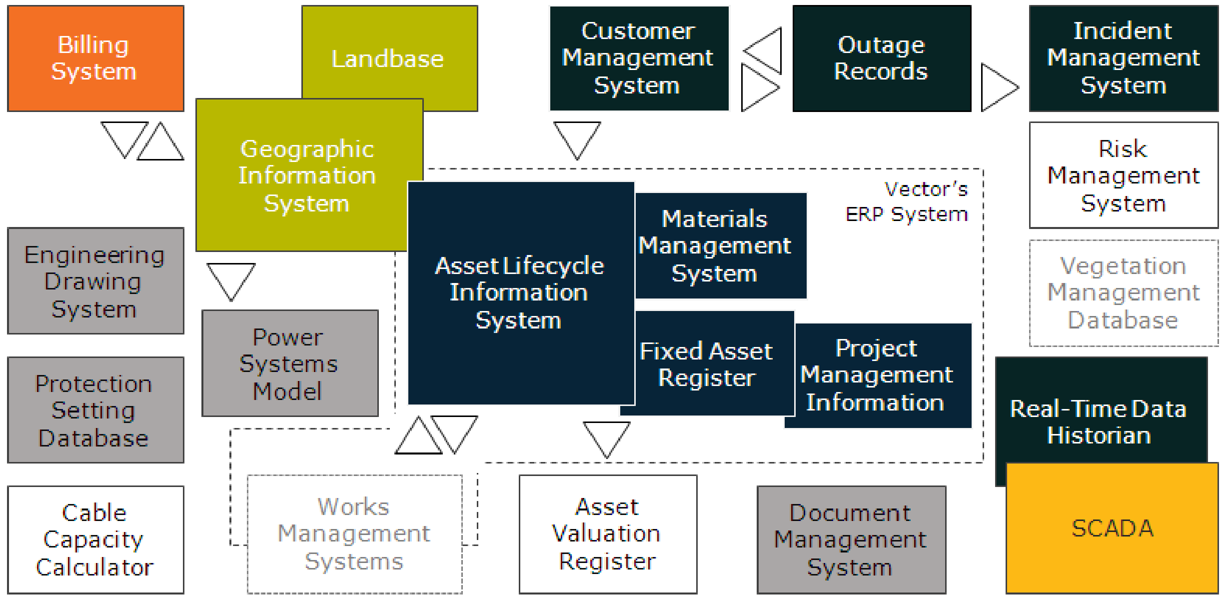


Figure 7-2 : Vector's asset information systems landscape: current state

The following sections describe the functionality of each system. Section 7.2.7 describes the linkages within Vector's ERP system and related systems.

7.2.1 Asset Lifecycle Information System (ALIS)

The primary purpose of the ALIS is to maintain, in the Technical Asset Master (TAM) register, a complete inventory of all network physical assets, including strategic spares, as the master record of all static information (attributes or characteristics) about Vector's network physical assets, with the exception of geospatial information and connectivity.

As a core operational application, the ALIS is continually updated by asset data specialists within Vector's FSPs through an as-building process in which attribute data is captured and partially transferred to GIS and geospatial data is captured in GIS and transferred back to ALIS. These activities are controlled by asset data standards, business rules, work instructions and the relevant provisions of the MUSA agreement.

In line with the objective of optimising our lifecycle asset management capability, the ALIS has been designed to hold the planned maintenance regime for each asset, according to the relevant engineering standard.

The secondary purpose of the ALIS is to capture, from Vector's FSPs, the transactional history of each asset record, in terms of inspection and maintenance activities and defects. Data is provided continually from the FSPs' Works Management Systems via a file upload facility; master data is also downloadable from the ALIS.

As described below, the ALIS is also linked with Vector's Materials Management System (MMS) and Project management Information System (PMIS).

7.2.2 Fixed Asset Register (FAR)

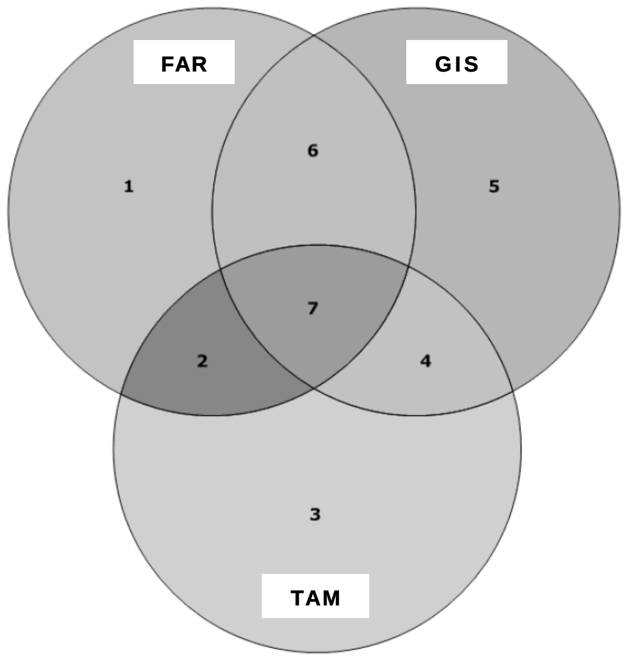
The FAR holds the master register of financial fixed assets, providing the basis for depreciation, taxation, valuation and financial reporting, and is linked with the TAM, being continuously updated by the TAM as assets are commissioned, refurbished and decommissioned.

7.2.3 Geographic Information System (GIS)

A geospatial model of Vector's electricity network between the Transpower GXPs and the customer connection interfaces is maintained in a proprietary database. The model is continually updated by Vector's FSPs via the ALIS, and by direct input, as described above. GIS acts as the master register for asset geospatial information and default network connectivity.

The base data in Vector's GIS is made accessible to third parties as a reference for underground service locations, and for other purposes including the coordination of works within Vector and externally.

Most electricity network fixed assets are recorded in all three of the TAM, FAR and GIS registers, as defined by category seven in Figure 7-3. However, as shown in the diagram, the GIS excludes certain asset types and there in some special cases, assets are not recorded in the TAM; the GIS also holds information about non-Vector assets. The category definitions are governed by asset data policies, standards and business rules.



KEY		Category Definition	*Examples*
	1	Non-network assets with no maintenance requirement	*Land, computer systems*
	2	Non-geospatial network assets with a maintenance requirement	*SCADA / comms, auxiliary equipment*
	3	Non-geospatial, non-capitalised network equipment with a maintenance requirement	*LV Connectors, Crossarms*
	4	Non-capitalised assets with a maintenance requirement	*Cable terminations, Telecom poles*
	5	Non-Vector owned objects with no (Vector) maintenance requirement	*Streetlights*
	6	Capitalised geospatial assets with no maintenance requirement	*None*
	7	Capitalised network assets with a maintenance requirement	*Most assets are in this category*

Figure 7-3 : Categorisation of asset data in the TAM, FAR and GIS registers

7.2.4 Materials Management System (MMS)

Vector's Materials Management System (MMS) is used to manage the supply chain for network equipment. The ERP system link between the MMS and the TAM register enables seamless tracking of serialised equipment along the supply chain, through procurement, to inventory, to network asset, through refurbishment cycles and finally through to disposal.

7.2.5 Project Management Information System (PMIS)

Vector uses a project management module in its ERP system to capture capital and operational costs and also a separate enterprise system for programme / project management of its capital works programme generally. Settlement of capital costs from project accounts through to financial asset records is readily facilitated and tracked through the ERP system link to the FAR.

7.2.6 Customer Management System (CMS)

Vector's Customer Management System (CMS) is a core operational application in which a full record of network faults and other customer information is captured by Vector's FSPs. This includes certain asset-related technical information as well as the operational and customer information more conventionally associated with a CMS. In order to enable reporting and analysis of this information from an asset management perspective, whenever a specific asset is associated with a network fault event, the service request (SR) number from CMS is cross-referenced against the technical object record in the ALIS.

7.2.7 Overview of ERP and Related System Links

The organisation within Vector's ERP system and the interfaces between the ALIS and the GIS, the CMS and Vector's FSPs' Works Management Systems are shown in more detail in Figure 7-4. This arrangement, together with the supporting business processes, offers a number of advantages in terms of asset lifecycle information management, as described below.

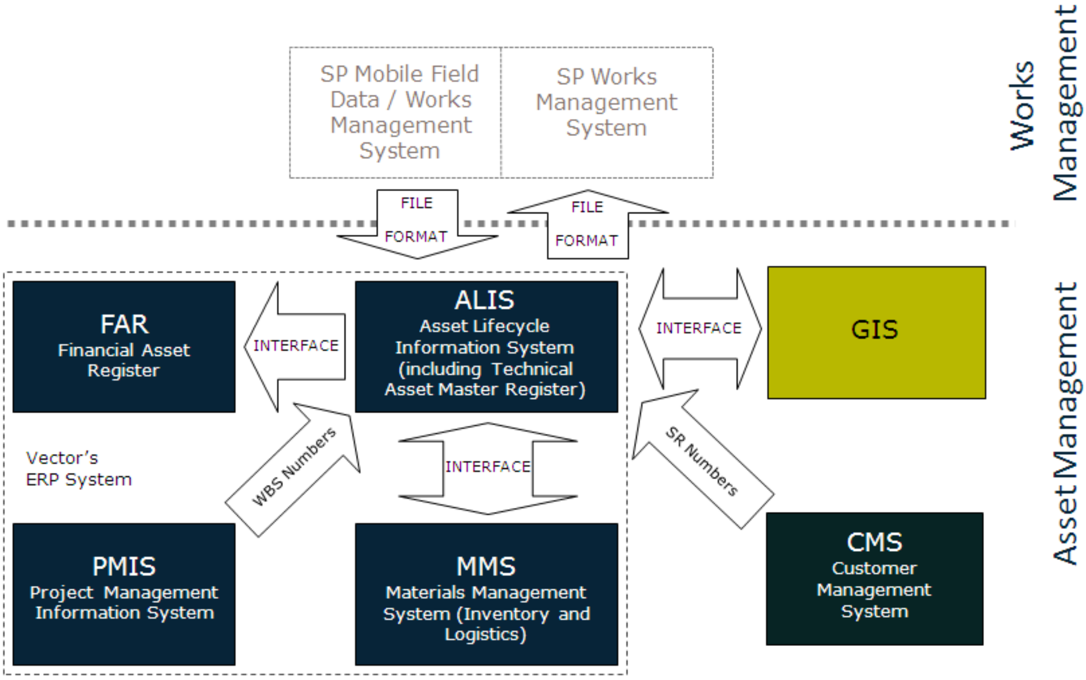


Figure 7-4 : Asset management / works management: organisation of information systems

- By linking the Technical Asset Master (TAM) register (within the ALIS) and the Financial Asset Register (FAR), via an inherent ERP system interface, Vector's technical and financial registers are able to be maintained in synch. Geospatial asset information in the GIS is maintained in synch with the ALIS, and hence also with the FAR. In this way, regulatory, statutory and other audit compliance is supported.
- The link from the MMS to the ALIS also enables equipment records in the TAM to be pre-populated efficiently and accurately from material master data in the MMS.

As noted above, the link also enables efficient asset creation, installation, refurbishment and disposal.

- Settlement of capital costs from project WIP accounts through to financial asset records is facilitated by the link from the PMIS to the FAR.
- Faults information is captured in the Customer Management System (CMS); by cross-referencing the Service Request (SR) numbers from the CMS into the ALIS, a complete transactional history of maintenance information is available at the asset (or network segment) level. This supports investment decisions related to network upgrading, asset replacement / refurbishment and the optimisation of operational / capital expenditure.
- Finally, by providing a relatively loose form of integration with the FSPs' Works Management Systems, via a specified set of file formats for up-loading and down-loading to and from the ALIS, the minimum possible degree of constraint is imposed on the FSPs' choice of mobile data capture technology. The link itself provides for improved oversight of works management.

7.2.8 Landbase

Vector has a long-term contract with an external organisation for the provision of a comprehensive, managed national land and property information database. This "landbase" is derived in turn from over 100 different sources, and enables Vector to have confidence that the information in the GIS is accurately mapped, and to leverage relevant up-to-date contextual information.

7.2.9 Asset Valuation Register

Vector's regulatory asset valuation register is derived from the data maintained in the FAR, TAM and GIS, in accordance with the guidelines set down by the Commerce Commission. The register is maintained in a standalone PC-based database.

7.2.10 Engineering Document System (EDS)

Vector network standards and technical specifications have been developed for design, construction, operation and maintenance of the network, and are the subject of continuous improvement.

Key documents are accessible via Vector's intranet. Engineering drawings and related technical documents from network projects are maintained in a proprietary document management system.

7.2.11 Power Systems Model (PSM)

Vector employs a specialised Power Systems Model (PSM) application for the purposes of analysing the network from an electrical power systems perspective. The PSM is programmatically updated via importing from GIS on a periodic basis, and covers the entire high voltage and medium voltage networks and strategic parts of the low voltage network.

The PSM enables Vector to undertake a wide range of power systems studies on the network in its present state and to model the potential impact of changes to the network configuration or to the network load. The model is built in line with the principles outlined in IEC 61850 (as described in Section 5) and Vector's technical requirements for protection and control, in order to support enhanced reliability and security analysis.

7.2.12 Protection Settings Database (PSD)

Vector also maintains a Protection Settings Database (PSD) supplied by the same vendor as the PSM, which holds the master register for the settings of the network protection relays and other intelligent electronics devices (IEDs) located in zone substations and other key points around the electricity network. The PSD is also used to download the protection settings and other configurations to the IEDs.

7.2.13 Cable Capacity Calculator

The Cable Capacity Calculator simulates the thermal behaviour of power cable installations by performing capacity and temperature rise calculations. The calculator is used to determine the maximum current power cables can sustain without deterioration of their electrical properties and underpins decisions related to the design of the network.

7.2.14 Real-Time Data Historian

A very large archive database of historical time-series data is maintained in an OPC (Object linking and embedding for Process Control) formatted repository, which captures data transmitted across the SCADA system from the IEDs. This information is used to provide asset utilisation information and support decision-making in network planning and operational control.

In line with Vector's policy to adopt best practice industry standards, we have adopted a standardised convention for a topological data model in accordance with the electric power system Common Information Model (CIM) defined by IEC61970-301. This allows easy alignment with the IEC61850 standard for the exchange of time-series and real-time data between IEDs and systems, including SCADA and the Historian.

The Historian application can be used to perform advanced calculations practically in real-time, and to create notifications, either directly, or via the ALIS. In due course, by combining time-series data with the TAM data, Vector's ability to execute condition-based/risk-based asset maintenance strategies will be enhanced.

7.2.15 Outage Records

A replica of Vector's high voltage and medium voltage network structure is maintained in a bespoke system, HVEvents, to manage the recording of interruption events and to prioritise network reconfiguration and restoration after an event.

The number of customers affected and the duration of interruptions to be identified against each event, by event type and location is enabled by logging events at the individual distribution transformer level.

Reporting of network reliability and calculation of asset performance statistics is derived from the data captured in this system.

Network performance is monitored through ongoing review of the data captured in HV Events by the Network Performance team comprising representatives from Asset Investment, Customer Services and Network Operations. Significant equipment-related incidents are cross-checked with the relevant asset engineer in order to identify root causes of incidents and put in place immediate and permanent corrective actions as appropriate. Results are currently logged in a stand-alone faulted-equipment database.

7.2.16 Billing System

Vector's billing system records all metered revenue data, and includes a database of all Installation Control Points (ICPs). The database is linked to the GIS and HVEvents and to the Metering and Reconciliation Industry Agreement (MARIA) electricity industry connections register.

7.2.17 Engineering Drawing / Document Management Systems

Vector maintains engineering drawings related certain other rich content documents in an Engineering Drawing System (EDS) which supports workflow management and version control. More generally, Vector operates a corporate Electronic Document Management System as a secure, centralised repository for key documents such as contracts, certificates and reports.

7.2.18 SCADA

Vector's electricity network is monitored and controlled in real time using the SCADA system, which is described in detail in Sections 5 and 6.

7.3 Asset Management Reporting

Whilst Vector's corporate Business Intelligence (BI) toolset includes a range of professional reporting applications for the reporting, visualisation and analysis of asset data, traditionally, Vector's approach to BI in the asset management context has been one of ad-hoc extraction of data directly out of a single operational system, such as the ERP or CMS, into a standalone PC-based database or spreadsheet.

In some cases, notably for the analysis and thematic mapping of geospatial information, specialised BI tools have been employed.

In order to maximise the value available from Vector's asset information systems, we are developing an asset management reporting strategy in using BI tools in a framework based on the asset management lifecycle, as illustrated in Section 1.11. Reporting requirements for decision making and other purposes are identified across the asset management lifecycle, drawing on data from several operational systems. In addition to the operational sources shown, a significant amount of relevant data is also sourced from outside of the organisation, including geospatial, meteorological and other contextual data, so that intelligence is gained from a blend of internal and external data sets.

Following this approach, at the "Condition and Performance Reporting" stage of the framework, BI tools have been used to develop a suite of network reliability reports, based on data from Vector's Outage Records and CMS.

Our objective is to make information accessible, by hosting / posting data (for example, via Vector's intranet) rather than by sharing or sending large amounts of data around the organisation. Our approach takes an iterative and collaborative engagement with users to identify requirements, which are often not fully understood at the outset, and builds the data into a seamless (rather than monolithic) repository of asset data. A key objective is to eliminate dependence on "human data warehouses".

In this way, by exploiting the functionality of all BI tools to export to spreadsheets, we are encouraging self-service of data by asset management specialists and teams thereby enabling rapid data extraction, visualisation and analysis to support better, faster decision-making.

All data sets held in BI tools, in common with data sets in operational systems, are defined in the Corporate Date Catalogue described in Section 7-1, and governed accordingly by data standards, business rules and processes.

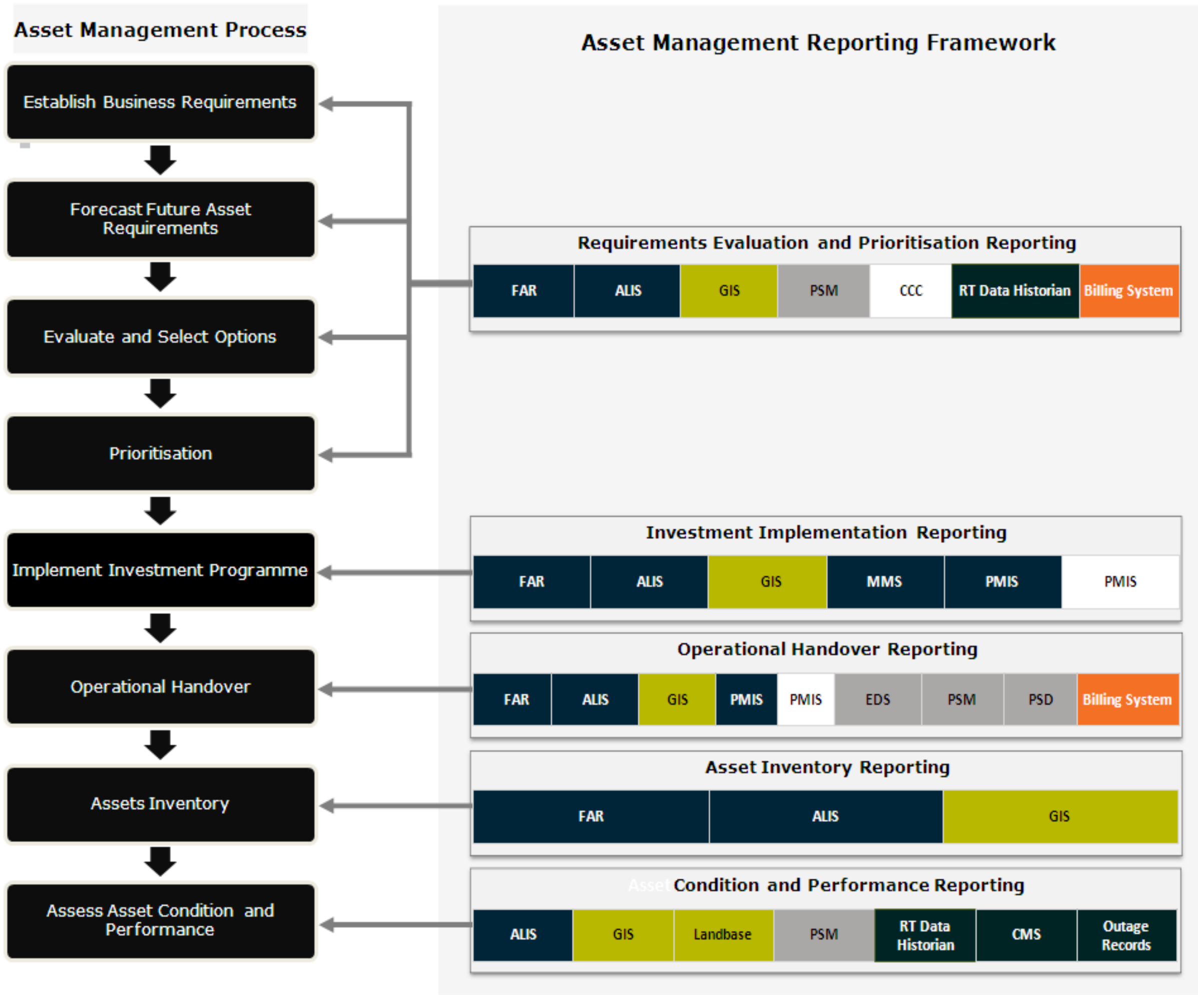


Figure 7-5: Proposed asset management reporting framework

7.4 Improvement Initiatives

Vector, as a provider of integrated infrastructure solutions, is by its nature complex and has, over time, acquired additional layers of complexity in the way its systems, processes and data is structured and managed. In order to address the challenges this presents, and in line with Vector's group goals of operational excellence, cost efficiency and customer and regulatory outcomes (Section 1.3), Vector is adopting a more unified approach to managing asset information.

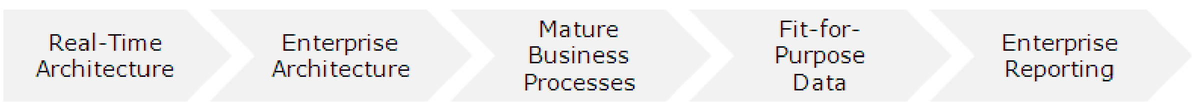


Figure 7-6: Vector's unified approach to asset information

This approach has led to the development of a programme of initiatives with the following objectives.

Focus	Objectives
Asset data	• Reducing the amount of datasets, particularly those in stand-alone systems • Improving all data sets in terms of its ownership, definition, quality, completeness, accuracy, security and sourcing • Continuing to cleanse data through a prioritised programme of improvement initiatives • Achieving full connectivity (allowing tracing from customer to supply)
Business processes	• Developing mature, consistent and repeatable business processes with the objective of simplifying the end-to-end management of asset information • Ensuring ownership and quality assurance by closing the "information loop" • Improving communication within and between business units to avoid duplication of effort.
Information systems	• Extracting the maximum value from information systems; • Developing improved and simplified means of transforming data into information; and • Delivering integrated solutions, and developing simple user interfaces.

Table 7-2 : Asset information objectives

In order to deliver the programme, a 10-year asset information systems roadmap for has been developed that addresses these areas of focus and covers three core asset information systems: GIS, ALIS and SCADA.

In terms of the information systems themselves, Vector's unified approach, as illustrated in Figure 7-5 below, is to develop integrated solutions at all levels, rather than simply at the application level.

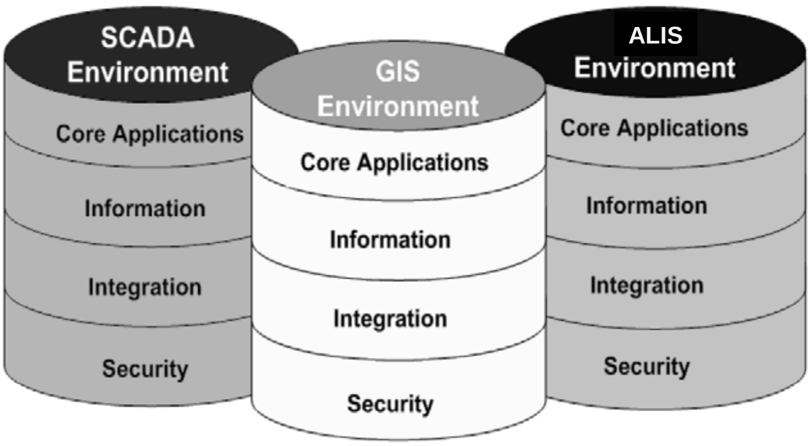


Figure 7-5 : Core environments

For the GIS, ALIS and SCADA environments, this approach is designed to enable a number of specific improvements, as summarised in the Table 7-3 below.

System	Planned Improvements
ALIS	• Extending the functionality of the ALIS and related ERP and other systems • Exploiting market developments in ERP system functionality • Improving the usability for infrequent users, for example by improving the user interface • Developing capability in equipment performance analysis • Streamlining the interface with GIS • Developing the ability to create notifications from data residing in the Real-Time Historian
GIS	• Eliminating customisation in order to simplify maintenance and reduce the cost and complexity of upgrades • Simplification of the data model • Streamlining the interface with the ALIS (minimising double handling and duplication of data) • Exploiting the full functionality of the system, for example use of GIS for design work (rather than importing and re-drawing from computer aided drawing systems) • Mitigating data extraction issues (such as connectivity) • Supporting closer alignment with real-time systems, in particular SCADA • Development of on-line mapping and spatial analysis
SCADA	• System consolidation (as described in Section 5) • Defining the relationships between SCADA / GIS / ALIS / PSM Further development of the operational representation of connectivity • Extension of the scope of SCADA (for example, for real-time power systems analysis and outage management) • Phasing out the use of hardcopy in the Control Room • Supporting the implementation of Outage Management / Distribution Management Systems

Table 7-3 : Asset information objectives

Figure 7-6 provides an overview of the strategic direction.

Following the implementation of the ALIS, the GIS and SCADA are now the focus of development. Subsequent developments, such as the implementation of a new Outage Management System (OMS) and Distribution Management System (DMS) capabilities will be contingent on the outcomes of this work. Figure 7-7 illustrates the proposed integrated structure for Vector’s asset information systems.

The roadmap is now in its second year, and is shown in outline in Figure 7-8.

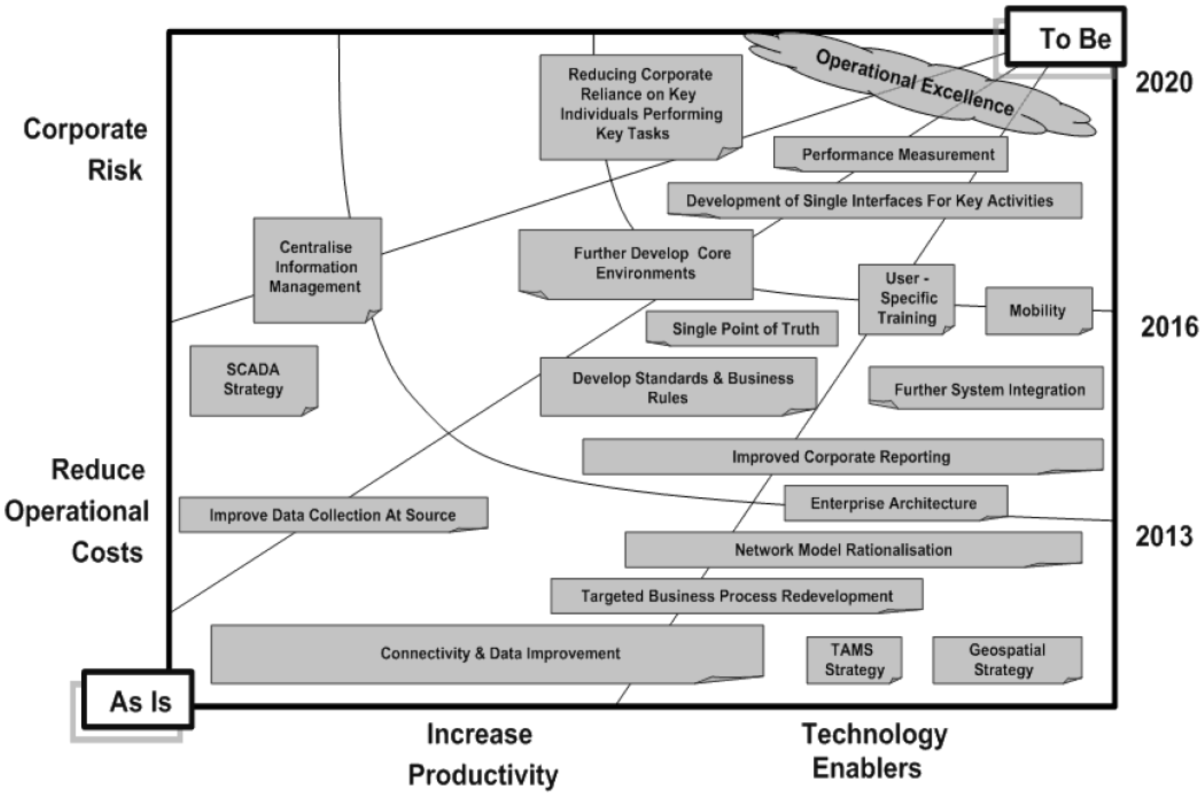


Figure 7-6 : Indicative strategic direction for Vector's asset information systems

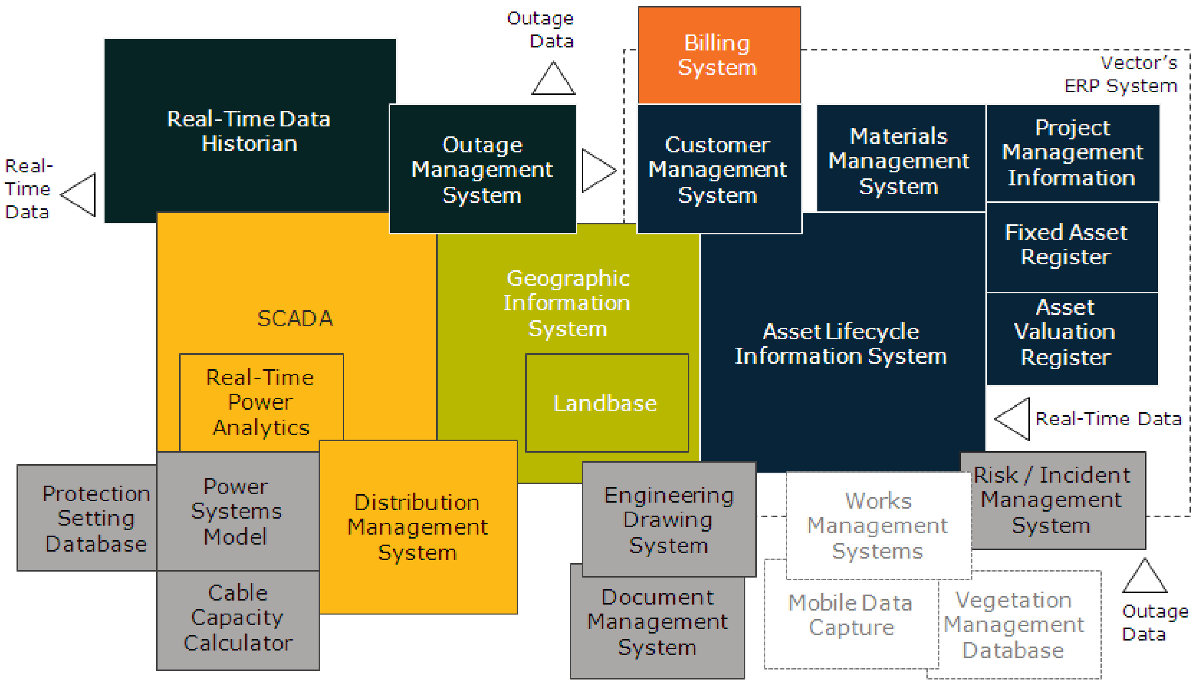


Figure 7-7 : Proposed integrated structure for Vector's asset information systems

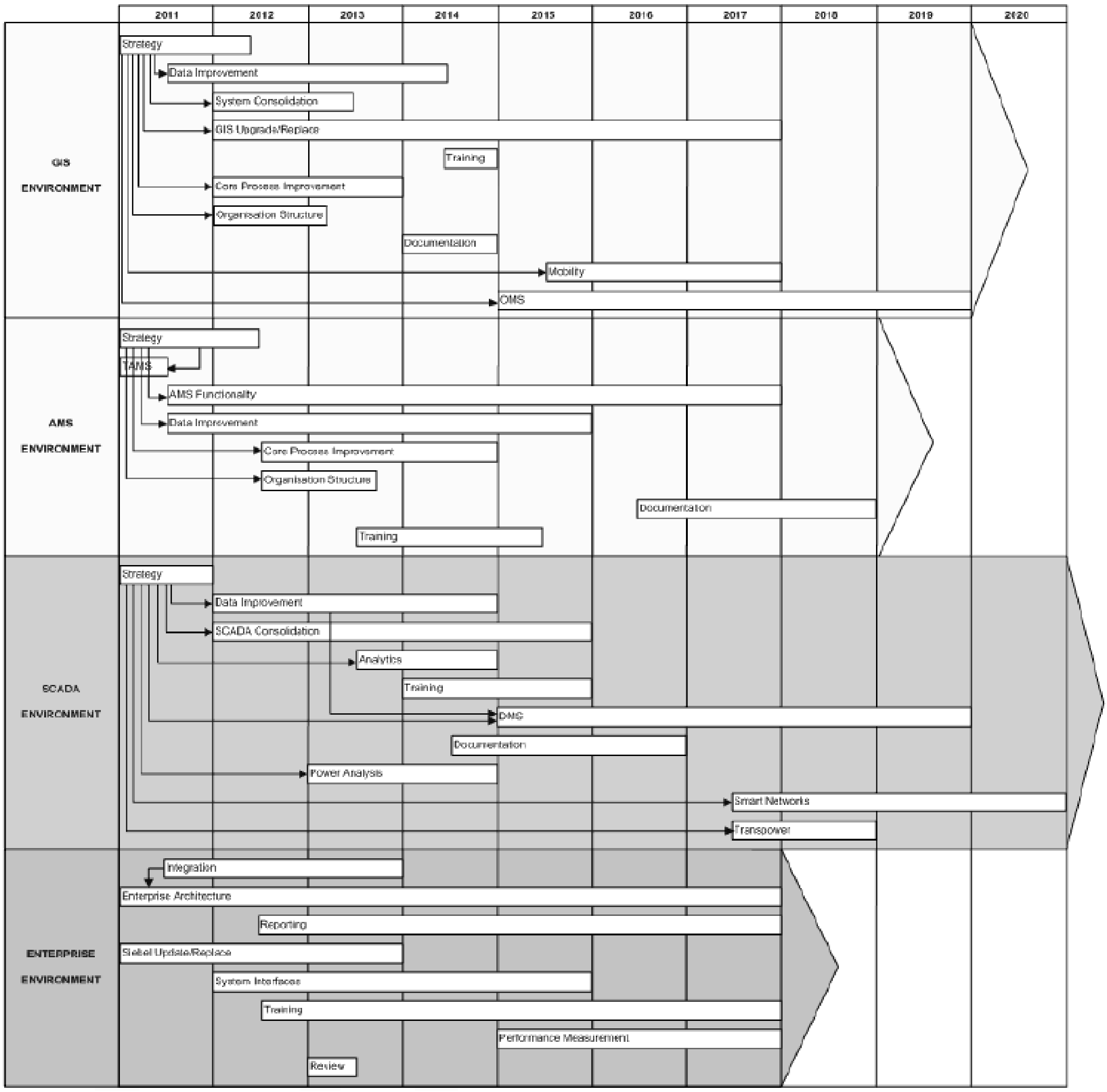


Figure 7-8 : 10-year roadmap for Vector's asset information systems

7.5 Asset Data Quality

Asset lifecycle management data sets have been quantified in terms of data quality in the Corporate Data Catalogue, as described in Section 7.1. Where limitations have been identified, initiatives are put in place to address the root causes and remediate data where required. These initiatives are prioritised and managed in an Asset Information Improvement Plan. Table 7-4 below summarises some of the current base data issues related to the electricity network addressed by the plan.

Initiative	Legacy data	System level data	Process or standard	Resource required	Target date
Audit and update as necessary zone substation engineering drawings; tidy up EDS and on-site folders; implement upgraded control processes	✓		✓	High	2014
Substantially rectify incomplete or inaccurate distribution equipment asset attribute data in ALIS	✓			High	2014
Correct or populate inaccurate and missing spatial location data in GIS	✓			Medium	2014
Refine ALIS data model specification to address TAM / GIS master data inconsistencies		✓		Low	2012
Simplify the process for settlement of capitalisable project costs to fixed assets in FAR	✓			Medium	2013
Rectify connectivity issues associated with LV open points in GIS; align with SCADA where possible	✓		✓	Medium	2013
Clean up ICP data set in GIS and Billing System	✓		✓	High	2014
Develop a robust process for managing distributed generation sites in GIS			✓	Medium	2012
Electronically capture archived network drawings so that historical asset records are easily accessible		✓		Low	2012
Review and enhance the project close out process to ensure all asset information is captured right first time			✓	Medium	2013

Table 7-4 : Asset Information Improvement Plan

Electricity
Asset Management Plan
2012 – 2022

Risk Management – Section 8

[Disclosure AMP]

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8 Risk Management

8.1 Risk Management Policies

Risk management is integral to Vector's asset management process. Vector's risk management policy sets out the company's intentions and directions with respect to risk management including its objectives and rational. Vector's goal is to maintain robust and innovative risk management practices, consistent with the ISO31000 standard and implement those practices in a manner appropriate for a leading New Zealand publicly-listed company that supplies critical infrastructure and manages potentially hazardous products.

Vector's core operational capabilities, such as asset, operational and investment management, are supported by robust risk management decision-making, processes and culture. Risk and assurance management also underpin Vector's ability to meet its compliance obligations. By the nature of the electricity distribution business there are many inherent risks and safety management is one of Vector's top priorities in the day to day operations of the network. Vector takes this responsibility seriously and has stringent risk management processes in place covering hazard identification, risk assessment and the monitoring and review of hazards. The primary principle in managing risk is to achieve acceptable risk criteria and to reduce the risks to as low as reasonably practical (ALARP).

The risk management capability is built on a risk management process which requires risks to be identified and analysed. This analysis takes the form of understanding both the nature of a risk and its level. This includes identifying and evaluating any controls in place. A 'control' is any policy, practice or device which is in place to modify (reduce) a risk. With this information risks are evaluated against Vector's risk management framework and a decision made as to whether the level of risk is acceptable. If it is not acceptable a 'treatment' is developed and prioritised against others. In terms of asset management these often become security of supply or asset integrity capital projects, or become the basis for work practice decisions. The effectiveness of the controls and the delivery of these projects are subject to ongoing monitoring. The consequences and likelihood of failure or non-performance of assets, the current controls to manage these, and required actions to mitigate risks, are all documented, understood and evaluated by Vector as part of the asset management process.

The acceptable level of asset-risk will differ depending on the impact, should an asset fail, on the electricity supply or its potential for harm. This in turn is influenced by the different categories of customers, communities' willingness to accept risk and the circumstances and environment in which the risk would occur. Risk analysis covers a range of risks from those that could occur at a relatively high frequency but with low impact, such as tree interference, through to low probability events with high impact, such as the total loss of a zone substation for an extended period.

Risks associated with assets are primarily managed by a combination of:

- Reducing the probability of failure through the capital and maintenance work programme and enhanced work practices; and
- Reducing the impact of failure through the application of appropriate network security standards, robust network design supported by contingency and emergency plans.

8.2 Risk Accountability and Authority

8.2.1 Vector Risk Structure

Figure 8-1 shows Vector's risk management structure and reporting lines.

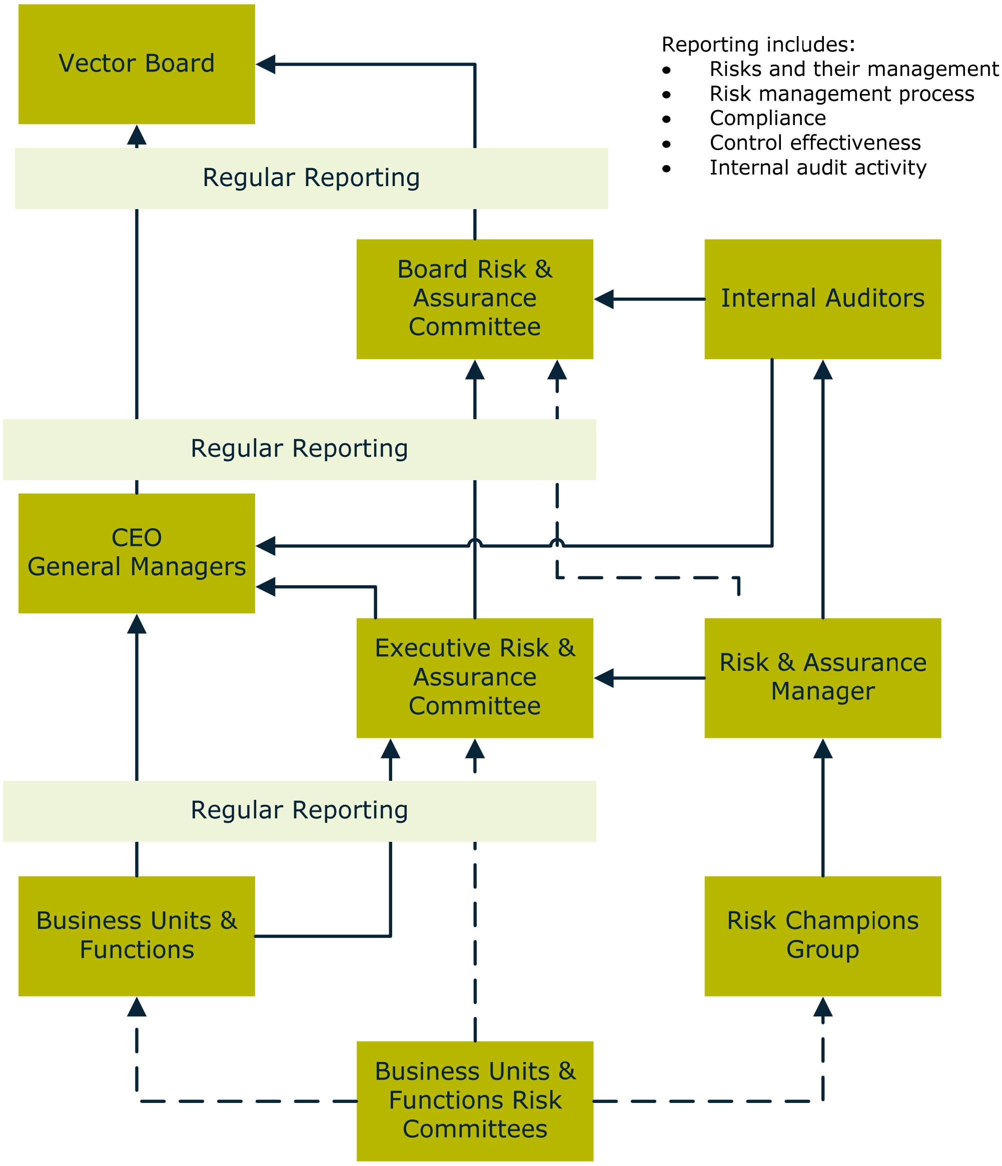

Figure 8-1 : Vector's risk management structure

The following paragraphs describe the accountabilities and authorities of the committees within the risk management structure.

8.2.2 Board Risk and Assurance Committee

Vector's board has overall accountability for risk management. This responsibility (excluding security of supply risks which remain a full board responsibility) has been delegated to the Board Risk and Assurance Committee (BRAC) which provides oversight of Vector's risk and assurance framework and performance.

The BRAC meets four times a year to review the group's risk context, key risks and key controls, which include the internal audit and insurance programmes.

8.2.3 Executive Risk and Assurance Committee

The Vector executive has established an Executive Risk and Assurance Committee (ERAC) to provide special specific focus and leadership on risk management. The committee has the overarching responsibility of ensuring risk management and assurance in Vector is appropriate in terms of scope and strategy, as well as implementation and delivery.

The ERAC meets six weekly to review risk management policy and its implementation, as well as key risks.

Vector has also established a Business Continuity Management Steering Committee made up of a mixture of executive and management with specific related responsibility to focus on the development and management of Business Continuity Management (BCM) throughout the company including the operations of electricity networks.

8.2.4 Management and Business Areas

The group general managers and their direct reports have responsibility for ensuring that sustainable risk management and assurance practices are developed and effectively implemented within each of Vector's business groups.

Asset related risks and their control and mitigation measures are largely the responsibility of the Asset Investment (AI) and Service Delivery (SD) groups. The AI group oversees network asset management strategy and performance and includes the development of standards for the electricity network and its component assets.

The SD group manages the operational delivery of the strategy. This includes delivery in the field of the requisite levels of maintenance and capital expenditure (capex) so the network meets the stated reliability, safety, environmental and performance standards. The SD group also manages the safe and reliable operation of the network to predefined levels.

8.2.5 Risk Champions

Risk champions have the responsibility of facilitating risk management practices in their business groups by:

- Ensuring, in conjunction with the risk-owners, that their risk registers are accurate and up to date;
- Completing general risk management reporting requirements within their business groups;
- Ensuring effective risk management meetings are conducted in their areas (and cross-functionally as appropriate); and
- Ensuring appropriate risk communication and induction is undertaken in their business groups.

8.2.6 Risk and Assurance Manager

The Vector Risk and Assurance Manager is responsible for the development of a risk management framework, which includes a risk management plan outlining the approach, management components and resources applied to risk management. The risk management framework is approved by the ERAC.

The role includes the monitoring and reporting of progress against this plan and overall delivery of risk management and assurance, as well as communicating on risk management and assurance issues across Vector.

8.2.7 Staff

Each staff member is responsible for ensuring they understand the risk management practice in Vector and how it applies to them. This includes being actively engaged in the identification of new risks and ensuring these are appropriately acknowledged.

Individual staff may have specific responsibilities for the ownership and management of a specific risk, control or treatment depending on their roles.

8.3 Risk Management Process and Analysis

8.3.1 Risk Management Process

Vector has adopted the risk management principles and guidelines detailed in AS/NZS ISO31000:2009. This standard was largely based on AS/NZS 4360:2004 which Vector had used in the development of its initial policy and framework. Given the consistencies between the standards there were no major problems with the adoption of the new principles and guidelines.

The risk management process adopted by Vector is shown in Figure 8-2 below.

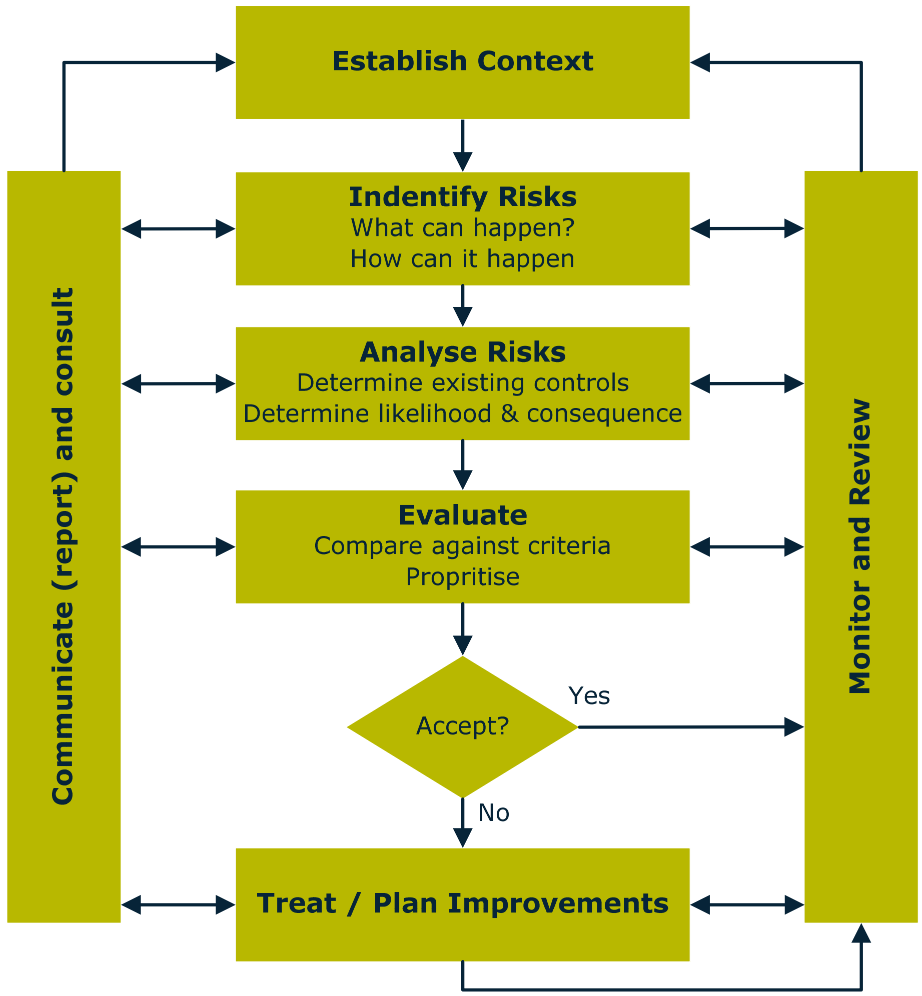

Figure 8-2 : Vector's risk management process (based on ISO31000: 2009)

The level of a risk is determined by considering the combination of the "likelihood" and "consequences" of the risk occurring given current controls. This is then compared to Vector's risk assessment matrix shown in Figure 8-3 below. The overall risk level is used as a key factor in determining the acceptability of the risk and driving the need and priority of any subsequent action.

Risks which have "catastrophic" or "major" risk consequences include those which could lead to loss of life, cause serious damage to the environment, create a major loss of electricity supply, lead to major financial loss or have a significant impact on Vector's reputation.

Vector has controls in place to manage key risks and has internal review processes associated with these controls. A key component of the assurance process is Vector's internal audit programme which provides assurance around controls, including organisation-wide 'risk management' and BCM governance. The Internal Audit programme is overseen by the BRAC.

Risk Assessment

	Minor	Moderate	Serious	Major	Catastrophic
Frequent	H	H	VH	E	E
Likely	M	H	VH	VH	E
Possible	L	M	H	VH	VH
Unlikely	L	M	M	H	VH
Rare	L	L	L	M	H

Risk Assessment Using Consequence And Likelihood

L = Low
M = Moderate
H = High
VH = Very High
E = Extreme

Red = Board Attention
Orange = Executive Attention
Green = Management Attention

Figure 8-3 : Vector's risk assessment matrix

The asset management process is also specifically reviewed by an independent third party as a requirement of the AECT Trust Deed which governs key aspects of how the company must operate. The results from this review are reported through to the full board.

8.3.2 Network and Asset Risk Management

The management of the electricity network assets is underpinned by the risk management principles described above. The AI group which oversees network asset management and performance uses these principles in the development of standards for the electricity network and its component assets.

The SD group manages the operational delivery of the strategy. This includes delivery in the field of the requisite levels of maintenance and capital development so the network meets the stated risk rated reliability, safety, environmental and performance standards. The SD group also manages the safe and reliable operation of the network to predefined levels.

The AI and SD groups both have an integrated approach to risk management and their respective responsibilities in relation to it, which encompasses:

- Identifying and assessing risks;
- Managing and maintaining controls;

- Developing and implementing treatments proportionate to the risk involved;
- Monitoring risks, the effectiveness of controls and progress of treatments;
- Maintaining up to date risk registers which clearly identify risks, the ownership of the risks, possible outcomes and mitigation measures; and
- Reporting these risks, controls and treatments to the ERAC and BRAC as appropriate.

Regular risk meetings are held at all levels of Vector, and within the AI and SD groups, at which the existing risk registers are reviewed, potential risk scenarios discussed, and new risks identified for inclusion in the risk registers (along with the appropriate mitigation measures).

8.3.2.1 Risk Registers

Vector's risk registers identify risks and capture their management at different levels of detail and at different levels of responsibility, taking a tiered approach. These are routinely reviewed and reported on.

The risk registers report absolute risk classification (.e. excluding any organisational controls) and the risk classification with controls and treatments in place. The treatments are initiatives which are undertaken primarily to reduce the risk. These risks are managed at various levels, as appropriate, within Vector. The findings are reflected in Vector's asset planning outcomes. The most significant risks have visibility through to the ERAC and to the BRAC. Table 8-1 below shows the key information requirements for risks in Vector's risk registers.

Heading		Description
Unique ID number		Unique code for each risk
Risk Description	Short name	Short name for the risk to ease communication
	Full name and consequence	Full name defines the event or circumstance and the consequences which emanate from this risk
Categorisation	Strategic impact	One of 5 predefined categories
	Strategic objective	One of 18 predefined categories
Risk tier		Categorises risk in to one of three groupings in terms of breadth verses detail
Product type	Product type #1	What product in the group the risk is associated with, such as electricity, gas etc
	Product type #2	What - sub product of the above the product risk is associated with, such as for gas - wholesale gas
Risk Ownership	Function / Business Unit	Reporting unit
	Sub function	Reporting sub-unit within reporting unit
	Owner	Name of owner of risk

Heading		Description
Absolute	Consequence	Absolute - Consequence. Likely impact with no controls in place
	Probability / Likelihood	Absolute - Probability. Likelihood of risk occurring if no controls were in place
	Risk Assessment	Absolute - Risk Assessment. Assessment of risk as a combination of likelihood and consequence with no controls in place
Controlled	Consequence	Controlled - Consequence. Impact with (effective) controls in place
	Probability / Likelihood	Controlled - Probability. Likelihood of risk occurring with (effective) controls in place
	Risk Assessment	Controlled - Risk Assessment. Assessment of risk as a combination of likelihood and consequence with (effective) controls in place
Treated / 'As Low As Reasonably Practicable' (ALARP)	Consequence	Treated - Consequence. Impact when treatments are completed
	Probability / Likelihood	Treated - Probability. Likelihood of risk occurring when treatments are completed
	Risk Assessment	Treated - Risk Assessment. Assessment of risk as a combination of likelihood and consequence when treatments are completed
Assurance process	Key Controls	A brief description of controls
	Status	An evaluation of the quality of the control
	Process	How we get assurance of the control
	Control review date	When the control gets reviewed
	Control owner	Who manages the control
Treatments	Treatment name	A brief description of treatment
	% Complete	% of project complete
	Completion date	Date when treatment is scheduled to be complete
	Treatment owner	Owner of treatment
Admin	Risk origin	To track risk origin in terms of any past register / or to note as "new"
	Date listed	Date when risk was added to register
	Reviewer	Name of person who reviewed the risk
	Last updated	Date when risk has last been reviewed

Table 8-1 : Risk register headings

8.3.2.2 Key Operational Risks

Table 8-2 below outlines the most significant electricity risks Vector has identified in its asset management risk profile. While control and mitigation measures are in place to address these, work is ongoing to improve the controls and to ensure they remain effective.

Risk ID	Risk description	Risk Assessment Classification		
		Absolute	Controlled	Treated
AIAE5006	An asset or the way Vector operates the business exposes staff, contactors and/or the public to various forms and levels of risk. If a risk eventuates it could lead to a health concern, injury or death of any one of those parties leading, also to costs, liabilities/penalties and potential regulatory consequences.	Very High	Moderate	Moderate
AIAE5008	Risk from underperformance, breakdown failure of equipment or processes associated with running the networks or plants potentially leading to lost revenue, cost/losses, liability reputational, customer dissatisfaction and potential regulatory outcomes.	Extreme	Moderate	Moderate
AIAE5001	External events such as natural disasters (storms, earthquakes, volcanoes) or man-made related disasters (accidental or sabotage) disrupt the operations, or damage or destroy Vector assets potentially leading to lost revenue, cost/losses, liability, reputation damage, customer dissatisfaction and/or potential regulatory consequences.	Very High	High	High
AIAE5002	An asset or the way Vector operates the business exposes the environment to damage in different forms and levels. If a risk eventuates it could potentially lead to damage to the environment, creating a health concern, which in turn could lead to costs, liabilities or regulation/ penalties being incurred.	High	Moderate	Moderate
AIAE1007	Electricity SCADA system failure resulting in reduced visibility and/or control of electricity distribution network inhibiting response in an event.	High	Low	Low
AIAE1014	Electricity SCADA system resilience. An audit of the Vector electricity SCADA environment by Deloittes identified a number of actions that can be undertaken to improve network performance and safety.	Very High	Very High	Moderate
AIAE4024	Security of supply to Wairau Rd substation (110kV). 110kV supply to Wairau Rd substation is dependent on a double circuit 110kV line. Loss of this line would result in significant outages on the network.	Very High	Very High	Low
AIAE1038	Power quality performance below compliance levels. The risk is that Vector is unable to deliver power quality to acceptable standards, which has the potential to lead to a loss of reputation and regulatory consequences.	Very High	High	Moderate
AIAE3017	Risk of tower failure due to corrosion. There are a number of rusted and deteriorated towers on the Northern Network. The failure of a tower could potentially cause bodily harm.	Very High	Moderate	Moderate
AIAE3018	Uninsulated stay wires leading to risk of public injury.	Very High	Low	Low
AIAE3020	Potential failure of certain 33kV heat shrink joints undertaken by jointers 1999 -2000.	High	High	Moderate
AIAE3031	Injury caused by asset failure with uncertain ownership or Point of Supply location (including abandoned Telecom poles).	High	Low	Low

Risk ID	Risk description	Risk Assessment Classification		
		Absolute	Controlled	Treated
AIAE3040	King-bolt corrosion on overhead distribution transformer brackets. Possibility of harm as a result of king-bolt failure due to corrosion causing transformer to fall to the ground.	High	High	Moderate
AIAE4021	Loss of 110kV switchboard at Liverpool substation.	High	High	Low
AIAE4025	Electricity transmission supply security into the Auckland region. Transpower's Annual Planning Report identifies capacity and voltage constraints within the Auckland region. There is a risk to Vector's supply security if Transpower is unable to deliver to their plan or their plan is not aligned with Vectors needs.	Moderate	Moderate	Moderate
AIAE1040	Failure of ripple control plant resulting in the inability to control load which may cause high demand.	High	Moderate	Low
AIAE5013	The risk that appropriate new technologies are not adopted to reduce cost, enhance performance or protect the distribution market space. This leads to lack of competitiveness, loss of reputation, stranding of assets and/or increase in cost.	High	Moderate	Moderate
AIPI0003	Inability to identify network operational issues due to poor / corrupted field data. Robust long term maintenance plans and asset renewal strategies to be continually improved to minimise Vector's risk profile while meeting performance targets at the optimal cycle cost. This has the potential to lead to increases in cost, increased SAIDI, loss of shareholder confidence, poor asset management and decision making, which could have implications on cost, network and asset performance and HS&E.	Very High	High	Moderate
AIPI0004	Inadequate utilisation (load profile) information. High capital and operating costs resulting from inability to optimise asset utilisation.	High	High	Low
AIPI0011	Serious breaches of electricity reliability criteria.	Very High	High	Moderate

Table 8-2 : Most significant asset risks identified in the Vector electricity asset risk register

8.3.2.3 Integrated Risk Management – Our Aspiration

Vector continues to look to enhance the integration of the risk management process into its core planning and prioritisation activities. It is recognised many of the risk control or mitigation measures require capital investments, and capital investment is largely driven by risk-associated factors.

Anticipated risks identified in the risk register that can be treated by capital investment are included in the 10 years capital works programme (capital expenditure forecasts). These projects are identified by the risk identification number (from the risk register).

Other residual risks are controlled / mitigated through maintenance programme of works. These projects are part of the corrective or reactive maintenance programme.

Table 8-3 gives a summary of the key risks identified in the risk register (cross reference to the risk ID) and the expenditure programme to control / mitigate these risks.

Risk ID	Risk Description – Short	Expenditure Programme
AIAE3003	Possible harm resulting from explosion of leaning fused switches in SD oil filled distribution switchgear	Routine and preventive opex Refurbishment and renewal opex Capital expenditure projects
AIAE3014	Cast metal cable pothead failure causing possible harm	Fault and emergency opex Capital expenditure projects
AIAE3015	Unidentified loose neutral connections causing possible harm	Fault and emergency opex Capital expenditure projects
AIAE3016	Marine cable failure	Fault and emergency opex
AIAE3017	Risk of tower failure due to corrosion	Fault and emergency opex Refurbishment and renewal opex
AIAE3018	Uninsulated stay wires leading to risk of public injury	Refurbishment and renewal opex
AIAE3021	Uncontrolled oil spillage at zone substations with inadequate protection leading to environmental damage	Fault and emergency opex Refurbishment and renewal opex Capital expenditure projects
AIAE3026	Electricity distribution critical spares, tools and equipment	System management and operations opex
AIAE3046	Building Code compliance – seismic risk to substations	Routine and preventive opex Capital expenditure projects
AIAE3031	Possible harm caused by asset failure with uncertain ownership or POS location (including abandoned Telecom poles)	Routine and preventive opex
AIAE3040	King-bolt corrosion on overhead distribution transformer bearer arms	Fault and emergency opex Refurbishment and renewal opex
AIAE3042	Leaking Series 1 SD distribution switch gear	Routine and preventive opex Refurbishment and rrenewal opex Capital expenditure projects
AIAE3045	Possibility of harm or significant property damage associated with equipment failure at a distribution substation	Routine and preventive opex Refurbishment and renewal opex
AIAE3047	Uncontrolled discharge of oil from oil cables	Fault and emergency opex Refurbishment and renewal opex Capital expenditure projects
AIAE3048	Uncontrolled oil loss from distribution assets	Fault and emergency opex Refurbishment and renewal opex
AIAE3049	Possible fatality or serious harm resulting from a failure of a “letter-box pillar” (meter)	Fault and emergency opex Refurbishment and renewal opex Capital expenditure projects
AIAE 3050	Increase in fault level due to Vector’s work resulting in potential damage to customers’ properties	*Routine and preventive opex*
AIAE3052	Aluminium suspension clamps. Accelerated corrosion of conductor at the suspension clamp interface	Capital expenditure projects

Table 8-3 : Summary of the key risks identified in the risk register

Vector is looking to increase the standardisation of risk descriptions, assessments, evaluations and the prioritisation of treatments and is investigating enhanced computer-based platforms to aid in their overall analysis and management.

Vector is also intending to develop an overall risk-performance measurement structure which will be used to measure, track and report over time on the effectiveness of the management of individual risks and the overall risk-management process itself (and specifically asset-related risk management).

Components of this integrated risk-management suite are currently being investigated or tested and it is anticipated to have the full system in place by 2012.

8.3.2.4 Incident Management and Reporting

Vector recognises that the effective and efficient management and reporting of incidents is a major element of the risk management process as it is a significant source of information on risks, both their nature and level, and controls, and their effectiveness. Incident management in particular is seen as a key aspect of Vector's health and safety management system. It provides a key mechanism to gain insight into the root cause of incidents and provides a valuable opportunity to learn, improve, and avoid similar events in future. In managing incidents, Vector's priorities are to:

- Stabilise and manage the situation. Depending on the event this includes ensuring the safety of its employees, contractors and members of the public; limiting damage to assets; limiting environmental harm, and preserving operations;
- Notify the appropriate internal staff and external authorities, agencies and organisations of the incident;
- As appropriate, investigate the incident and prepare an incident report that considers all of the contributing factors, identifies the root cause(s) and recommends remedial actions as appropriate;
- Carry out any remedial actions; and
- Close out the incident.

Vector has reviewed its incident reporting processes and has implemented enhancements including ensuring there is greater consistency in weekly reporting across the different businesses within Vector.

A team has been established to identify Vector's needs and the options available to move towards the implementation of a more holistic incident management approach to:

- Build a more consistent, cross-business culture focused on reporting and learning from incidents and improving our business;
- Enhance the linkages with risk management processes and definitions;
- Enable efficient reporting;
- Reduce support costs including maintenance, support, licensing, training, etc; and
- Ensure lessons are shared and leveraged across the business.

8.4 Business Continuity Management

8.4.1 Business Continuity Policies

Vector requires an appropriate level of BCM capability in order to meet:

- Its obligations as the owner of "lifeline" utility businesses; such that it is able to function to the fullest possible extent (even though this may be at a reduced level during and after an emergency);
- Customer expectations that service disruptions will be minimised; and
- Shareholders' expectations in terms of protecting value if a disruptive event occurs.

To deliver this Vector has developed a BCM policy which requires that following a range of possible events, emergencies and crises Vector can:

- Minimise their impact on people, operations, assets and reputation;
- Maintain services to the fullest possible extent; and
- Recover to a business as usual position as quickly as reasonably practicable.

To deliver this Vector has established, and maintains, a robust BCM capability. Critical components are live tested on a regular basis to assess the ability to accommodate physical, business and personnel changes. Sufficient personnel are trained to manage serious situations and cope if key people are unavailable.

Vector extends the requirement to maintain a robust and workable BCM capability to its key business partners and external service providers that are relied upon by Vector to support its operations.

8.4.2 BCM Responsibilities

The overall BCM framework and plan is developed and monitored by the Risk and Assurance Manager. Vector's overall BCM capability and programme activities are overseen by a BCM steering committee. Additional oversight is provided by the BRAC and the ERAC.

The head of each business and functional unit is responsible for maintaining the appropriate BCM capability and compliance requirements for their areas. All employees are responsible for contributing to the maintenance of the BCM capability and to assist with the emergency/crisis response and recovery efforts in a real situation.

8.4.3 Business Continuity Capability

To deliver on its BCM policy Vector, as a whole and within its individual functional and business units, as appropriate:

- Undertakes Business Impact Analysis (BIA) and reviews of key disruptive events and recovery timeframes to determine BCM capability requirements;
- Ensures it has in place the appropriate level of BCM capability to be able to respond when a disruptive event occurs. This capability consists of:
  - People;
  - Plans; and
  - Infrastructure.
- Reviews and updates this capability annually (or as required if material external or internal changes have occurred) and has a full review scheduled on an appropriate timescale;
- Ensures the BCM capability extends to third parties where they are key agents in the delivery of an activity for Vector;
- Requires a BCM associated programme of testing to be planned and delivered; and
- Ensures it has appropriate:
  - BCM communication/awareness processes in place;
  - Levels of BCM training; and
  - Monitoring and reporting.

8.4.4 Business Continuity Plans

With respect to individual Business Continuity Plans (BCP) Vector's policies require appropriate governance aspects to be in place as well as each plan to have certain components.

With respect to governance each BCP:

- Has an owner. The owner has responsibility for the plan and all aspects of the capability around this plan;
- Is developed by those who are associated with the activity and who are named in the plan;
- Is reviewed annually and fully reviewed within a timeframe appropriate to the associated activity, or when required if significant external or internal changes occur;
- Has a programme for testing the combination of:
  - People;
  - Plan;
  - Infrastructure; and
  - Has an appropriate associated training and communication plan.

With respect to components, each BCP:

- Identifies which individuals/groups are notified of an event, including naming appropriate alternates, and having an appropriate escalation process defined;
- Identifies third parties that are required to support a given activity and identifies planning around their disruption;
- Outlines key activities to be undertaken;
- Provides key information required to make the implementation of the plan achievable; such as:
  - Contact lists (internal and external);
  - Maps/plans/drawings/instructions/flow charts;
  - Criticality information;
  - List of required associated equipment; and
  - Appropriate check lists.
- Has appropriate metadata:
  - Owner;
  - Versions; and
  - Date last reviewed and by whom.

8.4.5 Civil Defence and Emergency Management

Vector is classed as a "lifeline utility" under the Civil Defence and Emergency Management Act 2002 (CDEM) and 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". Vector also is required to have plans regarding how it will function during and after an emergency and to participate in the development of a CDEM strategy and BCPs.

Vector has a number of BCPs in place as well as an overall crisis plan.

Vector participates in CDEM emergency exercises on a regular basis to ensure CDEM protocols are understood as well as to test aspects of Vector emergency and BCP plans.

Vector has in place individual emergency response plans for major events and a National Civil Defence Emergency Management Plan that sits above these plans for use in the event of a declared civil defence emergency.

Vector is a member of the Auckland Engineering Lifelines Group (AELG). Membership in the AELG helps ensure Vector keeps abreast of developments in the CDEM area and that it is fully prepared for emergencies arising from identified threats including volcanic eruption, tsunami, earthquake, tropical cyclones and storms, both in general and in particular as they relate to Auckland where it has its electricity distribution assets.

A key area of focus for the company is to better utilise information from the AELG and from other Lifelines groups around the country into its asset management process.

Vector is also a member of the National Engineering Lifelines Committee and keeps abreast of national issues and initiatives through this forum.

8.4.6 BCP and Emergency Response Plans

Vector has a number of plans to cover emergency situations. These plans are reviewed and updated regularly to ensure they are current. Examples of the plans are:

- Crisis Management Plan;
- Emergency Response Plan;
- Switching Plans;
- Electricity Operations Centre Emergency Evacuation Plan;
- Emergency Load Shedding Plan;
- Participant Outage Plan;
- Vector Group Crisis Communications Plan;
- Vector Group Pandemic Health Plan;
- Transpower Contingency Plans;
- Call Centre BCP; and
- Spill Response Protocol for transformers, switchgear and fluid-filled cables.

These plans are further described below.

8.4.6.1 Crisis Management Team Plan

The Crisis Management Team Plan identifies procedures for a crisis affecting Vector, its customers and/or its employees, contractors and other stakeholders. The plan and procedures outlined in this document identify how Vector will manage the consequences of a crisis. It is designed to establish clear lines of communication and reporting, as well as action guidelines for the Vector group.

While the Crisis Management Team Plan procedures have been developed to cover a broad set of circumstances, Vector is mindful that every crisis has its own unique set of circumstances, which will require good judgement from Vector employees to be managed ably.

The Crisis Management Team Plan is not intended to cover operational emergency response requirements, as these are covered by the relevant emergency response plans. The plan is designed to support those plans, better enable staff to fulfil their roles as efficiently and safely as possible, and to ensure the wider public implications of an emergency are identified and addressed.

8.4.6.2 Emergency Response Plan

The purpose of the Emergency Response Plan is to ensure Vector is prepared for, and responds quickly to, any major incident that occurs or may occur on the electricity network. The plan describes the actions required and the responsibilities of staff during a major incident.

A key component of the plan is the formation of the emergency response team. This team includes senior staff whose role it is to oversee the management of potential loss, and restoration, of supply following a significant event. The team is very experienced and undertakes exercises periodically at least annually.

This plan is currently under review as Vector looks to standardise all its approach to operational incidents across the group and across the various product types it manages.

8.4.6.3 Switching Plans

For all major feeders, the network is designed to allow reconfiguration by switching so supply can be restored through an alternative path if there is a failure or a need to shift load. Distribution switching may be carried out remotely via SCADA at all zone substations and selected distribution sites. Vector has an ongoing programme to increase the number of remotely operated distribution high voltage (HV) switches. This enables faster restoration of the power supply by not having to send field staff to operate switches.

In the event of a supply failure on any feeder, the control room staff undertake network analysis and restore power to as many customers as possible by a combination of remote switch operations from the control room and instructing field staff to manually operate field switches.

The control room also has pre-prepared Contingency Switching Plans for major outages such as complete loss of a zone substation.

There are 210 Contingency Plans for the Auckland region. Generally these relate to events that have a “very high” or “extreme” classification within the risk matrix (see Figure 8-3), which corresponds with the loss of a zone substation or critical sub-transmission feeder. These Contingency Plans are reviewed once a year.

8.4.6.4 Electricity Operations Centre Emergency Evacuation Plan

The purpose of this plan is to ensure that Vector’s network control centre is prepared for, and responds quickly to, any incident that requires the short, medium or long-term evacuation of the electricity operations centre located at Vector’s head office at 101 Carlton Gore Road, Newmarket, Auckland.

The plan describes actions and responsibilities of staff during an evacuation and focuses on continuously improving systems and communications (internal and external) to ensure the management and operation of the electricity network is maintained.

The Vector network control centre has a fully operational disaster recovery site located at Massey, in west Auckland. Regular evacuation exercises are held to ensure evacuation of the control centre can proceed smoothly and at any time.

8.4.6.5 Emergency Load Shedding Strategy

The purpose of this document is to provide procedures for emergency load shedding when required, as requested by Transpower during a grid emergency, or during planned load shedding for energy shortfall. The document does not cover water heating load shedding for reducing peak loads either for network constraints or reducing transmission (peak demand) charges.

Vector is required, under the Electricity Industry Participation Code (2010), to provide automatic under frequency load shedding (AUFLS) capabilities in two blocks, each of 16% of the total load at all times to maintain grid security. Load shedding will occur automatically under specified system frequency excursion situations. The load groups are reviewed regularly to ensure the required capability is maintained and the priorities are appropriate.

From time to time, Vector is requested by Transpower, acting in the capacity of Transmission Grid System Operator, to shed load to avoid cascade tripping of the grid under emergency situations. Vector has assigned load groups to cover such contingencies.

8.4.6.6 Participant Outage Plan

As a result of the Electricity Industry Participation Code 2010, the Electricity Authority has prepared a Security of Supply Outage Plan (SoSOP). Vector is a specified participant and is required to produce a Participant Outage Plan (POP), as specified in the SoSOP.

Under the regulations, POPs are required to specify the actions that would be taken to reduce the consumption of electricity in order to:

- Reduce electricity consumption when requested by the Electricity Authority;
- Comply with requirements of the Electricity Authority's SoSOP;
- Comply with Electricity Governance (Security of Supply) Regulations 2008; and
- Supplement the Electricity Authority's SoSOP.

8.4.6.7 Vector Group Crisis Communications Plan

The Vector Group Crisis Communications Plan has been written to ensure that, in any emergency, crisis or business continuity event affecting Vector, Vector's customers, the affected community and other stakeholders are kept well-informed and up-to-date of:

- The status of the crisis;
- Any actions they can or should take to mitigate the affect or consequences of the emergency; and
- When the situation is expected to be (or is) resolved.

The plan is designed as a template that can be tailored to the management response requirements determined by the particular nature of the emergency, crisis or business continuity event. It is designed to provide a consistent, robust and scalable approach to communications.

8.4.6.8 Vector Group Pandemic Health Plan

As a lifeline utility the Civil Defence and Emergency Management Act (2002) requires Vector to be able to function to the fullest possible extent during and after an emergency.

The objective of this plan is to manage the impact of a pandemic on Vector's employees and our business to ensure continuation of our network operations through two main strategies including the containment of disease by reducing spread within Vector's offices and facilities, and maintenance of essential services if containment is not possible.

8.4.6.9 Transpower Contingency Plans

The purpose of these plans is to assess the consequences of loss or reduction of supply from Transpower's Grid Exit Points (GXP), and planning around the restoration or partial restoration of supply following a catastrophic failure.

The contingency plans have been prepared by Transpower for loss of supply at each GXP. Depending upon the GXP lost, other Transpower substations may also be affected. For example, loss of the Otahuhu GXP would affect all of Vector's network north of Otahuhu. Some Transpower GXPs have more than one busbar so supply lost could be to a single busbar or to a whole substation.

8.4.6.10 Call Centre Business Continuity Plan

The core business of Telnet Services, Vector's call centre provider, relies heavily on various computer and telephony technologies that, by their very nature, have the potential to fail.

The purpose of the Call Centre BCP is to assess the potential risks and planned workarounds for those risks in order that Telnet's core business can continue in the event of any failure or disaster. In addition to the general BCP/DR strategy employed at Telnet, there are a number of specific provisions as part of Telnet's relationship with Vector to provide additional services to ensure the continuity of service around handling of safety critical and emergency calls.

8.4.6.11 Spill Response Protocol for Transformers, Switchgear and Fluid-filled Cables

The purpose of this protocol is to document Vector's expectations in the management of liquid spills from all transformers, switchgear and fluid filled cables (FF cables). The document forms part of Vector's overall environmental management response, but places emphasis on the immediate and specific risk of environmental impact from spills from existing facilities.

8.4.6.12 Critical Spares

A stock of spares is maintained for critical components of the network so that fault repair is not hindered by the lack of availability of required parts. Whenever new equipment is introduced to the network an evaluation is made of the necessary spares required to be retained to support the repair of any equipment failures. Refer to Section 6.4 for further details.

8.5 Insurance

The Treasury function manages the placement of insurance for Vector.

Vector's approach to its insurance programme has been to balance risk and cost and has involved regular review of the financial risk appetite of the group. This translates into a programme whereby Vector seeks cover for low probability, major or catastrophic events, and carries as an operational expense the cost of other events which have a lesser financial impact. With respect to the latter category, risk mitigation activity is undertaken to reduce the likelihood of these events through proactive maintenance programmes and thorough management processes.

8.6 Health and Safety

8.6.1 Health and Safety Policy

Vector's Health and Safety Policy states the company's overarching commitments and requirements for health and safety. Vector conducts its business activities in such a way as to protect the health and safety of employees, contractors, members of the public and visitors in and within the vicinity of our work environment and those people in the vicinity of our assets. The company is committed to continual and progressive improvement in its health and safety performance and ensures it has sufficient, competent resources and effective systems at all levels of the organisation to fulfil this commitment.

Any work conducted on and around Vector's assets by external parties, including our service providers, is also required to be conducted in line with the Vector Health and Safety Policy.

Vector's Health and Safety policy objectives are to:

- Provide a safe and healthy work place for all our people, contractors, the public and visitors;
- Ensure health and safety considerations are part of all business decisions;
- Monitor and continuously improve our health and safety performance;
- Communicate with our people, contractors, customers, and stakeholders on health and safety matters;
- Operate in a manner that minimises health and safety hazards; and
- Encourage safe and healthy lifestyles, both at work and at home.

To achieve this Vector:

- As a minimum, meets all relevant legislation, standards and codes of practice for the management of health and safety;
- Identifies, assesses and controls workplace hazards;
- Accurately reports, records and learns from all incidents and near misses;
- Has established health and safety goals at all levels within Vector, and regularly monitors and reviews the effectiveness of our Health and Safety Management System;
- Consults, supports and encourages participation from its people on issues that have the potential to affect their health and safety;
- Promotes its leaders', employees' and contractors' understanding of the health and safety responsibilities relevant to their roles;
- Provides information and advice on the safe and responsible use of our products and services;
- Suspends activities if safety would be compromised; and
- Takes all practicable steps to ensure our contractors work in line with this policy.

8.6.2 Health and Safety Practices

All Vector employees and contractors working for Vector are responsible for ensuring their own and others' safety by adhering to safe work practices, making appropriate use of plant and equipment (including using protective clothing and equipment) and promptly reporting incidents, near misses and hazards to Vector.

Vector's safe work practices manual defines the essentials necessary to maintain an incident free environment. These practices reflect the basic approach necessary for Vector and our Field Service Providers (FSPs) to identify and eliminate incident causes.

Key elements of our health and safety practices, as they relate to our asset base and asset management, include the following:

- Wherever practicable Vector will eliminate, isolate or minimise hazards or control risks to As Low As Reasonably Practicable (ALARP), so as to ensure the safety and health of personnel, the public, the environment;
- The identification of safety and health hazards and the assessment of their associated risks to ensure they are managed to an acceptable level during their operation or associated activities ;
- Vector practices preventative maintenance strategies to all critical plant and equipment to ensure continued safe, environmentally sound, economic and effective operation. In addition, Vector ensures the reliability of critical safety backup equipment, protective devices and key operating equipment is maintained;
- Safety considerations are incorporated into Vector's design standards and asset selection criteria;
- Appropriate safety equipment is installed, inspected and maintained and staff are competent to identify items in need of repair or replacement;
- All FSPs working for the company are required, as a minimum, to comply with Vector's safe work practices whilst carrying out any work on the network. FSPs are also required to report all employee and third party incidents related to work on the Vector network, together with their investigations and corrective and preventive actions;
- Vector monitors electricity related public safety and employee/contractor safety incidents. These incidents are reviewed monthly to ensure lessons are captured and shared with our FSPs;
- Ongoing public safety awareness communications programmes on electricity are undertaken. These include:
    - Our "Stay Safe around electricity" schools programme, which was started in 2005. Since conception, more than half of Auckland's primary schools have been visited and over 60,000 children have been through the programme, which is designed to raise children's awareness of the hazards of electricity;
    - An annual "Switch on to Safety" campaign which targets people who undertake Do It Yourself (DIY) activities around their homes. The campaign encourages people to 'think first' before working or playing near our networks and their service lines. This includes high risk activities such as gardening (digging), fencing, tree trimming, painting, water blasting and boating (boat masts and lines hazards, and submarine cables). The campaign is run over the spring/summer months when these activities are most prevalent. A variety of integrated and targeted media is used -including newspaper (the NZ Herald), internet, email and radio – to deliver the key messages;
    - Promoting safe work practices extensively to external contractors whose work brings them in close proximity to our networks i.e. council and water service contractors, arborists. As well as protecting the contractors themselves, the programme aims to protect the community from hazards and ensure an ongoing safe and reliable power supply to our customers. We provide free services and resources to help contractors work safely around our networks, including free network maps, on-site mark outs and supervision, safety guides and presentations. To ensure it is easy to get in touch with us we have dedicated freephone numbers;

- Vector is also a founding member of the "before-u-dig service" (www.beforeudig.co.nz). "Before-u-dig" enables contactors to obtain plans from a number of asset owners like Vector, simply by making one enquiry, rather than calling each asset owner individually; and
- On a regular basis Vector holds a Safety Day, involving all of its staff, management and strategic contractors. The Vector Safety Day is a visible demonstration of the commitment Vector and its contractors place on safety, with keynote presentations reinforcing the importance of safety excellence being given by the Chief Executives of Vector and our service providers.

A full review is currently being undertaken of Vector's health and safety framework in order to identify potential improvement opportunities. Vector continually strives for excellence in safety performance and recognises the importance of a robust, well structured safety framework to assist in delivering an incident and injury free workplace.

8.6.3 Safety Management System for Public Safety

The passing of the Electricity Amendment Act 2006 and Gas Amendment Act 2006 required companies in New Zealand engaged in the generation, transmission and distribution of electricity or gas to develop, implement and maintain a Safety Management System that will ensure their generation and distribution systems will not pose a significant risk of serious harm to members of the public risk or of significant damage to public property. Vector is well positioned to meet the requirements of the new regulations and intends to review and update its current policies and practices in preparation for an external audit that is to be completed in 2012.

8.7 Environmental Management

8.7.1 Environmental Policy

Vector's environmental policy confirms its commitment to managing the environmental impact of its businesses, and ensuring as a minimum, compliance with legislation, standards and any resource consents held by the company. The company conducts its operations in such a way as to respect and protect the natural environment, and sensitive sites and is committed to continual and progressive improvement in its environmental performance. Sufficient competent resources and effective systems are provided at all levels of the organisation to fulfil this commitment. Vector also requires all employees and service providers working for Vector to proactively manage their employees and work for Vector in line with this policy.

Vector's environmental policy is to:

- Ensure environmental considerations are part of all business decisions;
- Meet or exceed all relevant environmental legislation, regulations or codes;
- Participate and work with government and other organisations to create responsible laws, regulations, standards and codes of practice to protect the environment;
- Monitor and continuously improve our environmental performance;
- Operate in a manner that minimises environmental and social impacts;
- Take appropriate action where there is a negative impact on the environment and a material breach of the Resource Management Act 1991; and
- Communicate with employees, contractors, customers and other relevant stakeholders on environmental matters.

To achieve this Vector:

- Has plans in place to avoid, remedy or mitigate any adverse environment effects of its operations; and
- Focuses on responsible energy management and will practice energy efficiency throughout all of its premises, plant and equipment, where possible.

The long- term operational objectives of Vector are to:

- Utilise fuel as efficiently as practicable;
- Mitigate, where economically feasible, fugitive emissions and in particular greenhouse gas emissions;
- Wherever practicable use ambient and renewable energy; and
- Work with its customers to maximise energy efficiency.

8.7.2 Environmental Practices

Vector also puts significant emphasis on environmental management and continues improving its environmental management in partnership with our FSPs. Vector's key practices in this regard include the following:

- Vector continually explores opportunities for minimising waste generation and, when identified, pursues economically viable opportunities consistent with business priorities and community expectations. All wastes generated from our operations are effectively managed and disposed of in a cost effective manner in compliance with statutory requirements;
- When addressing environmental issues, consideration is given to both long-term impacts of waste disposal and to potential long-term issues;
- One of Vector's key performance indicators (KPIs) is to avoid any activity that would cause Vector to be in breach of the Resource Management Act 1991;
- Vector's safe work practices manual includes minimum acceptable standards on environmental management and a focus on eliminating damage; and
- Environmental incidents are reported, recorded and investigated with any learnings and improvements shared across our FSPs at the safety leadership forum.

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Electricity
Asset Management Plan
2012 – 2022

Expenditure Forecast and Reconciliation – Section 9

[Disclosure AMP]

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9 Expenditure Forecast and Reconciliation

This section summarises how the capital, operating and maintenance expenditures are compiled, including prioritisation of projects. The budget expenditure range for the 2011/12 regulatory year as well as the expenditure forecast range for the 2012/13 to 2021/22 regulatory years (RY) are also presented.

As Vector operates to a June financial year all its budgeting, financial and management reporting activities align with the June year. However, the Commerce Commission's Electricity Information Disclosure Requirements 2008 require Vector to disclose its AMP and the respective expenditure information on a March year basis, as presented below. There are, therefore, time shift differences in the expenditure forecast disclosed in this section of the AMP compared to the budget Vector operates to and figures that may be reported in Vector's financial statements or elsewhere. The budget and forecasts presented in sections 5 and 6 of this AMP are on a Vector financial (July – June) year basis. These figures are then adjusted to a regulatory year basis for presentation in this section of the AMP.

Due to the difference between the regulatory calendar and Vector's corporate planning cycle the Board has not yet approved the 2012/13 budgets and the 2013 forecasts are, therefore, still subject to change to reflect changing operating, commercial or regulatory environments. In addition, while the expenditure forecasts for later years presented in this AMP are the best estimates available at the time of preparing this plan they will be subject to change in future as circumstances change and projects are reviewed.

It is possible Vector will need to apply to the Commerce Commission (the Commission) for a "customised" price path, which takes into account future capital expenditure (capex) requirements. In that event, Vector would be locked into a five year capex forecast which would underpin prices. While the expenditure forecasts in this AMP have been prepared according to good industry practice, Vector would need to review its expenditure plans to ensure they provide a suitable basis for such a fixed price path.

9.1 Expenditure Forecast

9.1.1 Capital Expenditure

Vector's capex forecast for the regulatory years ending 31 March from 2013 to 2022 is set out in Table 9-2.

This is our forecast of the expenditure required to achieve Vector's customer, network and business goals and execute the asset management activities described in this AMP and is subject to Vector being able to earn commercially appropriate return on its investments. The capital expenditure is presented under the following categories:

- Customer connection, covering reticulation of subdivisions, building customer substations, and connecting customers to the distribution network;
- Network growth, covering augmentation of the distribution network to provide capacity and security to cater for demand growth and solutions to supply quality issues resulting from demand growth;
- Asset replacement and renewal, covering replacement and refurbishing network assets to address condition related issues;
- Reliability, safety and environmental, covering work to ensure network reliability and to address safety and environmental issues; and
- Asset relocation, covering the moving or replacement of distribution network assets where requested by requiring authorities, and under-grounding overhead lines to satisfy Vector's obligation under the AECT trust deed.

While these estimates have been prepared based on the best information at Vector's disposal, it should be noted electricity distribution businesses are still experiencing a period of significant economic volatility. Factors that may materially influence investments levels going forward include:

- Economic cycles and the impact of these on electricity demand. GDP figures published by Statistics NZ over the past three years ending March 2011 show two recent years of very low growth (1.4% and 1.8% for the years ending March 2011 and 2010) following a year of negative growth (-3.5% for the year ending March 2009). Other economic indicators such as consumer and business confidence, unemployment rate and housing construction are also pointing towards a cautious recovery. During the same period, electricity delivered through the Vector network recorded growth rates of 4.4%, 0.8% and 0.5% respectively. Overseas, various economies are facing uncertainties caused by state debt burden, the fading effect of economic stimulus packages and low consumer confidence leading to low rates of job creation and economy activities. The impact of this on New Zealand's export earnings and therefore the state of its economy is still uncertain;
- Over the past year, Christchurch experienced two major earthquakes. This has caused significant erosion in the recovery of the New Zealand economy while the longer term impact of a rebuild of the city on the economy may turn out to be positive, the outcome on Auckland's economy and electricity consumption in the region is not yet clear. The situation is being reviewed and will be reflected in future plans;
- The rebuilding of Christchurch and the Government's infrastructure programme (including the Ultra Fast Broadband project) is likely to put significant pressure on construction resources both in terms of availability of the required skills and costs of construction;
- We continue to see relatively rapid change in electricity distribution and consumer technologies (see discussions in Section 3). New applications, associated with more intelligent networks, could have a substantial impact on how networks develop in the medium to longer term future, and hence also on the associated expenditure patterns;
- As a large supplier of electricity distribution services, Vector's electricity distribution business is subject to price and quality regulation. This regulation is undertaken by the Commerce Commission under Part 4 of the Commerce Act 1986. Part 4 was introduced in 2008 with objectives including the promotion of regulatory certainty and incentives for regulated businesses to invest due to concerns that previous regulatory settings were insufficient to promote investment in essential infrastructure;
- The Commerce Commission, with input from stakeholders including Vector, is currently in the process of implementing Part 4. As part of this process it determined Input Methodologies for electricity distribution businesses in December 2010 and is currently working to develop starting price adjustment methodologies which, in accordance with a recent High Court decision, must also be Input Methodologies. Vector does not believe that the current Input Methodologies provide an adequate level of certainty or investment incentives. In particular, the cost of capital input methodology would not permit commercially realistic returns on investment (e.g. they provide a lower rate of return than the comparable Australian regulatory regime). Further, the asset valuation input methodology does not allow for a new and robust asset valuation to be developed at the start of the new regulatory regime and is based on prior valuations that are not fit for purpose. The Commission's decisions on the input methodologies and the regulatory processes in which they were developed have been subject to a series of legal challenges, including from Vector;

- More certainty and stronger incentives for investment should be evident once the legal challenges are decided. However, these may not be settled until 2013 and final prices may not be determined until 2014. As the next regulatory price reset is scheduled for 2015, it is likely that considerable regulatory uncertainty will remain a feature of the investment environment until 1 April 2015. There is a risk that a legally required review of input methodologies in 2017 could further exacerbate the uncertainty with the regulatory settings; and
- It is also not clear whether the regulatory regime and/or customer expectations will support investment in reliability improvements or energy efficiency. The quality requirements for electricity distribution businesses focus only on maintaining the current level of quality of supply (i.e. the principle of "no material deterioration"), not on improving it. The Commerce Act (Section 54Q) requires the Commission to promote investment by electricity distribution businesses in energy efficiency. However, the Commission has yet to implement this requirement. In the absence of quality or efficiency incentives, investment may only maintain, not improve, energy efficiency or quality of supply on regulated networks such as Vector's.
- An earlier Commission review of the AMP provided feedback that sources of uncertainty were discussed but that assumptions made in relation to them had not been identified. Vector would like to clarify in this AMP something that is seemingly counter intuitive; assumptions made in response to the uncertainties stated above have little bearing on historical trends which show a predictable growth trend regardless of the complex, intertwined and non linear relationship between them. As an example, there does not seem to be a direct relationship between GDP growth and electricity demand growth.

In addition to those discussed above, Vector has also observed other factors that have historically caused major variations between forecast and actual expenditure:

- While longterm customer connection numbers have been relatively stable, annual figures can vary greatly. This is driven by factors outside Vector's control.
- Electricity demand, which is a prime driver for network investment, is closely linked to customer connection numbers.
- The timing of large customer and relocation projects is very uncertain, and Vector often experiences large discrepancies between previously requested timelines, which drives the AMP cost estimates, and actual construction periods.
- Vector is continually improving the manner in which we collect, store and analyse asset information data. As better and more information becomes available, this sometimes identifies a need for accelerated (or decelerated) renewal.

To accurately accommodate this level of uncertainty in a ten year investment programme presents challenges. To reflect this, Vector has prepared a range of forecasts bound by an upper and a lower expenditure level as shown in **Error! Reference source not found.**.[1] The criteria used to prepare these forecasts are described below (in this section and in section 9.2). The boundary lines reflect the impact that regulatory settings could have on expenditure – this is the biggest uncertainty factor we face. Expenditure variances caused by other uncertain factors can lead to actual expenditure lying anywhere within the indicated range.

The lower line represents minimum expenditure Vector would have to commit in order to deal with known health, safety and environmental issues, comply with its legal obligations, and provide sufficient network capacity to just meet peak demands under

[1] This expenditure range differs from that set out in the 2010 AMP to reflect the factors discussed in Section 9.3.1.

normal conditions, but without necessarily maintaining security of supply under fault conditions.[2]

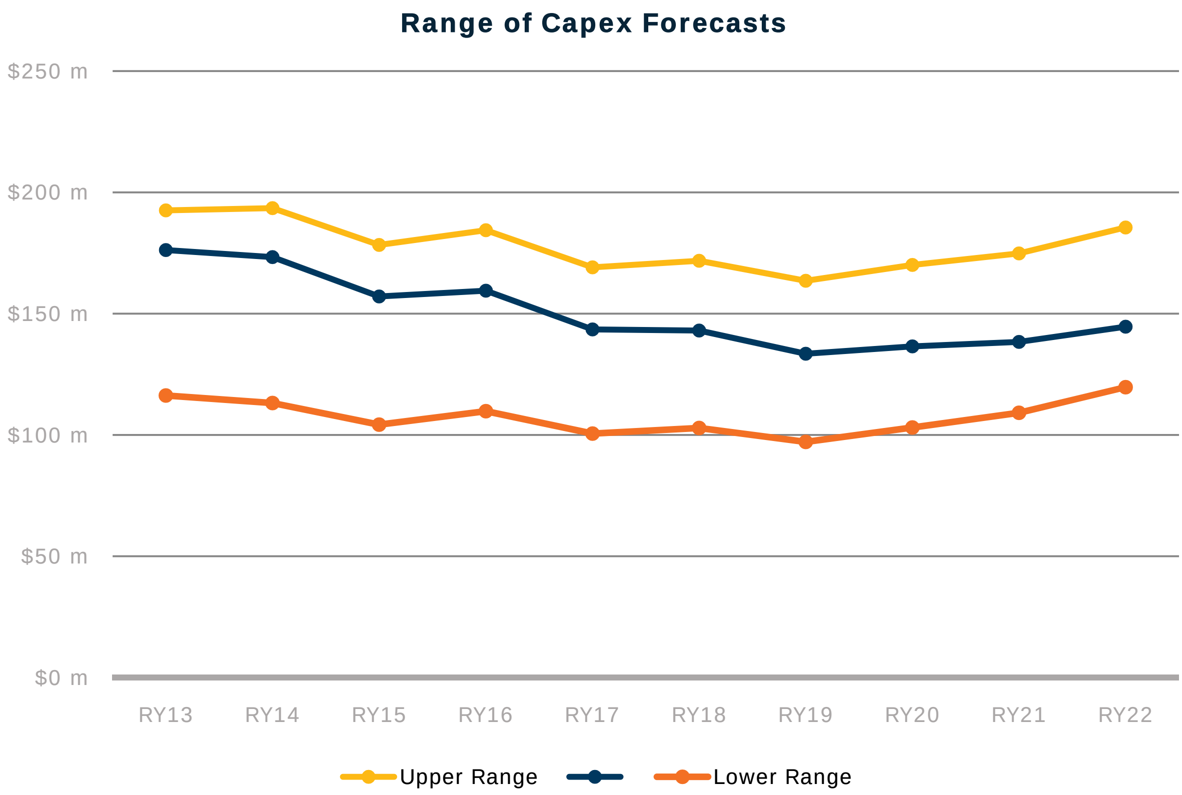

Figure 9-1 : Forecast capital expenditure range

It includes the minimum essential expenditure on planned asset replacement, network performance improvement, customer growth (only where Vector is obliged to supply) relocation projects (where Vector is obliged) and security of supply based projects.

This expenditure profile is not sustainable in the medium and longer term and would result in increasing asset failure rates and breaching of Vector's security of supply criteria, increasing the likelihood of a breach of the regulatory quality levels two years out of three. This would result in a reduction in customer service levels (reduced reliability and extended outages due to lack of back stopping capability) and sharply increasing operational expenditure on fault response and customer complaints. Furthermore, this scenario represents a running down of Vector's assets which would not only lead to deteriorating network performance but would also defer expenditure until a very substantial replacement requirement arises in the medium-term future. Overall, adopting this profile would have a severe impact on our customers, far outweighing the value of the cost savings. Vector would, therefore, be very reluctant to embark on this profile and would only do so if forced to by excessive regulatory uncertainty and risks around achieving a commercially realistic return on investment.

The upper line represents expenditure levels that would allow Vector to achieve a substantial step improvement in network performance (as opposed to current forecast expenditure levels, which are targeted at maintaining current performance levels). This higher expenditure would enable Vector to:

- Effect major, rapid improvements in the quality of service (reliability) provided by the network;

[2] It does not refer to a lower demand growth scenario, to which a response would be tailored as details become available and which would not lead to under-investment on the network.

- Accelerate asset replacement rates to improve age profiles of selected asset categories, where warranted by condition or reliability impact;
- Make investments to specifically target reduced electricity losses and improved network efficiency;
- Underground more selected parts of the network where external interference is currently impacting on reliability[3];
- Substantially reduce maintenance expenditure over time;
- Invest in a more wide-spread roll-out of smart network technologies to expand on the substantial investments made in the past decade; and
- Significantly enhance network security of supply performance.

This expenditure profile, which would improve the quality of service delivered to customers, [4] is currently not sustainable as under the present regulatory regime Vector cannot recover the higher expenditure to provide the higher level of service and efficiency.

Vector's proposed capex forecast is based on the portfolio of projects selected using the Asset Investment Prioritisation Matrix as shown in Table 9-1 below. The projects selected for the proposed investment portfolio are based on the latest available information on growth, asset condition, regulatory requirements and risks to deliver the target level of service in a sustainable manner.

9.1.2 Maintenance and Operations

Vector's maintenance budget for the 2012 regulatory year and the expenditure forecast to 2022 are listed in Table 9-2.

Vector's operating expenditure is grouped under the following categories:

- Routine and preventative maintenance covering the cost of planned regular maintenance of distribution assets to maintain their service capability and avoid premature failure.
- Refurbishment and renewal maintenance covering the cost of replacing assets that have failed or likely to fail soon.
- Faults and emergency maintenance covering the cost of fault repairs and attending to emergency situations such as storms to effect restoration of supply.

If the upper or lower capex scenarios discussed previously are adopted this would have a direct impact on the maintenance expenditure resulting in upper and lower range expenditure as reflected in Figure 9-2.

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[3] Vector has an ongoing under-grounding program, but the scope of this is based on meeting the AECT Trust Deed obligations. For more discretionary under-grounding, the focus would rather be to reduce external network interference (such as car versus pole incidents) on parts of the network where this occurs frequently.

[4] It will be ensured that such improvements are well aligned with customers' actual requirements and willingness to pay for the improved quality.

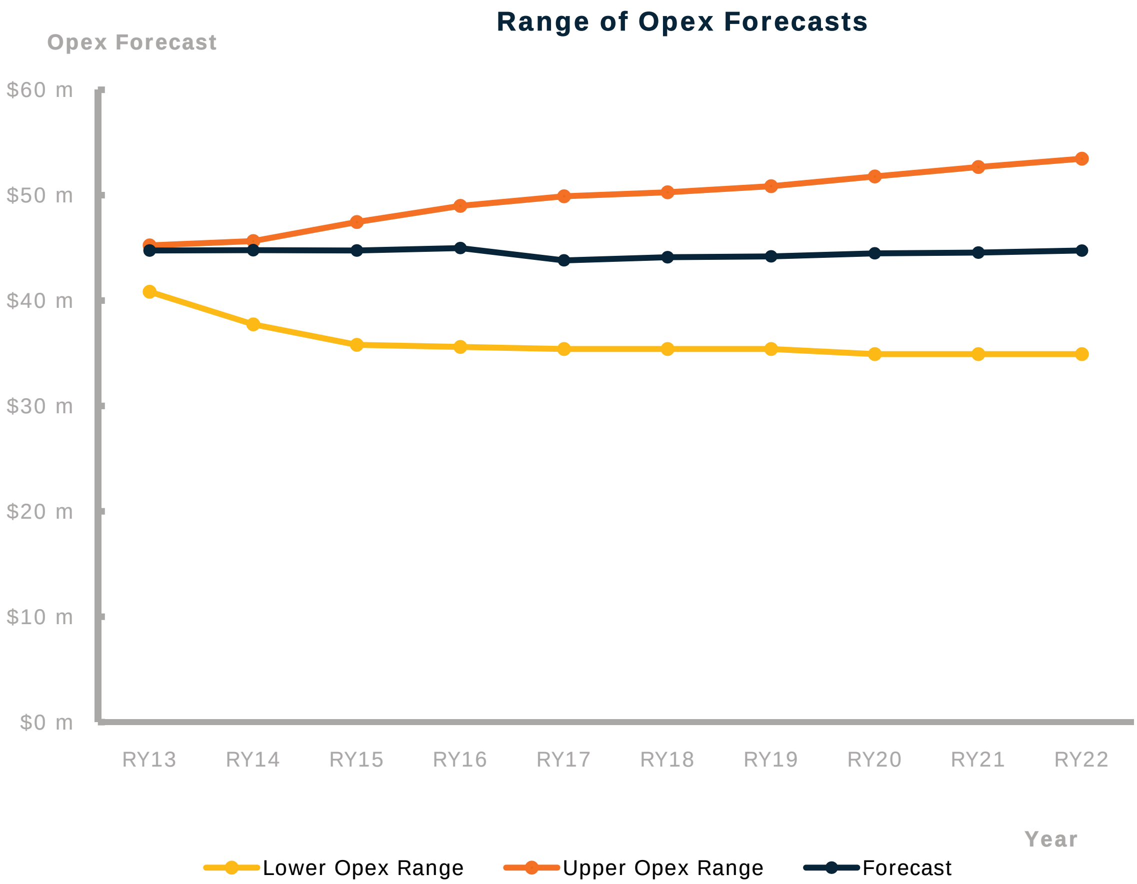


Figure 9-2 : Forecast opex range

Adopting the lower capex range, in which the general asset base would be allowed to age and no major network improvements would be implemented, would cause escalating fault and maintenance expenditure.

Should the high capex scenario be adopted, the average network age would decrease (higher proportion of new assets) and there will be substantially increased levels of network automation (as measured against the current provisional capex programme). The net effect of this is that the fault frequency should reduce (especially in the first three years), as would the maintenance costs. There would also be a reduced requirement for renewal maintenance.

The proposed opex forecast was developed to maintain the service potential of the network to deliver the target level of service in a sustainable manner.

9.2 Prioritisation of Expenditure

Section 1 of this AMP explains the relationship between Vector's goals and strategies, its asset management and investment strategies and policies and how these are used to guide the capital and maintenance works programme.

Section 5 of this AMP details the planning policies and standards, industry information, grid and grid exit point information, load growth assumptions, asset capacities, network operations information and network data required for the preparation of a ten year network development plan. A ten year expenditure projection on customer and growth works programme has been prepared, based on the network development plan.

Section 6 of this AMP details the asset inspection, maintenance, replacement and refurbishment policies and standards. A replacement and refurbishment programme has been prepared for each asset category, based on these policies and standards and taking into account the information on asset age and condition and unit rates (material and labour). Following from this works programme, a ten year capital and operating expenditure projection on maintenance and replacement has been prepared.

Similarly a programme for under-grounding in the Southern region has been prepared in accordance with the requirement laid out in the AECT Trust Deed. An asset relocation programme is also identified based on information available from roading and local authorities.

An expenditure prioritisation process has been developed in line with Vector's strategies and goals to ensure those projects of the highest importance and with the highest cost-benefit are implemented. A four band prioritisation matrix has been developed to rank all projects identified in Section 5 and Section 6, as illustrated in Table 9-1 below. The four priority bands are:

1. Vital investments;
2. Critical investments;
3. Essential investments; and
4. Beneficial investments.

The prioritisation process involves assigning a priority band to each of the value drivers for each project based on an understanding of the purpose, value and risk of the project. The value drivers[5] as illustrated in Table 9-1 below are:

- Health, safety and environmental;
- Security and capacity;
- Customer connections;
- Network reliability and asset performance;
- Brand and reputation;
- Legal compliance;
- Financial performance; and
- Operational performance improvement.

The highest priority band will be chosen as the score for the project. The projects are then ranked according to the scores, with a ranking of one being the highest priority. Projects and programmes with a ranking of 1 to 3 are selected as the main expenditure forecast (refer to Table 9-1).

[5] The value drivers are not listed in any order of priority.

Rank	Security & Capacity	Customer Connections	Network Reliability & Asset Performance	Brand & Reputation	Legal Compliance	Health, Safety & Environment	Financial Performance	Operational Performance Improvement
1. Vital investments	Mitigate capacity breach leading to asset damage. Mitigate capacity breach to widespread or critical areas.	Mitigate capacity breach to critical customer.	Reactive replacement of critical assets.	Avoid potentially serious reputation damage.	Avoid serious breach of technical regulations. Avoid serious breach of HSE or environmental legislation.	Mitigate imminent serious HSE or environmental threats.	Mitigate extreme and very high risks	Mitigate critical cyber security breach.
2. Critical investments	Mitigate security breach to widespread or critical areas. Mitigate capacity breach.	Satisfy contractual obligations (critical customers). New connections and capacity increase (critical customers).	Replacement of severely deteriorated assets with high risk and high consequence of failure. Reactive replacement of assets required for network operation.	Avoid potential reputation damage.	Regulatory compliance (including Industry Participation Code, environmental, HSE, etc). Asset relocation as required by statute.	Mitigate anticipated serious environmental or HSE threats.	Mitigate high impact direct risks.	Overhead improvement programmes (AECT obligation). Mitigate serious cyber security breach.
3. Essential investments	Mitigate security breach in the general network areas (except for remote rural areas).	Customer capacity and security requests. Customer funded projects.	Replacement of rapidly deteriorating assets or assets at the end of technical life with increased risk of failure. High consequence of failure. Medium term mitigation against natural disasters. Reliability improvements (to widespread or critical areas).		Regulatory improvement. Mitigate breach of technical regulations (voltage, etc) in localised areas. DG connections.	Medium term safety & environmental improvement.	Assets costing more to maintain and operate than to replace.	Technology trials. Enhance operational efficiency. Asset relocation required by requiring authorities.
4. Beneficial investments	Mitigate security of supply breach in remote rural areas.		Asset condition deteriorating gradually with increased risk of failure. Steady state asset replacement programmes. Reliability improvements.			Long term safety & environmental improvement.	Safeguard future options. Discretionary initiatives that are NPV>0.	Asset relocation requested by consumers and land owners. Enhance supply quality. Improve asset management and operational practices.

Table 9-1 : Asset investment Prioritisation matrix

9.3 Factors Influencing the Expenditure Forecasts

In preparing this AMP and the expenditure forecasts, several factors contributed to some significant changes in the capex forecasts, as compared with that disclosed in 2011. The main factors are discussed below:

- As part of Vector's ongoing efficiency drive, all planned capital works for the AMP planning period were subjected to detailed further review prior to commitment. Through a combination of innovation, judicious investment allowing deferment of major installations, higher asset utilisation and better focused renewal expenditure, the capex investment plan now shows a significant improvement in efficiency over that proposed in 2011. A comparison[6] between the proposed 2013-2021 expenditure forecast and the expenditure forecast over the same period reported in the 2011 AMP shows a reduction of $10.0 million over the whole period, while the volume of planned work is significantly increased over that included in the previous AMP.
- The $10.0 million reduction in expenditure forecast is made up of a combination of forecast expenditure reductions and increases:
  - $12.6 million increase in forecast connection expenditure, reflecting an expectation of higher connection rates later in the AMP planning period;
  - $51.7 million reduction in network growth expenditure mainly due to deferment of large customer initiated projects and network reinforcement projects. This is supported by a review of asset capacity carried out in FY11, which in many instances resulted in increased asset ratings and hence potential for deferring reinforcement decisions;
  - $13.3 million increase in safety and environmental expenditure mainly due to addition of substation seismic strengthening programme;
  - $16.0 million increase in planned and reactive asset replacement expenditure mainly due to more asset replacement identified based on better asset condition information; and
  - $0.2 million increase in relocation expenditure.
- The comparison also shows that forecast expenditure increases of $11.7 million, $12.1 million, $2.2 million and $6.1 million over the four years RY13 to RY16 is expected. This increase is offset by a reduction in forecast expenditure of $17.2 million, $14.4 million and $7.0 million in the three years between RY19 and RY21 respectively. The main reason for the changes in the expenditure profile is due to change in timing of asset relocation projects,[7] of large network growth projects and increases in planned asset replacement and seismic strengthening expenditure.

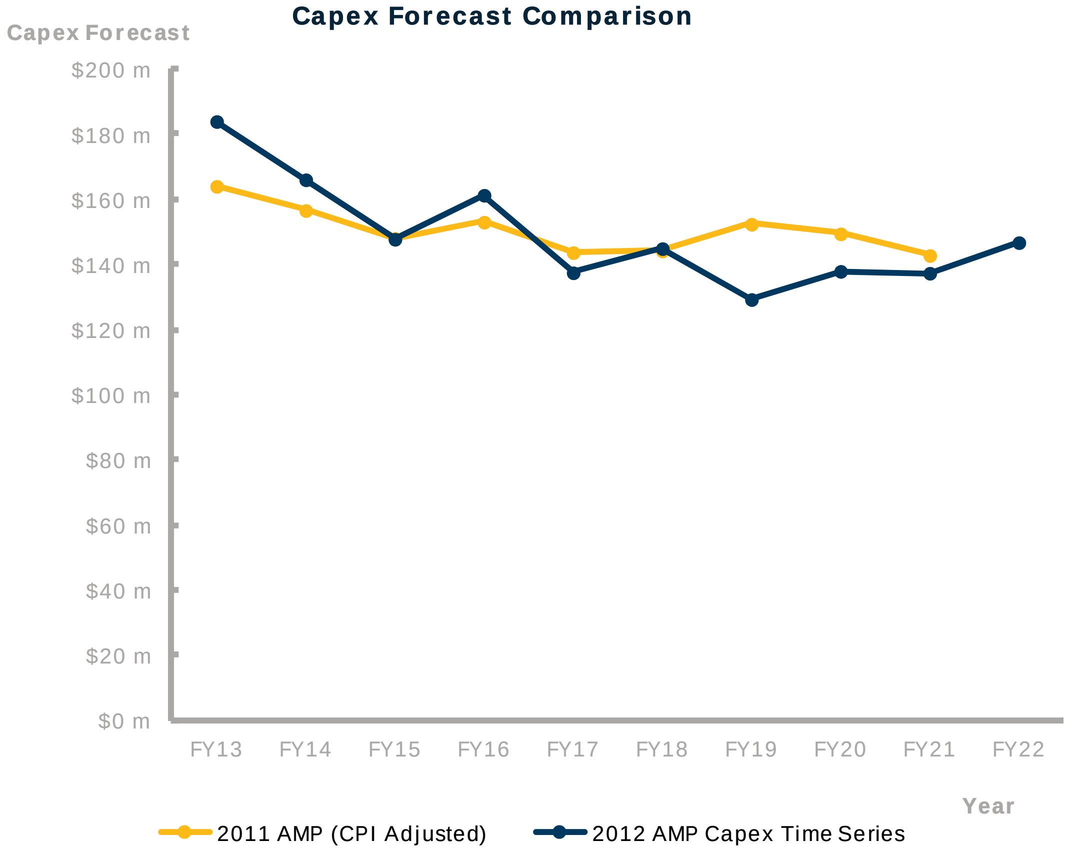
[6] The 2011 expenditure forecast was inflated by 3.5% to reflect the PPI increase for the 12 months ending 30 September 2011. The OIP forecast was inflated by 4.76% to reflect the PPI increase as required under the AECT deed.

[7] Following the amalgamation of the various Auckland Councils into a single structure, and a moratorium on construction works in parts of Auckland during the rugby world cup period, several infrastructure projects were delayed. Many of these involve relocation of Vector assets that were planned for FY12 but which will now be done during FY13.

9.3.1 Comparison of Expenditure Forecasts

The net effect of all of these adjustments is to accelerate near-term growth expenditure over those previously forecast, with a reduction in the later years. This is illustrated in Note: The figure is based on Vector financial years, not regulatory years

Figure 9-3, where the forecast capex profile under the present AMP (2011) is compared with the previous forecast (2010). The previous forecast has been adjusted for inflation to enable meaningful comparison between the two forecasts.



Note: The figure is based on Vector financial years, not regulatory years

Figure 9-3 : Comparison of capital expenditure profile between this AMP and the previous forecast

9.4 Reconciliation of Actual Expenditure against Budget

Table 9-2 below summarises the capital and O&M expenditure projection of the electricity business over the planning period for all capital and operating expenditure categories. The forecasts were prepared based on Vector's financial year (from 1 July to 30 June of each year) and were converted to the regulatory financial year (from 1 April to 31 March of each year) using a 25%:75% proportional allocation[8]. It should be noted that in reality, the spending profile is not evenly distributed throughout the

[8] For example, the forecast for the regulatory year ending 31 March 2015 is made up of 25% of the forecast for the Vector financial year ending 30th June 2014 and 75% of the forecast for the Vector financial year ending 30 June 2015. This is with the exception of the first year of the planning period (year ending 31 March 2011) for which the forecast for the Vector financial year (ending 30 June 2011) was adopted.

year. This increases the variance between the actual expenditure and the budget as presented.

Expenditure forecasts expressed in Vector's financial years (1st July to 30th June) are shown in Table 9-3.

Budget and Expenditure Forecast	Actual	2011 AMP budget	Forecast									
	RY11	RY12	RY13	RY14	RY15	RY16	RY17	RY18	RY19	RY20	RY21	RY22
Customer connection	$25.7 m	$21.6 m	$25.0 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m
System growth	$31.1 m	$55.5 m	$56.1 m	$47.5 m	$40.3 m	$46.9 m	$37.2 m	$35.8 m	$27.0 m	$30.0 m	$34.9 m	$42.8 m
Asset replacement and renewal	$56.1 m	$55.9 m	$65.9 m	$69.6 m	$63.2 m	$63.7 m	$59.0 m	$60.0 m	$59.2 m	$59.5 m	$57.2 m	$56.4 m
Reliability, safety & environmental	$2.6 m	$3.4 m	$6.9 m	$6.6 m	$5.1 m	$4.4 m	$4.4 m	$4.4 m	$4.1 m	$3.4 m	$2.5 m	$2.3 m
Asset relocation (including undergrounding)	$17.1 m	$25.8 m	$25.2 m	$22.3 m	$19.2 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m
Capital Expenditure Subtotal	**$132.6 m**	**$162.2 m**	**$179.1 m**	**$170.6 m**	**$152.4 m**	**$158.0 m**	**$143.5 m**	**$143.1 m**	**$133.2 m**	**$135.8 m**	**$137.5 m**	**$144.4 m**
Routine & preventive maintenance	$15.2 m	$19.6 m	$19.6 m	$19.8 m	$19.7 m	$19.9 m	$19.9 m	$20.0 m	$20.0 m	$20.1 m	$20.2 m	$20.3 m
Refurbishment & renewal	$10.3 m	$11.6 m	$11.6 m	$12.0 m	$11.9 m	$11.9 m	$11.0 m	$10.7 m	$10.7 m	$10.8 m	$10.7 m	$10.7 m
Fault and emergency	$13.1 m	$13.0 m	$13.0 m	$13.1 m	$13.1 m	$13.2 m	$13.3 m	$13.3 m	$13.4 m	$13.5 m	$13.6 m	$13.6 m
O & M Subtotal	**$38.6 m**	**$44.2 m**	**$44.2 m**	**$44.8 m**	**$44.8 m**	**$44.9 m**	**$44.1 m**	**$44.0 m**	**$44.2 m**	**$44.4 m**	**$44.5 m**	**$44.7 m**
Total Direct Expenditure	**$171.2 m**	**$206.4 m**	**$223.2 m**	**$215.3 m**	**$197.1 m**	**$202.9 m**	**$187.6 m**	**$187.1 m**	**$177.4 m**	**$180.2 m**	**$182.0 m**	**$189.1 m**
Overhead to underground	$7.7 m	$17.3 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m

* Figures are in 2012 dollars (million);

** The year reference indicates the end date of the regulatory year

Table 9-2 : Asset management plan expenditure forecast (regulatory years)

Budget and Expenditure Forecast		Budget	Forecast									
		FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Customer connection		$22.5 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m	$24.6 m
System growth		$59.2 m	$60.2 m	$43.3 m	$39.3 m	$49.5 m	$33.1 m	$36.7 m	$23.7 m	$32.1 m	$35.9 m	$45.1 m
Asset replacement and renewal		$57.0 m	$67.4 m	$70.3 m	$60.9 m	$64.7 m	$57.2 m	$60.9 m	$58.6 m	$59.8 m	$56.3 m	$56.4 m
Reliability, safety & environmental		$4.0 m	$7.6 m	$6.3 m	$4.7 m	$4.3 m	$4.4 m	$4.4 m	$4.0 m	$3.1 m	$2.3 m	$2.3 m
Asset relocation (including undergrounding)		$27.8 m	$24.2 m	$21.7 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m	$18.3 m
Capital Expenditure Subtotal		**$170.4 m**	**$184.0 m**	**$166.1 m**	**$147.8 m**	**$161.3 m**	**$137.5 m**	**$144.9 m**	**$129.3 m**	**$137.9 m**	**$137.4 m**	**$146.8 m**
Routine & preventive maintenance		$19.2 m	$19.7 m	$19.8 m	$19.7 m	$19.9 m	$19.9 m	$20.0 m	$20.0 m	$20.2 m	$20.2 m	$20.3 m
Refurbishment & renewal		$10.2 m	$12.0 m	$11.9 m	$11.9 m	$11.9 m	$10.7 m	$10.7 m	$10.7 m	$10.8 m	$10.7 m	$10.7 m
Fault and emergency		$12.9 m	$13.0 m	$13.1 m	$13.1 m	$13.2 m	$13.3 m	$13.4 m	$13.4 m	$13.5 m	$13.6 m	$13.7 m
O & M Subtotal		**$42.4 m**	**$44.7 m**	**$44.8 m**	**$44.7 m**	**$45.0 m**	**$43.8 m**	**$44.1 m**	**$44.2 m**	**$44.5 m**	**$44.5 m**	**$44.7 m**
Total Direct Expenditure		**$212.8 m**	**$228.7 m**	**$210.9 m**	**$192.6 m**	**$206.3 m**	**$181.3 m**	**$189.0 m**	**$173.5 m**	**$182.4 m**	**$181.9 m**	**$191.5 m**
Overhead to underground		$15.6 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m	$13.2 m

Table 9-3 : Asset Management Plan expenditure forecast (Vector financial years)

Table 9-4 summarises the actual 2011 regulatory year expenditure against the forecast for the year for all capital and operating expenditure categories.

Variance between Actual Expenditure and Previous Year's Forecast	Actual Mar-11	2011 AMP Forecast Mar-11	Variance	Variance %
Customer connection	$25.7 m	$17.5 m	$8.2 m	47.1%
System growth	$31.1 m	$43.3 m	-$12.2 m	-28.2%
Asset replacement and renewal	$56.1 m	$47.5 m	$8.6 m	18.1%
Reliability, safety & environmental	$2.6 m	$4.5 m	-$1.9 m	-42.5%
Asset relocation (including undergrounding)	$17.1 m	$23.3 m	-$6.2 m	-26.8%
Capital Expenditure Subtotal	$132.6 m	$136.1 m	-$3.5 m	-2.6%
Routine & preventive maintenance	$15.2 m	$13.7 m	$1.5 m	10.6%
Refurbishment & renewal	$10.3 m	$11.8 m	-$1.5 m	-12.6%
Fault and emergency	$13.1 m	$14.9 m	-$1.8 m	-11.8%
O & M Subtotal	$38.6 m	$40.4 m	-$1.8 m	-4.4%
Total Direct Expenditure	$171.2 m	$176.5 m	-$5.3 m	-3.0%

Table 9-4 : Asset management plan expenditure reconciliation

An explanation for variances over 10% is provided below:

- The variance in relation to actual Customer Connection expenditure is due to higher level of expenditure for new connection work, disconnections, customer substation upgrade requests, subdivision activity (especially in the Northern region) and relocation requests from customers. The forecasts were set during uncertain economic times where it was difficult to predict levels of activity for these types of work. Actual connection activity proved to be higher than expected at the time.
- Actual expenditure in the System Growth category was below forecast by $12.2 million, due to the following reasons:
    - Expenditure incurred on upgrading the transformers at Liverpool substation was $2 million less than forecasted as at 31st March 2011.
    - The purchase of land for a future substation in Newmarket ($2.5 million) did not proceed (it is still under negotiation).
    - Network reinforcements ($2.5 million) at Warkworth, Orewa and Remuera were deferred due to reduction in demand against forecast.
    - A number of large customer projects ($5 million) were deferred upon agreement with the customers.
- The reliability, safety and environmental category was underspent by $1.9 million due to reduced need for asset performance improvement projects.
- The asset replacement and renewal category was overspent by $8.6 million due to:
    - The acceleration of Transpower's Wairau Road project (with the associated Vector works);

- The advancement of the Sandringham cable project – combining future stages into one project with the current stage; and
- Increase in cost of some reactive replacement projects.

- Expenditure on large scale relocations was similar to previous year's level. However expenditure on small scale relocation projects has increased reflecting greater level of activities by the Council. The overhead improvement programme was approximately $5 million below forecast due to project deferral.
- The expenditure in Routine and Preventative Maintenance was $1.4 million over the forecast level while the expenditure in the Refurbishment and Renewal Maintenance category was $1.4 million below forecast. This is in part due to some activities being re-categorised between these two expenditure categories, and in part due to reprioritization of some activities.
- Faults and Emergency Maintenance was $1.7 million below budget due to a lower fault incidence in the period than originally allowed for.